The Lines Company Limited

ASSET MANAGEMENT PLAN

2015

Copies of this plan are available at www.thelinescompany.co.nz

Cover photograph:

TLC Contracting staff performing pole replacements on the Taharoa A Line and Coast Feeders.

Schedule 17

Certification for Year-beginning Disclosures

Clause 2.9.1 of section 2.9

We, Angus Malcolm DON and John McFadyen RAE, being the directors of The Lines Company Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) The following attached information of The Lines Company Limited prepared for the purposes of clause 2.4.1, clause 2.6.1 and subclauses 2.6.3(4) and 2.6.5(3) of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

26 MARCH 2015	26 MARCH 2015
Date	Date
Signatory A	Signatory B

Contents

Glossary

ABS..... Air Break Switch
AC..... Alternating Current
ACSR..... Aluminium Conductor Steel Reinforced
Al..... Aluminium
AMG..... Asset Management Group
AMP ..... Asset Management Plan
CAPEX ..... Capital Expenditure
CPI ..... Consumer Price Index
Cu..... Copper
DC ..... Direct Current
DG ..... Distributed Generation
DGA..... Dissolved Gas Analysis
DOC..... Department of Conservation
Dy..... Delta-star
EGCC ..... Electricity and Gas Complaints Commission
ETAP..... Electrical power system analysis software
GIS..... Geographical Information System
GXP ..... Grid Exit Point
HSE..... Health and Safety in Employment (formerly OSH)
ICP..... Installation Control Point
KCE..... King Country Energy
LDC..... Leased Direct Circuit
LV ..... Low Voltage (400 Volts)
MDI ..... Maximum Demand Indicator
MD ..... Maximum Demand
MRP ..... Mighty River Power
ODV..... Optimised Deprival Value
PILC ..... Paper Insulated Lead Cable
POS ..... Point of Supply
RAB ..... Regulatory Asset Base
RAL..... Ruapehu Alpine Lifts Ltd
RCPD ..... Regional Co-Incidental Peak Demand
RTE..... A type of internal rotary transformer switch
RTU ..... Remote Terminal Unit
SAIDI ..... System Average Interruption Duration Index
SAIFI ..... System Average Interruption Frequency Index
SCADA..... Supervisory Control and Data Acquisition
SMS..... Safety Management System
SWER..... Single Wire Earth Return
TDMA..... Time Division Multiple Access
TLC ..... The Lines Company Ltd
UHF ..... Ultra High Frequency
VHF ..... Very High Frequency
WACC..... Weighted Average Cost of Capital
XLPE ..... Cross-Linked Polyethylene Cable
Yd..... Star-delta
YY ..... Star-star

STANDARD UNITS AND PREFIXES

m	milli	(x 10^{-3})
k	kilo	(x 10^{3})
M	mega	(x 10^{6})
G	giga	(x 10^{9})
A	amperes (AMP)	Current
g	grams	Weight
Hz	hertz	Frequency
m	metres	Distance
m/s	metres per second	Speed
N	newtons	Force
V	volt	Voltage
VA	volt-amperes	Apparent power
W	watts	Power
Wh	watt-hours	Energy

VARIANCE CALCULATIONS

For the purposes of the AMP, variance has been calculated as follows:

$$\text{Variance} = \frac{(\text{Actual} - \text{Target})}{\text{Target}} \qquad \text{which may also be written as} \quad \left(\frac{\text{Actual}}{\text{Target}}\right) - 1$$

When actual results are better than expected, the variance is deemed favorable and preceded with an (F).

When actual results are worse than expected, the variance is deemed unfavorable and preceded by (U).

Section 1

1. Executive Summary

1.1 Asset Management Strategy

Strategically TLC is focused on ensuring that its assets are performing and producing the necessary returns for stakeholders whilst exceeding customers' service expectations and ensuring the network is hazard controlled with respect to staff and the public.

To achieve this TLC will focus asset management to meet a required level of service, while considering risk, in the most cost effective manner, through the effective management of assets for the present and the future. Safety has always been at the forefront of TLC asset strategy and will continue to be part of TLC's long term strategy. This can be seen in the extensive renewal programme detailed in the AMP.

1.2 Purpose of the Asset Management Plan

The purpose of Asset Management Plan (The Plan) is to manage the asset portfolio in the most cost-effective and sustainable manner to meet the requirements of stakeholders as reflected in the Statement of Corporate Intent. This sets guiding principles for The Lines Company (TLC) of continuing to invest in the distribution network:

- to minimise and/or eliminate hazards;
- to meet reliability targets;
- in a manner that keeps charges as affordable as possible.

The Plan provides a formal performance monitoring and reporting framework to demonstrate TLC is meeting its statutory obligations under the Electricity Act 2010. The Plan is drafted to comply with the Electricity Information Disclosure Requirements 2012, Decision No. NZCC 22 and covers the period 1st April 2015 through to 31st March 2025.

1.3 The Network Assets

The TLC network has many contrasts and includes:

- Single wire earth return systems (SWER).
- A direct connection to two major generators upstream of the Transpower grid exit (Atiamuri, Whakamaru)
- A generator directly connected to an energy park network supplying energy intensive industries.
- Distributed generation connections.
- A number of large industrial connections.
- A declining population base.
- A rugged rural environment.
- High number of necessary zone substations.
- Long lengths of 33 kV lines in mainly rugged and remote areas.
- Long lengths of privately owned 11 kV lines connected to the network.
- Approximately 30% of TLC assets are used to supply remote customers.

The network covers the area shown in the illustration below.

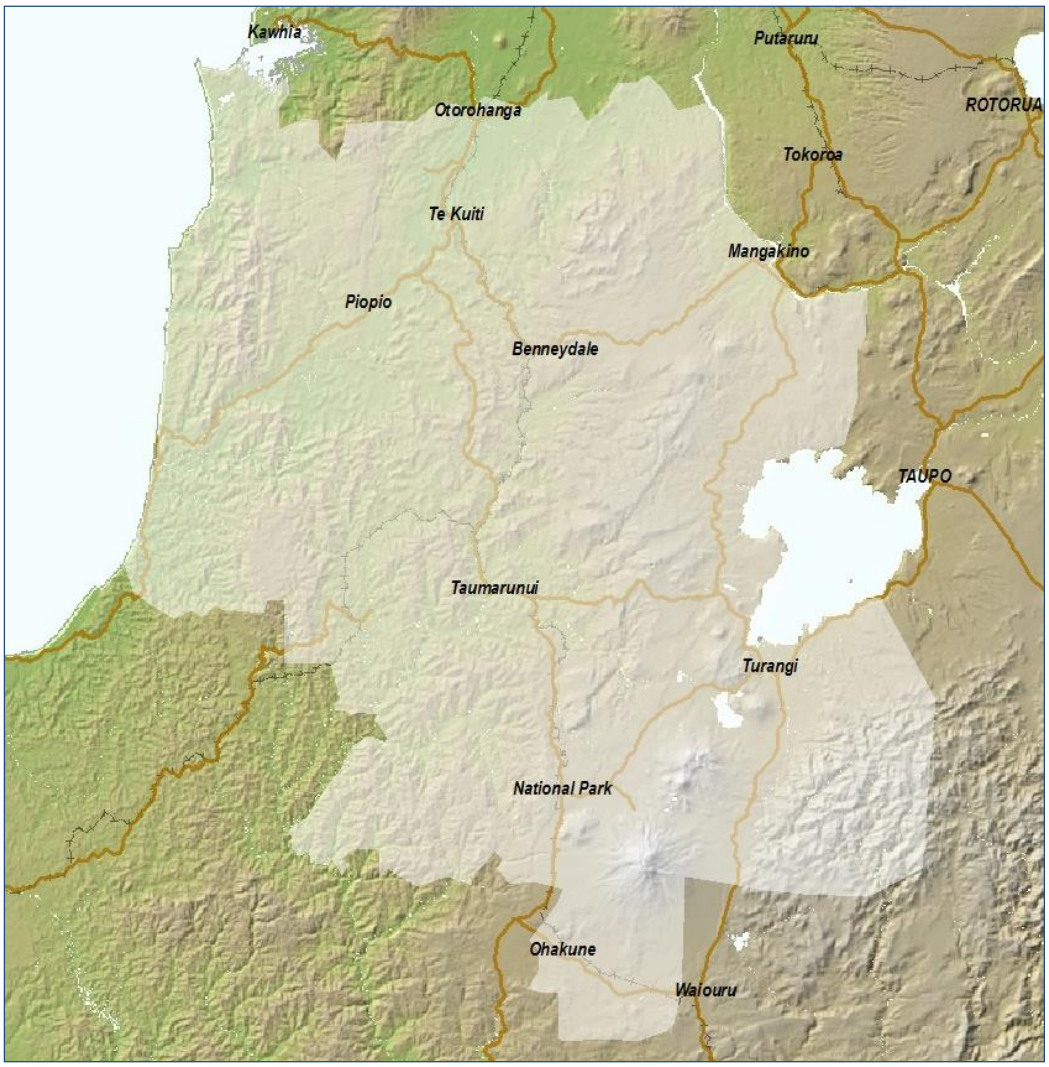

FIGURE 1.1.1: AREA OF NORTH ISLAND OF NZ WHERE TLC ASSETS ARE LOCATED

The assets have a regulatory value of $176 million (Valued using March 2014 Information Disclosure). The weighted average remaining life of fixed assets is 31.4 years (Electricity Line Businesses 2014 Information Disclosure compendium, PwC).

The two original networks that now make up the TLC network did not experience the large asset renewal programme that most networks in New Zealand experienced in the 1970's. The network has experienced low growth over recent years and there has consequently been no reason to invest in large amounts of new assets. There has been no renewal 'by product' effects from the extensive growth many networks have experienced.

There are no large urban centres in the area covered by TLC. This has the following implications:

Firstly, there is limited ability to cross-subsidise rural supplies. Rural customers must therefore be exposed to a price that is closer to the cost of supplying them than is traditional in other parts of New Zealand.

Imposing the renewal costs of all TLC's uneconomic lines, most of which were originally funded by grants from the Rural Electricity Reticulation Committee (RERC), on TLC's customers as a sole funding source means that urban customers will face line charges above the cost of supply. The deprived urban areas cannot sustain substantial price increases to fund this work.

It is important that the income from the towns is not simply used to subsidise rural supply, leading to the towns themselves receiving a substandard supply. The strongest domestic growth in the region is from

holiday homes. There has been a lack of investment in some of these towns in the past. Investment in the infrastructure for these towns, especially Ohakune and Turangi, has been significant in the past ten years, and continues to feature in this Plan.

Renewals will increase the values of these assets and thus revenue requirements. To minimise this effect renewals need to be aligned closely to depreciation. Assets have to be managed in a way that fulfils hazard control requirements, produces the optimum service level and minimises the value increase. This is reflected in our segment-by-segment approach to asset development, renewal, and maintenance, and our commitment to greater information flows to our customers.

1.4 Network Performance

The performance of the TLC network has been steadily improving as the renewal programmes embarked upon in the mid-2000's are having the desired effect. Figure 1.3A and 1.3B show the historical data for both SAIDI and SAIFI along with TLCs performance targets. Transpower related outages are not included in these illustrations. Outage performance has stabilised around the target of about 307 SAIDI minutes.

FIGURE 1.3A: 2002-2014 TOTAL SAIDI (EXCLUDING TRANSPOWER)

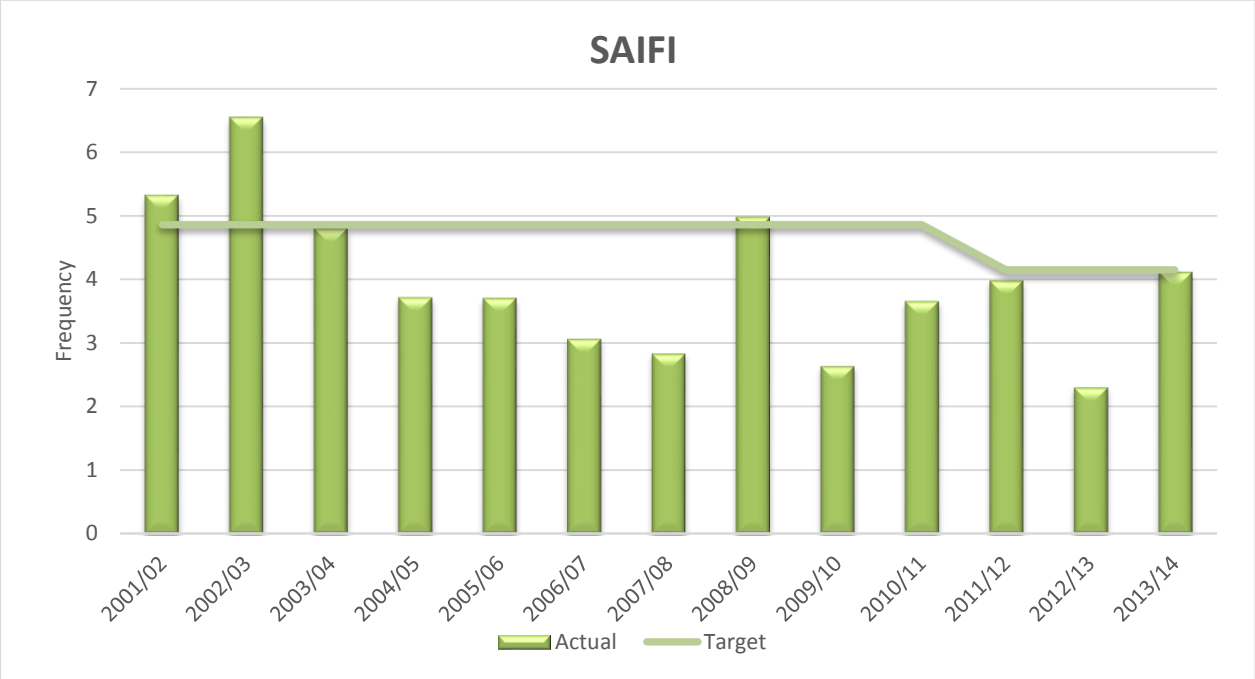

FIGURE 1.3B: 2002-2014 TOTAL SAIFI (EXCLUDING TRANSPOWER)

The Commerce Commission Default Price-Quality Path (DPP) 2015-2020 has reset the levels of quality standards to be met. In addition, amendments to input methodologies have introduced new revenue-linked quality mechanisms (the Incremental Rolling Incentive Scheme, IRIS). Both of these regulations will come into effect on 1 April 2015.

The SAIDI and SAIFI limits from 2015 are set at one standard deviation above the 10-year historical average, which is the same for the SAIDI and SAIFI caps under the quality incentive scheme. The new regulatory SAIDI and SAIFI targets and incentive limits are outlined in Table 1.1 below. These SAIDI and SAIFI totals emphasise unplanned outages with planned outages being weighted at 50%. To limit the impact of severe weather events on the annual reliability measures the maximum daily SAIDI or SAIFI figures are limited to normalised values of 10.97 SAIDI minutes and 0.144 SAIFI.

REGULATORY TARGETS AS AT 1ST APRIL 2015			
	Collar	**Target**	**Cap**
SAIDI	**183.4**	**208.8**	**234.2**
SAIFI	**2.67**	**3.07**	**3.47**

TABLE 1.1: RELIABILITY TARGETS

Figures 1.4A and 1.4B show the effect of the new calculation method for both SAIDI and SAIFI using the previous 5 years as an example. This shows that the new methodology will not cause significant changes to reliability targets.

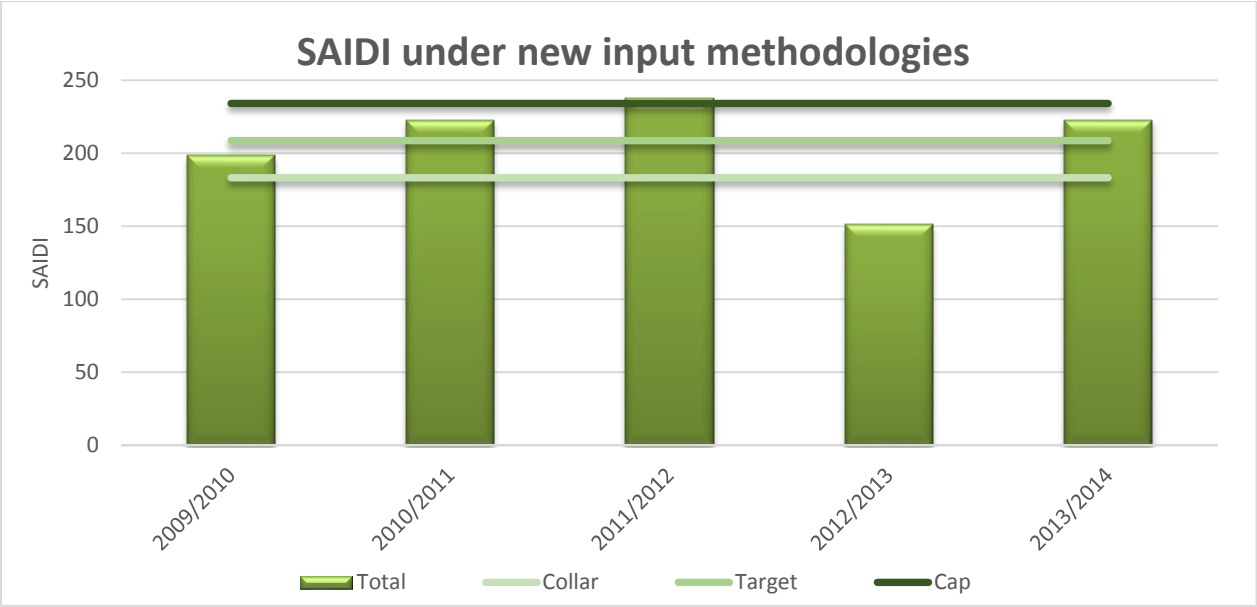

FIGURE 1.4A: 2009-2014 SAIDI CALCULATED USING INPUT METHODOLOGIES FROM THE 2015 DPP

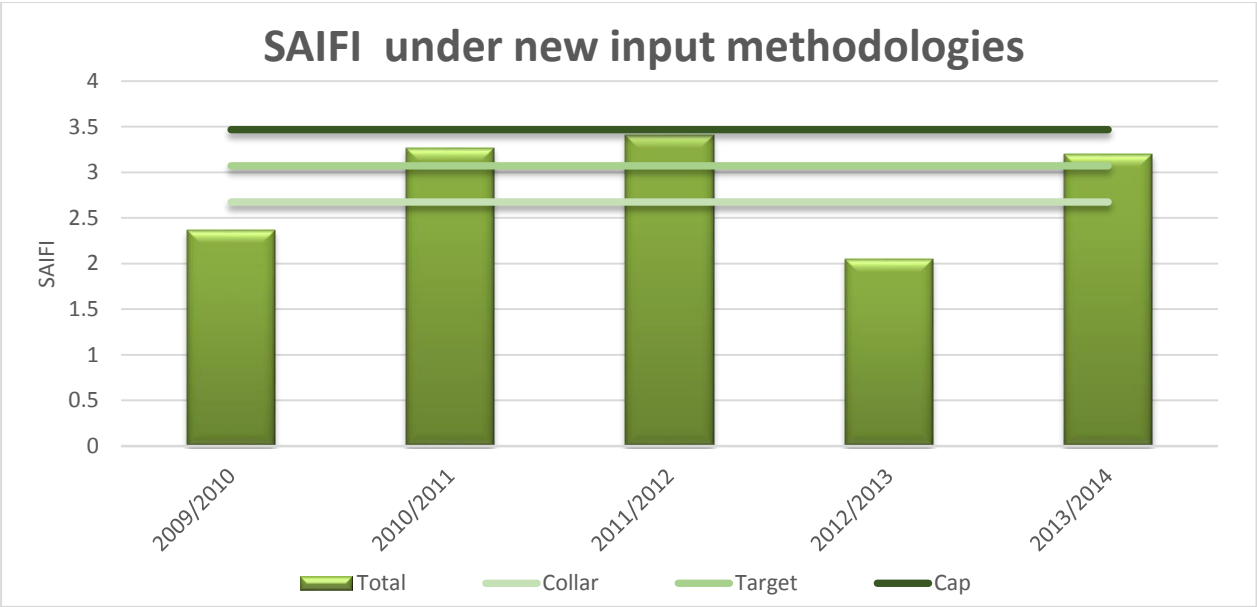

FIGURE 1.4B: 2009-2014 SAIFI CALCULATED USING INPUT METHODOLOGIES FROM THE 2015 DPP

Both SAIFI and SAIDI are sensitive to threshold compliance due to the nature of the TLC network. SAIFI will be driven up at a greater rate as opposed to SAIDI during periods when extensive use of generator by-pass for planned outages is used and extensive switching occurs during unplanned events.

The key to the long-term control of the indices is an effective renewal and maintenance programme. The first phases of the TLC renewal programme were focused on replacement of failing and aged equipment, poles in particular. This generally has had the most impact on SAIDI as durations of outages are influenced by the time it takes to replace failed assets. The counter to this is an apparent increase in SAIFI in recent years. When combined with the new regulatory targets, these results will require some change in emphasis on renewal plans.

To control SAIFI outages have to be limited to less than a minute. This necessitates more of an ability to restore power and isolate faults remotely but also potentially automatically, requiring investment in "smart-grid" style control systems and equipment. For a largely rural network of sparse population, the outcomes of balancing further quality improvement (driven by Regulators) with this style of investment will need to be evaluated carefully in coming years. TLC is keeping close track on the technologies becoming available in this field, in particular the wave form type detection technologies that it believes will be more suited to a rural network.

In previous years, TLC had been contemplating undertaking a Customised Price-Quality Path (CPP) application in order to vary the SAIDI and SAIFI limits. The intention was that by gaining customer feedback on acceptable reliability targets, TLC could contain or reduce expenditure requirements and therefore costs to customers. After weighing the potential costs of a CPP process against the benefits to be gained, this course of action was curtailed in favour of retaining the application funds in the renewals and maintenance programmes.

1.5 Network Challenges

Environmental factors including lahars, storms, plantation trees, earthquakes, floods and snow all present risks to the network. There are large sections of the network that were constructed after the Second World War years by farmers to supply remote areas. These installations were fit for purpose at that time and were constructed at low cost. They inherently have a lesser ability to withstand extreme weather events than more expensively constructed and resilient networks.

Vegetation and other maintenance/renewal programmes are essential for getting these installations to perform to present day expectations with an acceptable level of hazard risk. Feedback from customers suggests that most are happy with the performance of the network over the past few years, and instead are looking for other benefits, such as ways to control costs. Some customers are also asking for under-grounding in holiday areas. Allowances in this Plan include replacing any aged, high risk, low voltage systems in holiday areas with aerial bundled conductor reticulation. Additional funding to go to the next stage of undergrounding would have to come from an external source.

The network area also encompasses significant energy generation resources. There are currently over 25 distributed generation machines connected. Applications for new generation connections are increasing, and many of our projected constraints are caused by the limited ability of our network to receive the projected injection. Much of the generation is at remote sites and is utilising TLC's extensive 33 kV network. In some situations, it is possible that high load customers will leave the areas, meaning that the cost of renewing and supporting distant sections of the 33 kV network will possibly need to be supported by these generators. This will lead, in some cases, to uncertainty in pricing levels.

With any aged assets, issues of hazards and their attendant risks arise. It is our first priority to eliminate or mitigate any hazard that comes to our notice that has a high probability of causing serious harm to either employees or members of the public. Recent AMPs and works programmes have addressed high-risk hazard issues. New Zealand Standard 7901:2008 provides for further documented proof that all practicable steps are taken to prevent *"serious harm to any member of the public or significant damage to property from electricity generation, transmission or distribution network assets, and the operation of these assets*." The Plan includes allowances for the completion of the high-risk improvements, and all of the medium and known lower risk issues will be addressed through the planning period.

Engineering resources have been constraints in the past, but a combination of additional staff, and existing staff up-skilling, is taking place in the engineering and asset management area to address this. Any work, whether it is maintenance, renewal or development, needs to be adequately designed if it is to be cost effective. Unfortunately, there are limited resources within New Zealand that have an understanding of the problems of remote rural networks, and experience can only come over time. The additional engineering resources and the upward pressure on salaries for these people, given the unduly wide shortage, has meant an increase in costs.

1.6 Expenditure Forecasts

The projected direct maintenance expenditure for the planning period is shown in Figure 1.5. (The figures are adjusted for inflation).

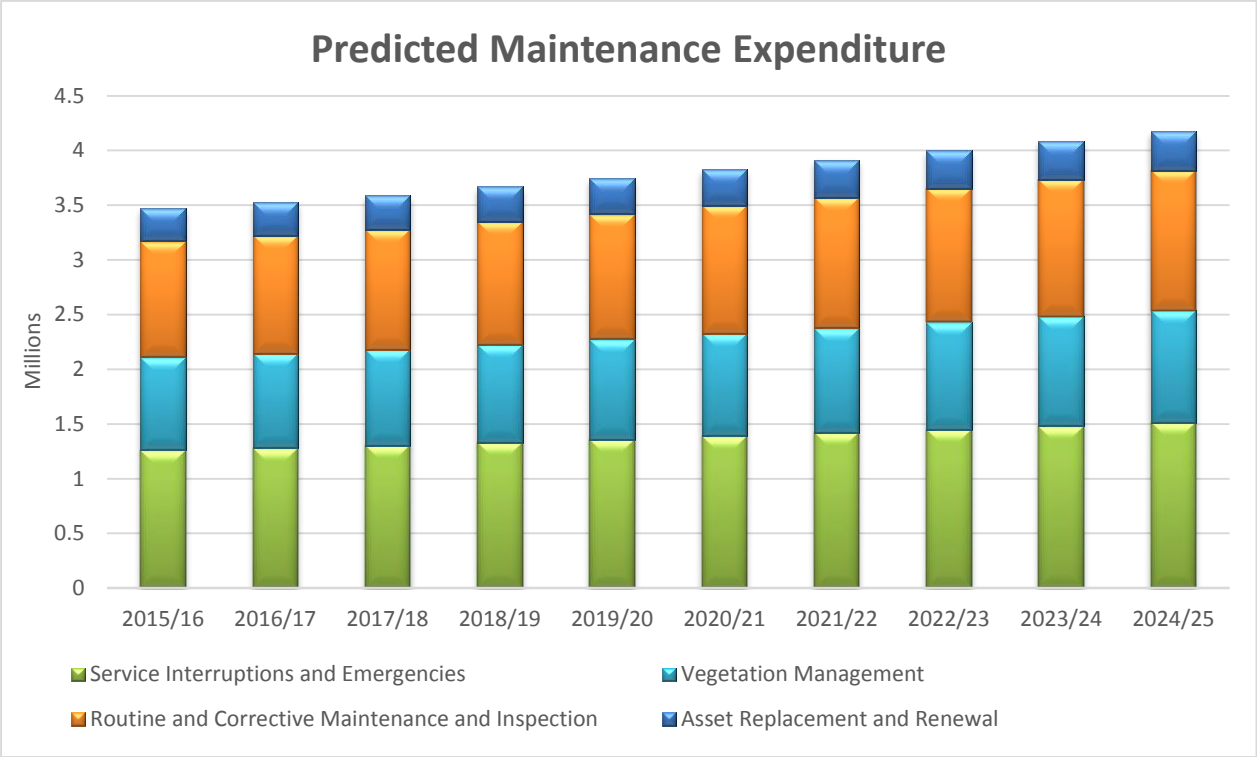

FIGURE 1.5: FORECAST DIRECT MAINTENANCE EXPENDITURE

Maintenance expenditure is expected to remain relatively stable over the planning period. The single highest cost included in maintenance expenditure is vegetation control. This has involved the issuance of many second cut and trim notices and completing three yearly inspections of the network. Customers are generally co-operating in either trimming trees, or they allow TLC to do total removals. There are on-going problems with plantation trees and often the owners of these contest TLC's right to have lines on their land (pre-1993). The damage by plantation trees adds substantially to TLC's overall operating costs and impacts substantially on reliability.

The core elements of maintenance expenditure are

- Inspection condition monitoring of overhead lines, line equipment, zone substations and associated equipment.
- Routine and corrective maintenance of zone substations and associated equipment.
- As mentioned above vegetation control.
- Inspection and corrective maintenance of zone substation and distribution transformers.

Figure 1.6 illustrates forecast capital expenditure for the planning period in 2014/15 dollars including adjustments for inflation.

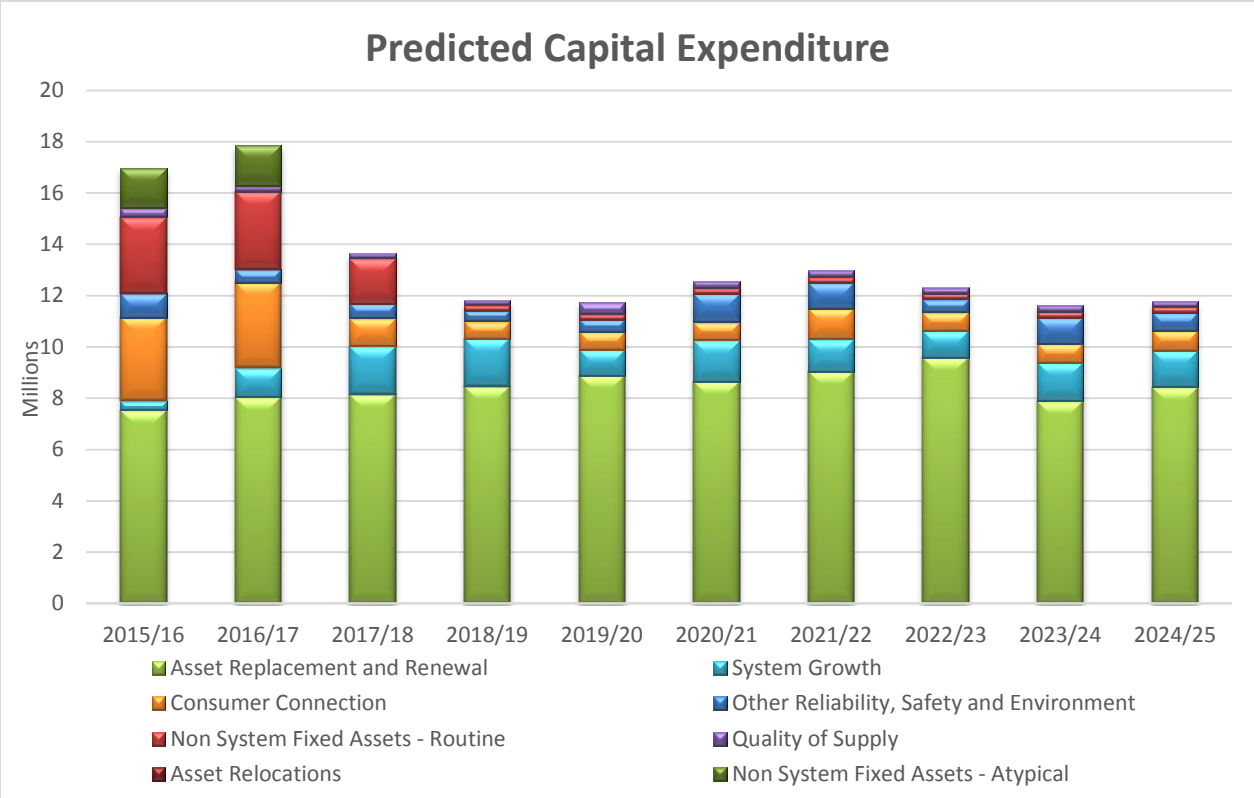

FIGURE 1.6: FORECAST CAPITAL EXPENDITURE

The Capex predictions are based on renewals to meet the hazard elimination/minimisation, reliability, and quality expectations of stakeholders and allow the levels of growth that are expected. The estimates are the sum of actual projects and contingencies have been included only for unknown reasons such as emergent repairs and renewals that are necessary to keep the system operating.

An assessment of the performance and age profile of network assets has emphasised the need to renew assets (particularly for overhead assets) as an increasing number of our assets reach the end of their service lives. The key drivers of replacement and renewal are:

- Expectation of continued line renewal work over the next 5 years.
- Automated switch installation.
- Half-life servicing of zone substation transformers
- Replacement of zone substation bulk oil breaker.
- Replacement of ground mounted transformers that have reached their end of life.
- Replacement of 2 pole structures that have height related hazards.
- Renewal of rapidly deteriorating of cables in urban area.

Capital expenditure in the first two years of the planning period are higher than the remaining planning years. This is due to budget allocations for the following items;

- The expansion of the Taharoa site to meet a customer's needs and the repair/rebuild of the King Street office (Customer Connection and Non-system Fixed Assets – Atypical categories above);
- Cable renewal due to a number of cable failures that have impacted network reliability. Allowance has been made in the plan to begin cable renewal in the Turangi and Whakamaru areas.

1.7 Network Growth

Network growth is driven either by subdivisions for holiday homes, lifestyle blocks, commercial development, and by the plans of our major customers. Apart from the western coastal area and the Western Bays of Lake Taupo, the subdivision growth is generally close to the sub transmission network. The growth itself is cyclic and uncertain. TLC cannot afford to carry assets that are substantially underutilised. TLC therefore has a low organisational appetite for planning risk, investing instead in the resources to maintain a close contact with the customers, and other drivers of growth, so that we can ensure that network development occurs only if, and when, it is required to produce revenue.

Growth is funded from borrowing, as the revenue stream from the growth should meet the borrowing costs. This approach means that customer growth is not constrained by funds.

The capacity of two of the supply point transformers will exceed either N or N-1 capacity limits during the planning period. It is fortunate for TLC that at both these sites the transformers are up for renewal and it will likely be possible to increment the size of these transformers at minimal cost to TLC customers i.e. the cost difference between a 20MVA or 40MVA transformer is relatively small given they have to be renewed any way.

Much has been said about alternative supply solutions; however, work completed by TLC and other independent bodies shows that these technologies are not advanced enough to meet the needs of busy farmers who are focused on maximising the efficiency of their enterprises.

The reality is that these supplies can be suitable for short term operations such as woolsheds but they do not provide the convenience most customers expect from a power supply. Most lifestyles require a supply reliably available on a 24 hours a day, seven days a week basis. This has been further cemented by the requirement for environmental reasons for farmers to fence water ways. A typical dry stock farm needs 4500 to 5500 stock units to be economic in today's trading environment. These stock numbers result in a daily water need of about 45,000 to 55,000 litres that has to be pumped. Alternative power supplies to cope with supplying the amount of energy to achieve this outcome are relatively large.

The costs, particularly of solar cells, have reduced over the last few years; however, economic analysis shows that they are still a distance away from competing against present energy rates (excluding lines chargers). TLC is continually monitoring these technologies and is recommending them to customers when they are more economic and capable of producing similar lifestyle or enterprise outcomes.

1.8 Asset Management Development

TLC is now revisiting where its asset management capabilities should be with a view to developing an appropriate improvement plan in the upcoming year. As part of revisiting its asset management capabilities TLC has engaged external consultants to review the following areas;

- Project management
- Benchmarking review
- Asset management review
- Health and safety review

The results of the review have highlighted a number of areas in which TLC requires improvements; these will form the basis of the improvement plan.

The main areas identified for improvement are:

- Ability to clearly demonstrate the cascade between corporate goals and strategies with asset management objectives & AMP's; through to activity objectives and subsequent service levels and performance measures.

- Sufficient and appropriate data to sustain a complete decision making process (including better understanding of network reliability).
- A decision making & prioritisation framework based on multi-criteria (ODM) analysis process, that satisfies the technical diversity required for the electrical activity and processes while maintaining consistency with customer, community and regulatory requirements.
- Understanding of asset/network risk profiles and have the ability to demonstrate the impacts / 'trade-offs' on Levels of Service (Los) and risk exposure through different funding scenarios.
- The ability to more accurately forecast new capital, renewal / replacement & maintenance programmes using criticality, risk & condition-based assessments.
- The ability to forecast the expected Levels of Service for a 10 year period (based on funding scenarios for prioritised programmes of work).
- The overall development and implementation of capital, operational and maintenance strategies and programmes that provide a clear link to levels of service and strike a balance between performance, risk and cost.
- An integrated asset management system/s to govern the planning, investment, operation, maintenance and disposal of assets, supported by technology and people.
- Asset Management documentation that clearly articulates AM policy and processes, with an improvement programme based on SMART objectives; and alignment with best practice (e.g. PAS55 & International Infrastructure Management Manual (IIMM)).
- Appropriate training and development for staff to align with and deliver best practice asset management.

Section 2

2. Background and Objectives

2.1 The Purpose of the Plan

The purpose of Asset Management Plan (The Plan) is to manage the asset portfolio in the most cost-effective and sustainable manner to meet the levels of service required by TLC's customers. To achieve this, the AMP provides the maintenance, renewal and replacement needs of the network assets. The AMP focuses on the next 10 years, providing guidance to the Asset Management Team to ensure they deliver the right activities in the right way and as efficiently and effectively as possible.

The Plan provides a formal performance monitoring and reporting framework to demonstrate TLC is meeting its statutory obligations under the Electricity Act 2010. The Plan is drafted to comply with the Electricity Information Disclosure Requirements 2012, Decision No. NZCC 22.

The goal of asset management is to meet a required level of service, while considering risk, in the most cost effective manner, through the effective management of assets for the present and the future.

Asset management planning is the means of planning and understanding the assets:

- What they are
- Where they are
- What condition they are in
- How much they are worth
- What level of service is expected of them and at what cost
- How they are performing
- What are the risks of failure?
- What extra capacity they have
- What capacity is required in the future?
- When they need to be replaced/upgraded
- What the cost will be to replace/upgrade them
- What the non-asset solutions are
- What options are available?
- What further works are required to meet future demand?
- What improvements are programmed?

2.1.1 Principles and Practices

TLC uses asset management principles and practices to achieve these tasks. The key features of infrastructure asset management are:

- A whole-of-life asset management approach
- Planning for a defined level of service
- Performance monitoring
- Meeting the impact of growth through demand management and infrastructure investment
- Managing risks associated with asset and service failures
- Sustainable use of physical resources

- Continuous improvement in asset management practices.

Asset management planning will inform TLC's capital investment decisions for new assets as well as expenditure for the operation, maintenance and renewal/rehabilitation of existing assets.

2.1.2 Benefits

TLC recognises the following benefits are gained through the effective implementation of asset management principles:

- Good governance and asset stewardship
- Good knowledge of customer and stakeholder requirements now and going forward
- Legislative compliance
- Good asset knowledge including the condition and performance required to deliver services
- Good knowledge of the risks associated with assets
- Good management of asset knowledge
- Good knowledge of what is required to provide services sustainably.

The application of asset management principles encourages a holistic, integrated approach to guide where and how finances and resources are allocated.

2.1.3 Current status

The Plan has been continually developing and has become one of the key internal planning documents. The importance and significance of the document has been increasingly recognised by stakeholders, regulators and staff. TLC has focused efforts on bringing systems, data and knowledge into a common framework. The challenge over the next few years is to improve asset management decision-making through optimisation of networks, levels of service analysis, risk management and lifecycle costing.

2.2 Relationship with Other Planning Functions

The Plan aligns to and is part of TLC's asset management policy and forms a significant part of the asset management strategy. Figure 2.1 illustrates the documents and papers that have a relationship with the writing of the AMP.

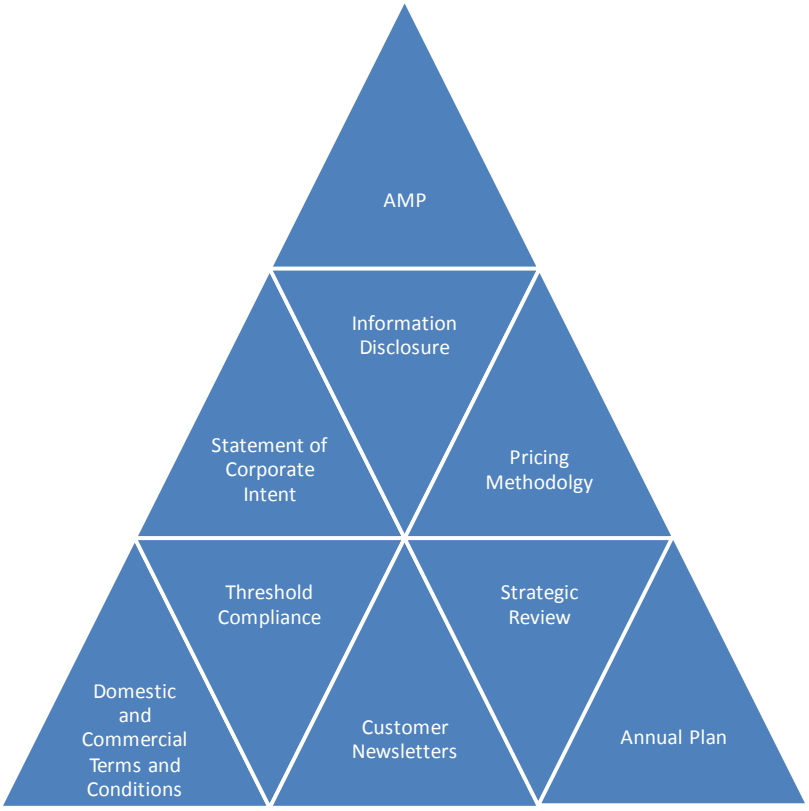

FIGURE 2.1: RELATIONSHIP PYRAMID OF AMP

The organisations core values are to keep our customers connected and it will deliver this service with unyielding pride and be passionately focused on driving customer success in a culture of constant innovation, excitement, informality, team work, trust, hazard control and environmental focus. TLC believes that by adopting this mission it can develop a long-term sustainable business for the benefit of its owners, while giving its customers an energy supply that is as reliable, secure, sustainable and efficient as is practicable in the circumstances.

In order to deliver a strong sustainable network TLC will continue its investment in network renewal and development. It will use innovative customer billing and engineering to encourage demand side management and other network tuning to maximise network utilisation and minimise, as far as practical, customers' combined network and energy costs. To achieve these ends, TLC recognises it must excel at the following:

- Asset management including strategy development and implementation.
- Pricing structures that promote energy efficiency, the reduction of network energy demand and better asset utilisation.
- Customer consultation and promotion of demand side management.
- Demand side control systems and advanced metering.
- The investigation and promotion of network alternatives; as appropriate.
- Asset renewal and hazard control programme management including SMS strategies compliant with NZS7901:2008.
- Network analysis/automation and the intellectual learning needed to develop advanced systems.
- Innovation in all aspects of the business.

- Completing works in a manner that minimises costs whilst meeting stakeholder quality expectations. This includes informing customers of the trade-offs associated with energised versus de-energised work.

2.3 Key Planning Documents and Processes

Listed in Figure 2.1 are the documented plans that are produced as a result of the annual business planning process

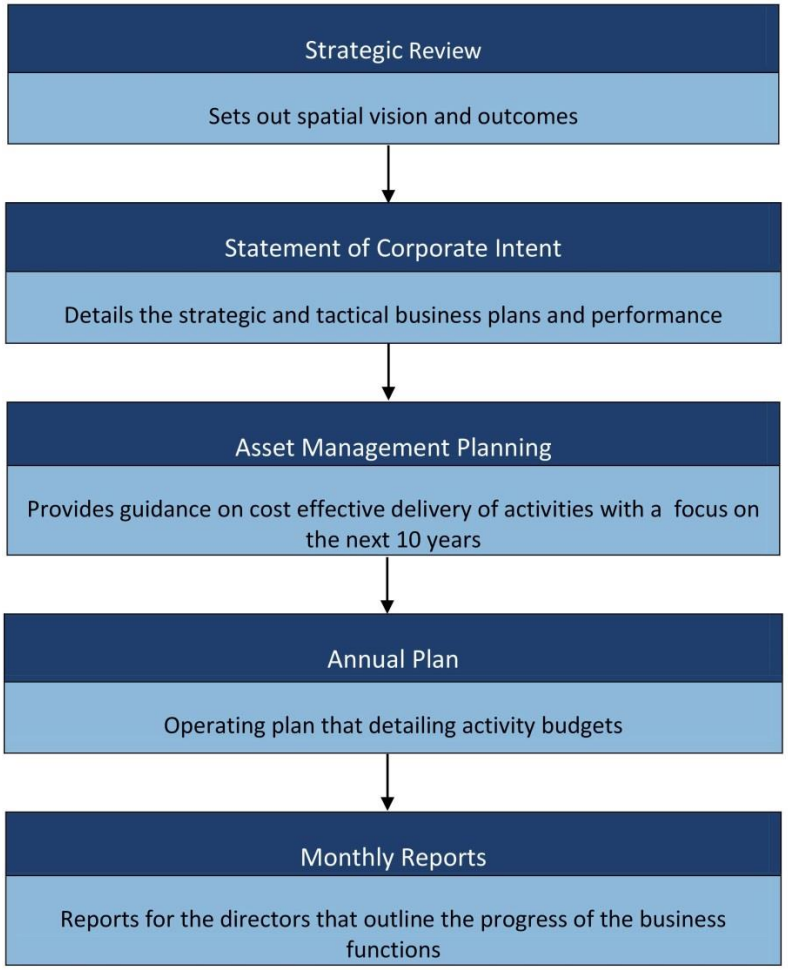

FIGURE2.1: DOCUMENTED PLANS PRODUCED AS OUTPUTS OF THE ANNUAL BUSINESS PLANNING PROCESS

The documented plans that are produced as a result of the annual business planning process include:

- Strategic review outlines the business activities that TLC is involved in and contains high-level details on the business environment and the planned strategies for these areas of activity. This document is approved by Directors.
- Statement of Corporate Intent is prepared in parallel with the strategic review and contains more detail. This document is approved by Directors.
- Asset Management Plan (AMP) covers the major investment owned by TLC. It provides guidance on the cost effective delivery of activities with a focus on the next 10years. This document is approved by Directors.
- Annual Plan/Budget is an operating document that details the activity budgets approved by Directors. This is prepared in parallel with the Asset Management Plan.
- Monthly Board Reports update the Directors on progress against the plan and details other issues that they need to know and/or approve.
- Annual pricing reviews are approved by the Directors and relates closely to the above documents.

2.4 The Planning Period

This Plan is approved by the Board of Directors; it covers the period 1st April 2015 through to 31st March 2025. The Plan is reviewed annually, although there is now provision under Information Disclosure regulations to only produce an update document in specific years.

It needs to be acknowledged that the TLC network covers a large area with low population densities. There are no fast growing urban areas. The growth of the network in the planning period will be dominated by the primary processing industrial sector, farming, holiday homeowners, a few lifestyle blocks and distributed generation demands. These are highly unpredictable. This, coupled with both the low existing return on the network assets and the unwillingness of many customers to pay more, means that investment in growth normally occurs once customer commitment to load growth becomes certain.

The unpredictability of the investment due to customer growth means that the difference between medium and long term forward predictions and actual will vary. Assets needed to support a customer's specific need can only be added when customer contractual details are confirmed.

The time scale needed for projects to be completed is also increasing due to a number of reasons, including landowner awareness, regulatory consenting and available skilled resources.

It is recognised that the accuracy of short to medium term plans is better than the long-term projections. TLC has however put considerable effort into trying to get the best long-term picture possible of future network expenditure and the justification for this. This is required for pricing continuity, i.e., the need to minimise stepped changes.

Table 2.1 lists the expenditure categories as per disclosure requirements and outlines the level of detail taken into consideration in preparing estimates within the various timeframes.

LEVEL OF DETAIL AND EXPECTED CAUSES OF FLUCTUATIONS IN ESTIMATES	
Disclosure Expenditure Category	**Recognition of Accuracy**
Capital Expenditure	
Customer Connection	Difficult to predict. Driven by levels of economic activity.
System Growth	Affected by customers. Predictions reasonably accurate for the next 5 to 10 years given present constraints identified by network studies. Is dependent on forecasts. New technologies such as advanced networks and small scale generation may also impact on this.
Asset Replacement and Renewal	Reasonable level of accuracy for the next 5 to 10 years. Data out to 2025 also contains a reasonable level of accuracy. Variation will come from levels of hazards and risks stakeholders are willing to accept. (The estimates are based on the general condition known and determined by patrols of the assets. Detailed estimates are put together for the ensuing year) Estimates for line renewals are generally based on 10% of poles in first 15 year cycle needing renewal. Analysis shows that approximately 30% are not compliant with strength codes. If stakeholders want the 30% replaced, costs will be greater than the estimates included in this plan. Generally, estimates should be within ±10% for the next 10 years and ±15% for remainder of period.
Quality of Supply	Estimates out to 2025 are based on specific jobs and projects. Variation will come through the need to do something before planned dates because of failure or other issues. Because estimates are based on specific detail, accuracy levels will be relatively accurate, i.e. within ±10%.
Asset Relocation	Estimates are difficult due to the six months or less lead time (generally) associated with the need for alterations for road works and the like. The amount of expenditure however is not significant.
Non Network Assets	Estimates are reasonably accurate for the next 5 to 10 years based on specific jobs. Variation will come through the need to do something before planned dates because of failure or other issues.
Operational Expenditure	
Routine and Corrective Maintenance and Inspection	Estimates are based on present activities. Activities are known for next 5 years. Beyond this, various issues have not been detailed or studied at this time. For example, more work is needed on analysing the effects of the renewal programme on maintenance costs in the medium term.
Asset Replacement and Renewal Operating Expenditure	Estimates based on present levels and future renewal plans. (Definition on the actual detail of what can be included in this expenditure category will cause the greatest variation.)
Service Interruptions and Emergencies	Expenditure will fluctuate, mostly dependent on the weather. Over time, estimates are based on average expectations and the assumption that renewal and vegetation programmes will reduce fluctuations.
Vegetation Management	Estimates based on present levels , however it is possible for expenditure to fluctuate.
System Operation and Network Support	Estimates are based on present activities. Predictions reasonably accurate for the next 5 to 10 years.

TABLE 2.1: LEVEL OF DETAIL AND EXPECTED CAUSES OF FLUCTUATIONS IN ESTIMATES

Note: Estimates have been prepared based on the performance targets included in Section 4. The estimates and performance expectations align with the asset management strategy that takes into account the lifecycle of assets, asset types and asset systems.

2.5 Stakeholder Interests

In developing the Asset Management Plan, TLC has taken into account the interests of the following key groups outlined in the table below.

Stakeholder Interests			
Stakeholder	**Interests**	**How Interests are Identified**	**How Interests are Met**
Shareholders	• The business being sustainable in the long term and the strategies to achieve this. • Public relations are improving and complaints are reducing. • A reasonable standard of service being given to customers. • The price to customers being equivalent to that charged in other rural areas. • A network that meets acceptable industry hazard related risk standard as well as environmental and efficiency expectations. • The development of innovative solutions, focused on reducing hazards, maintaining reliability and promoting customer choice including demand side management while saving costs. • An acceptable return being earned from the assets. • An acceptable cash return from the network, as cash return is the only way that customers who are the beneficiaries of the trust can receive benefit from their ownership. (Customers leaving the area cannot	• The interests of our shareholders are identified through the Corporate Review process, director performance reviews and appointments, regular discussions, presentations and meetings.	• Strategic and tactical planning • Investment in public relations and demand side management. • Dividends and revenue aligned to Commerce Commission limits. • Regular meetings and communication with shareholders. • Adjustment of policies and pricing to be more aligned to customers' perceptions and expectations. • The requirement that any customer-driven development work produces at least its cost of capital. • Funding development work that is expected to produce future revenue by debt, rather than reducing cash returns to existing customers. • The performance targets • Strong, but targeted, re-investment in renewals to provide a long-term hazard controlled and sustainable network. • Charging systems that give choice to customers. • This asset management plan and the related strategies.

Stakeholder Interests			
Stakeholder	**Interests**	**How Interests are Identified**	**How Interests are Met**
Shareholders (continued)	receive cash for any capital growth they have funded while with TLC.)		• Communication of the key parts of the asset management plan and related strategies.
Customers	• Receiving a secure and reliable supply of known and agreed quality. • Receiving timely information that enables them to know the service they can expect from the network so that they can plan accordingly. • Receiving up to date information if an outage occurs on the network so that they can plan accordingly. • Being charged a fair price, with information to justify that price. (Individually most want to pay the least amount possible whilst the present quality is either maintained or improved.) • Long term, the lowest charges possible for present and slowly improving quality. • Receiving information updates on what is being done to ensure the network infrastructure is hazard controlled and sustainable. • Having choice to reduce charges by reducing demand/energy use and improving power factor.	The interests of our customers are identified through direct discussion with large customers, meetings with customer representatives (e.g. Federated Farmers), regional level focus group discussions, and day to day customer feedback.	• A corporate culture based around keeping customers connected and delivering this service with unyielding pride in the organisation and be passionately focused on driving customer success in a culture of constant innovation, excitement, informality, team work, trust, hazard control and environmental focus • The reliability targets that are as focused as possible. • By performance targets, including the asset group based performance targets (and evaluating gaps in this performance), to ensure each customer is receiving the promised standard of services. • Re-investment in renewals. • Strong customer consultation and information commitment including mechanisms to communicate key issues, impacts and strategies in this plan that are likely to affect them.

Stakeholder Interests			
Stakeholder	**Interests**	**How Interests are Identified**	**How Interests are Met**
Customers (continued)	• Having clear claim and compensation systems when TLC assets do not perform. • Having several pricing options available.		• Direct customer billing, including demand based charges for all customers. This signals demand, leading to fairer charging and better asset utilisation. • Customer and tradesman education. • Public meetings. • Supply point and density based pricing structure. • Dedicated asset charges. • Developing several pricing options to give customers more choice. • Rules for payment of compensation being included in the Terms and Conditions of Supply. • Keeping community groups and leaders informed on issues. • Establishing and maintaining regular meetings with customer focus groups. • Engaging local community people to assist customers to understand demand and other charges. • Engaging local community people to assist TLC follow-up and resolve customer concerns. • Developing customer focused systems and processes throughout the organisation. • A long term focus on energy efficiency and innovation.

Stakeholder Interests			
Stakeholder	**Interests**	**How Interests are Identified**	**How Interests are Met**
Customers (continued)			• A charging system that encourages retailer competition and minimises the opportunity for additional retail pass through margins to assist in giving customers the lowest possible combined line and energy costs.
Employees	• Advanced knowledge of work requirements so that they can plan their lives. • A network and working practices with acceptable hazard related risks so that they are not harmed. • Fair remuneration. • Enjoyable work. • Being part of an organisation with a positive culture. • Having a clear purpose for coming to work and "making a difference" for the benefit of customers and their personal development. • A safe working environment.	The interests of our employees are identified through direct discussion with them and their representatives.	• The high priority given to eliminating or mitigating hazards. • Adoption of SMS • Advanced planning of work. • The recognition that our staff have unique skills, associated with a rural network in a rugged environment. • Creating a positive work environment. • Communicating the long-term Asset Management Plan and Statement of Corporate Intent to them so they can understand company direction. • On-going development of innovative techniques and work practices. • Supporting personal development and training. • A continuous improvement asset management strategy driven by this plan.

Stakeholder Interests			
Stakeholder	**Interests**	**How Interests are Identified**	**How Interests are Met**
Transpower	• Protection of its Grid and the electricity system from harm caused by generation investors and load customers who are connected to the TLC network. • Receiving revenue from TLC. • Building capacity to meet present and future loads. • Complying with regulatory needs. • Improving public and industry perception.	Transpower's interests are identified through communication and direct discussion.	The interests are recognised in the Plan by the sums we have programmed for expenditure due to anticipated growth in distributed generation and load. A significant proportion of this is to ensure the protection of the Grid.
Contractors and Suppliers	• A secure work programme known sufficiently in advance so that they can plan their resource allocation. • A network and working practices that align with industry standard SMS hazard related risks, so that their staff members are not harmed. • A profitable work stream. • Prompt payment for goods and services. • A customer with a clear vision and defined needs so they can focus on producing the outcome.	Contractors' interests are identified through direct discussion.	• The high priority given to eliminating or mitigating hazards. • Advanced planning of work, particularly commitment to a long-term asset renewal programme. • Developed practices for receiving and paying accounts. • An asset strategy/plan that communicates supplier requirements.

Stakeholder Interests			
Stakeholder	**Interests**	**How Interests are Identified**	**How Interests are Met**
Landowners	• Protecting areas of heritage value. • Protecting amenity value. • Having their property treated with respect. • Protecting property values. • Having an electricity supply at a competitive rate, suitable for the activities on their land. • Clear understanding of asset management strategies and plans that affect their land.	Landowner issues are identified through discussion with their representatives (e.g. Federated Farmers), individual landowners, Maori landowners/trusts, customer service inquiries, landowner complaints, outage notifications and the pre-access land notification process. There is also feedback from the customer communications and consultation processes.	Cost conflicts are managed by using cost reflective charge rates and polices.
District Councils	• Growth in their community is not hampered. • Civil Defence capability is maintained. • Access to the road corridor is managed appropriately. • The electrical infrastructure delivers an acceptable electricity supply. • Customer dissatisfaction is minimised. • Asset management strategies are aligned to minimise reworking of road, footpath, and other services and disruption of further infrastructure assets such as water, sewerage and public lighting.	District Council interests are identified through direct discussion	Having sufficient infrastructure is accommodated in the Plan by the requirement that any customer driven development work undertaken produces the cost of capital at least. The Civil Defence requirement is accommodated in the Plan by identifying the risks, having plans in place to control these and being involved in various emergency preparedness planning groups. Access to the road corridor is accommodated in the Plan via the inclusion of allowances for forward spend plans and by virtue of having the AMP. The AMP is used to communicate and detail when works are proposed. Having infrastructure that produces acceptable quality of supply is accommodated throughout the Plan. Council's needs/policies.

Stakeholder Interests			
Stakeholder	**Interests**	**How Interests are Identified**	**How Interests are Met**
Regional Councils	Regional Council interests include protecting the environment and ensuring adequate emergency response. These interests are recognised in the environmental and emergency response sections of the Plan.	Regional Council interests are identified mostly by correspondence and written information.	The contact with regional councils is not extensive; however this Plan is used to communicate TLC's asset strategies and policies.
Central Government	Central government interests include ensuring that a reliable fairly priced, supply of electricity is available to the King Country and Southern Waikato regions and that the network has acceptable levels of hazard related risk. These bodies are aware of the existence of the AMP and often refer to it in communications that occur between the groups.	Central government's interests are identified mostly by internet correspondence, written information, meeting with officials, and legislation.	The interests are recognised through compliance, submissions and the direction required by the authorities. Conflicting interests occur when laws, regulations, policies and codes do not fit with TLC's or its customers' needs.
Retailers	Retailers are interested in selling energy to customers that produce profits. They like to have simple to apply pricing options via automated billing systems. They also want advanced metering systems that have a long term benefit of reducing their operating costs.	Retailers' interests are identified through industry papers, communication and direct discussion.	TLC has representatives on industry working groups associated with pricing and retailer interfaces. This Plan is used as the basis for communicating TLC's asset management strategies to these industry working groups.
Maori	Maori are interested in having supply available in their homes and Marae, which are sometimes located in very remote areas.	Maori interests (such as protecting cultural values especially with long tenure Maori land) are identified through discussions with various groups.	The Maori interests are accommodated in the Plan by the overriding objective of maintaining supply at the lowest possible cost whilst meeting quality expectations. The Plan also includes a commitment to use local labour as far as practicable to create income for people who may live in remote areas.

Stakeholder Interests			
Stakeholder	**Interests**	**How Interests are Identified**	**How Interests are Met**
Distributed Generation	• Connecting new plant at the lowest possible cost. • Operating plant at peak capacity when energy sources are available. • Having on-going costs as low as possible. • Minimising their investment in engineering resources to research potential problems and develop solutions. • Maximising their share of transmission avoidance credits. • Minimising investment in connection equipment. • Minimal planned and unplanned outage events.	Distributed generation investor interests are identified by way of new connection applications and the issues associated with the continuing operations of existing plant.	• Detailed information on existing larger connections and the implications of these. • Technical detail on the general implications of distributed generation connections. • A list of the conditions that must be fulfilled before connecting distributed generation equipment.

TABLE 2.2 STAKEHOLDER INTEREST IDENTIFIED AND HOW THEY ARE ADDRESSED.

2.6 Conflicting Interests that are Common and Affect All Stakeholder Groups

2.6.1 Hazard Elimination/Minimisation

Experience has shown that all stakeholders want a network, as far as practically possible, with an acceptable minimum level of hazards. Determining what is a hazard is not black and white and is constantly evolving as time goes on. As events occur, and expectations advance, safety codes are repeatedly re-written and re-drafted. This means that equipment, which was considered acceptable when installed, has over time been eclipsed by changed and improved modern equivalents. Technology has moved forward over time.

When growth occurs in a network, equipment is constantly replaced and updated. In the TLC network a lack of growth has meant that much of the old legacy equipment has aged and not been replaced as part of the natural growth cycle.

This leads to conflict between funding hazard elimination/minimisation work, and other renewal and capital expenditure work.

Fortunately, much of the renewal associated with hazard elimination/minimisation also improves security, reliability, and general network capacity. Available resources (particularly funding) tend to dominate the conflict as to how much can be done at once. (This funding is associated with the available revenue).

The conflict between an acceptable and unacceptable hazard is based on:

- Observations of obvious problems.
- Industry accident reports.
- The various Acts, Regulations and Codes that control the industry.
- The principles of equipment operation and the potential risk levels when things go wrong.
- Experience from investigating and being involved with various industry incidents.
- Review of equipment by suitable qualified and experienced professionals.
- Audits by the Energy Safety Inspectors.
- Asset management policies that promote a sustainable network including strategies/polices that take into account the lifecycle of assets and asset types.
- Feedback inter-relationship with the Safety Management System.

2.6.2 Electricity (Continuance of Supply)

Most stakeholders want TLC to have the lowest charges possible. The most significant influence on charges is the cost of maintaining and renewing rural lines.

The Electricity Industry Act 2010 was enacted and, amongst other things, repeals Section 62 of the Electricity Act 1992. Hence legislation now requires supply to be maintained to rural areas beyond 2013 via existing supplies or alternative supplies.

There was a change in the definition of the place to which supply has to be maintained. The funding for maintaining supplies has to come from other customers connected to the network.

Most remote rural lines were funded through a national Rural Electricity Reticulation Committee (RERC) levy on all electricity users. Research of TLC's, and national data, shows that about 1700 km of TLC's current 5000 km of lines were constructed using RERC funding.

Most of these lines were built in the 1950's as part of farm development for returning soldiers from World War II.

In TLC's case, the majority of these lines were constructed using sections of second hand railway track as poles. Most of these railway iron poles have given 50 years' service as rail tracks and a further 60 years plus as power poles. Many are now in poor shape.

Many of the rural lines were constructed by farmers, and there was little design detail. This has meant that many are low strength and do not comply with present codes. Many are SWER systems that have always had greater loadings than the codes of practice specify as the maximum acceptable limits. SWER lines, because of the way they work, are inherently higher risk than two or three wire systems.

TLC completed an exercise confirming the lengths of uneconomic lines in 2009. Lines were considered uneconomic if the load connected is less than 20 kVA per customer (ICP) and the customer density is less than three customers (ICPs) per km. This is the criteria as prescribed in the 2001 ODV handbook issued by the Ministry of Economic Development.

The network was analysed on a feeder-by-feeder basis. The customers in each of the uneconomic segments were also individually identified and the income and demand from them was summed.

The associated analysis showed the total assets required to supply these customers equated to 31% of the total asset value and produced 13% of the income. Time has elapsed since this work was done; however, the percentages of assets used to indicate the income required for supplying remote areas will have remained largely unchanged.

Further analysis showed that economic customers would have to subsidise the uneconomic customers by between 25% and 50% under the legislation. The amount would depend on the extent of cross subsidy.

Many of these rural lines supply national infrastructure in the way of repeater sites. Figure 2.1 illustrates one such site about 10km North West of Taumarunui with approximately 14 repeaters covering all types of essential services.

FIGURE 2.1: ILLUSTRATION OF HILL WITH NATIONAL AND LOCAL INFRASTRUCTURE

The actual costs of renewing the segments individually included in the long-term Plan have not been calculated or reconciled in detail at this time. In general terms however, the cost impact of renewing these lines is about $3m annually.

The Act gives the option of alternative supplies for these areas. The difficulty with this is that these technologies are not advanced enough to supply most of these customers with the convenience of a grid connection. Alternative power supply system's involve batteries, generators, etc. that need fuel and regular maintenance. Generators generally burn petro chemicals, make noise during operation and have limited life spans.

Plugging equipment into a grid supply is a much more convenient option for busy farmers. A similar situation applies to larger radio repeaters and water pumps in rural areas; alternative power supplies are not a realistic option at this time.

The conflicting interest options for TLC to fund this renewal are:

- Cross subsidies from economic residential, small commercial and holiday homes by about 50%.
- Cross subsidies from industrials to uneconomic customers.
- Charge uneconomic customers full costs.
- A combination of above.

Any of the options are difficult. Holiday homeowners do not want to subsidise rural property. Industrials do not want to subsidise rural property. It may drive them from the area. Uneconomic areas include many lower socio economic communities. Accommodating the conflicting interests is difficult and TLC is, at this time, focusing on developing its demand side management approaches to try and minimise the impact on rural customers.

The focus on the present to medium term is renewal; beyond this time, development will become the focus. Unless there are price adjustments, TLC will have difficulty doing both.

The introduction of separate billing has seen retailer price movements that are less than the rest of the country. The make-up of TLC's lines charges gives customers the option of reducing their costs through moving load without substantially affecting their lifestyles. Controlling demand and not needing to upgrade (for example, SWER systems) will have a long term saving on TLC's pricing to rural areas.

The need to maintain remote rural lines that were built with RERC subsidies, but now have to be renewed without them, is central to TLC's asset management challenge. This point has been communicated to all stakeholders including officials employed by regulators (some of whom have visited our area), customers, trustees and various lobby groups as part of TLC's asset management process.

2.6.3 Supply to Holiday Home Areas

There was a conflict between our shareholders requiring an adequate return on assets (with the revenue being received from holiday areas being well below what was necessary to produce a return) and belief by holiday homeowners that consumption based charges was a fair way of pricing. The previous way of managing the conflict was to reduce the level of investment. However this produced a service level that customers were not happy with. When holiday homeowners were given information about the structure and level of our costs and how they influenced them, including the Transpower peaks, overall their view of what a fair price was changed. This enabled us to introduce demand charges, which in turn enabled us to increase our investment in these areas with a resulting increase in service provided.

The energy based higher holiday home charges were superseded by the demand charges. Now holiday home owners pay for demand at the same rates as other customers. Holiday home owners, as a group, generally accepted demand based charges.

It is accepted that some holiday home customers have difficulty understanding the receiving of separate accounts for line and energy services when comparing this to charges for other properties they own. Most understand the separation when it is explained to them via the call centre or in consultation with customer advisors.

During mid-2011, two independent reports became available on the options TLC has for recovering revenue fairly from holiday homes. An extensive consultation process based on these reports was undertaken as part of the organisation's focus on asset management and getting funding to manage assets through their lifecycles in a long term sustainable way.

2.6.4 Retailers

Retailers want to take network line charges and repackage them as part of their marketing strategy. This masks customers' understanding of TLC's function and the services that line charges fund. It conflicts with TLC's and our stakeholders' objectives, who feel charges should reflect the cost of supply. Retailers can also add a margin for line charges onto customer accounts and keep penalties for late payments. This also negates demand side management messages that TLC wishes to pass on to customers.

To remove such negative influences, TLC charges the customers directly at a cost that is lower than margins charged by retailers for collecting TLC's revenue. This strategy places TLC in direct communication with customers regarding revenue and asset management and makes line charges totally transparent. This helps customers understand network issues and encourages competition amongst retailers. It also helps unbundle the issues associated with connecting distributed generation, promotes demand side management, signals power factor improvement needs and, along with numerous other benefits, improves asset utilisation.

This strategy is believed to have been part of the reason why retailers operating on the TLC network have not increased charges at the same rate over the last few years as retailers on the more densely populated networks.

Retailers are aware of the existence of TLC's asset management strategies and plans. They are only interested in the sections that relate to them and the associated interfaces. These are communicated to them as part of the asset management strategy.

2.6.5 Network Capacity Demand, Dedicated Asset Charges and Demand Side Management

Historically, networks based charges on transported energy and fixed components (and perhaps, demands). The cost of transporting energy has a demand and fixed component. TLC has changed the structure of all its line charges to better reflect costs by having separate capacity, demand and, where provided, dedicated asset charges.

The capacity charge is based on the anytime size of the capacity made available at the point of connection. The demand charge is based on the peak demand an installation takes during a network constraint or control period. The dedicated asset charge is for assets that are shared by a low number of customers or single customer. The advantages of this charging structure are numerous.

The most significant of these advantages is that demand based charging passes on the major cost drivers for a network company. Consumption based charging does not. The effect of this is that long term prices under consumption pricing would have to increase at a faster rate than demand based charges.

Most of the conflict was caused by change and customers who saw charges increase. The most common cause of increased charges was the result of customers changing historically controlled load to uncontrolled and then not understanding why demand charges had increased. This conflict is being managed by customer advice and communication with the affected customers.

There was also conflict caused by TLC not having network-wide advanced meters and, as such, charges were based on calculations. This conflict will be managed going forward by deployment of more advanced meters, due for completion in mid-2016.

The consultation between TLC and stakeholders is focused on this conflict. An objective of this is to communicate asset management policies, strategies and plans. A likely outcome will be a series of pricing options based on demand, capacity and dedicated assets that give customers an improved choice.

Customers are accepting that demand based charging using advanced meters is the way of the future.

The customers who have had the asset strategies and plans communicated to them are understanding and supportive. One of the keys going forward is to give them more input and choice into how revenue will be provided.

2.6.6 Conflict between Customer Interests as Customers and Shareholders

As beneficiaries of the shareholders, customers get a dividend return. Some customers would prefer lower upfront charges or to see the money reinvested in the network. TLC believe that it is the responsibility of the Trustees, who are elected by our customers, to resolve this conflict by consultation and advice to the company through the Strategic Review process.

The shareholders did accept lower returns for the 2008/09 and 2009/10 years. From the 2010/11 year forward, prices were regulated and returns aligned with Commerce Commission guidelines.

As stated in earlier sections the Commerce Commission issued a decision to reset regulatory controls of electricity distribution businesses from 2012 to 2015, the document indicated that TLC's return is below the Commission's expectation. The DPP was further reset in 2015 and the output of this process was such that TLC's prices were still about 7% below Com Coms limits. Price adjustments will be a subject of debate with the stakeholders, along with which areas they should be targeted at. This is part of the extensive consultation that is currently taking place, and of the corporate high level asset management governance. Strategically it has been decided that by 2020 TLC prices will be tracking as closely as possible to Commerce Commission limits.

2.6.7 Conflict between the Requirements of Legislation and Customers' Wants

There has been a trend over the last decade or more towards distancing Parliament from more technical or commercial decisions in areas such as industry regulations. Detailed implementation decisions, for example Electricity Regulations, are now being made by the Commerce Commission. The Electricity Authority has been given direct regulatory powers. Some of the advantages of this approach have been offset however by the whole government oversight. For example, while the Commerce Commission has been focused on eliminating cross-subsidies, the Government Policy Statement on Electricity promotes cross-subsidies of rural lines, and various regulations require distributors to apply cross-subsidies to charges for low consumption levels etc. Existing political processes are likely to maintain this pattern of principle-based regulation, mixed with fairly haphazard populist interventions, without coherent overview.

There is also little cohesion or understanding of the relationship between the impacts of legislation coming out of the various government bodies. For example hazard control, quality and prices are closely related. These functions are split by the Electricity Act and the Commerce Act. Neither are focused on perhaps the most important long term issue, the environment.

The Commerce Commission regulates both price and quality. Quality includes planned and unplanned work on the network. Monitoring workers hazard control decisions around outages is a constant focus given the safest way to carry out work is to de energise. This conflicts with the Commerce Commissions quality objectives. The organisation does have a strong view around this issue and parallels can be made to the background to the Pike River Mine tragedy. TLC has submitted its concerns around this aspect of the DPP to the Commerce Commission. The Commerce Commission has taken steps to minimise the impact of planned work by adjusting the calculation method for SAIDI and SAIFI targets, this includes a 50% weighting on planned outages.

Given the rural nature of the TLC network these conflicts are particularly pertinent. Managing the rural urban cross-subsidy using consumption based charges is not possible, particularly when the urban areas are generally low socioeconomic regions. The change to separated demand based charging was, amongst other things, seen as a way of managing one element of this conflict.

The asset management policies, strategies and plans TLC has in place are focussed on managing all of the "balls in the air" through asset lifecycles.

Once legislation is passed TLC's only option is to understand the rules and then set about developing strategies for compliance aligned to providing the best solutions for our stakeholders and asset management policies, strategies and plans. It will however continue to make its views known through submissions on the inclusion of planned quality measures in the DPP measures.

2.7 Accountabilities and Responsibilities for Asset Management

2.7.1 Governance

TLC is owned by the Waitomo Energy Services Customer Trust. The Waitomo Energy Services Customer Trust appoints Directors. The Directors are responsible to the shareholders for the overall performance of the company.

The strategic direction of the company is reviewed annually by management and submitted to Directors. From this, the company's Statement of Corporate Intent is developed. Both documents are closely aligned to the asset management policies, strategies and plans.

The Board of Directors considers and approves the Asset Management Plan. The key asset management strategies and projects are generally approved by Directors before incorporation into the Asset Management Plan document.

Trustees also read the Asset Management Plan and forward their comments and any concerns relating to the document back to the Directors.

Key system performance indicators are reported on a monthly basis. These elements form important parts of feedback on asset management plan performance. The Directors approve variations, caused by unpredicted work and customer demand, upwards of $100,000 for work that is not included in the AMP and $500,000 for budgeted capital works.

2.7.2 Executive Level

The Chief Executive Officer is responsible for the overall performance and operation of the company.

The responsibility for overall network management, including the preparation, drafting, and all aspects of implementation of the Asset Management Plan, is delegated to the Chief Asset Officer. The Chief Asset Officer is involved in the technical aspects of most commercial decisions and modelling of network income associated with the management of TLC assets.

2.7.3 Asset Management and Engineering

The Asset Management Plan, policies and strategies are used as reference and form the basis of asset management decisions. Decisions can be referenced back to this document.

Most asset management tasks, including asset inspection, are undertaken in-house. In this way, TLC can control the work on the asset so that the desired outcomes are achieved. Planned work is allocated to the in-house service provider. The finished work is inspected by Asset Management Group (AMG) staff to ensure that it meets acceptable hazard and quality standards.

Vegetation work is controlled and issued by the AMG group to tree contractors who have the necessary quality and hazard control systems in place. These contractors include a local helicopter operator who provides a large proportion of the overhead line fault finding service.

The AMG group inspects and prepares detailed designs including regulatory approvals before forwarding line, mechanical workshop and faults activities to the service provider group. External drafting and engineering consultants are used when workloads are high. Specialist data, valuation and safety consultants are also engaged to assist as required.

The individuals within this team have various delegated authorities to implement the Plan. The supply chain logistics are handled by field service providers; however, specification of the actual items is completed by the Engineering and Asset group. This information is included in distribution standards and individual project details.

The current structure for this group is illustrated in Figure 2.3.

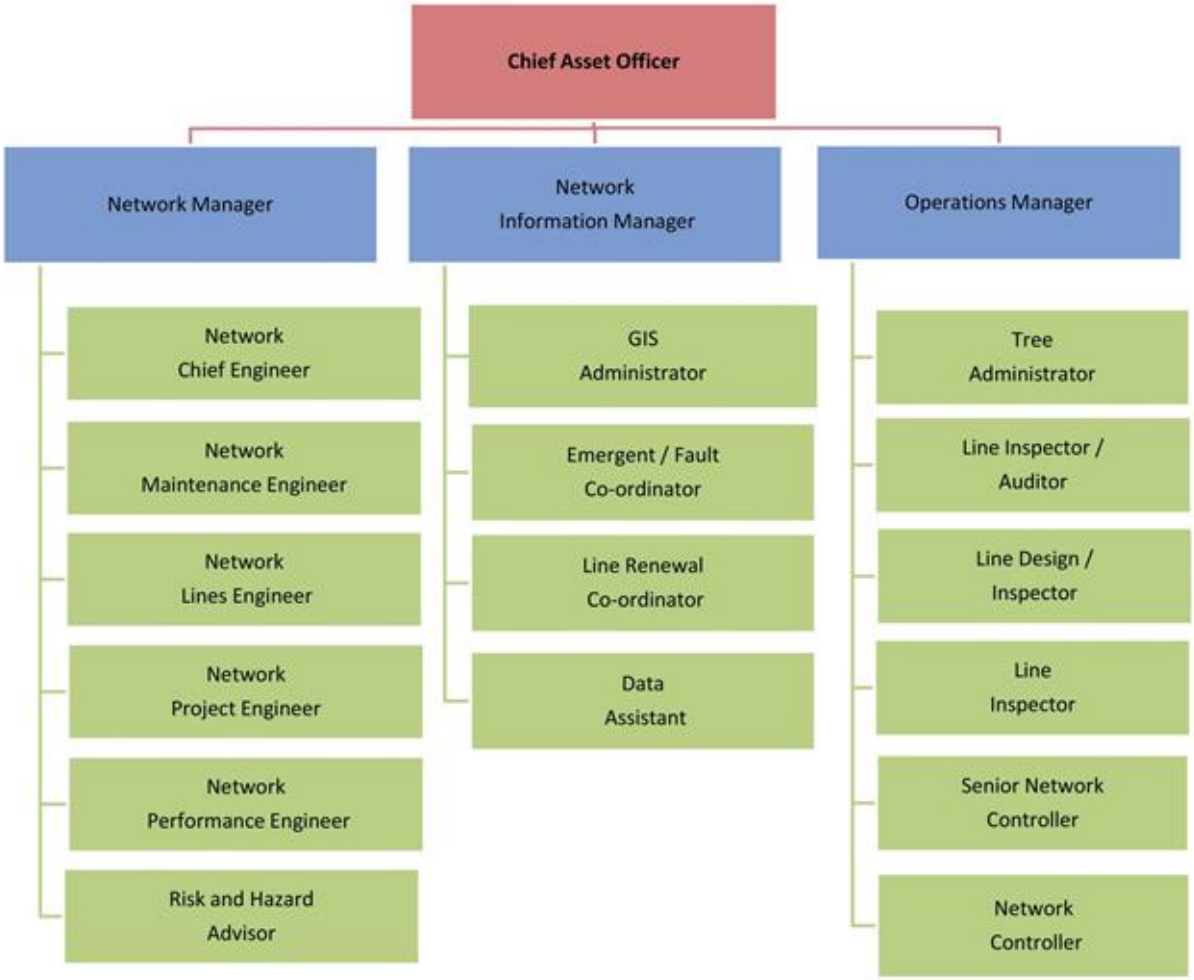

FIGURE 2.3: GROUP STRUCTURE

2.7.4 Field Operation Level

Maintenance and capital works (excluding vegetation) are issued to the internal service provider, which undertakes them with a mix of internal staff and outside contractors.

The Contracting Manager is responsible for the contracting operations. He reports to the Chief Asset Officer. Regular management meetings take place to ensure that the network's needs are being fulfilled.

The internal service provider operation is mainly staffed for faults response and carries out about 70% of the capital and maintenance works. It has approximately 50 staff consisting of supervisors through to utility workers. There are depots at Whakamaru, Taumarunui, Turangi, and Ohakune. The central depot and store are based at Te Kuiti.

The balance of the technical and specialist projects and renewal projects are subcontracted to external contractors. The specifications for this work are prepared by the AMG engineers and allocated to the internal contractors as early as possible so that they can divide work between the internal and subcontracted staff. The use of external contractors provides a cost benchmark.

The internal contractor must submit price estimates before major projects commence. Any excessive profit margins are removed from capital works before costs can be put against assets. Costs are benchmarked against external providers' work and industry surveys.

2.8 Details of Asset Management Systems and Processes, including Asset Management Information System/Software and Information Flows

2.8.1 Systems Overview

TLC operates 3 core IT platforms: a Financial System (Navision); Billing System (Gentrack); and an Asset Data System (BASIX). All have SQL server databases and data is being exchanged between systems. Figure 2.3 illustrates, in a very simplified format, the overall system layout and interaction.

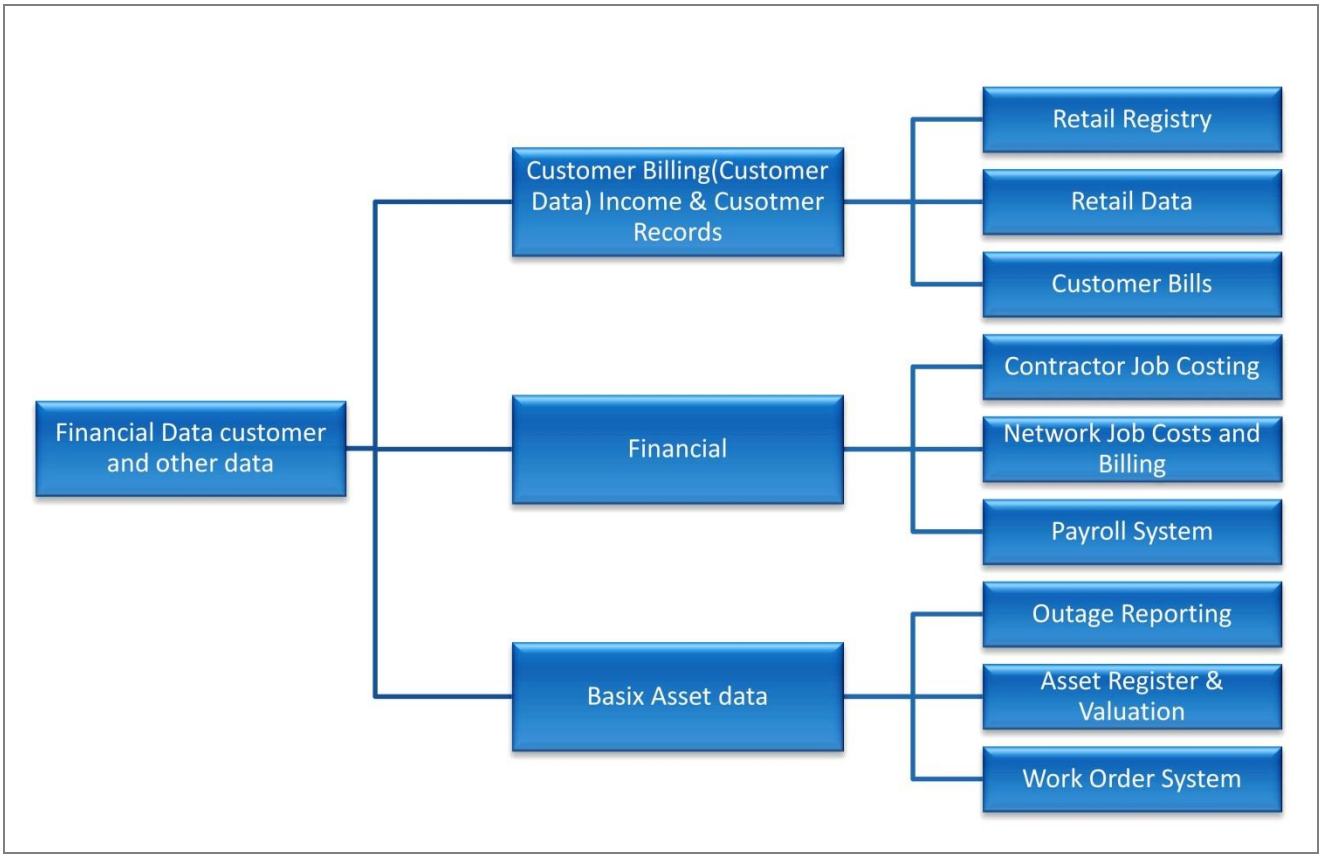

FIGURE 2.3: OVERALL SYSTEM LAYOUT AND INTERACTION

Setting up a stand-alone customer billing system with correct customer data and links to the financial and asset management has been a major undertaking. The process highlighted the incorrect retail data supplied by retailers. This was a major implementation obstacle and, effectively, all customer details had to be manually checked. The billing software is based on a heavily modified Gentrack system over an SQL server database. The "off the shelf" volumetric traditional billing system had to be modified to an extent far greater than originally envisioned to cope with demand based billing. The next iteration of our customer relationship management (CRM) platform is now in planning stages.

The financial system is based on a Navision software package over an SQL server database. In addition to processing and providing financial information for the various companies associated with TLC, it includes detailed job costing packages. The financial system is stable, but further development is needed to give the low level detailed reports required.

The asset management system is based on BASIX software over an SQL server database. The BASIX system contains asset data and is used to calculate reliability statistics and valuations. It also produces reports that align with the network performance criteria.

Assets are layered in many dimensions into components, items, segments, asset groups, density bands and service level groups in addition to categories, feeders, zone substations, distribution asset class, supply areas etc. Age is a key criterion for calculating depreciation and other reporting.

Details of proposed projects for the planning period are entered into the annual planning section of the Basix database. These projects are allocated to the assets within the data base. Financial forecasts are then extracted from the database for AMP and disclosure purposes.

Currently TLC has an ESRI GIS system (mapping package) that has been operating in a "stand-alone" mode for the last few years. The next major development step is to integrate this mapping package, or an equivalent, with the other systems. The objective is to allow users to drill down into asset data from a map and allow asset data to be presented in a geographical format. To date carrying out this development has been a lower priority than the reporting required for network performance and compliance.

If TLC could not operate out of the current TLC building due to a disaster that collapses the building etc. current backup copies of all TLC's information systems and databases are kept off site. In major disasters this will make the relocation and setup of information systems and databases a lot quicker and easier.

2.8.2 Asset Data Accuracy

The data is stored in various SQL server tables that are viewed and written to by the various BASIX user interface forms. Data accuracy continues to improve. The BASIX system is stable and is steadily being refined. Variances between actuals and the system held data are being corrected from work associated with renewals, maintenance, capital development and other asset checks.

It should be noted that assets will continue to be found until the entire network is inspected in detail as part of the 15 year renewal programme and other data collection projects.

The base data and models in a number of the asset categories are now generally accurate. In these asset categories; individual assets down to poles, cross arms and spans etc. are identified and capacity/condition is recorded. Accurate pole condition data including 2 to 3 photographs per pole are held for about 60% of the network. For the remainder, the accuracy is limited and based on the area and pole type.

There are two main reasons for these accuracy variances. The first was the difficulty in understanding and recording data against the assets given the on-going changes of ownership boundaries. Legislation on ownership has been developing since the mid 1970's. The ownership of private lines has been, and in some cases remains, complex.

The second is that data collection and records, to date, have focused on the 11 kV network. The low voltage systems have tended to be treated with less importance and accurate data has not been collected. This has also been partly caused by low voltage systems being more complex especially when integrated with underground systems; linesmen based data gatherers have tended to have difficulty with understanding and following the systems. Similarly SCADA and communication systems are not understood by linesmen data gatherers.

A focus is now being put on gathering this data. It will however take a number of years of gathering information before records are accurate unless additional resources to do this task can be funded.

In summary TLC data accuracy is continuing to improve as more of the network is inspected in detail.

The BASIX system includes a connectivity model that is used for outage reporting. This model connects various assets together and then has a calculation that produces the regulatory performance indications. The physical processes required to set this model up and then maintain it resulted in data errors being found and addressed. Customer numbers are transferred automatically from the billing system on a regular basis.

The BASIX outage calculator works off the connectivity model, in recent years this has allowed TLC to collect more accurate outage data.

2.8.3 Asset Management Information System and Data Structures

The BASIX system consists of various modules including:

- Asset Register.
- Business Entities.
- Works Management.
- Outage and Reliability.
- Reporting.
- Customer Service and other related assessment activities.

The asset register is used to access the network data and is broken down into:

- Lines.
- Installations.
- Zone substations.
- Transformers.
- Switchgear.
- Protection and Control.
- Network Model.
- Property.
- Batteries.
- SCADA & Radio
- Other tools and instruments.

Each of these asset categories is further broken down with a tree structure. Lines, for example, are further broken down into poles, cross arms, and spans. Figure 2.4 shows a typical screen shot of held pole data.

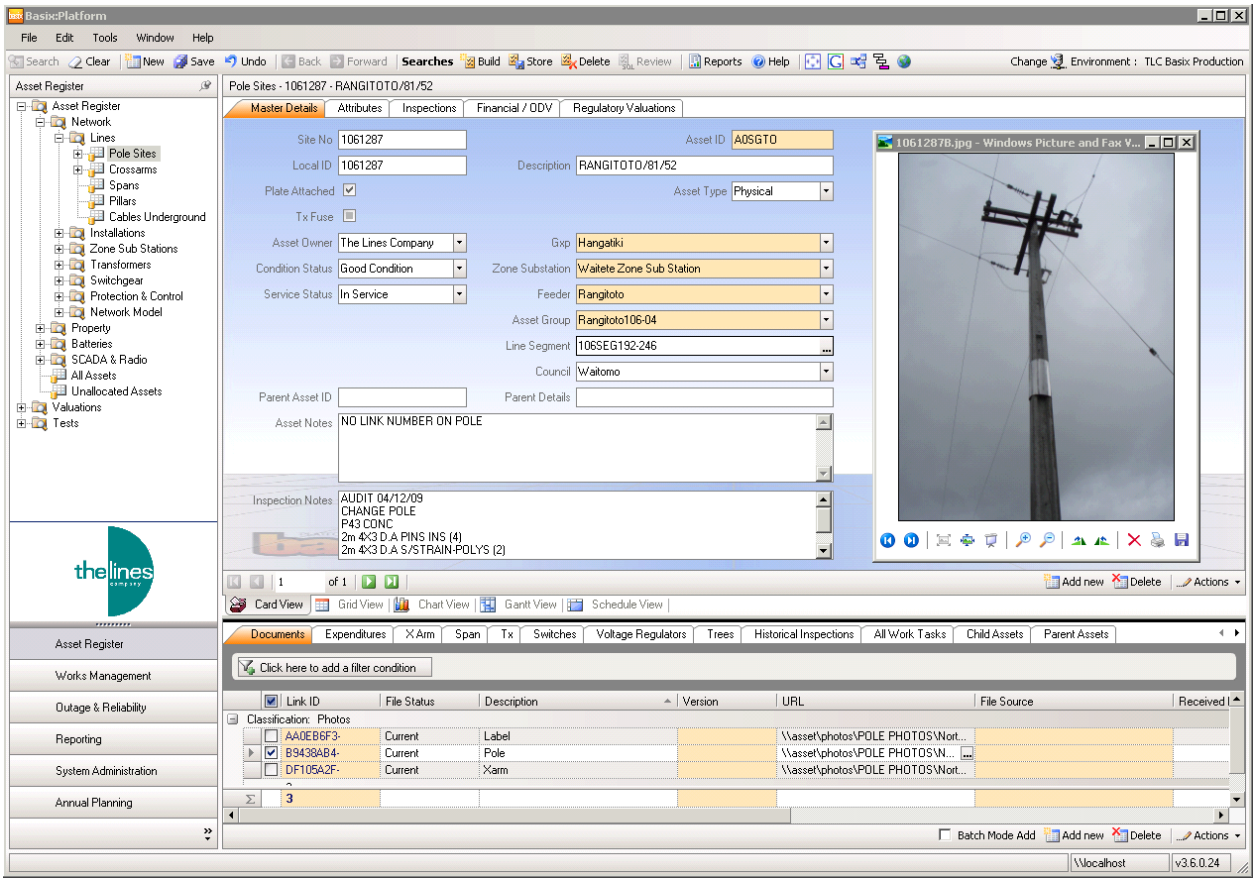

FIGURE 2.4: EXAMPLE OF BASIX POLE DATA SHOWING LINK TO ATTACHED PHOTO

Overhead lines and associated equipment are broken down into approximately six to ten asset groups per feeder. These asset groups are segmented in a way to control maintenance and are structured so that costs, faults data, billing densities and customer service criteria are linked. Poles are numbered and the type, assessed age and condition are recorded (this includes private lines).

Photographs of each pole are taken and used for:

- Physical information of site and layout, pole type, cross arm configuration and other hardware. (Providing this to contractors reduces time and cost necessary to price and plan jobs.)
- A desktop second opinion when assessing condition.
- A flexible record for all types of information enquiry.
- Reference when processing new customer connection requests.
- Fault information.
- Other day to day operating and asset enquiries.

Works orders and estimated costs of works are raised in the BASIX system and put against assets. Cost information from completed jobs is also put against assets.

The BASIX system also includes a reliability calculator that is attached to the asset data. All data in the BASIX database is connected together in single line diagram format. A parent-child connection has been established between assets.

Data from the billing system gives accurate details of customers connected to each transformer. The reliability data is entered regularly and results are calculated. All historic outage data has been loaded into the BASIX system and is used for calculating reliability and previous historic data needs.

Root cause analysis is undertaken when components fail. Care is taken to recover as many of the damaged items as possible and these are examined in detail.

Protection, fault current levels and other technical detail are modelled using a network analysis package. Once the cause is established, a course of action is decided. Samples of recovered failed components are often labelled and stored for future reference.

Vegetation data is stored in the BASIX package and systems have been set up for compliance with the vegetation regulations.

TLC has GIS (Geographical Information System) software that is operating from its own database; it is not linked to BASIX at this time. The GIS program is mostly used to give geographical information of asset locations. The intent is to link it to BASIX and use a common database in the future. The GIS platform is ESRI Arc View.

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An improved customer service has been delivered by an in-house call centre, including calls outside business hours. The customer billing information is entered into the billing system. Network related issues are entered into the BASIX system. This information is placed against individual ICPs. From this it is possible to report on repeated fuse blowing events and the like and then reconcile this to billing information. The tool is used to identify customers who have understated the required capacity and this allows TLC to control its revenue risks.

2.8.4 Processes for Managing Routine Asset Inspection and Network Maintenance

As part of the preparation of the annual Asset Management Plan review, TLC is continuing to add more detail to its long-term renewal and maintenance plans. The renewal and development expenditure plan lists expected renewals under lines (33 kV, 11 kV and LV), substations, distribution transformers, SCADA, communications, protection and switchgear renewal by individual jobs, items, and asset groups. Estimates are reported in equipment categories and Commerce Commission disclosure format.

The maintenance plan details activities for:

- Cables.
- Lines.
- Distribution transformers.
- Zone substations.
- Faults.
- Vegetation.
- Other technical equipment.

Both the renewal and maintenance plans extend to the end of the planning period and report by asset class and Commerce Commission disclosure format. The projects involved and the reasons for them are described in detail in this Plan. A major driver for the need to establish forward expenditure trends with relative accuracy is for forward revenue predictions.

The long-term renewal and maintenance plan is on a year-by-year and activity-by-activity basis out to the end of the planning period.

The activities for each coming year are then extracted and reviewed. These form the basis of the annual plan for the coming year. The plan is adjusted when justified due to previously unknown environmental, customer, equipment and other issues, which mostly feed into the 1 to 5 year forecast period.

Over the planning period, all predictions are transferred into the BASIX system. Ideally, projects should be controlled by a project planning package that allows linking of projects. The long-term plan flows down and controls the various asset inspections, network maintenance (renewals), planning and network development projects.

2.8.5 Overhead Lines: Routine Asset Inspections and Network Maintenance

2.8.5.1 Planned Work

A 15 year rotation inspection programme is undertaken on an asset group by asset group basis, i.e. a time-based inspection programme. Experience has shown that pole conditions can be more accurately assessed for a 15 year period as opposed to shorter or longer time frames. The rotation also produces manageable work outputs.

The asset groups to be inspected are identified by the long term plan. Gap analysis is used to compare service achieved with the promised service standard; other factors such as general condition, hazard related risk, environmental risk and the importance to the overall network integrity are also considered when determining the amount of work that is required to be done. Calculation of pole strengths and ground clearances are completed and the results used to assist with renew or leave decisions. Power flows and fault level models are used as appropriate to assist with decision making.

The data gathered during inspections includes:

- The condition of overhead line hardware.
- Line clearances.
- Pole conditions.
- Pole type.

- Span lengths by direct measurement.
- Hardware attached including details of fittings.
- GPS position.
- Two or three photographs per pole/span.
- Pole test data using Deuar technology (when appropriate).
- Estimated age.
- Estimated life remaining.
- Labelling.
- Earth test results as appropriate.

Once this information is available, a detailed review of the asset condition, and what needs to be done to ensure it will last for another 15 years, is carried out.

In addition to the 15 year detailed condition and fit for purpose inspection, TLC carries out a three yearly hazard and vegetation inspection. This inspection is less detailed and the focus is on obvious vegetation and line hazard issues. Where possible this inspection is done from a helicopter to minimise costs. The cost of patrolling in a helicopter is $40 to $50 per km. Ground patrols cost 3 to 4 times this amount in the rugged rural areas of the TLC network.

Data gathered during three yearly inspections includes GPS locations, descriptions and photographs of problem areas. This data is loaded into the BASIX database and appropriate works orders are raised. Detailed specifications are prepared for many jobs.

Vegetation problems are reconciled with previous cut information and notices issued in compliance with the 2003 Tree Regulations. An administrator oversees this process.

The GIS database also contains information on line types and locations. Further information on line electrical characteristics is kept in the system analysis package (ETAP). The ETAP model includes power flow, fault current, circuit breaker sequencing, distributed generation, harmonic and arc flash modelling capability.

Hard copies of original construction drawings, inspection sheets and system single line diagrams are also referenced for further information as necessary when inspection, maintenance and renewal work is being carried out.

2.8.5.2 Unplanned Work

There are two principal drivers for unplanned renewal of overhead lines. These are faults and reported information of performance hazard issues.

Faults that cause a line to trip and stay tripped are fixed by faults staff. Advice on how to go about repairs is often sought from the Asset and Engineering group, particularly by field staff, for larger faults. This usually involves lines inspectors or technical staff going to site and specifying repair requirements. Works orders against the particular assets are then issued for these repairs.

About 80% of faults however are more intermittent in nature and, because of the rugged country, a more controlled approach to finding the problems often needs to be taken. After an initial check by faults staff, a line inspector will be dispatched to complete a detailed line fault inspection. Tools such as a discharge detector are often used. Technical staff will visit the upstream circuit breaker and download any fault history electronic records to ascertain the type of fault, and the fault current levels flowing into it. Modelling using the network analysis program to determine the fault location based on the fault currents may also be undertaken.

Often a helicopter inspection will also be completed to hasten progress as compared to ground based patrols. Once problems are found, plans and specifications are prepared and forwarded to the field staff. The level of detail in plans and instructions is vital for controlling the quality and consistency of repairs. The Asset Management Group establishes and follows up landowner entry permission. Engineering staff may also follow up with further technical studies and protection reviews.

Reports of problems are received from customers, staff and contractors. As soon as the Asset Management Group or control room becomes aware of a reported problem, an emergent work form is completed. This form becomes the tracking record of the problem. A lines inspector is then dispatched to investigate the problem further and complete the necessary designs, specifications and landowner arrangements. This work includes an understanding of the problem and overview of the line security issues in the area.

Once this work is done, the requirements are brought back and the package (inclusive of any labels, switch numbers, special safety requirements and suggested scope of outages) is forwarded to the field staff. The asset system tracks dates and jobs issued. On completion, a lines inspector is dispatched to audit the completed work against the design and work specifications. Board approval is needed for larger jobs via a variation to the Annual Plan.

The integration of the outage reporting, financial and customer systems are assisting with improved tracking of individual and lower level faults. Improved information is allowing better reconciliation of blown transformer fuses to individual ICPs for both revenue and SMS reasons.

This is important given TLC's capacity and dedicated asset components of charging. It is also important that faults on privately owned lines are tracked, as they often indicate a hazard. Customers may decide to minimise capacity and dedicated asset charges by having smaller transformers. Regular fuse blowing is recorded and billed to customers. Customers may choose to upgrade their transformer by sourcing a bigger one themselves or paying increased capacity/dedicated asset charges as opposed to paying fuse repair costs.

TLC keeps all historic line drawings as a backup information reference.

2.8.6 Ground Mounted Transformers: Routine Asset Inspections and Network Maintenance

2.8.6.1 Planned Work and Information: Ground Mounted Transformers

Ground mounted transformers are inspected on a five yearly cycle and major maintenance is scheduled based on the inspection results. There are a large number that have been identified as having hazards. Renewal of hazardous installations is included in the renewal programme and detailed in the long-term plan. Maintenance to reduce hazards has been included in the maintenance programmes. This mostly involves taping and covering exposed bushings etc. This is also included in the long-term maintenance plan. The inspection dates, hazards, repairs and other notes are recorded and this data is stored in the BASIX system. It is also available for use by the SMS.

The ground mounted equipment site information including type, capacity, current loading and condition is recorded and used to control the maintenance cycle. Most ground mounted transformer sites are also fitted with Maximum Demand Indicators (MDIs) which are read on an annual basis. Records are kept of these loadings and Maximum Demand (MD) loading data is being used to monitor connected loads.

Data, in addition to type, capacity and condition, includes full details on the types of locks and other fasteners etc. that secure the units from unauthorised access. This detailed information is stored in the BASIX system. Each site is photographed during the five yearly inspections. These photographs are currently accessed from the BASIX system and will be linked to the GIS system in the future. Further integration with SMS information is also being developed.

High-level data including site number and connected installations are stored in both the BASIX and customer billing systems. The BASIX system receives regular updates from the billing system on connected customers.

Original paper drawings, single line diagrams, GIS data, and photographs are all used as necessary during the management of routine asset inspection and network maintenance. The inspection and maintenance cycles are currently being managed by the BASIX system.

2.8.6.2 Unplanned Work: Ground Mounted Transformers

Feedback from customers, staff and others triggers such as faults cause the need to carry out unplanned work from time to time on ground mounted substations. The needs are identified and the repair requirements are specified to the level that is needed to ensure staff can carry out repairs in an efficient and effective manner.

Works and all information necessary to complete the repairs are recorded in the BASIX system.

2.8.7 Zone Substations

There are a number of systems in place to manage various aspects associated with zone substations.

These systems include the following.

2.8.7.1 Zone Substation Transformers: Planned

The zone substation transformers are maintained mostly on the basis of time, condition and duty cycles. A key driver for planned transformer maintenance are the oil test results for the main tank and tap changer.

The records kept as part of these tests include:

- Main transformer and tap changer type.
- All oil test results and consultants' notes on the assessment of transformer condition.
- Results of further tests, such as insulation loss angle.

Once completed, the test results are stored in BASIX against each individual zone substation transformer.

Maintenance including oil and transformer refurbishment is completed based on this data. As works orders are raised, more of the associated data are being entered into the BASIX system.

The cycle for oil tests is detailed in the lifecycle section of the Plan.

The normal condition and duty cycle issues are also taken into consideration when planning transformer maintenance. Examples of the issues that are considered include leaks, paint condition and the work that has been done in the past.

2.8.7.2 Zone Substation Transformers: Unplanned

The unplanned work is normally caused by an unexpected event such as a fault of some type. When these occur the solution options are evaluated and the best for each particular circumstance is selected. Appropriate designs and instructions are prepared and works orders are issued to the appropriate organisations. All related information is stored in the BASIX system against the assets.

2.8.7.3 Protection and Switchgear: Related Processes for Managing Routine Asset Inspections and Network Maintenance

Protection and switchgear records detail manufacturer's information, settings and maintenance. Generally this information is stored in paper-based folders. Protection setting data are also being recorded in network analysis software (ETAP). Duplicate copies are stored at both onsite and offsite locations.

Maintenance of this equipment including oil and contact maintenance, relay testing and other work is based on a 15 year cycle or need to maintain sooner basis. Works orders are raised and data updated in the BASIX system.

Protection valuation data and outage calculations are currently done in the BASIX system. Protection setting data are also being put into network analysis software (ETAP) to simulate circuit breaker, recloser and fuse operation under fault conditions. Electronic files associated with protection equipment are stored in at least two separate areas on the general computer system and separate mass storage devices.

Where equipment includes electronic software driven relays and other equipment, memory buffers are downloaded annually and settings are reconciled with records and network models. Similar checks and reconciliation are completed when it is suspected that equipment is not operating correctly.

2.8.7.4 Overall Zone Substation Related Processes for Managing Routine Asset Inspections and Network Maintenance

Planned and unplanned work (maintenance, renewal and capital) is controlled by the BASIX system. Asset and maintenance data on zone substations are stored in the BASIX system.

Several filing systems are used to store all other zone substation drawings and information. Two monthly inspections identify unplanned work and works orders are generated to rectify the problems found.

The long-term inspection and maintenance forecasts, expenditure and plans are listed in the long-term network maintenance master plan.

2.8.8 Low Voltage Overhead Systems: Related Processes for Managing Routine Asset Inspections and Network Maintenance

Historically very little data has been available on low voltage overhead systems, particularly in the rural villages. Steps are being taken to gather data as part of the 15 year line renewal programme

This data is entered in the BASIX system. In addition to data capture, the more complex low voltage arrangements have drawings and single line diagrams completed. Drawings are referenced via a drawing database.

The data in the BASIX system is used for valuations and works orders are issued against the assets. The geographical locations of low voltage systems are held in the GIS database.

The long-term inspection and renewal plan for low voltage systems is detailed in the overall long term renewal plan. The actual work flows and processes are the same as those described in the earlier overhead line system for both planned and unplanned activities.

Planned activities (excluding pillar boxes, which are discussed later) are generally completed on a 15 yearly inspection and renewal cycle.

Hazard and Vegetation patrols are completed on an 18-monthly cycle in dense urban areas and 3 yearly in the less dense areas. Issues identified are recorded and managed via the BASIX system. The 15 yearly inspection is considerably more detailed than the shorter term patrols and looks at overall issues that include tasks such as earth testing and the like.

Completed works are audited against quality, hazard control and work specifications. Unplanned events are focused on restoring supply and repairing the assets in a like-for-like manner. Works orders and instructions are created and all details of what took place and the costs involved are stored in the BASIX system.

2.8.9 Distribution Transformers: Related Processes for Managing Routine Asset Inspections and Network Maintenance

Distribution transformers are linked to sites by their serial number and sites are linked to ICPs within the BASIX system.

The condition of distribution transformers is assessed:

- When customers request increased capacity or new connections.
- As part of the 15 year line renewal programme.
- When identified by faults or as part of emergent or planned project works.

A transformer serial number provides a record of the locations and other maintenance details of the transformer. The site number is the key linking number for data systems. Maintenance details such as earth tests are recorded against the site number. In addition, the site number links customers for billing and outage reporting purposes. Site numbers are linked to assets as part of the connectivity model in the BASIX system.

The distribution transformer data are complete in the BASIX system. All maintenance and inspection tasks are raised against the assets. The overall inspection, maintenance and renewal is controlled by the maintenance and capital long term plans.

Planned works are completed as part of the 15 yearly and hazard control programs in these plans. Unplanned works are completed as required to maintain supply in a secure and hazard controlled manner. The actual criteria applied to renew or replace are discussed in the maintenance section of this Plan.

2.8.10 Other Equipment: Related Processes for Maintaining Routine Asset Inspections and Network Maintenance

Other field-based equipment has an equipment number that is attached to a site. The BASIX system allows maintenance to be controlled. Batteries and reclosers are examples of this equipment. The overall inspection, maintenance and renewal is controlled by the maintenance and capital long term plans.

2.8.11 SCADA and Communication Equipment: Related Processes for Maintaining Routine Asset Inspections and Network Maintenance

SCADA and communication equipment is managed by two external specialists who recommend renewal/development activities. The list of equipment is kept updated and has been transferred to the BASIX system.

TLC technical staff work closely with the external specialists to make sure there are long-term plans for renewal and maintenance of the SCADA and communication equipment. These plans are included in the maintenance and capital long term plans.

Works orders and specifications are prepared for all works and, on receipt of invoices, works are verified and recorded against the specific assets.

2.8.12 Vegetation Management: Related Processes for Managing Asset Inspections and Network Maintenance

The initial parts of the tree programme embarked on in 2003 focused on establishing a plan with the objective of improving reliability.

The focus shifted in 2007/08 and systems were set up to manage the second cut process in compliance with the Electricity (Hazards from Trees) Regulations 2003 (subsequently referred to as the 2003 Tree Regulations). Systems were tested and modified to get a simple but effective method that complies with the regulatory requirements. The system that was found to work best is a three yearly inspection of rural areas via helicopter with ground based 12 to 18 monthly patrols of the 24 villages and towns and 33 kV lines in the network. These patrols also identify other line hazards. Approximately 33% of the network is flown annually in a helicopter.

Problem areas are photographed and GPS positions recorded. A helicopter internet connected GPS device is used to identify locations accurately. The location and problem data are sorted after flights and various actions taken depending on the problems found.

Good records of where trees have been cut, landowner details and agreements reached, costs, number of trees and dates, types of trees etc. have been kept for many years. This data has been taken and additional fields added to manage this in compliance with the 2003 Tree Regulations.

The data associated with tree management is stored and linked to other asset records in the BASIX system. The vegetation work is carried out by one primary contractor and about five other smaller operators. TLC has no ownership stake in these contractors. Orders are raised for all works (both planned and unplanned) and activities are audited to ensure quality and hazard control meets expectations.

TLC has to control the hazard implications of customers receiving their second trim notices and then attempting the work themselves to save costs. Vegetation notices and staff are alerting customers of the risks of cutting trees around power lines with each communication.

A detailed model of the tree programme has been put together and used to predict future needs and expenditure based on several scenarios and assumptions. This model was used to develop a strategy that will increase focus on maintaining the areas that have been cut previously. The tree model feeds into the long-term maintenance and is co-ordinated with capital works projects.

2.8.13 Pillar Boxes: Related Processes for Managing Asset Inspections

In undergrounded urban areas pillar boxes are often damaged by vehicles, and when damaged can potentially be accessed by children. Pillar boxes are inspected on a five yearly cycle, numbered, the position confirmed by GPS and details recorded in the database. As each new subdivision is connected, all boxes are audited for security, numbered and details recorded. The BASIX system has been developed to hold service box data including age, type, condition and other details.

The long-term renewal and maintenance plans include allowances for planned renewals and unplanned renewals/repairs. Further details on these are included in subsequent sections.

All works are managed by the works order system and completed works are audited for quality, hazard control and SMS compliance.

2.8.14 Processes for Planning and Implementation of Network Development Projects

As outlined previously, TLC has formulated a network development plan for a 10 year planning period. This Plan is integrated with the renewal and maintenance plans. Inputs include the load growth predictions discussed in later sections of this Asset Management Plan. These were developed from load and other relevant data. Projections of loading on individual assets were developed using the ETAP network analysis package.

The results of this analysis is also reconciled to demands on the various network segments that customers are charged, i.e. measured system loadings are reconciled to reports coming from the billing system to ensure that the sum of customer demand charges are within expectations.

The long-term development plan washes down into the Annual Plans. It is reviewed and, from time to time, has to be varied. Most variations are triggered by customer demands. The constraints, development options, the year works are planned for and estimated costs are included in the development section of this AMP.

2.8.15 Customer Driven and System Growth: Planning and implementation

There are various processes for customer driven development based around the size of customer needs. Once a customer need is established, concept options are developed. Needs for major customers are normally established by site visits and discussions. Tools such as load flow studies and fault analysis are used to develop the concepts. The network details, down to distribution transformer level, are stored and regularly updated on the ETAP network analysis program to assist with the process.

Once 'what will work' options are determined, high-level costs are estimated and the advantages and disadvantages of each option are debated. This will normally include customer consultation so that the benefits of each option can be accurately assessed by the customer. These discussions are used to determine a number of things, including the amount of future proofing a developer or industrial customer wants to fund.

Customers are also encouraged to consider alternative supply options if these will fulfil their lifestyle or enterprise expectations. Customers normally do not have a technical background and as a consequence have little understanding or sometimes an incorrect perception of what alternatives are available. TLC staff keep up to date with where the various technologies are at including the latest costs and performances. Information given to customers is based on these facts.

Most of the customer development requirements involve modifying or extending the network. Customers may choose to build their own private lines to the network point of connection. (The point of connection is often different from the point of supply; point of supply is where a line crosses into the customer's property, except as otherwise specified in the Electricity Act.) They may also nominate the capacity of their connection and customer ownership options for dedicated assets such as transformers, i.e. either they own them or TLC owns them and they pay for this as part of their account. The implications of ownership such as compliance with the Electricity (Safety) Regulations 2010 is pointed out when this option is chosen.

Where the network presently owned by TLC needs upgrading, discussions are held with the customer as to funding options. These are usually either an upfront payment or an appropriate dedicated asset charge when revenues will not fund the development. These funding requirements are either individually calculated or, for smaller connections, generically determined. All charges are based on Commerce Commission criterion and determined using discounted cash flow type modelling.

The long-term plan includes expected levels of customer development needs and a few known customer projects. Also included are core network strengthening projects necessary due to the cumulative effects of customer development. The costs of these plans are included in each year's Annual Plan and the forward projections and projects that we have details on are included in the overall master plan.

New customer connections trigger a whole number of processes that include:

- Asset record updates.
- Electricity market registry.
- TLC charges and billing system.
- Single line diagram and control room maps.
- GIS system.
- Connection costs.
- Equipment records.
- Land access information.
- Metering and load control data.

Where specific customer needs are unknown, estimates have been included in the forward plans based on the expected times developments will occur.

2.8.16 New Connections: Distributed Generation: Planning and Implementation

The processes detailed in the Electricity (Distributed Generation) 2009 Regulations are followed. Experience has shown that investors tend to not want to employ the engineering expertise they need to complete applications to a level where they can be approved.

TLC does not employ contingency engineering or legal resources and, as a consequence, additional resources must be employed to handle larger applications. These resources have to be funded by the generation investor.

There is a lot of variation in the needs for processing distributed generation applications. Small applications can connect without any significant effects. Large applications quickly become considerably more complex, especially on a remote rural network.

The current distributed generation regulations were not designed for the realities of connecting complex installations. At present hardcopy and electronic filing systems are used to manage distributed generation applications in compliance with the regulations.

2.8.17 Other Projects: Planning and Implementation

Security, hazards and reliability projects feed from a list of long term development plans, which are detailed in the later sections of this document. These are reviewed annually and, if necessary, varied. The amount of variation is minimised as far as possible. The latest customer needs, security, SMS, worker hazards, reliability information and performance criteria are used as the foundation for any variation from the long-term plan.

2.8.18 Processes for All Projects

While the planning and control depends on the specific project, the same underlying steps are applied to all projects. These steps are:

- Identifying the needs/justification.
- Determining the options.
- Concept design to produce pricing estimates.
- Funding/revenue agreements.
- Detailed design.
- Approvals.
- Construction.
- Auditing against Quality, Specifications, SMS and Worker Hazard Control.
- Commissioning.
- Administration and data control.
- Systems to receive on-going revenue.

Many of these underlying steps are very minor for small projects and significant for larger ones.

Detailed justification is developed and compared against criteria to justify the project on financial, worker hazards, SMS reliability, capacity or system security or combinations of each of these. The proposals are written up and approval sought from Directors to proceed. About 90% of these are included in the Annual Plan and budget. The remaining 10% are submitted during the year when an emergent need occurs. Examples of emergent needs include unanticipated customer growth projects and major emergent repairs after faults. Once approval is obtained, detailed plans, specifications and other details are finalised. A job package is prepared and forwarded to the Service Provider for construction. On completion, an audit is undertaken to ensure compliance with specifications. Engineering resources are made available to address any technical issues associated with construction and commissioning.

The works order system is used to compare actual costs of projects with estimates. Major projects are ring fenced and compared against high-level concepts that are initially developed to analyse options.

The Service Provider provides a final cost and this is reconciled against the estimates. Approvals are sought for any variations against the estimates that were part of the planning process. Work orders are raised against assets in the BASIX system for all works. Actual costs are reconciled when these become available from the financial system.

Network supply point power factor is measured from the national data set available from the Electricity Authority.

2.9 Future Asset System Integration and Advanced Network Vision

The technology available for more advanced networks is developing with increasing speed. There are many aspects to this but a central component to most schemes is the need to control demand in customers' installations.

TLC's demand based billing uses the tools currently available to do this. Advanced meter firmware has now been developed to the point that it will read both retailer and TLC demand based charging data and includes the capabilities for future communications and in-home displays. With this technology available the pricing strategies can be further refined. Meters in the future may include elements for measuring power quality and it is likely that customers who pollute will face the costs associated with this. It is probable that communication between meters and customers will also significantly improve in the future.

Running in parallel with this there are significant advances being made with distribution equipment technology. For example, protection and system automation equipment has advanced significantly over the last few years. Controlling and using all of this equipment is a key consideration for data and information systems looking forward.

TLC has given considerable thought to the 'future vision' when selecting and designing the way its data and information tools are selected and developed as part of its continuous improvement approach. The owners of packages such as ETAP (TLC's network analysis program) have developed some comprehensive network automation capability.

Similarly, the present SCADA, billing and asset management packages will all have a place in the asset management processes for advanced network schemes throughout the planning period.

A major focus over the next period is to develop a plan to bring these technologies together in an innovative way to benefit customers.

2.10All Significant Assumptions

Growth Funding

Assumption:	It has been assumed the cost of developing the network for growth and customer connections, will be financed by the additional income from the increased customer demand.
Principle Sources of Information:	The principle that growth funding will come from increased income is based on having charges and pricing structure in place that create income to fund investment in new connections and system growth from this development. The principal sources of information for developing this assumption are: • Network models that calculate network capacity and the impacts of growth on the connection chain. • The cost of the necessary network development. • Bankable investment criteria.
Potential Effects of the Uncertainty:	If growth as assumed does not go ahead, the expenditure for customer connections and growth as detailed in the long term plan would reduce. Similarly, if growth increase is greater than estimates, expenditure will be greater.

Continuance of supply

Assumption:	The 2010 Electricity Act has been amended in a way that requires TLC to continue to operate uneconomic lines.
Principle Sources of Information:	The 2010 Electricity Act.
Potential Effects of the Uncertainty:	The 2010 amendment of the Electricity Act has meant that the effect on the organisation of the renewal programmes will be as described in this Plan. Hence there will be no external money to subsidise rural lines and, as such, the programmes have to be funded from TLC's income.

Distributed Generation

Assumption:	It is taken distributed generation connections will continue to be developed and that the regulators will resolve rules on complex issues associated with the likes of grid exit power factor. It is also assumed that existing load taking customers will not be penalised in a way that cross subsidises the connection of generation.
Principle Sources of Information:	Government policy statements. Electricity Governance Rules Transmission connection charges. Various papers produced by officials. Network studies showing the effects of distributed generation.
Potential Effects of the Uncertainty:	If regulators enforce grid exit power factor requirements and costs are passed on to generation, the economics of some existing and new distributed generation sites will become marginal. If the costs are passed on to load taking customers, charges will have to increase.

The costs associated with a greater uptake of distributed generation will mean that the customer connection and system growth expenditure will increase to accommodate this.

Demand side management and peak control

Assumption: That the industry will increasingly recognise the importance of demand side management and peak control. A consequence of these will be recognition and support for TLC's demand based charging system by regulators.

Principle Sources of Information:

- This assumption is based on the fact that power systems have to be designed for peak capacity.
- Network models that calculate power factor
- Data analysis of field test results

Potential Effects of the Uncertainty: If TLC were not signalling network constraints, then the demand would likely grow faster than if it was signalled. The figures used in the long term estimates are about .25% to .75% less than the average demand growth if it were not implemented.
If a greater demand growth reduction occurs then system growth needs will be less. If customers do not react, the growth in demand will cause a higher level of expenditure
If retailers introduce incentives and the industry moves to implement more demand side management schemes, then customers will likely understand the issue better and greater savings will occur. The national roll out of advanced meters will make it easier for more parties to adopt this approach.

Economic activity

Assumption: It has been assumed that economic activity based on primary production and processing will continue to develop. It is assumed that when land is converted to dairying, present day technologies will be incorporated into new milking sheds. These tend to be bigger and more automated than older installations. The forward land use assumption does not include large scale development of irrigation.

Principle Sources of Information: The network studies have assumed continued development of the area. Different rates have been used on the land types and present usage. For example, it has been assumed flat or rolling land will see greater development than extreme hill country in remote locations. Areas to which people are currently attracted to build new homes and invest in related enterprises have been given greater growth rates than locations that are less popular and more remote.

Overall, an average growth rate of less than peak "boom" times, but reflective of average consistent growth, has been used as a base. TLC's growth is also influenced by rural based industrial enterprises. Models have assumed that most of these industries will continue with a gradual increase in load as various machines within the plant are renewed. It has also been assumed that, because of TLC's pricing structures, industrial customers will focus on demand side management by way of power factor correction.

The principal sources of information for developing these assumptions are:

- CPI.
- Land information.
- Subdivision development: sizes and numbers.
- Distribution capacity and numbers.
- New connection numbers.
- New housing areas.
- Areas that are static, or depopulating.
- Industrial customer feedback and comment.
- Previous energy and demand growth figures.
- Primary produce pricing and trends in these.
- Predictions on primary produce long term forecasts.
- Predictions on the leisure markets.

Potential Effects of the Uncertainty:	If economic activity increases, growth related capital expenditure will increase. If economic activity reduces, the reverse will take place. If economic activity declines to a level that sees a number of the rural processors leave the area, then TLC will have to either reduce renewals or increase revenue from the remaining customers.

Reliability and quality

Assumption:	It has been assumed that customers will want reliability and quality standards equivalent to or better than present to support lifestyle tools such as electronic appliances, computers and media devices
Principle Sources of Information:	The reliability and quality assumption is based on the understanding that customers want a continual improvement in reliability and quality. Specifically, this assumption is based on the number of complaints that occur when the power goes off and/or appliances will not go or are destroyed. The principal sources of information for developing these assumptions are via: • Customer feedback. • Complaints. • Focus groups. • Customer surveys. • Customer representatives. • Other community input.
Potential Effects of the Uncertainty:	If stakeholders do not want an improvement of reliability then reliability expenditure could be reduced.

Hazards

Assumption:	It has been assumed that stakeholders want a network that does not cause an unacceptable level of hazard to the general public, staff, or animals. It is assumed that there will be no stepped inputs to significantly alter this plan. .
Principle Sources of Information:	The hazard assumption is based on people not wanting to get shocked or electrocuted and, if they do, the legal and emotional liabilities that stakeholders will face if this is caused by lack of renewal programmes, maintenance, and general failure to operate a network with acceptable levels of hazards. It is also assumed that the organisation complies with Electrical

	(Safety) Regulations. The assumption is also based on the liabilities associated with not taking all practicable steps to eliminate, isolate or minimise hazards.
Potential Effects of the Uncertainty:	If stakeholders decide not to have a programme with projects that eliminate/minimise hazards, then the forward development expenditure would reduce by approximately $1million p.a. The present programme eliminates or minimises the worst of the hazards by about 2019. The annual spend would be reduced in the medium term if the programme were lengthened.

Pricing

Assumption:	It has been assumed that TLC will continue with its present pricing structures that are designed to be transparent, promote demand side management, encourage distributed generation and reflect asset values/costs.
Principle Sources of Information:	The assumption is based on the regulators and stakeholders continuing to encourage efficient network development and for revenue to reflect cost drivers.
Potential Effects of the Uncertainty:	The present pricing structure promotes demand side management and protects revenue against movements in energy flow triggered by shortages or greater uptakes of small generation behind meters. A change in the structure would increase the risks to revenue in the future during energy shortages or greater uptake of solar panels etc.

Inflation

Assumption:	It has been assumed that inflation will continue through the planning period.
Principle Sources of Information:	The rate of inflation for cost increases has been based on recent CPI figures. The assumption is based on published CPI data.
Potential Effects of the Uncertainty:	Forward estimates are based on an inflation rate of 2.5%. Higher inflation will mean higher costs in dollar terms. Lower inflation will give the reverse. (The inflation referred to is that associated with the renewal and construction of distribution networks, not general inflation).

Performance Measures

Assumption:	It has been assumed that stakeholders want development of performance measures that align with customer expectations.
Principle Sources of Information:	• Terms and Conditions of Supply. • The connection code/standard. • Customer surveys. • Customer complaints and feedback. • Commerce Commission performance measures. • Measures that have been aligned and developed over time with the objective of making information more understandable to customers.

Potential Effects of the Uncertainty:	The performance measures are currently aligned with customer simplification needs, the asset management system and Commerce Commission criteria. Variation from these will lead to periods of uncertainty in terms of performance measurements. It will take time to set up systems to measure new indices.

Customers' Ability to Pay

Assumption:	It has been assumed that customers in the King Country are not affluent and have limited ability to pay increasing line and energy charges.
Principle Sources of Information:	The principal source of information suggesting customers have limited ability to pay includes things such as: • School decile ratings. • Government "wealth information" associated with electorates. • Customers and stakeholders feedback.
Potential Effects of the Uncertainty:	There is little uncertainty associated with the limited ability of TLC's customers to pay ever increasing charges. The potential effect of this uncertainty/certainty will be an increased pressure for TLC to carry out its renewal work at the lowest possible cost.

Other Significant Assumptions

Considerations:	If some sort of plan is not followed for maintenance, renewal and development, then the chance of adverse events substantially increases. The principal sources of information from which they have been derived include: • Legislation. • Engineering industry experience. • Industry papers and event information. • PAS55 asset management standard.
Likelihood consequence control:	This plan details the various policies and strategies that are in place to control the impact of adverse events. Adverse events have a high level of uncertainty. i.e. earthquakes, storms, floods, volcanic eruptions etc. Any of these events has a level of likelihood that flows through into this Plan and other disclosed information. The other variables include economic prosperity in the rural and tourism areas and the future regulatory climate.

The price inflator assumptions used to prepare the financial information disclosed

Factor:	An inflation factor of 2.5% has been built into expenditure forecasts. This figure has been derived based on the following factors: The inflated figures hold most relevance in the short term (2-3 years). It was decided that the figure used should therefore be as derived with this in mind. The current economy is gaining but slowly. It is likely this will continue to be the case short term.

Section 3

3. Assets Covered

3.1 High Level Description of the Distribution Area

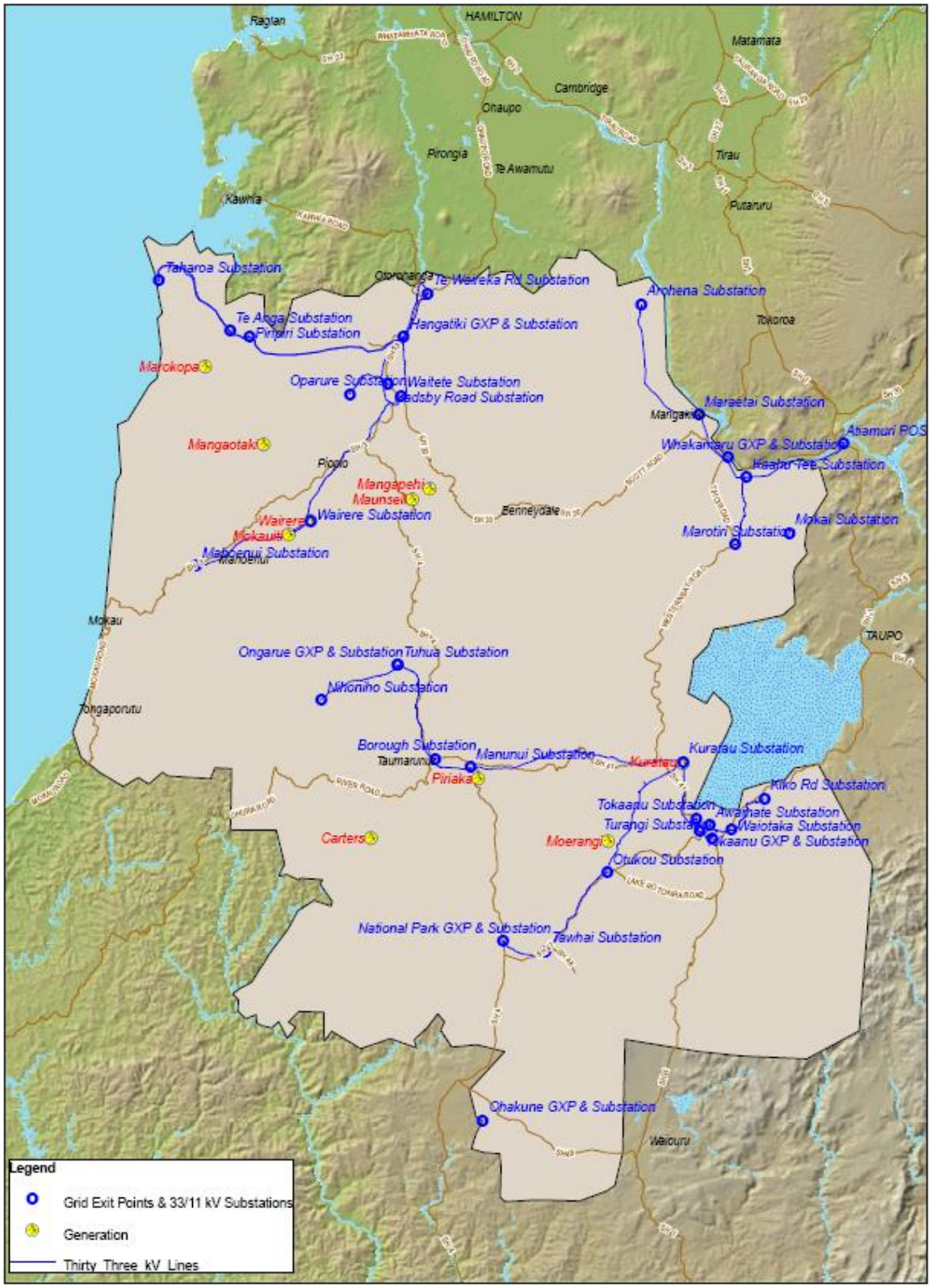


FIGURE 3.1: DISTRIBUTION AREA COVERED BY TLC NETWORK SHOWING GRID EXIT POINTS, GENERATION AND SUB-TRANSMISSION NETWORK

3.1.1 Distribution Area Covered

Figure 3.1 illustrates the distribution area covered by The Lines Company network. Also illustrated are 33 kV sub-transmission zone substation and lines, Transpower grid exit connections, and major generator supply points and embedded generation.

The coastal western edge of the network starts on the south side of the Kawhia harbour and extends south to Mt Messenger. Heading south and east, the network includes Mt Ruapehu and the two large ski fields (Whakapapa and Turoa), Ohakune and most of the area around Lake Taupo excluding Kinloch and the town of Taupo. North from Lake Taupo, the area follows the south bank of the Waikato River to Arohena then west back to the southern side of the Kawhia harbour. The area covers 13,700 km².

3.1.2 Network Characteristics

Some of the asset layouts within the TLC network are unique, while others are typical of New Zealand network companies. The unique configurations include:

- Few lines on roadsides. Lines tend to go from hill to hill in predominately rugged terrain.
- Large numbers of Single Wire Earth Return (SWER) systems (60 plus).
- Significant area is supplied directly from major Waikato generation plants bypassing Transpower grid exit points (GXP). (Note: A milk plant at Mokai means that this arrangement has become a little more unique and includes an inter-connectable embedded network supplied directly from the Mokai geothermal plant.)
- Large numbers of distributed hydro generators.
- Sparsely populated rural network with no major urban centres.
- Long lengths of 33 kV network connecting distributed generation and zone substations.
- Long lengths of privately owned 11 kV lines, often in remote rugged country.
- Apart from the 11 kV cables on Mount Ruapehu, there are relatively few 11 kV cables in the network.
- Generally old network.
- Many of the lines have low mechanical strength, with close conductor spacing and long spans.

The typical layout is grid exit connection being at 33 kV and this is passed onto zone substations. 11 kV feeders radiate out from these substations to towns, settlements and rural customers where supply is transformed to 400/230 V. Collectively (overhead and underground), the network length is 4,323km.

3.1.3 Demarcation and Ownership

The asset boundaries are downstream of the Transpower grid exit points, as defined in Transpower standards, through to customers' points of connections as defined in TLC's Terms and Conditions of Supply. The point of demarcation between customer and network assets can be complex and difficult to define in legislation, partially due to various amendments to Acts and Regulations over the last 40 years being inconsistent on this issue.

In cases where supply is taken from more complex arrangements such as the Whakamaru area, the demarcation point is that defined in the contractual documents, or at the boundaries of the assets owned by TLC. The asset boundary for distributed generators is the 'Point of Connection' as detailed in TLC's Terms and Conditions of Supply.

The Waikato River connection arrangement for part of the TLC network means this section of the network is not subjected directly to Transpower connection and interconnection charges. However, other asset and generator costs replace a number of these charges.

Company policy is to regard any line that supplies a property owned by a single entity as private regardless of voltage. The private lines start at the Point of Connection to the network and then travel to individual properties. The 'Point of Connection' may or may not be the 'Point of Supply'. The 'Point of Supply' is defined in legislation and, in most cases, is the point where a line crosses the boundary to a property.

If these lines were included in the assets owned by TLC, the likely line length increase would be a further 17% or approximately 730km.

These private lines can be non-compliant with present day codes and from time to time can cause faults that affect other customers. The Electricity (Safety) Regulations 2010 have also imposed further liabilities on the owners of these lines in terms of compliance.

3.1.4 Large Load Customers and the impact on network operations

TLC recognises that large customers need to be competitive in their enterprises in both the national and international market places. As a consequence it is not possible to increase prices to this group of customers to subsidise the renewal of remote rural lines. Pricing to large customers has to be calculated on the actual cost of supply.

The large load customers have a significant impact on network operations and management priorities. In TLC's case, there is on-going communication with each of these customers and the long-term asset plans for the network consider the expectations communicated by them.

3.1.4.1 Large load customers: description, impact and management

Iron Sands Extraction

Description:	Iron sands processing and ship loading at Taharoa
Impact on TLC Network:	The plant has a steady mining load of about 3MW that increases to 8.5MW at interval of 4 to 5 weeks during ship loadings over a four day period. It is during these periods that the Hangatiki grid exit system peak loads occur. The amount of dedicated asset, including the Taharoa zone substation built on the West coast iron sand beach, means maintenance and renewal requirements for the site are high. The income received from this business, the size of peaks and ensuring the assets operate reliably have significant impact on network operations. Also, the plant has an impact on system losses. The customers' commitment to increase the size of the bulk carrier ship means that there will be a re-investment into the site over the next two years. The projected site load is in excess of 25MW from the end of 2016.
Asset Management Priorities:	The iron sand extraction process involves pumping product in undersea pipelines to about 3.5 km off shore onto large ships. Supply reliability is essential and work has been taking place to improve this. The economic downturn stalled plans for reinvestment at the site, however the plant has recently indicated that it is willing to fund reinvestment as a consequence of forward customer supply contracts as the NZ Steel owners look to expand production. The substation is in poor condition, and the need to eliminate/minimise hazards and other impacts of the Iron Sand's operation has been considered in this Asset Management Plan.

Ski Fields

Description:	Whakapapa and Turoa ski fields at Mt Ruapehu. Operators of chairlifts, ski field facilities and snow making equipment.
Impact on TLC Network:	An additional 3.5MW (approx.) of winter peak load is added to the TLC network. The installations are in extreme, very sensitive environments that require constant maintenance and renewal work. The owner and operator of the ski field are progressively investing in development of the ski field.

Asset Management Priorities:	Both ski fields have some hazard related risk sites, which the operators are aware of. Most have been addressed with the installation of significant amounts of appropriately rated switchgear as part of a hazard minimisation/elimination program. Reliability to the Ski Fields has improved as a by-product. Included in this asset management plan are estimates for addressing the remaining hazards on both of the ski field sites. The ski fields operate in a World Heritage Park and TLC has developed a strong working relationship with DOC. TLC is also working with ski field owners to minimise peak-based charges by operating on-field generation into the network. The ski field and related accommodation use affect National Park and Ohakune grid exit peak loads. These loads are included in asset management planning.

Corrections Department

Description:	Hautu and Rangipo Prisons.
Impact on TLC Network:	Adds about 1 MVA of load to the Tokaanu grid exit point. The customer has requested and funds a higher level of reliability.
Asset Management Priorities:	The Department of Corrections is undertaking changes to the site, in particular increasing security and changing property ownership status. However there are no significant load implications - planning implications are primarily for line and asset relocations on a one-off basis.

Limestone Extraction and Processing

Description:	Six plants at various locations in the Te Kuiti district.
Impact on TLC Network:	The plants have a combined load of about 8 MVA. Operating loads tend to be seasonal and dependent on orders. Connected plant consists mainly of large motors that tend to reduce network power factor.
Asset Management Priorities:	Owners of a number of these plants have concerns about voltage sags and reliability, which have led to a change in asset design approaches. Specifically, TLC is planning for smaller localised zone substations to fulfil these customers' needs. A number of the plants have hazards associated with the transformer enclosures and switchgear they own. Some have proposals to eliminate/minimise these hazards and issues. The peak lime processor loadings coincide in late summer. The timing of these loadings is currently driving the loss of n-1 capacity at the Hangatiki grid exit. During the late summer when these peaks occur, the run of the river distributed generation has low output. Most of the energy that these plants consume through these periods has to be sourced from the national grid as opposed to the outputs of distributed generation.

Meat Processors

Description:	Two plants on the Te Kuiti urban boundary and a third rural plant at the end of two, 40km long, 11 kV feeders.
Impact on TLC Network:	The 3 plants have a combined load of about 5 MVA. Plants on town boundaries are connected to 11 kV feeders. Reclosers are located on these feeders just beyond the plant Point of Connection, with the objective of maintaining the supply to the plants by isolating the sections of rural line should a fault occur beyond the plant. These plants are sensitive to switching surges and early

	discussions were held to provide the plants with dedicated 33/11 kV zone substations to reduce voltage sag.
	The rural plant at the end of two long 11 kV feeders, needs three to four regulators to support voltage and adds to the operating complexity of these feeders. (Half the plant is supplied from one feeder and half from the other.) The plant location has an impact on system losses.
Asset Management Priorities:	TLC is also working with Meat processor owners to minimise peak-based charges. Due to the impact of the load of the Crusader Meats plant TLC is looking at options for smaller localised zone substations to fulfil these customers' needs.

Timber Processors

Description:	Two plants are on the Te Kuiti urban boundary. A third plant is located at Tangiwai and other smaller plants at Otorohanga.
Impact on TLC Network:	Two Te Kuiti plants have a combined load of about 3 MVA. The plants are connected to the 11 kV network and are sensitive to feeder faults, auto recloses, and surges beyond the connection points.
	The Tangiwai plant is supplied from Tangiwai GXP. This plant only connected to the TLC network when the Tangiwai GXP is taken out of service for maintenance purposes. This is usually done during low load times.
Asset Management Priorities:	Owners of a number of these plants have concerns about voltage sags and reliability, which have led a change in asset design approaches. Specifically, TLC is planning for smaller localised zone substations to fulfil these customers' needs.

Mokai Energy Park: Milk Plant: Glasshouses

Description:	The Tuaropaki Trust have created an industrial Energy Park adjacent to the Tuaropaki geothermal plant at Mokai. The complex encompasses the Miraka milk powder plant and Gourmet Mokai glasshouses.
Impact on TLC Network:	The Mokai Energy Park network is directly connected to the Tuaropaki Power 120 MW geothermal plant. The network interconnects with the TLC network and 2 way energy transfer is possible.
	The entire development was established in a remote area, with the TLC network initially providing supply to low demand farming communities. The establishment of the energy park means the network is operated at the limits of its capability, particularly when the geothermal station has its annual maintenance outage.
Asset Management Priorities:	TLC has constructed a network that interconnects with other assets and supplies energy park customers. TLC assets supply the milk plant and glasshouse in the industrial complex. These loads cannot be back fed totally from the surrounding legacy network and hire generators have to be used to support this load when the geothermal plant is not available. The fault levels are high and appropriately rated assets have to be used. It is a complex interconnection that requires careful balancing of power flows by System Operators and Engineers. For the short periods of operation in this manner, a large investment for a more stable supply is difficult to justify.

3.1.5 Generation Customers and the impact on network operations

3.1.5.1 Distributed generation

Most sites connected to the TLC network have issues that require network engineering attention. To date these issues have held a lower priority for engineering time than other needs such as hazard elimination/minimisation. Looking forward however it is planned to change this and tune the integration of these plants into the network to improve energy efficiency.

The tuning of generator plant will become a higher asset management priority as TLC's analysis models are developed and reactive power flows become better managed. This will include generation investors fitting modern controllers, and TLC updating regulator controllers and protection.

All sites have a significant effect on grid exit power factor. (A full explanation of why and how is included in Section 5 of this Plan.) The poor power factor may have a significant impact on grid connection charges if the Electricity Authority and Transpower enforce power factor requirements associated with the Governance Rules. TLC has an exemption from the rules for the Hangatiki Grid Exit and will extend this to other sites.

A summary of the distributed generation connected and injecting >=1 MW into the network is listed in Table 3.1.

Ongarue GXP Load Support			**Hangatiki GXP Load Support**		
Machine/Location	**Nameplate size (kW)**	**Notes**	**Machine/Location**	**Nameplate size (kW)**	**Notes**
Kuratau 1	3000	1	Wairere 4	3000	2
Kuratau 2	3000	1	Wairere 5	1190	2
Piriaka 1	1000	1	Mokauiti 1	1000	2
Piriaka 2	250	1	Mokauiti 2	600	2
Piriaka 3	250	1	Mangapehi 1	1500	2
			Mangapehi 2	1500	2
			Speedies Road	2200	3

TABLE 3.1: GENERATION >=1 MW

Notes:

1. *Ongarue is the GXP that these generators generally support; however, they can be switched to support National Park or Tokaanu as required.*
2. *Hangatiki is the GXP that these generators generally support; however, they can be switched to support Whakamaru on a limited supply basis.*
3. *Hangatiki is the GXP that this generator supports. It cannot be switched to support other GXP's*

3.1.5.2 Distributed Generation >=1 MW

Kuratau Energy Retailer Site

Description:	6 MW supporting Ongarue GXP under normal conditions. Switching may be altered to support National Park or Tokaanu as required.
Impact on TLC Network:	Normal operation of the plant causes Ongarue grid exit to run backwards for long periods. The Kuratau generation connection arrangement and controller restricts auto-reclosing on some 33 kV lines which has caused longer outage times. The input into the transmission grid causes Transpower charges at Ongarue to be proportioned between injection and off-take. In the present operational configuration, the Manunui to Kuratau 33 kV line is almost exclusively used for the transportation of this generation back towards the Ongarue grid exit point. The generator controllers at Kuratau cause some unhealthy surges in combination with the investor owned Moerangi generation on rundown after a line tripping. At light load times the Kuratau controller's limited ability to absorb reactive power means the light load voltages can become excessive. (Some improvements to this have recently been made.) The output is used to maintain network voltages during shutdowns of the Ongarue, National Park, and Tokaanu grid exits. The plant increases the network voltage at Taumarunui during some periods. Injection of the Kuratau generation into Ongarue adds to system losses as compared to the alternative Tokaanu. Kuratau generation does not tend to island except for the above-mentioned oscillations on rundown. The plant reduces the Ongarue grid exit power factor.
Asset Management Priorities:	Adjustment of controllers to stop voltage surges on rundown, TLC are working with owner to ensure plant can be auto-reclosed and renegotiating connection contracts and allocation of the costs of dedicated assets. The owners have modified control systems to absorb reactive power during light load periods to hold down the voltage on the sub-transmission network. Integration of this plant into the TLC network requires further work and there have been tripping events at the site which require further analysis.

Piriaka Energy Retailer Site

Description:	1.5 MW supporting Ongarue GXP. Piriaka was the original supply point for Taumarunui
Impact on TLC Network:	The output is used to maintain network voltages during shutdowns of the Ongarue, National Park, and Tokaanu grid exits. Recent improvements have been made to the plant controllers and protection by the owners. Previously the plant islanded and produced varying frequencies and voltages. These varying frequencies and voltages had the potential to destroy large numbers of customers' electronic appliances. The plant causes a reduction in the Ongarue grid exit power factor. The plant increases the network voltages during some periods.
Asset Management Priorities:	Researching the controllers that have been recently fitted and running network models to see how these can be better integrated into the network. Work is also needed on the commercial connection contracts.

Wairere Falls Energy Retailer Site

Description:	4.2 MW supporting Hangatiki GXP. The plant was originally built to supply the Piopio area.
Impact on TLC Network:	The plant will island, cause surges on rundown and restrict auto-reclosing. It can however be used to support the network. Preliminary discussions have been had with the plant owners to improve the controls at this plant site. The plant causes a reduction in the Hangatiki grid exit power factor.
Asset Management Priorities:	Adjustment of controllers to stop voltage surges on rundown. TLC are working with the owner to ensure the plant can be auto-reclosed, and renegotiating connection contracts and allocation of dedicated assets costs. The owners have modified control systems to absorb reactive power during light load periods to hold down the voltage on the sub-transmission network. Researching the controllers that have been recently fitted and running network models to see how these can be better integrated into the network. Work is also needed on the commercial connection contracts.

Mokauiti Energy Retailer Site

Description:	1.6 MW supporting Hangatiki GXP
Impact on TLC Network:	The connection is integrated into that of the Wairere Falls complex. The site has two induction machines that tend not to cause many adverse operational effects. The plant causes a reduction in the network and Hangatiki grid exit power factor. There are currently no operational capacitors providing additional power factor connection.
Asset Management Priorities:	Adjustment of controllers to stop voltage surges on rundown. TLC are working with the owner to ensure the plant can be auto-reclosed, and renegotiating connection contracts and allocation of dedicated assets costs.

Mangapehi

Description:	3 MW supporting Hangatiki GXP. The plant is a wholly owned subsidiary of TLC.
Impact on TLC Network:	The generation is 'run of the river' and there is growing industrial load in the area. When water is available, regulators have to be used in reverse to reduce generation output voltage In more recent times most of these problems have been understood. An innovative control scheme has been developed to co-ordinate the output of the generation and industrial load to improve power quality and energy efficiency in the area. The plant increases network voltages and causes a reduction in the Hangatiki grid exit power factor.
Asset Management Priorities:	Tuning of regulator, protection settings and adjustment of about 20 to 30 local transformer tap settings.

Speedies Road, Te Anga

Description:	2.2 MW supporting Hangatiki. The single, synchronous plant is a subsidiary of TLC and Investor owned.
Impact on TLC Network:	The plant increases network voltages that have to be managed and causes a reduction in the Hangatiki grid exit power factor.

Asset Management Priorities:	Modify the current SCADA program so that real time data can be made available for network analysis on Hangatiki GXP. Currently the system records instantaneous KW data at half hourly periods.

3.1.6 Description of the Load Characteristics of different parts of the network

High-level descriptions of the load characteristics of the different parts of the network, grouped in non-electrically contiguous, but abutting, supply regions are outlined in the following sections.

3.1.6.1 Hangatiki area (north western region)

Regional Activities Affecting Load

- Industrial loads including iron sand extraction, sawmilling, limestone and meat processing.
- Rural loads include dry stock and dairy farming.
- Run of the river hydro generation.
- Domestic load base of residents who are largely employed in the above activities.

Resulting Load Characteristics

The peak system load is dominated by the monthly cycle of the loading of the iron sands ship. If this loading coincides with dry periods and low river flows -resulting in low distributed generation output - then a grid exit point connection local peak is set.

Limestone and meat processing peaks are seasonal and operate for varying periods throughout the year. Most of the sawmilling operations tend to be 5 ½ days per week, 10 hours per day activities.

Dairy farming is a seasonal activity that produces a peak springtime load. Most dairy farms have two daily peaks when milking is underway, with a down time between May and August.

The cumulative effects of these activities results in a local grid peak in March or April and a late winter/autumn system peak. (System peak is the sum of grid exit and distributed generation inputs.) The system peaks tend to have lower power factors due to the effects of the distributed generation.

3.1.6.2 Whakamaru area (north eastern region / Waikato River area)

Regional Activities Affecting Load

- Predominantly a dairy farming area.
- Has a “sub-set” network that supplies the Mokai Energy Park. The Energy Park has two major customers; a glasshouse and a milk plant.

Resulting Load Characteristics

The peak system load in this area occurs during the dairy season. This region of the network is connected to three major generators and is upstream of the grid exit point as detailed in other sections of this Plan. Consequently, it is not directly subjected to Transpower interconnection or connection charges. An additional connection is proposed to increase security for the milk plant.

3.1.6.3 Central region (includes National Park, Tokaanu and Ongarue grid exit points)

Regional Activities Affecting Load

- Holiday homes around Lake Taupo.
- Whakapapa Ski Field.
- Kuratau Distributed Generation.
- Domestic load in Taumarunui.
- Corrections Department load in the Turangi area.

Resulting Load Characteristics

The holiday homes around Lake Taupo cause an Easter and school holiday peak on the Tokaanu grid exit point. The timing of this peak depends on which holiday period has the coldest weather. These can occur over cold holiday periods, during the ski season and occasionally at Christmas.

The ski season dominates the peak loading at the National Park grid exit point. During summer there are medium levels of load due to activities such as farming operations, accommodation, and ski field activities such as chairlifts that are run to provide access for trampers. During periods of light load and after heavy rainfall, the Kuratau distributed generation often causes the Ongarue or Tokaanu grid exit points to run backwards.

The Taumarunui load follows the normal domestic pattern and typically causes a system peak during the winter period. The timing of the grid exit peak is dependent on rainfall and the generation available. Taumarunui has little industrial load and over recent years the peak demand has increased. The power factors of each of the three grid exit points are reduced whenever the Kuratau, Piriaka and Moerangi distributed generation is connected to them.

3.1.6.4 Ohakune region

Regional Activities Affecting Load

- Ski season.
- Carrot processing.
- Increasing dairying load.

Resulting Load Characteristics

Peak load is based on winter holiday periods and dependent on weather during the ski season. The weather conditions during school holiday weekends have a significant effect.

3.2 A Description of Network Configuration

3.2.1 Identification of Bulk Electricity Supply Points

3.2.1.1 Arapuni to Bunnythorpe 110 kV system

Figure 3.2 illustrates a simplified layout of the Hangatiki, Ongarue, National Park, and Ohakune grid exit points.

Supply to the Hangatiki grid exit point is via two Transpower circuits from Arapuni or one from Bunnythorpe. The southern Bunnythorpe circuit has Ongarue, National Park, Ohakune and Mataroa connected to it. (Mataroa is not a TLC supply point.)

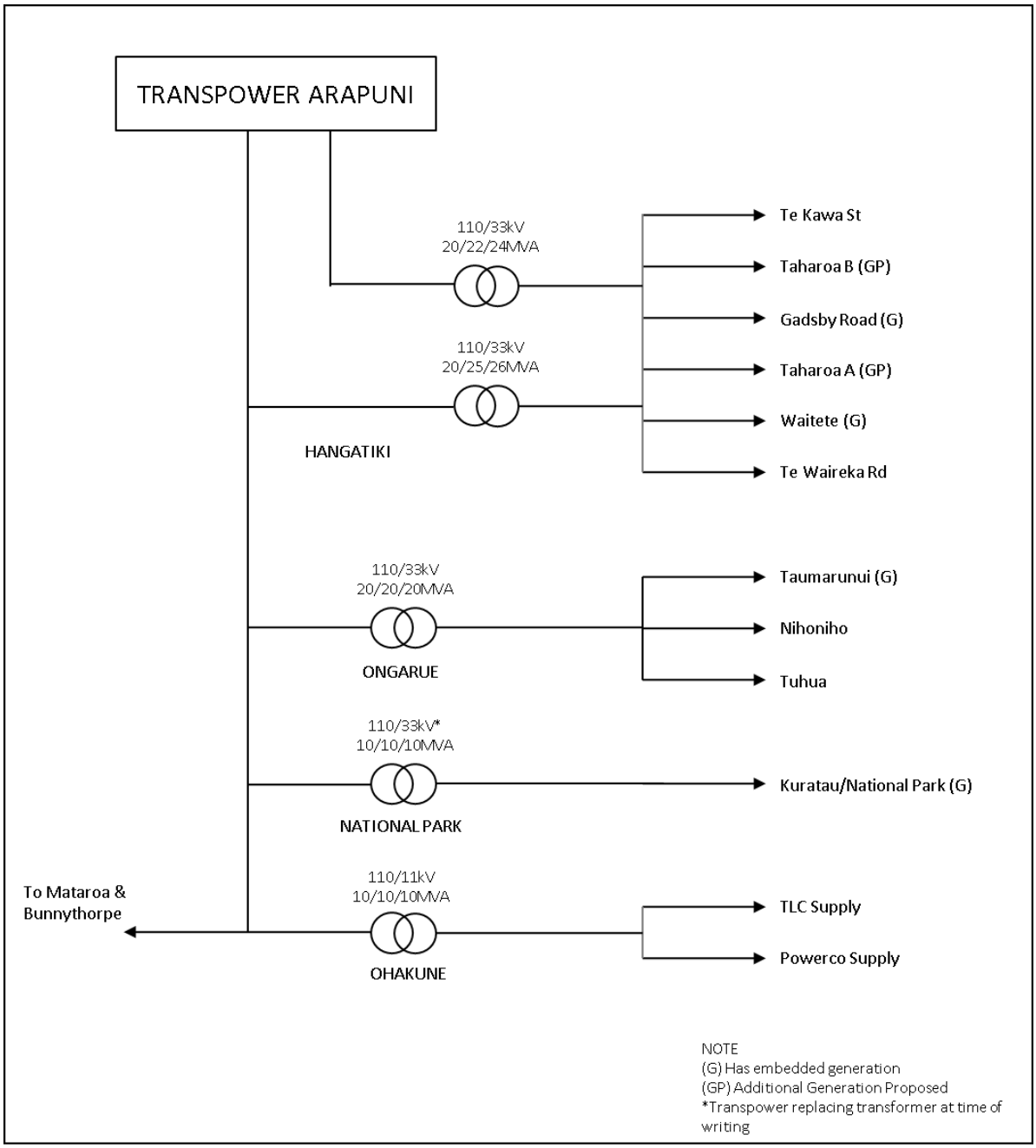


FIGURE 3.2: SIMPLIFIED SINGLE-LINE DIAGRAM OF THE HANGATIKI, ONGARUE, NATIONAL PARK AND OHAKUNE GRID EXIT POINTS

Note: Transformer Ratings shown are Maximum Continuous/Summer/Winter (e.g. 10/10/10MVA). Ohakune has the only regulated transformer supply. The tee into Hangatiki from the circuit going south is about 6km from the substation.

3.2.1.2 Tokaanu

Figure 3.3 illustrates the arrangement at Tokaanu whereby TLC takes energy from Transpower via two 220/33 kV transformers. These transformers are unregulated.

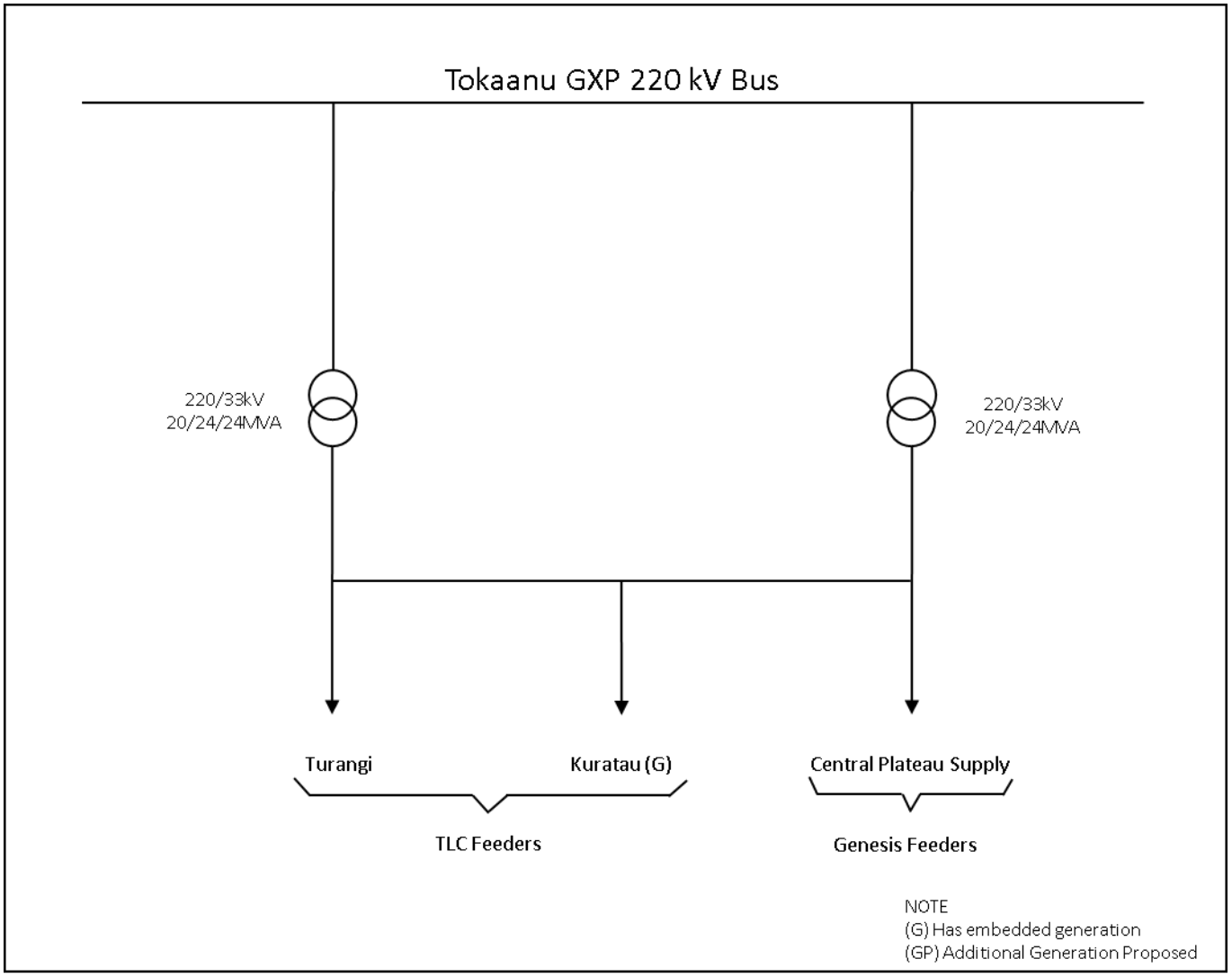


FIGURE 3.3: TOKAANU CONNECTION DETAIL

Note: Transformer Ratings shown are Maximum Continuous/Summer/Winter (e.g. 20/24/24MVA).

3.2.1.3 Whakamaru and Atiamuri

Figure 3.4 illustrates the arrangement at Whakamaru where energy comes directly from either the Mokai investor owned geothermal station or Mighty River Power (MRP) G4 generator.

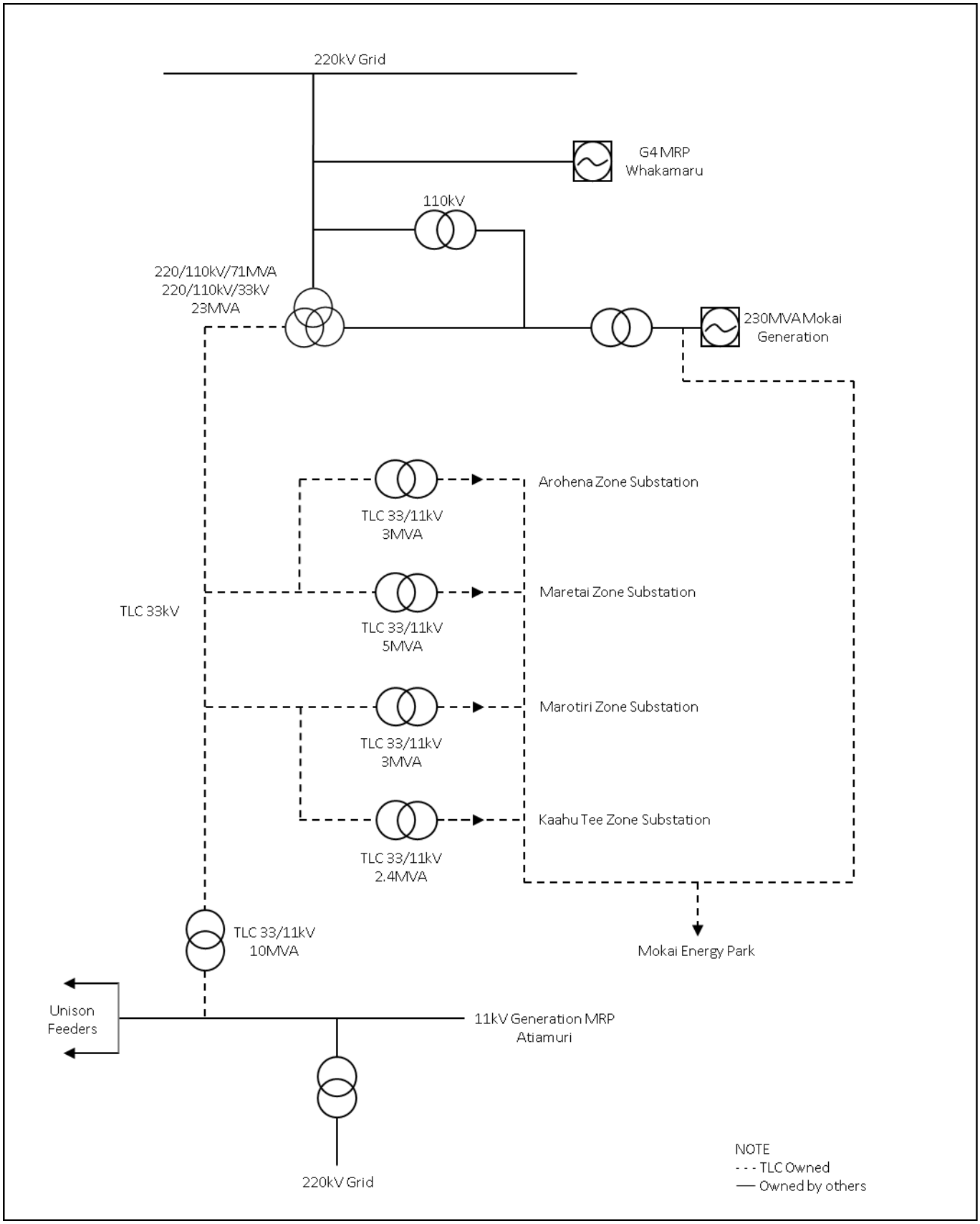


FIGURE 3.4: WHAKAMARU AND ATIAMURI CONNECTION DETAIL

At Whakamaru, the TLC 33 kV network is connected to the third-winding on a three-winding transformer that also connects the 110 kV output from Mokai to the 220 kV G4 generation bus. This network has another connection and alternative supply via a TLC 33 kV line from the MRP Atiamuri site. This bus also connects to the Unison network and the grid via 11/220 kV transformation. Mokai and/or G4 are run to supply TLC so the connection contracts at these points are not with Transpower.

The link also gives MRP the ability to shut down Atiamuri and supply Unison network customers via the TLC network during periods of controlled river flow control. A third interconnection on the 11 kV network between TLC and the Mokai generation is used principally to supply the Mokai Energy Park.

The arrangement at Whakamaru and Atiamuri is unique and means that the TLC network is operating a mini transmission grid in parallel with Transpower. This arrangement came about when Transpower decided it wanted to significantly increase the cost of supply into the area as a consequence of its decision to decommission the Waikato 50 kV system in the late 1990s. The best solution found at the time was for TLC to purchase the 50 kV Atiamuri to Arohena segment of Transpower assets, including the Arohena, Maraetai, Kaahu Tee and Marotiri substations. The sub-transmission was then converted to 33 kV and connected the substations to Mokai and Whakamaru G4 outputs. The development of the Mokai Energy Park resulted in an off-take to supply this from the Mokai geothermal generation.

3.2.1.4 Ohakune emergency supply

TLC has assets in place to take an 11 kV connection from Winstones plant at Ohakune. This supply comes via the Transpower 220 kV to 11 kV supply to the mill. TLC has a metered tap off via an 11 kV remotely controlled circuit breaker back into the Ohakune network.

This connection is used to:

- Supply Ohakune when the Transpower Ohakune grid exit point connection is out of service for planned and unplanned work. (The connection cannot supply the total Ohakune load during the winter period.)
- Supply the mill during maintenance periods when the 220/11 kV supply to the mill is not available. The connection is not capable of running the mill operation, but allows the site to be energised for maintenance activities.
- In an emergency when the 15km 11 kV line between the mill and Ohakune is not available, this supply can be used for the Whangaehu Valley area.

3.2.2 Existing Firm Supply Capacity and Current Peak Load of each Supply Point

Table 3.2 lists the existing firm supply capacity and current peak load of each supply point.

FIRM SUPPLY POINT CAPACITY AND PEAK LOAD				
Grid Exit Point	**Capacity Arrangement**	**Current Peak (2013/14 Year) (MW)**	**(MVA)**	**Power Factor**
Hangatiki	1 x 20/22/24 1 x 20/25/26	32.73	36.90	0.887
Ongarue	1 x 20/20/20	8.24	8.31	0.911
National Park	1 x 10/10/10	5.81	5.87	0.990
Ohakune	1 x 10/10/10	6.81	6.98	0.976
Tokaanu	2 x 20/24/24	9.27	9.52	0.974

TABLE 3.2: SUPPLY CAPACITY AND CURRENT PEAK LOAD AT EACH GRID EXIT POINT

Note: Whakamaru is not a grid exit point as it is upstream of Transpower assets. Accordingly, it has not been included in this table.

The Hangatiki grid exit point is presently peaking above its firm (n-1) capacity at times when generation is not available. The Ohakune supply point is expected to reach full transformer capacity with ski field expansion.

One of the significant effects of distribution generation is to reduce the grid exit power factors. This occurs at the Hangatiki and Ongarue and Tokaanu grid exits. This reducing power factor effect is discussed further in later sections.

3.2.3 Assets at Locations not owned by TLC

Table 3.3 lists the locations where TLC own assets but not the site land.

ASSET LOCATION	
Owner / Location	**Assets**
Mighty River Power: Atiamuri (site leased to Transpower)	Atiamuri zone substation, 33 kV breaker, protection and controls, RTU and 11 kV cabling.
Mighty River Power: Whakamaru (adjacent to Transpower substation)	Whakamaru zone substation, 33 kV circuit breaker, protection, SCADA and communication assets, an earthing transformer and metering.
Transpower: Hangatiki	Hangatiki zone substation, 11 kV switchgear, relays, SCADA and 317 Hz ripple plant.
Transpower: National Park	National Park zone substation, ripple injection plant (also containerised) and associated SCADA assets.
Transpower: Ongarue	Termination spans, bypass switching, site development and fencing. Containerised ripple injection plant, SCADA and associated communication equipment.
Transpower/Genesis Energy: Tokaanu	Load control plant and 33 kV switchgear.

TABLE 3.3: ASSETS AT LOCATIONS NOT OWNED BY TLC

3.2.4 Sub-transmission Distribution Network

3.2.4.1 Sub-transmission Network Overview

Figure 3.5 below summarises the 33 kV sub-transmission network, from point of supply to zone substation. The geographical layout is illustrated in section 3.1.

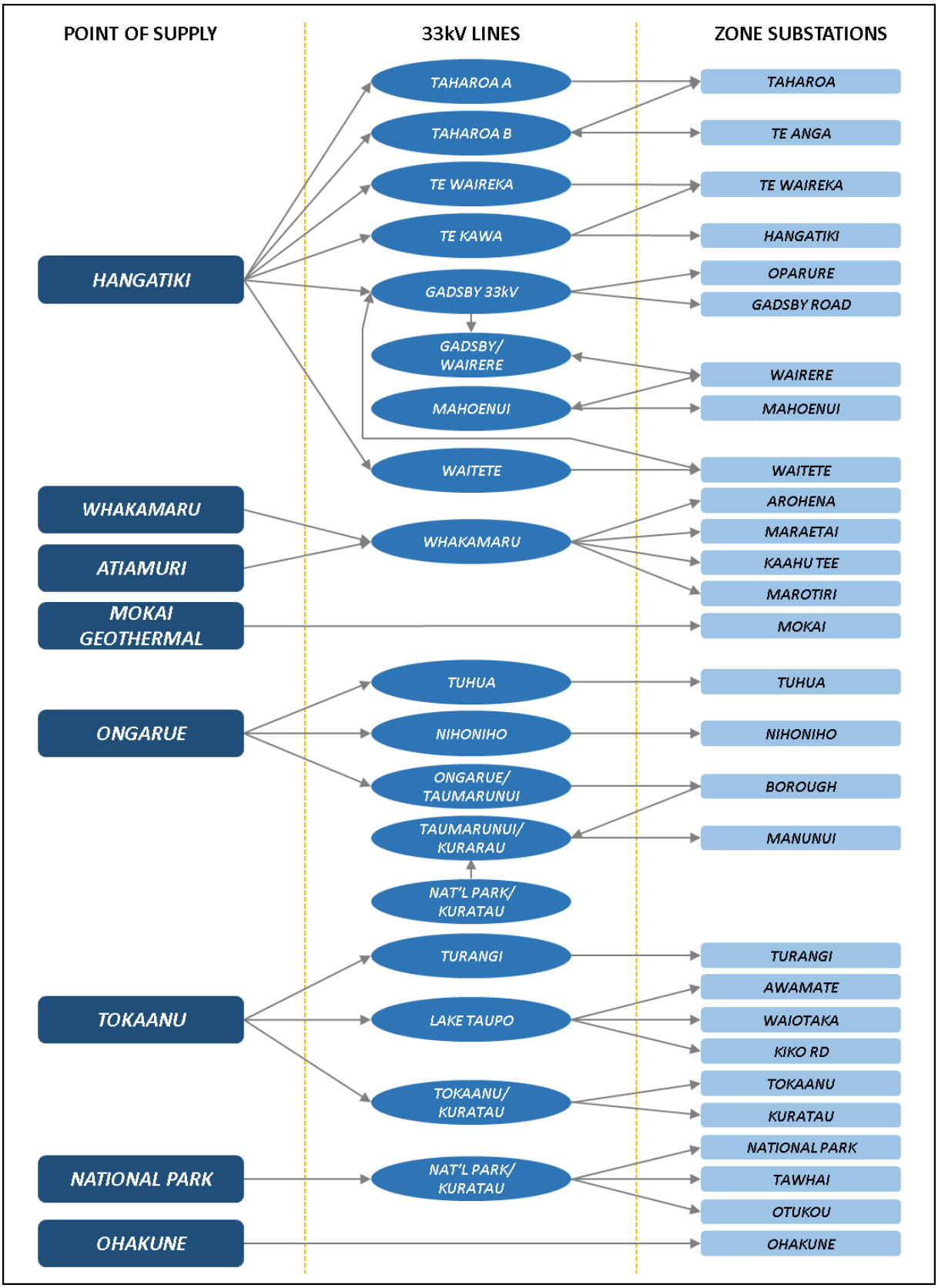


FIGURE 3.5: 33 KV SUB-TRANSMISSION SYSTEM

3.2.4.2 Sub-transmission 33 kV Lines and Cable

The configuration description and backup security of sub-transmission line assets is included in Table 3.4. The 33 kV feeder assets are listed by supply point. Overall, TLC sub-transmission network comprises 498 km of overhead line and 2.2 km of XLPE cable (primarily associated with zone substations).

SUB-TRANSMISSION SUPPLY POINT / FEEDER CONFIGURATION	
Description	**Configuration, Backup and Condition**
HANGATIKI SUPPLY POINT	
Gadsby / Wairere (FED307) Length: 34.1km	Part of ringed network linking Te Kuiti, Wairere generation and surrounding industrial areas to Hangatiki GXP. About 5% of the time it can be backed up by Wairere generation provided that generators are carefully controlled. Well-designed line that has been partly renewed over the last few years. Main problems generally involve trees, insulator failure due to fertiliser build-up and aged component failure. A substantial number of insulators have been changed from 33 kV to 44 kV ratings.
Gadsby Rd (FED305) Length: 17.7km	Part of ringed network linking Te Kuiti, Wairere generation and surrounding industrial areas to Hangatiki GXP. At the end of the planning period, these lines will be at full rating. Travels through hill country. Operated in closed ring. Backup from Waitete 33kV to about 75% of present full load. (Back up has difficulty when load is high and river flows are low). Well-designed line that over the last few years has been partly renewed. Main problems over recent years have been trees, insulator failure due to fertiliser build-up and aged components failure. A substantial number of insulators have been changed from 33 kV to 44 kV ratings.
Taharoa A (FED301) Length: 57.6km	Principally for supply to the iron sand extraction plant at Taharoa. Includes some local rural supply. Backed up to full load by Taharoa B line. A well designed line that over the last few years has been renewed in parts. Further renewal of poles and hardware is needed. Main problems over recent years have been trees, insulator failure due to fertiliser build-up and aged component failure. A substantial number of insulators have been changed from 33kV to 44kV ratings. Further renewal will have to be funded by the customer if they require an improved level of reliability.
Taharoa B (FED302) Length: 47.9km	Supply to the iron sand extraction plant at Taharoa. Includes some local rural supply. The line is not roadside and travels through hill country. Operated in closed ring. Backed up to present full load from Taharoa A line. Well-designed line that over the last few years has been extensively renewed in parts. Main problems over recent years have been trees, insulator failure due to fertiliser build-up and aged component failure. A substantial number of insulators have been changed from 33 kV to 44 kV ratings. Removal and renewal of hazardous equipment on the Taharoa B line is included in this plan.
Te Kawa St (FED304) Length: 12.0km	One of two lines supplying north from Hangatiki to the Otorohanga area. Loadings and security requirements show that the line is needed. Travels through hill country. Operated in closed ring. Te Waireka 33kV line. Backed up to present full load. A well designed line that over the last few years has been renewed for most of length. Main problems over recent years have been insulator failure due to fertiliser build-up and aged component failure. A substantial number of insulators have been changed from 33 kV to 44 kV ratings.

SUB-TRANSMISSION SUPPLY POINT / FEEDER CONFIGURATION	
Description	**Configuration, Backup and Condition**
Te Waireka Rd (FED303) Length: 8.2km	One of two lines supplying north from Hangatiki to the Otorohanga area. Loadings and security requirements show that the line is needed. Travels through hill country. Operated in closed ring. Te Kawa 33kV line. Backed up to present full load. A well designed line that over the last few years has been extensively renewed for most of length. Main problems over recent year have been insulator failure due to fertiliser build-up and aged component failure. A substantial number of insulators have been changed from 33 kV to 44 kV ratings. Has been strengthened for part of length to overcome fireball problems from conjoint 11 kV circuits below.
Wairere / Mahoenui (FED309) Length: 22.6km	Spur line between Mahoenui and Wairere. Supplies long 11 kV spur lines after transformation at Mahoenui. Considerable DG resource in area that is under investigation. Travels through hill country. 11kV backup for about 15% of time when light loads exist. Lighter construction than other 33 kV feeders. Main problems over recent years have been trees, insulator failure due to fertiliser build up and aged component failure. A substantial number of insulators have been changed from 33 kV to 44 kV ratings. An extension to this feeder is planned as development and demand in the Mokau area continues to grow.
Waitete (FED306) Length: 10.8km	Part of ringed network linking Te Kuiti, Wairere generation and surrounding industrial areas to Hangatiki GXP. Gadsby Road. Backed up to about 75% of present max loading. Well designed line that over the last few years has been renewed for most of length. Main problems over recent years have been insulator failure due to fertiliser build-up and aged component failure. A substantial number of insulators have been changed from 33 kV to 44 kV ratings to overcome the fertiliser problem.
NATIONAL PARK SUPPLY POINT	
National Park / Kuratau (FED609) Length: 59.6km	Interconnecting line between the National Park GXP and Kuratau marshalling site. Normal load on line is the Whakapapa ski field and Central Plateau rural area including supply to the Whanganui river diversion race controls. The line travels across difficult access country and sensitive Maori land. Backup from Kuratau up to about 25% load. In practical terms this means (n-1) except for ski season. The line has been split into two sections. The section between National Park and the Tawhai Substation supplies the Chateau and Whakapapa ski fields. The second section between Tawhai and Kuratau Substation is a secondary link and has been patched at known trouble spots. This line is under ideal design strength and frequently trips when wind speeds exceed about 60km/hr.
ONGARUE SUPPLY POINT	
Nihoniho (FED603) Length: 14.6km	Spur line connecting Ongarue GXP to Nihoniho Zone Substation. Line runs through very hilly and remote country with poor access. 50% load backup on 11kV from Tuhua. (Voltage drop causes issues.) Aged low strength line based on a low cost design. Has had problems with magpies, hardware failure and insulator flashover due to fertiliser build-up.
Ongarue / Taumarunui (FED604) Length: 20.4km	Main line supplying Taumarunui from the Ongarue GXP. Line runs through extremely hilly country. 50% load backup from Tokaanu provided Kuratau and Piriaka generation running. Originally built to a low strength design and upgraded in 2014. Much of the line is in very steep hill country with difficult access. Has had problems with magpies, hardware failure and insulator flashover due to fertiliser build-up.

SUB-TRANSMISSION SUPPLY POINT / FEEDER CONFIGURATION	
Description	**Configuration, Backup and Condition**
Taumarunui / Kuratau (FED608) Length: 43.3km	Interconnecting line between the Ongarue GXP and the Kuratau marshalling site. Normally loaded with output of Kuratau area Distributed Generation back into the Ongarue GXP. If Kuratau DG did not exist or was not paying a fair portion of this line, options for continuing renewal, maintenance and ownership will need further evaluation. The line travels across difficult access country. Backup from National park GXP and Tokaanu (n-1) depending on generation and ski season. The line has adequate size conductor but the poles are well under strength for today's environment. The poles are also very short and the line has a number of ground to conductor clearance issues. Renewal work on this feeder has been put on hold due to the fact that alternative options to maintaining this feeder are currently being assessed
Tuhua (FED602) Length: 0.1km	Few metres of spur line connecting Ongarue GXP to Tuhua Zone Substation. 50% load backup from Nihoniho on 11 kV network. The line is in average condition and not prone to faults.
TOKAANU SUPPLY POINT	
Lake Taupo (FED606) Length: 47.1km	Spur line connecting Tokaanu GXP to the Kiko Road, Awamate Road and Waiotaka substations. Crosses many plots of extremely sensitive Maori land. No fixed backup available, generators are used when back up is required. Line has been rebuilt to withstand the fault current capacity of the Tokaanu Grid Exit. Earlier parts of the rebuild were completed to a low cost design and do not have a high inherent strength. The line crossing the sensitive Tongariro River is of less than ideal design and presents a risk to trout fishermen who use conductive fishing lines. Work to mitigate this hazard is included in the plan.
Tokaanu / Kuratau (FED607) Length: 16.0km	Interconnecting line between the Tokaanu GXP and Kuratau. The line travels across difficult access country and extremely sensitive Maori land. Normally supplies Kuratau Zone Substation and is a backup for the connection of the Kuratau area distributed generation to the grid. Backup from National Park GXP and Ongarue via Taumarunui. (n-1) depending on generation and ski season. Line has adequate size conductor and recent upgrade work has addressed many pole strength and ground clearance issues.
Turangi (FED605) Length: 3.4km	Spur line connecting Tokaanu GXP to the Turangi Zone Substation. The line crosses sensitive Maori land. There is no back up for the Turangi 33kV line. The line includes a number of iron rail poles. Some renewal work was done in 2011.
WHAKAMARU SUPPLY POINT	
Whakamaru (FED310) Length: 113.1km	The line travels through hill country to connect Atiamuri and Whakamaru supply points to Arohena, Maraetai, Kaahu Tee and Marotiri Zone Substations. Very limited backup capacity (about 10%) through the 11kV network. The line was originally constructed as a 50kV transmission line. It was purchased by TLC in 2002 and has since been operated at 33kV. As part of the conversion process, aged conductor was changed and smaller 33kV insulators fitted. Planned work on this feeder includes installation of a second voltage regulator at Maraetai substation to meet increasing demand from dairy farming.

TABLE 3.4: SUB-TRANSMISSION ASSETS CONFIGURATION DESCRIPTION

Figures 3.6 And 3.7 Illustrate age profiles for sub-transmission spans and poles respectively.

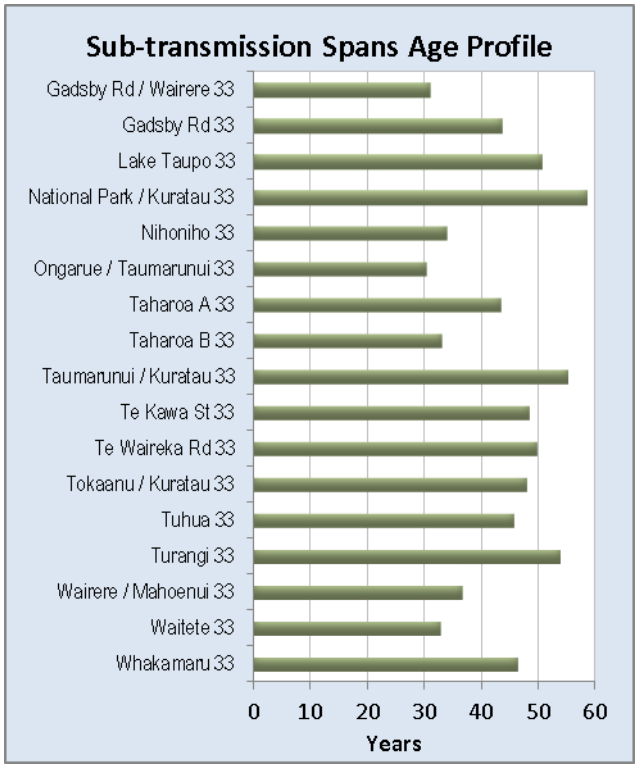


FIGURE 3.6: SUB-TRANSMISSION SPAN AVERAGE AGE PROFILE

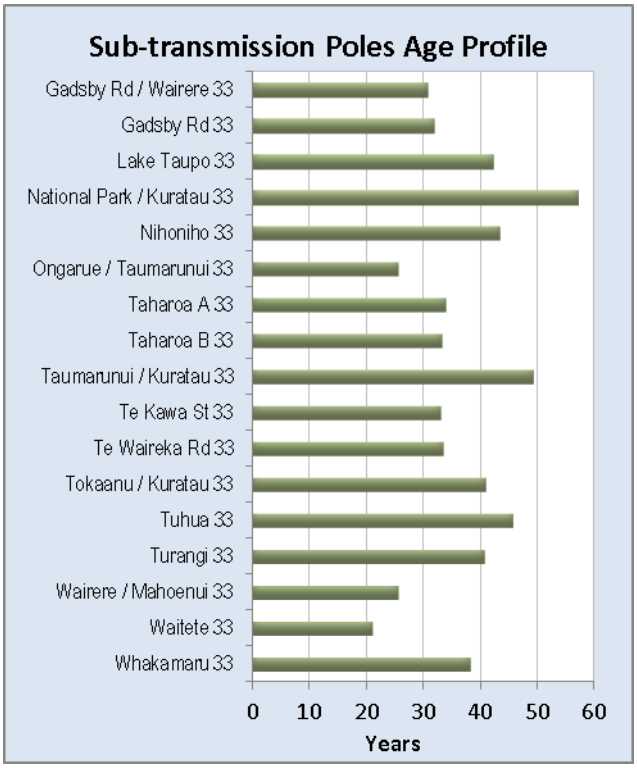


FIGURE 3.7: SUB-TRANSMISSION POLE AVERAGE AGE PROFILE

3.2.4.4 Zone Substations, Switchyards and Power Transformers

TLC has developed a modular, low cost way of establishing zone substations. These units consist of a 20-foot container, one 33/11 kV fixed tap transformer, two standard 11 kV line regulators, and an 11 kV line recloser. A 33 kV line recloser and a length of cable are used to connect the substation to the sub-transmission network. All equipment is installed in such a way that modern SCADA protocols can be used. The first substation was commissioned in 2006. Since then, a further 5 containerised units have been put into service.

The modular units are environmentally acceptable, making resource consents more easily obtained and casting a smaller land footprint. They are transportable, secure, cost 30 to 50% less to construct and offer lower operating costs. The design simplicity minimises commissioning and teething issues, along with reducing and controlling fault currents. They are a good solution to some of TLC's capacity growth strategy, i.e. they are modular and can be added in controlled increments.

It is expected that present development and renewal plans and strategies will see the age profiles of zone substations remain relatively static. New distributed modular substations will provide backup and reduce loading on sites with old equipment or single bus bar arrangements. This will ensure there is no shock to replace the entire assets provided the 15-year inspection and renewal cycle is continued and emergent problems are repaired when they occur.

The age profile of zone substation transformers will stay spread with a flow of new modular units into the lower age section. Older units will be refurbished to extend their life. Experience has shown that most transformers fail after the passage of fault current. Windings and packing become loose and wet with age. Fault currents cause movement and localised heating. Movement can deform windings and localised heating can result in ionisation of moisture in windings. The servicing of older units helps to minimise these effects.

A number of the newer ETEL units have had oil tests come back showing higher than ideal hydrogen levels. This problem has been taken up with the suppliers and a specific problem with oil reacting with galvanising in the tank has been identified. This issue is currently being worked through.

Table 3.5 details each of the zone substations, switchyards and power transformers in the TLC network.

ZONE SUBSTATIONS, SWITCHYARDS AND POWER TRANSFORMERS	
Site/Transformers	**Description / Security / Condition**
Arohena (ZSub211) 1 @ 3000 kVA	Single unit, 33 kV to 11 kV zone substation. The transformer was commissioned in 2002 and tests show the condition of the unit as acceptable. Ex Transpower site with bunding and oil separation. The zone substation has weatherboard housing for the relay room. Very limited, light load backup from 11kV network that cannot support the milking load in the area. In practical terms this means (N).
Atiamuri (ZSub215) 1 @ 10000 kVA	Single unit, 33 kV to 11 kV point of supply. The configuration is unique and part of the innovative arrangement to take supply directly from generators and by pass transmission charges. The transformer was commissioned in 2002 and tests show the condition of the unit as acceptable. Overall site condition is poor. The circuit breaker is planned for replacement in this document. Site is backed up from the TLC 33 kV network and Mighty River Power Atiamuri generation. Provides back up to Whakamaru. In practical terms this means (N).
Awamate (ZSub519) 1 @ 2000 kVA	Single unit, 33 kV to 11 kV zone substation. The transformer was commissioned in 2008 and tests show the condition of the unit as acceptable. A containerised asset in good condition and performing well. Part of backup network for Turangi, with backup from Turangi at light loads. In practical terms this means (N) transformers.

ZONE SUBSTATIONS, SWITCHYARDS AND POWER TRANSFORMERS	
Site/Transformers	**Description / Security / Condition**
Borough (ZSub508) 2 @ 5000 kVA	Two unit, 33 kV to 11 kV zone substation that is able to supply light load on one unit. Two 33 kV supplies are available. The transformers were both commissioned in 1965 and since been refurbished. Tests show the condition of one unit as acceptable and the other marginal. The 33kV switchgear has been renewed and new transformer bunding has been installed. Two of the Four feeder breakers are currently enclosed in a concrete block building and the remaining 2 feeders are in a container. An upgrade of the oil separation system has been included in this plan. Housed assets are currently enclosed in a concrete block building. Upgrades – including relocating and containerising - are included in the plan. Site is not fully backed up as 1x5MVA will not support all load at peak times. Limited light load backup is available from 11kV network with some transfer and embedded generation. In practical terms this means limited (N-1) transformers.
Gadsby Road (ZSub205) 1 @ 5000 kVA	Single unit, 33 kV to 11 kV zone substation on the north side of Te Kuiti. The site has two alternative 33 kV supplies running as a closed ring. The refurbished transformer was commissioned in 2006. Tests show the condition of the unit as acceptable. The site is well built and in reasonable condition. It has bunding and oil separation but not earthquake constraints. Housed assets are enclosed in a concrete block building. Medium load backup is available from the 11kV network. In practical terms this means (N).
Hangatiki (ZSub204) 1 @ 5000 kVA	Single unit, 33 kV to 11 kV zone substation at the Transpower point of supply. There are two alternatives for 33kV supply running as closed ring with a very short spur to substation bus. The transformer was commissioned in 1992 and tests show the condition of the unit as acceptable. A well-built site in reasonable condition. The site includes concrete block transformer housing. It has bunding but no oil separation. The installation of an oil separation unit has been included in this plan Medium load backup is available from the 11kV network. In practical terms this means (N).
Kaahu Tee (ZSub216) 1 @ 2400 kVA	Single unit, 33 kV to 11 kV zone substation embedded in the Marotiri / Maraetai network. The transformer was commissioned in 2009 and oil tests show the condition of the unit as acceptable. A containerised asset in good condition. Backup is available from Marotiri/Maraetai. Cannot be taken out of service during heavy load times. In practical terms this means (N).
Kiko Road (ZSub518) 1 @ 3000 kVA	Single unit, 33 kV to 11 kV zone substation. Single 33 kV line supply with no 11 kV alternatives. The transformer was commissioned in 2001 and oil tests show that high gas discharging is occurring in the transformer, this is currently being addressed by the transformer manufacturer . The site is in good condition and has automatic Aqua Sentry Device bunding. No backup available other than bypassing the substation and injecting 11 kV from Turangi into the 33 kV line. This is light load backup only. In practical terms this means (N).

ZONE SUBSTATIONS, SWITCHYARDS AND POWER TRANSFORMERS	
Site/Transformers	**Description / Security / Condition**
Kuratau (Switchyard)	Switchyard site is at the Kuratau Power Station, with various structures and switchgear. Some of the switchgear has been renewed.
Kuratau (ZSub509) 1 @ 3000 kVA 1 @ 1500 kVA	Two unit, 33 kV to 11 kV zone substation. Three 33 kV supplies are available; there are no 11kV alternatives. Local embedded generation exists when there is sufficient water available. The 3 MVA transformer was commissioned in 1955, is aged and returns poor test results. The 1.5 MVA unit was commissioned in 2009 and it is in good condition. The site is generally in average condition and bunded with a manual outlet valve. The setup provides backup on site however it will not cover full load situations. The backup is not able to be phased so an outage is needed to transfer load. In practical terms this means (N) for emergency use only.
Mahoenui (ZSub209) 1 @ 3000 kVA	Single unit, 33 kV to 11 kV zone substation supplied from a single 33 kV line. The transformer was commissioned in 1966 and tests show the condition of the unit as acceptable. The site bunding and separation unit is in the process of being renewed. The installation of an incoming 33kV breaker for reliability purposes has been included in this plan. Light load backup is available from the 11kV network. In practical terms this means (N).
Manunui (ZSub510) 1 @ 5000 kVA	Single unit, 33 kV to 11 kV zone substation. Two 33 kV supplies are available. The transformer was commissioned in 1965 and tests show the condition of the unit as acceptable. The site was upgraded in 2013. The oil separation now includes an extended sump and additional alarms. Light to medium load backup is available from the 11kV network. In practical terms this means (N).
Maraetai (ZSub210) 1 @ 5000 kVA	Single unit, 33 kV to 11 kV zone substation supplied from a single 33 kV line. Modification made to 24VDC actuators supplied from the 2 x 24 VDC cells. The transformer was commissioned in 2001 and tests show the condition of the unit as acceptable. The site is ex Transpower and has oil separation and bunding. The incoming 33 kV breaker was been renewed in 2014. Light load backup is available from the 11kV network, however it will not support the milking load in the area. In practical terms this means (N).
Marotiri (ZSub212) 1 @ 3000 kVA	Single unit, 33 kV to 11 kV zone substation supplied from a single 33 kV line. The transformer was commissioned in 2001 and tests show the condition of the unit as acceptable. A well maintained ex Transpower site in good condition with oil separation and bunding. Loading is at full or greater than rating. Housed assets are enclosed in a weatherboard building. Light load backup from the 11kV network. This backup will not support the milking and industrial load in the area. In practical terms this means (N).
Mokai (ZSub3358) 1 @ 7500 kVA	Single unit, 11 kV to 11 kV zone substation with a fault reducing transformer. The transformer was commissioned in 2011 and tests show the condition of the unit as acceptable. The substation is semi containerised - the regulator and switchgear is containerised but not the transformer. The site is in good condition and has oil separation and bunding. Light load backup from the 11kV network. In practical terms this means (N).
National Park (ZSub501) 1 @ 3000 kVA	Single unit, 33 kV to 11 kV zone substation with two 33 kV supplies. A new containerised site commissioned in 2014. Test results on the new transformer show some abnormalities this is currently under investigation. The site has bunding and oil separation. Light load backup available from 11kV network. In practical terms this means (N).

ZONE SUBSTATIONS, SWITCHYARDS AND POWER TRANSFORMERS	
Site/Transformers	**Description / Security / Condition**
Nihoniho (ZSub503) 1 @ 1500 kVA	Single unit, 33 kV to 11 kV zone substation supplied from a single 33 kV line. The transformer was commissioned in 2010 and tests show the condition of the unit as acceptable. The site is in poor condition with no bunding or oil separation. The structure currently presents hazard constraints. Improvements are included in this plan. Light to medium load backup is available from the 11kV system. In practical terms this means (N).
Oparure (ZSub208) 1 @ 3000 kVA	Single unit, 33 kV to 11 kV zone substation mostly supplying a limestone processing plant. Supply is via a 33 kV line spurred off a closed ring. The transformer was commissioned in 1994 and tests show the condition of the unit as acceptable. The site is in good condition despite operating in a harsh environment. The installation of bunding and an oil separation unit are included in this plan. Light load backup is available. In practical terms this means (N).
Otukou (ZSub512) 1 @ 500 kVA	Single unit, 33 kV to 11 kV zone substation with two 33/11 kV supplies. The transformer was commissioned in 2010 and tests show the condition of the unit as acceptable. Average condition site with no bunding or oil separation. Improvements for the site are included in this plan. No backup or alternative feed security. In practical terms this means (N).
Piripiri (Switchyard)	Switchyard only, with load in area picked up by Te Anga substation. The switchyard was constructed for Speedies Road Hydro and replaced the Piripiri Zone Substation which was decommissioned in 2010.
Taharoa (ZSub201) 3 @ 5000 kVA	Three unit, 33 kV to 11 kV zone substation supplying iron sand extraction and local load. Supply is from two 33 kV lines operating as closed ring. Two transformers were commissioned in 1971 and the other in 1979. Tests show the condition of all units as acceptable. The site is in poor condition, operating in a harsh environment on the beach and has hazard issues. Extensive upgrade work is included in this plan - as requested and funded by the industrial customer. Medium load backup available from 11 kV network. In practical terms this means (N-1).
Tawhai (ZSub513) 1 @ 5000 kVA	Single unit, 33 kV to 11 kV zone substation with two 33 kV supplies. The transformer was commissioned in 1966 and tests show the condition of the unit as acceptable the site is in good condition with oil separation and bunding. Light to medium load backup is available from the 11 kV network. In practical terms this means (N).
Te Anga (ZSub520) 1 @ 2400 kVA	Single unit, 33 kV to 11 kV zone substation. The transformer was commissioned in 2012 and tests show that high gas discharging is occurring in the transformer. This is currently being addressed by the transformer manufacturer. New containerised asset. The site has a single 11 kV bus with no bus coupler and may be backed up from Taharoa. In practical terms this means (N).
Te Waireka (ZSub203) 2 @ 10000 kVA	Two unit, 33 kV to 11 kV zone substation supplied by two 33 kV lines operating as closed ring. Each unit is able to carry full load. The transformers were commissioned in 1996 & 2001 and return acceptable test results. Recent upgrade work included oil separation and bunding and replacing aged, oil filled switchgear and protection. The site is now in good condition. Feeder loadings are high. Funding for diversity of the busbar arrangement is included in this plan. The zone substation includes brick housing. Firm transformer capacity feeding a single 11kV bus with no bus coupler. Limited light load backup available from 11kV network. In practical terms this means (N-1) transformers.
Tokaanu Village (ZSub507) 1 @ 1250 kVA	Single unit, 33 kV to 11 kV zone substation supplied by a single 33 kV line. The transformer was commissioned in 1996 and tests show the condition of the unit as acceptable. The site is in good condition with further improvements included in plan. Limited backup via 33kV to 400V which is then stepped-up to 11kV. No transformer or 11kV backup. In practical terms this means (N).

ZONE SUBSTATIONS, SWITCHYARDS AND POWER TRANSFORMERS	
Site/Transformers	**Description / Security / Condition**
Tuhua (ZSub502) 1 @ 1500 kVA	Single unit, 33 kV to 11 kV zone substation supplied by a single 33 kV line. The transformer was commissioned in 1962 and tests show the condition of the unit as acceptable. The tap changer for the transformer is mechanically weak and is due for replacement. The site overall is in poor condition with no bunding or oil separation and has hazard constraints. Full load backup from 11kV system. In practical terms this means (N-1) transformers.
Turangi (ZSub505) 2 @ 5000 kVA	Two unit, 33 kV to 11 kV zone substation supplied by a single 33 kV line. The transformers were commissioned in 1961 and 1964. Tests show the condition of both units as acceptable. The site is in improved condition with work continuing to upgrade protection and addressing hazards. Site has firm transformer capacity but the 33 kV supply and 11 kV outgoing configuration is weak. There is no 11 kV backup available. In practical terms this means (N-1) transformers.
Waiotaka (ZSub511) 1 @ 1500 kVA	Single unit, 33 kV to 11 kV zone substation supplied by a single 33 kV line. The transformer was commissioned in 2006 and tests show that high gas discharging is occurring in the transformer. This is currently being addressed by the transformer manufacturer. A new, containerised asset operating efficiently. 75% back up is available from Turangi 11kV. In practical terms this means (N).
Wairere (ZSub207) 2 @ 2500 kVA	Two unit, 33 kV to 11 kV zone substation with embedded generation. The transformers were built in 1963, purchased second hand and commissioned on site in 1980. Tests show the condition of both units as acceptable. The site is in average condition, bunded with a manual outlet valve. Protection and 33 kV bus arrangement needs reviewing and are addressed in this plan, as is transformer refurbishment. The switch room is enclosed in a brick building. One transformer capacity and 11kV network connections will support connected load customers but not generation customers. Supply will island. In practical terms this means (N-1) transformers.
Waitete (ZSub206) 3 @ 5000 kVA	Three unit. 33 kV to 11 kV zone substation. Able to supply full load with some 11 kV transfer and embedded generation. Two 33 kV lines run in a closed ring. Two transformers were commissioned in 1961, the other in 1955. Routine tests show the condition of all units as acceptable. The site is in good condition, with recent modifications including new bunding, oil separation and earthquake restraints. Housed assets are enclosed in a brick building. Normal operating loads are in the 6 to 7 MVA range. The site has firm capacity in its present configuration with limited backup from the 11kV network. In practical terms this means (N-1) transformers.
Whakamaru (Point of Supply)	This is a non-standard arrangement put in place to avoid Transpower charges for this area. Under the arrangement, TLC use the tertiary winding on a Mighty River Power owned transformer. Backed up from Atiamuri. In practical terms this means (N).

TABLE 3.5: ZONE SUBSTATION (N-X) SUB-TRANSMISSION SECURITY

Figure 3.8 illustrates the age profile of sub-transmission zone substations, based on commissioning date. Figure 3.9 Illustrates the age profiles for sub-transmission power transformers.

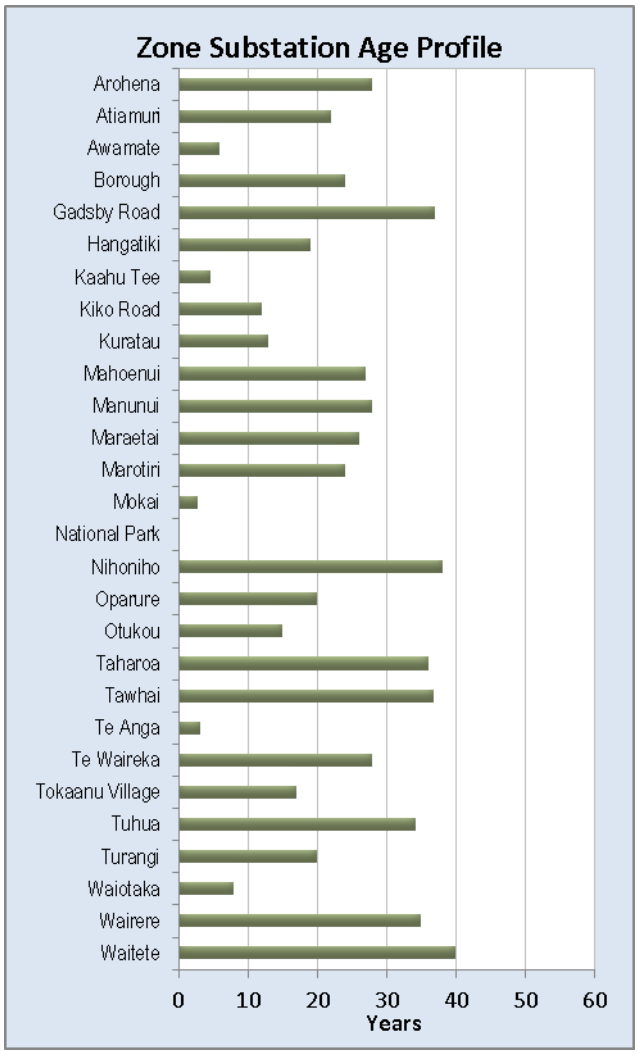


FIGURE 3.8: AGE PROFILE OF ZONE SUBSTATIONS – BASED ON YEAR OF COMMISSIONING

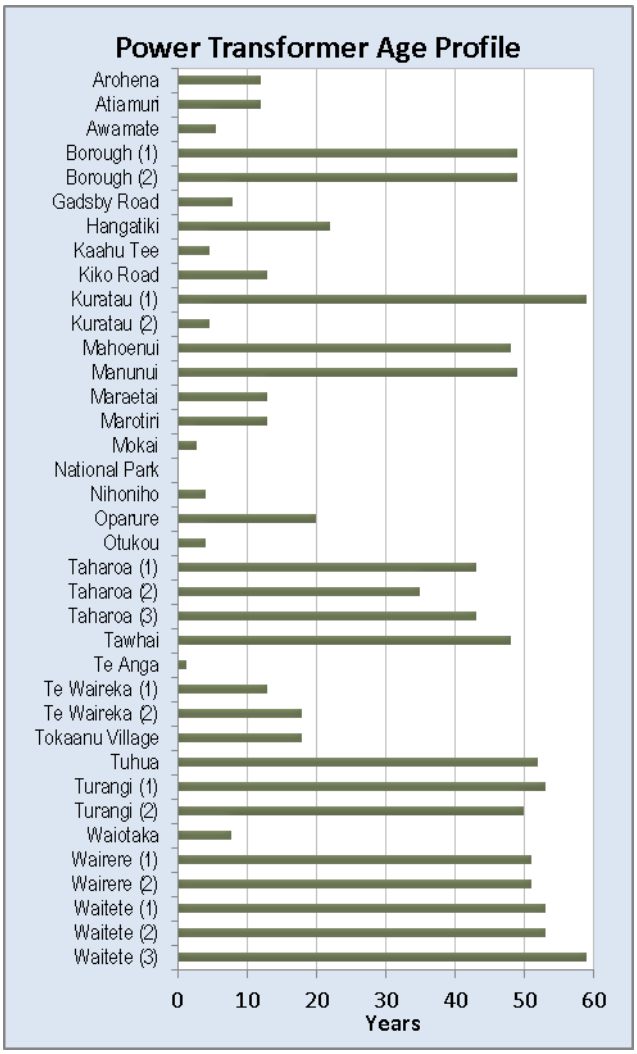


FIGURE 3.9: POWER TRANSFORMER AGE PROFILE

3.2.4.5 Sub-transmission Switchgear

The age profiles of 33 kV switchgear has improved and will continue to do so during the planning period with new units replacing the older ones as part of the renewal programme. New, modern, low maintenance equipment with electronic controls will improve the overall asset performance and lower the maintenance costs of switchgear over time.

Table 3.6 lists the quantity, location and condition of the sub-transmission (33 kV) switchgear assets. As per the figures shown, some of the assets are located in zone substations and others are in the field on sub-transmission lines. The switch ages and condition vary; they are renewed when no longer serviceable.

33 kV SWITCHGEAR ASSETS			
Description	**Field**	**Zone Subs**	**Total**
Air Break Switches	66	64	130
Circuit Breakers	5	50	55
Fault Throwers		1	1
Fused Links	6	4	10
Load Break Switches		1	1
Reclosers	7	5	12
Solid Links	30	10	40
Transformer Fuses		3	3
Total	**114**	**138**	**252**

TABLE 3.6: SUB-TRANSMISSION SWITCHGEAR ASSETS AND LOCATION

Figures 3.10 and 3.11 give an indication of the age profile of sub-transmission switchgear for both field and zone substation assets.

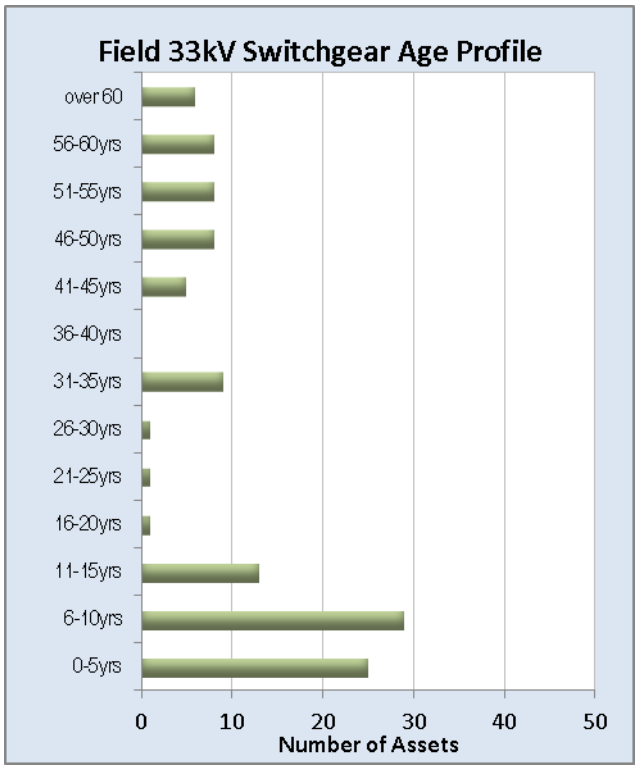


FIGURE 3.10: AGE PROFILE OF 33 KV SUB-TRANSMISSION SWITCHGEAR LOCATED IN THE FIELD

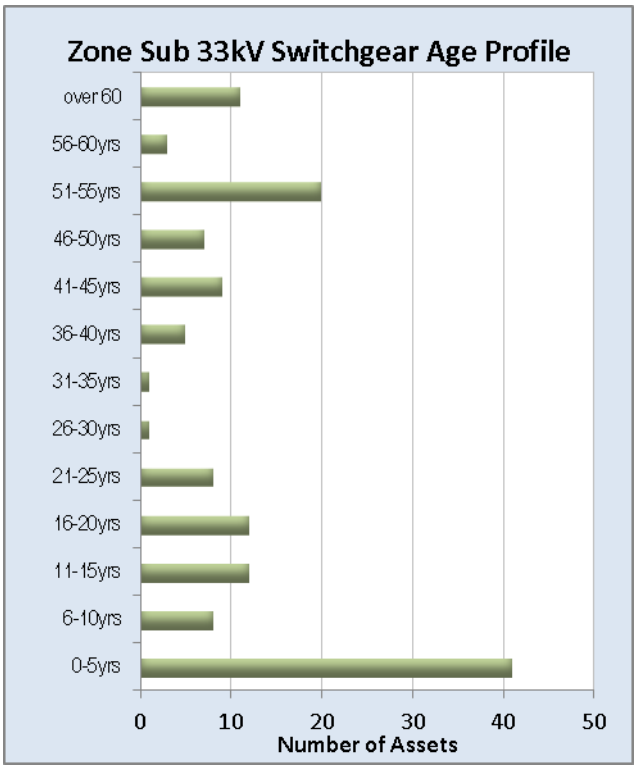


FIGURE 3.11: AGE PROFILE OF 33 KV SUB-TRANSMISSION SWITCHGEAR LOCATED IN ZONE SUBSTATIONS

3.2.4.6 Sub-transmission Systemic Issues

The effect of the present renewal strategies on this profile will be to bunch the age profiles and hold them in the 20 to 40 year range. The renewal programme will result in continuous asset technology upgrade as part of the renewal process.

The systemic issues that lead to premature replacement of 33 kV assets or parts of these assets include:

1. Insulator failure – mostly due to fertiliser build up causing corona discharge.
2. Flashover due to magpies on cross arms bearing smaller insulators.
3. Cement in older, bolt- insulator air break switches failing as the units age.
4. Early model lightning arrestors are prone to failure and make it difficult to find earth faults.
5. Vegetation and slips
6. Pole and cross arm failure
7. Insulator wire tie failure – mostly due to extreme weather
8. Wire clashes causing conductor failure. Original line design in rugged country meant conductor spacing is sometimes too close and clashes occur during high wind events or passage of fault currents.

In addition to the systemic issues, a batch of Air Break Switch Insulators manufactured in the 1980's are prone to failure by cracking and disintegrating. Voltage control relays and protection relays tend to fail at the rate of two to three every 5 years. Failed units are replaced with modern equivalents.

3.2.5 11 kV Distribution Network

3.2.5.1 11kV Feeder Lines and Cable

The 11 kV feeder network comprises overhead line, SWER systems and cable. Table 3.7 summarises these assets.

11 kV DISTRIBUTION NETWORK SUMMARY	
Description	**Length (km)**
Overhead line : 1, 2 and 3 Phase	2,250
Overhead line : SWER	855
Underground Cable	120

TABLE 3.7: 11 KV DISTRIBUTION NETWORK SUMMARY

Note: These lengths do not include privately owned 11kV lines. It is estimated that there are 730km of privately owned lines connected to TLC owned assets.

All SWER systems are fed by isolation transformers. The Tokaanu River and Pihanga systems operate at 6.6 kV to earth, all others operate at 11 kV to earth. Many of the systems have back feed options, which generally are not in phase and all switching has to be completed with supply removed.

Cabling on the two ski fields equates to about 50% of the network cable reticulation – predominantly this consists of steel wire armoured cables laid directly on the ground. There are on-going hazard control problems with these as changes occur in the mountainous environment where they are laid and snow grooming activity damages them from time to time. Legacy distribution cabling is mostly older generation XLPE cable in average condition. Sections of cable that cause problems are generally renewed under emergent works budgets.

Table 3.8 documents the 11 kV distribution network and includes information regarding location, length, ICP connections and general condition.

11 kV DISTRIBUTION NETWORK	
Feeder/Length	**Description**
Aria (FED114) O/H 74.2; U/G 0.0 km	Aria rural area servicing 258 ICPs. The feeder is in average condition and constructed predominantly on 10/2KN concrete poles. Problems have been experienced in recent times with aged insulator issues. Some renewal work has been completed. Feeder includes Kumara Road SWER system.
Benneydale (FED103) O/H 130.9; U/G 0.1 km	A long rural feeder servicing south east of Te Kuiti, Benneydale, Mangapehi Generation and Crusader Meats. It has 477 ICPs. The feeder carries four regulators in series - being run to the maximum - and has been substantially renewed. Travels through moderate hill country and includes many long spans with some close conductor phase spacings. There is a short span of cable out of the zone substation. Feeder includes Waimiha and Kopaki Road SWER systems.
Caves (FED101) O/H 59.7; U/G 0.6 km	Waitomo village and rural area to the west, servicing 321 ICPs. Rebuilt to Waitomo Caves. Beyond this there are long spans with light low strength conductor that is prone to failure. Poles are predominantly 10/2kN concretes and iron rails with aged insulator issues. Cable out of the zone substation. Feeder includes Kokakoroa Road SWER system.

11 kV DISTRIBUTION NETWORK	
Feeder/Length	**Description**
Chateau (FED419) O/H 0.0; U/G 29.0 km	Whakapapa Ski field and village supply, servicing 136 ICPs. The feeder is all cable, 60% of which is heavy armoured. About half of the network 11 kV cable is associated with the ski field supply. Much of this cabling has been laid directly on solid rock and does not comply with codes. The long-term strategy is to improve these installations whenever customers or other events such as emergent work and hazard elimination/minimisation projects trigger alterations in the vicinity.
Coast (FED125) O/H 78.0; U/G 0.0 km	Remote rural area around Marokopa servicing 322 ICPs. Generally aging rural feeder with parts exposed to severe coastal conditions. Several sections have been renewed. Mostly small ACSR conductor that is showing corrosion problems in some areas. Poles predominantly 10/2KN concretes and iron rails with aged insulator issues. A difficult feeder to automate due to lack of communication signals from existing repeaters. Feeder includes Mangatoa Road SWER system.
Gravel Scoop (FED109) O/H 91.6; U/G 0.2 km	South east of Otorohanga, servicing 524 ICPs. Average condition rural feeder supported by a mixture of wooden poles and 10/2KN concretes. Sections have been renewed. Cable out of the zone substation.
Hakiaha (FED401) O/H 3.8; U/G 1.9 km	Supplies central area of Taumarunui and rural areas on the town boundary. 273 ICPs. Cable in Taumarunui CBD. Rural part is small ACSR conductor and pole types are mixed with some wooden, 10/2KN concretes and iron rails. Insulators mostly low creepage distance. Some renewal work completed.
Hangatiki East (FED102) O/H 18.7; U/G 0.1 km	Area east of Hangatiki servicing 71 ICPs. Average condition rural feeder with two large limestone processing plants connected. Conductor size is less than ideal in places. Pole strengths should ideally be higher given the span lengths and conductor size. Some renewal work completed. Cable out of the zone substation.
Hirangi SWER (FED405) O/H 1.0; U/G 0.1 km	SWER feeder to semi residential area around Turangi. 370 ICPs. Average condition with some renewal work completed. Cable into substation.
Huirimu (FED121) O/H 46.7; U/G 0.0 km	Supply to rural area south of Arohena, servicing 154 ICPs. Average condition in dairying and dry stock area. Most of the feeder is constructed of light conductor and supported on iron poles. The insulators are mostly of the 1950's short creepage distance type. Some renewal work completed.
Kuratau (FED406) O/H 51.1; U/G 3.6 km	Supply to Kuratau Village area, servicing 1314 ICPs. Extensive renewal and strengthening completed. Cable in parts of the township. Feeder includes multiple SWER systems.
Mahoenui (FED113) O/H 98.4; U/G 0.1 km	Supply to Mahoenui and surrounding rural areas. 276 ICPs. Average condition. Most of feeder is supported on 10/2KN concrete poles. Some renewal work completed. Cable to ground mount transformers in Mokau and Awakino. Feeder includes multiple SWER systems.
Maihiihi (FED111) O/H 104.4; U/G 1.1 km	Rural area north east of Otorohanga servicing 892 ICPs. Rural feeder supplying dairying load that has been mostly renewed. Average to good condition. Cable runs out of the zone substation. Feeder includes Waituhi, Ngapuke and Kirton Road SWER systems.
Mangakino (FED118) O/H 20.3; U/G 2.2 km	Supply to Mangakino, servicing 490 ICPs. Average condition overall with a mixture of poles. Some asset groups have been renewed. Cable runs out of the zone substation.

11 kV DISTRIBUTION NETWORK	
Feeder/Length	**Description**
Manunui (FED408) O/H 84.4; U/G 0.8 km	Rural area to south and east of Taumarunui and Manunui village. 577 ICPs. Generally in reasonable condition but design is inherently light. Poles mainly 10/2KN concrete and iron rails. Renewal work and some upgrading is planned. Cable to ground mount transformers in Manunui.
Matapuna (FED404) O/H 14.8; U/G 2.0 km	Supply to western side of Taumarunui, servicing 1038 ICPs. Good condition, mostly supported by concrete poles with 10/2KN strength ratings. Cable in the Taumarunui urban area.
McDonalds (FED110) O/H 38.1; U/G 0.8 km	Rural area to the south of Otorohanga servicing 450 ICPs. Cable to ground mount transformers
Miraka (FED131) O/H 0.2; U/G 0.7 km	Supply to Mokai Energy Park and Miraka Milk Plant area. 2 ICPs. Cable to new subdivision
Mokai (FED123) O/H 71.0; U/G 1.9 km	Mokai rural area including western bays area of Lake Taupo. 312 ICPs. Average condition, mostly supported on mixture of hardwood and concrete 10/2kn poles. Consists of some long spans with close conductor spacings that can clash in wind and has aged insulator issues. Some renewal work completed; more planned. Cable to new subdivision.
Mokau (FED128) O/H 134.3; U/G 0.0 km	Mokau coastal area, servicing 641 ICPs. Long coastal 11kV feeder in very harsh environment. Gives problems with drop-out fuse connections and insulator failures. Has inherent line design weakness in the Awakino Gorge. Some renewal work completed. Feeder includes multiple SWER systems.
Mokauiti (FED115) O/H 70.2; U/G 0.0 km	Rural area south west of Piopio servicing 172 ICPs. Average condition, mostly supported on mixture of hardwood and concrete 10/2KN poles. Some long spans with close conductor spacings that can clash in wind and has aged insulator issues. Some asset groups have been renewed. Feeder includes Mokauiti Road SWER system.
Motuoapa (FED425) O/H 1.9; U/G 0.6 km	Supply to Motuoapa area on the eastern side of Lake Taupo. 419 ICPs. Overall average condition – parts have been renewed and parts very old construction. Cable to new subdivision.
National Park (FED411) O/H 44.1; U/G 0.2 km	Supply to the National park area including the village. 362 ICPs. Part renewed, part in very poor condition with long spans of light conductor on 10/2KN concrete and iron rails. Overall in average condition. Cable to ground mount transformers in village.
Nihoniho (FED412) O/H 28.5; U/G 0.0 km	Supply to the Nihoniho and Matiere areas. 61 ICPs. Remote lightly constructed rural feeder in poor to average condition with few customers. Will be renewed with some strengthening in key places as part of 15-year programme. (Some of this work has been completed.) Feeder includes Nihoniho SWER system.
Northern (FED402) O/H 106.7; U/G 3.0 km	Area north of Taumarunui servicing 1239 ICPs. A long feeder in average condition. Some renewal work has been completed. Most of the feeder is supported by 10/2KN concrete poles and iron rails. There are also two large SWER systems that can tie with other feeders attached to the end of the line. This feeder is the most heavily loaded out of Taumarunui. Cable exists in urban area of Taumarunui. Feeder includes Okahukura and Hikurangi SWER systems.

11 kV DISTRIBUTION NETWORK	
Feeder/Length	**Description**
Ohakune Town (FED414) O/H 8.0; U/G 3.5 km	Ohakune town supply, servicing 873 ICPs. Generally in average condition. Several security improvement projects and renewal /strengthening work have been completed to bring feeder up to industry standard for a supply to a popular tourist area. Cable in Ohakune CBD.
Ohura (FED413) O/H 163.3; U/G 0.1 km	Ohura and surrounding remote rural areas. Services 369 ICPs. Lightly constructed feeder in average condition overall. The area covers a large section of a remote part of the King Country, with a low customer density and a declining population base. Designs associated with renewal have to focus on maximum improvement for spend. Supplies several interconnecting SWER systems. Cable to ground mount transformers. Feeder includes multiple SWER systems.
Ongarue (FED421) O/H 125.7; U/G 0.0 km	Large rural area around Ongarue. 258 ICPs. Lightly constructed feeder in a remote part of the King Country. Feeder overall is in average condition with some renewal work completed. Has low customer density and a declining population base. Designs associated with renewal have to focus on maximum improvement for spend. Supplies multiple interconnecting SWER systems.
Oparure (FED107) O/H 74.3; U/G 5.4 km	Supply to an area west of Te Kuiti servicing 926 ICPs. Rural feeder of light construction. Suffers from long spans of light conductor in a few places. Mostly supported by 10/2KN concrete and iron rails. Low creepage distance 1950's insulators have given trouble on this feeder. Some renewal work has been completed to address the worst of these problems. Cable in urban area of Te Kuiti.
Oruatua (FED417) O/H 9.4; U/G 1.7 km	Eastern side of Lake Taupo, north of Motuoapa. 391 ICPs. Part renewed and part very old construction. Cable to new subdivision. Feeder includes Waitetoko and Tauranga-Taupo SWER system.
Otorohanga (FED112) O/H 48.8; U/G 1.4 km	Supply to most of Otorohanga town plus rural area to the southwest. 1150 ICPs. Overhead urban/rural feeder. Urban area is in average condition. The rural section has been partly renewed. Fault current levels are high and connections are often destroyed when through fault currents occur. Pole population is mixed but predominantly 10/2KN concrete and iron rails. More renewal work is planned. Cable in CBD of Otorohanga and out of the zone substation.
Otukou (FED418) O/H 5.7; U/G 0.0 km	Area around Sir Edmund Hillary Outdoor Pursuits Centre. 92 ICPs. Relatively short feeder on Central Plateau with SWER systems attached. Light construction has trouble supporting the snow loadings it is exposed to on the Central Plateau. Some renewal completed. Mostly supported on 10/2KN concrete poles and iron rails. Average condition. Feeder includes Otukou and Mangatepopo Intake SWER systems.
Paerata (FED130) O/H 3.3; U/G 0.5 km	Supply to Mokai Energy Park, Glasshouse and other customers. 9 ICPs. Mostly new - constructed as part of energy park supply. It does include some older sections that were part of the Mokai feeder. Cable to the new subdivision.
Piopio (FED116) O/H 52.0; U/G 0.1 km	Supply to Piopio rural settlement and surrounding rural area to north. 457 ICPs. Good condition overall with some renewal completed. Feeder does have long spans with close conductor spacings. It is predominantly supported by 10/2KN concrete poles. Cable to ground mount transformers in village.
Pureora (FED119) O/H 52.1; U/G 0.1 km	West of Whakamaru including supply to Crusader Meats. 170 ICPs. Supplies dairying and industrial load and is in average condition with parts having been renewed. Medium size conductor on mix of wooden and 10/2KN concrete poles. Two more regulators and some upgrading are included in the plan to support voltage levels. Cable out of zone substation.

11 kV DISTRIBUTION NETWORK	
Feeder/Length	**Description**
Rangipo / Hautu (FED424) O/H 28.9; U/G 6.1 km	Supply to areas east of Turangi, servicing 853 ICPs. Sections have been rebuilt in conjunction with work on East Taupo 33kV. Remainder is lightly constructed and in average condition. Some renewal has been completed. Cable across Tongariro River and at the prison. Feeder includes Tokaanu River and Korohe SWER systems.
Rangitoto (FED106) O/H 68.6; U/G 3.1 km	Area west of Te Kuiti servicing 726 ICPs. Average condition with some renewal work completed. Mixture of concrete 10/2KN, wooden and iron rail poles with some long spans and close conductor spacings. Cable in the urban area of Te Kuiti. Feeder includes Gardiner Road SWER system.
Raurimu (FED410) O/H 152.6; U/G 0.0 km	Raurimu village and rural areas to east, west and south. 293 ICPs. Average to poor condition and predominantly supported by iron rails. Limited income is available from this extremely rugged and remote area. Includes some major SWER lines that go deep into the King Country.
Rural (FED126) O/H 4.7; U/G 0.0 km	Rural area surrounding Taharoa. 115 ICPs. Average to poor condition rural feeder exposed to the harsh west coast seaside environment. Has a mixture of wooden, concrete and iron rail poles. Corroded hardware and conduction is an issue with this feeder. The feeder has small customer numbers and renewal is balanced against returns. Cable to ground mount transformers.
Southern (FED409) O/H 123.2; U/G 0.0 km	Area south of Manunui including connection for Piriaka distributed generation. 608 ICPs. Generally in good condition. The feeder is predominantly supported on 10/2KN concrete poles and has a number of long spans that are prone to clashing during periods of strong winds. Much of the feeder has conjoint SWER systems.
Tangiwai (FED416) O/H 84.3; U/G 1.9 km	Area east of Ohakune servicing 648 ICPs. Average condition with some renewal having been completed. This feeder is located in a moderate to heavy snow area and the inherent design has no allowance for ice loadings. The poles are either iron rails or 10/2KN concretes. Cable to subdivision.
Te Kuiti South (FED104) O/H 23.3; U/G 1.1 km	Part of Te Kuiti town and rural area to south. 580 ICPs. Average condition feeder principally supported on 10/2kN concrete poles. Has a number of long spans that are prone to clashing during periods of strong winds and aged insulators issues. Some renewal work completed. Cable from substation and in urban area of town.
Te Kuiti Town (FED105) O/H 1.9; U/G 0.8 km	Central area of Te Kuiti servicing 138 ICPs. Average condition with some renewal completed. Mostly supported by 10/2KN concrete poles and has a mix of AL and CU conductors. Suffers from joint failure when exposed to through fault currents. Cable from substation and in urban area of town.
Te Mapara (FED117) O/H 78.4; U/G 0.1 km	Area south east of Piopio servicing 229 ICPs. Rural feeder in good condition with some renewal complete. Mixture of wooden and concrete poles. Cable from substation. Feeder includes SWER systems.
Tihoi (FED124) O/H 65.4; U/G 0.0 km	Western bays area of Lake Taupo, servicing 201 ICPs. Average condition with some renewal completed. Parts of feeder have an on-going tree problem due to a large number of tree blocks owned by absentee landowners. Feeder includes Tihoi SWER system.
Tirohanga (FED129) O/H 68.4; U/G 5.1 km	Western bays area of Lake Taupo. 235 ICPs. Average condition with some renewal complete. Cable to subdivision.

11 kV DISTRIBUTION NETWORK	
Feeder/Length	**Description**
Tokaanu (FED420) O/H 0.0; U/G 1.2 km	Tokaanu town and marina. 84 ICPs. Cable in urban area and supply to marina is mainly in good condition. Includes some SWER.
Tuhua (FED422) O/H 41.4; U/G 0.0 km	Remote rural area around Ongarue servicing 144 ICPs. Average condition with a number of SWER lines connected towards its ends. Supported by mostly 10/2KN concrete poles and iron rails.
Turangi (FED423) O/H 0.9; U/G 8.1 km	Supply to Turangi Town and surrounding area. 1097 ICPs. Mostly underground feeder. The overhead section that supplies the underground is has been changed from a double circuit to a single circuit. Cable in urban areas.
Turoa (FED415) O/H 34.3; U/G 24.2 km	Turoa ski field and urban rural area to bottom of mountain. 442 ICPs. Main purpose is supply to Turoa ski field. The feeder is constructed with heavy conductor on moderate strength poles. There are a few long spans with inadequate conductor spacing. The overall condition is good but the line is generally constructed under strength for the heavy snow area it is in. Cable in urban area and at ski field.
Waihaha (FED426) O/H 73.5; U/G 2.3 km	Area around the south western edge of Lake Taupo. Services 317 ICPs. A feeder in mixed condition with a significant length of SWER. The lines are mostly supported on 10/2KN concrete poles and iron rails. Spans are long and conductor sizes are small. Some renewal has been completed however the expenditure needed is hard to justify. Cable to the Whareroa holiday area.
Waiotaka (FED427) O/H 9.0; U/G 1.2 km	Supply to prison and area east of Turangi. 8 ICPs. This feeder was originally part of the Rangipo / Hautu feeder. It was split off and renamed Waiotaka in conjunction with the new container substation (commissioned in 2007) to provide security of supply to prison and surrounding area. Average condition with some renewal work having been completed. Cable at the prison. Feeder includes Hautu SWER system.
Waitomo (FED108) O/H 10.5; U/G 0.70 km	Northern Te Kuiti area. Includes town, rural and industrial sites. 430 ICPs. Average condition, predominately rural feeder supplying part of Te Kuiti town, rural areas to the north and a major lime plant. Medium size conductor mostly supported on 10/2KN concrete poles. Has some larger spans with close conductor spacing. Cable from the substation and in the Te Kuiti urban area.
Western (FED403) O/H 124.9; U/G 1.2 km	Rural area north west of Taumarunui. 411 ICPs. Supplies part of Taumarunui and travels west along the Whanganui River until breaking into a number of SWER systems. Generally in poor condition with lines being mainly supported by 10/2KN concrete poles and iron rails. Some renewal has commenced and security has been increased by establishing a link to the Northern feeder. Cable from the substation and in urban areas of Taumarunui.
Whakamaru (FED120) O/H 64.6; U/G 0.2 km	Whakamaru village and surrounding area. 571 ICPs. Rural feeder supplying dairying area and Whakamaru Village. Overall feeder is in average condition with sections having been renewed. Cable from the substation.
Wharepapa (FED122) O/H 102.3; U/G 0.5 km	Large rural dairying area west of Arohena. 404 ICPs. A long rural feeder supplying dairying area and includes a large amount of 16sq.mm Cu conductor supported on iron rail and hardwood poles. Some renewal work has been recently completed. Further renewal, including some conductor, is included in this plan. Cable to transformer.
Winstones (FED428) O/H 0.1; U/G 0.0 km	East of Ohakune. 3 ICPs. Short feeder servicing Winstones industrial site at the end of the Tangiwai feeder. Good overall condition. Some cable within the industrial site.

TABLE 3.8: DISTRIBUTION OF 11 KV DISTRIBUTION LINES

3.2.5.1.1 Distribution Poles

The distribution system comprises the majority of the poles on the network. Primarily they carry 11 kV conductor. A limited number carry multiple circuits of 33 kV/11 kV or 11 kV / 400 V / 230 V. The ages and condition of the poles vary. Iron rail poles constitute a significant portion of the older assets.

The age profile of distribution poles by pole type is shown in Figure 3.12 below.

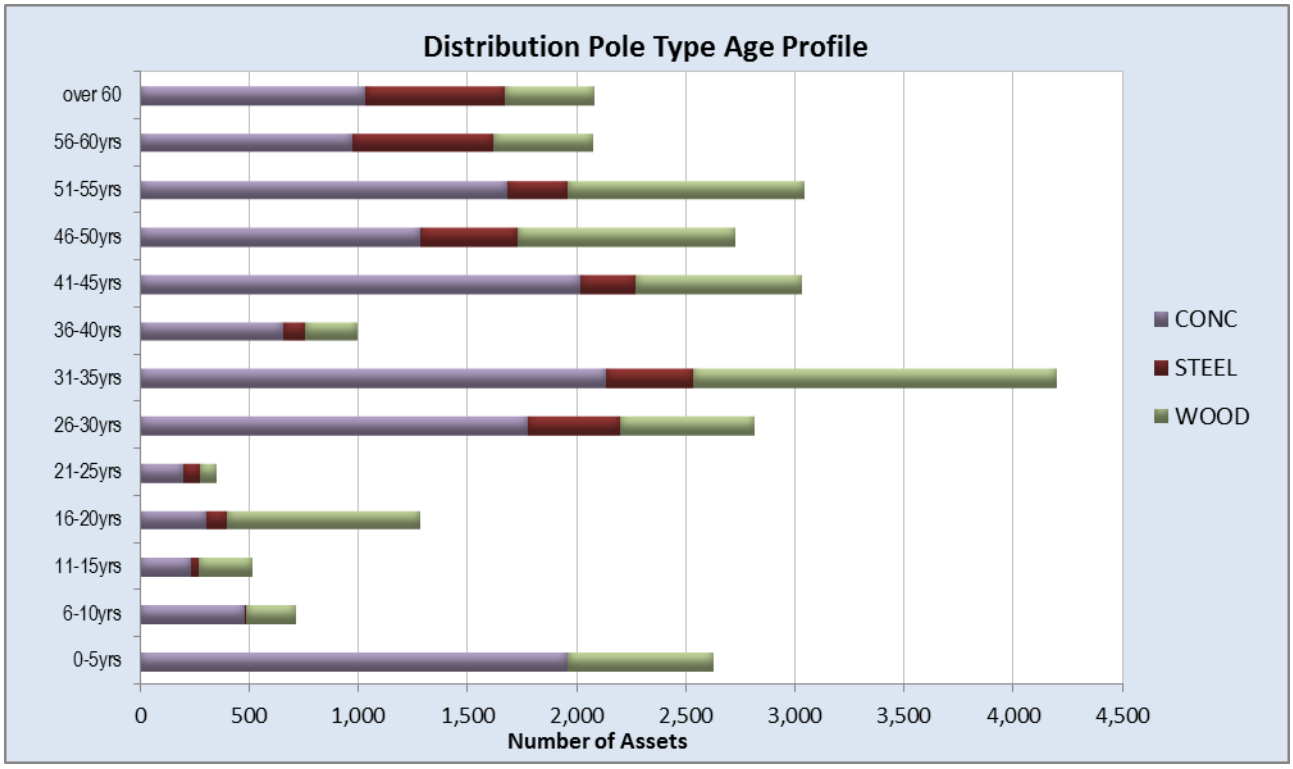


FIGURE 3.12: AGE PROFILE OF DISTRIBUTION NETWORK POLES BY POLE TYPE

3.2.5.1.2 Inherent 11 kV Distribution Issues

Common modes of failure with feeder assets in approximately the order of their effect on network performance are:

1. *Vegetation* - trees falling across lines or branches blowing into lines.
2. *Connection failure* – mostly jumpers between lines or on to equipment.
3. *Insulators* - low creepage distance 1950's insulators discharging to pin and cracking when wet.
4. *Conductor failure* - conductor clashing caused by wind, birds, or trees pushing wires together.
5. *Pole and Cross arm failure* – mostly caused by old age, rot or poor design.
6. *Private lines* – non-network lines interfering with network performance.

3.2.5.1.3 SWER Configuration

It should be noted that systems with more than (approx.) 225 kVA connected will be operating over the 8 amp limit in the Single Wire Earth Return (SWER) system code of practice (ECP41). Approximately 60% of the systems in Table 3.12 exceed this. Since 2002, a number of the systems have been broken up and the connected kVA reduced. Previously there were four with greater than 1000 kVA. This work, i.e. installing extra isolation transformers, has been part of line renewal, network development, and new customer connection programmes. Records suggest that these systems had more than the code of practice limit since their construction, which pre-dates the ECP41 code. (Note: This code is in the process of being redrafted to allow currents of greater than 8 amps; the focus of the new code will be limiting hazardous earth potential rises.) TLC has been working to redraft the code to align better with the operation of the SWER systems and its inclusion in the Electricity Safety Regulations 2010.

3.2.5.2 11 kV Distribution Switchgear

Distribution switchgear and control equipment is spread throughout the network. New switchgear coming into the network as part of the renewal programme is lowering the age profile and improving asset technology. Predominantly (97%) of these assets are located in the field, the balance are in zone substations.

The switchgear assets condition tends to track that of general feeder condition. TLC has had significant problems with early failure of dropout fuses. The main reasons for this are poor manufacturing quality, poor connections and corrosion.

Table 3.9 summarises the identified distribution switchgear and control assets. The figures include 236 switchgear assets contained in the 76 Ring Main Units on the distribution network. Figure 3.13 illustrates the age profile of these assets.

11 kV DISTRIBUTION SWTICHGEAR	
Asset Type	**Number**
11 kV Air Break Switches	649
11 kV Circuit Breakers	133
11 kV Fused Switches/Fused Links	956
11 kV Load Break Switches	173
11 kV Reclosers	114
11 kV RTE Integrated Transformer Switches	63
11 kV Sectionalisers	82
11 kV Solid Links	448
11 kV Transformer/Tap-off Fuses	5358
Total	**7976**

TABLE 3.9: 11 KV DISTRIBUTION SWITCHGEAR AND CONTROL ASSETS

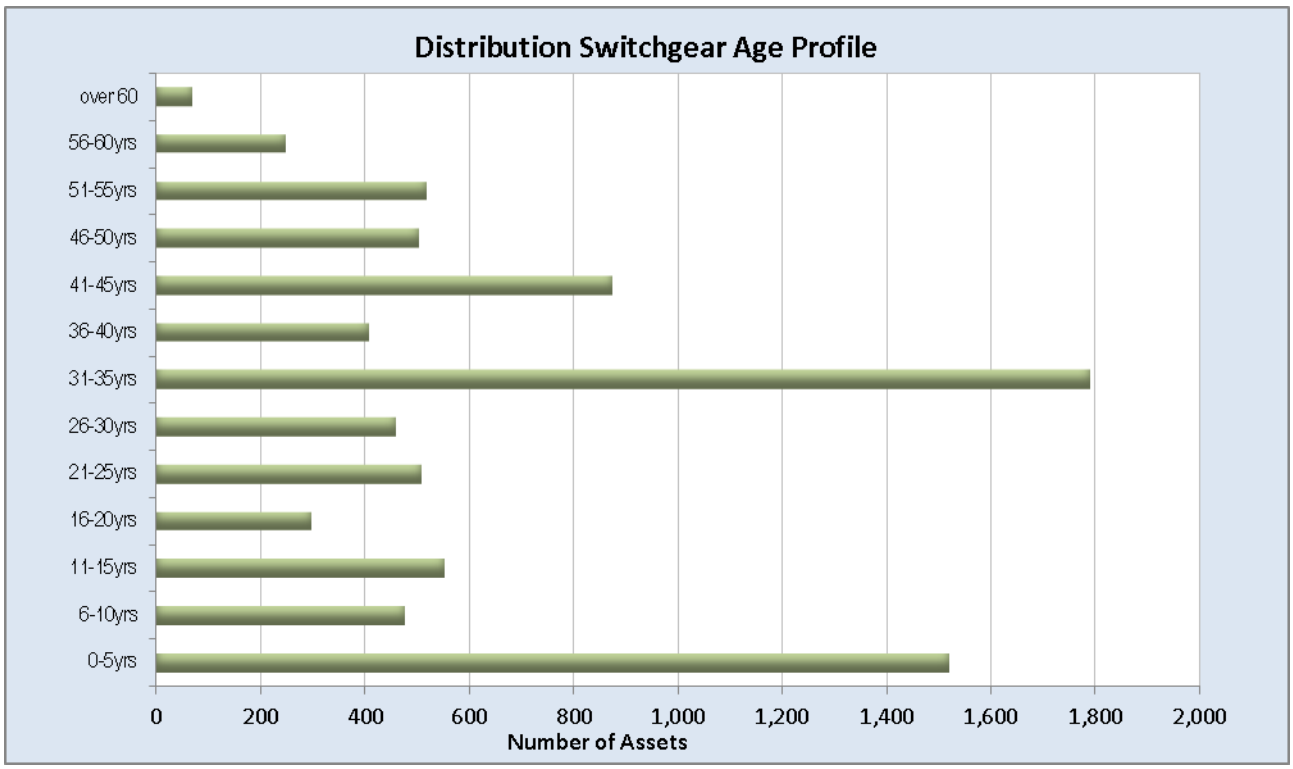


FIGURE 3.13: AGE PROFILES OF 11 KV SWITCHGEAR ASSETS

3.2.5.3 Distribution Substation/Transformer Arrangements

Typically, supply comes in via 11 kV cut-out fuses and into the transformer. A lightning arrestor is installed between the cut-out fuse and the transformer. Transformer sizes typically range from 5 kVA to 200 kVA, with the majority pole mounted. Isolation transformers feed all SWER systems.

For ground-mount transformers where there are lengths of cable greater than 100 metres, 3-phase isolation is required to stop Ferro resonance effects. Transformer housing arrangements include modified garden sheds, I tanks and double door configurations depending on the location. Distribution standards require transformer isolators, MDI's and protection for each away circuit.

There are a number of daisy-chained transformers on the network. The present standard is to install ring main equipment and rotary transformer switches at alternate sites when connecting units in series. Vacuum switches that have circuit breaker and automation options are used where appropriate at industrial or major sites on 11 kV feeders. The staggering of rotary switches and ring main units minimises costs whilst allowing hazard control expectations to be met.

The distribution transformer stock is in average condition and TLC refurbishes and reuses old transformers where possible. Whilst more economical, this results in a relatively static age profile. The primary reasons for premature failure are lightning strike, accidents (vehicle, vegetation), water damage, broken bushings, fault current passage and corroded cases.

Table 3.10 summarises TLC's distribution transformer assets by mounting, phasing and KVA.

DISTRIBUTION TRANSFORMER SUMMARY									
Pole Mount	**<=15**	**30**	**50**	**100**	**200**	**300**	**500**	**>500**	**Total**
Single Phase	2531	368	35	2	2				2938
Two Phase	158	33	9						200
Three Phase	398	572	266	186	27	7	2	2	1460
Ground Mount									
Single Phase	8	5	3	1	4				21
Three Phase	5	17	22	59	183	121	32	34	473
Total	**3100**	**995**	**335**	**248**	**216**	**128**	**34**	**36**	**5092**

TABLE 3.10: DISTRIBUTION TRANSFORMER SUMMARY

Figure 3.14 illustrates the age profile and quantity by transformer mounting.

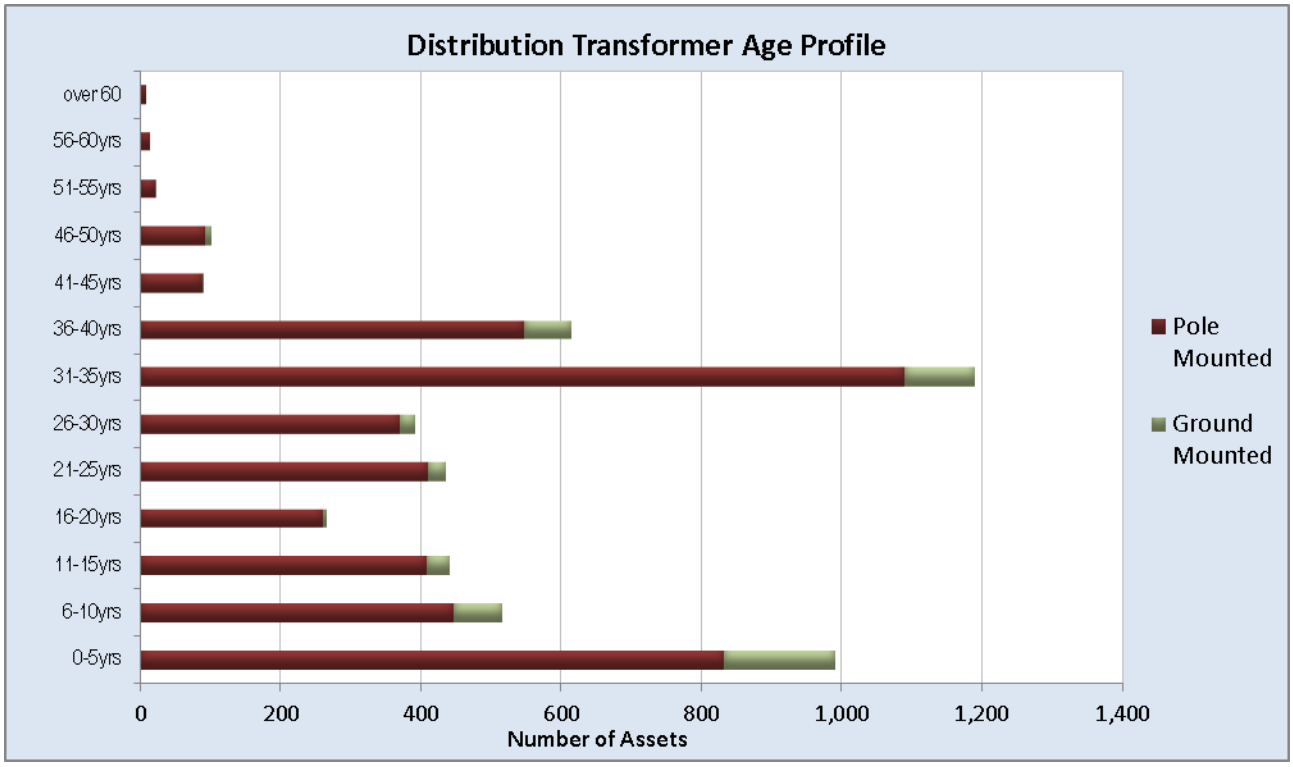


FIGURE 3.14: DISTRIBUTION TRANSFORMER AGE PROFILE

3.2.6 Low Voltage Distribution Network

3.2.6.1 Low Voltage (LV) Assets

The LV network operates at 400/230V and is mostly overhead line. LV assets include poles, conductor, cable and pillar boxes.

Overhead line is predominantly bare copper (Cu) and aluminium (Al) conductor. Insulated conductor is being used for renewals, as per present distribution standards. To solve clashing problems in high winds, spacers have been fitted in many places. Historically, LV systems were not designed with back feeds.

Low voltage underground cables exist to some extent in most township areas, with Turangi town having the most extensive network. There are few low voltage ties in the predominantly aged cable network. Underground cabling systems installed in the southern network during the 1970's and 1980's consist mostly of solid core, double pass, PVC insulated single core, solid aluminium cables. Often no marking or mechanical protection was installed, leaving the cables prone to corrosion and inadvertent damage.

TLC has inspected, numbered, and recorded its pillar boxes. These boxes are routinely checked, renewed and repaired. Pillar box susceptibility to vehicle and tree damage continues to be an issue.

The LV data held about the network is limited but improving as inspections continue. A simplified breakdown of known LV assets is shown in Table 3.11.

LOW VOLTAGE NETWORK ASSETS			
Assets	**Units**	**LV Circuit**	**km**
Poles – Concrete (inc Steel)	733	Overhead Circuit	419
Poles – Wood.....	4386	Underground Circuit	130
Pillar Boxes	4022	Streetlight Circuit	48

TABLE 3.11: BREAKDOWN OF LV ASSETS

The age profiles of LV poles (by type) and cables (by length) are shown in Figures 3.15 and 3.16.

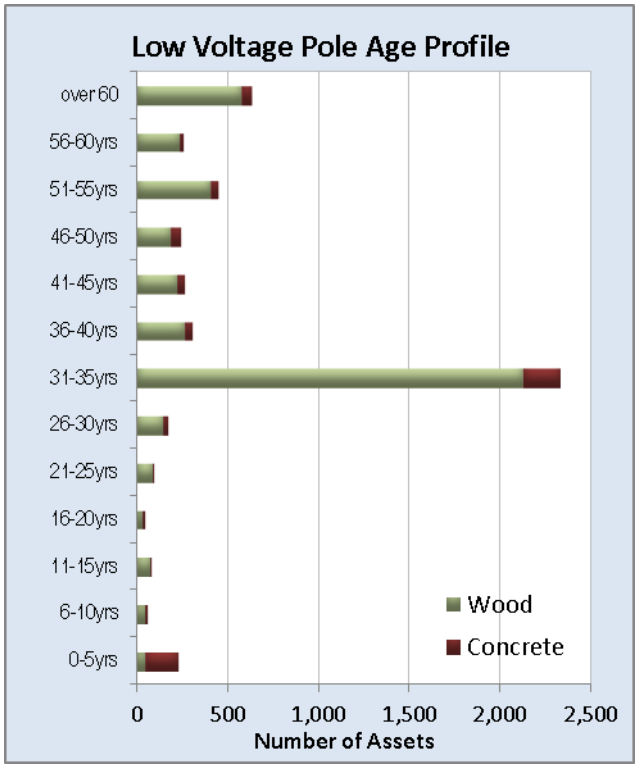


FIGURE 3.15: AGE PROFILE OF LOW VOLTAGE POLES

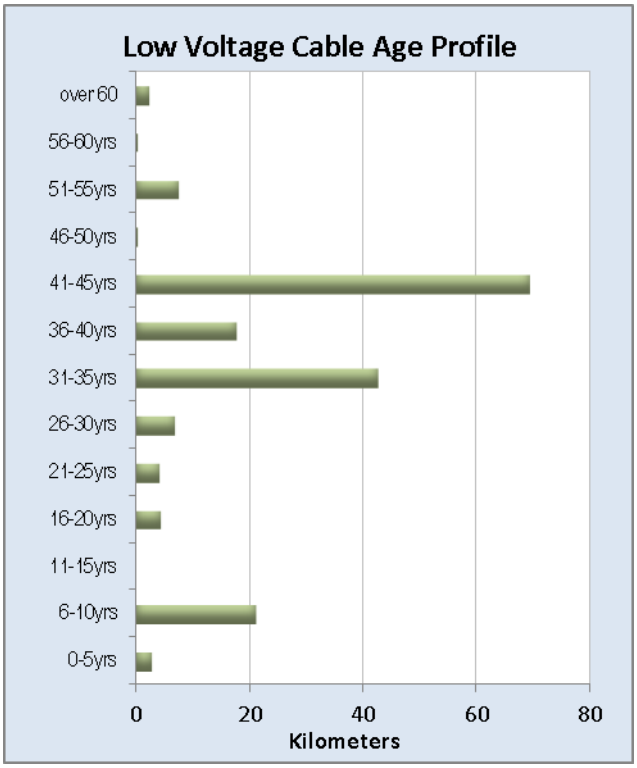


FIGURE 3.16: AGE PROFILE OF LV CABLE (INC STREETLIGHT)

3.2.6.2 Customer Service Connection Points

The identified customer service connection points (ICPs) on the network total 24,537. This figure does not include meters and relay assets. Figure 3.17 Illustrates the location of ICP sites across the network based on the source Grid Exit Point.

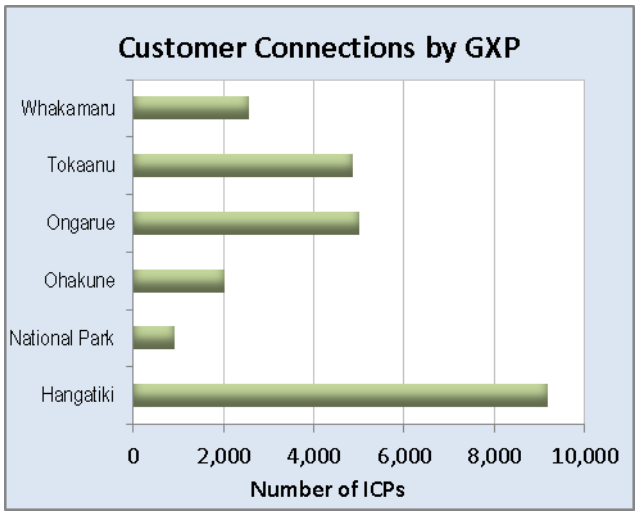


FIGURE 3.17: ICPS BY GRID EXIT POINT

3.2.7 Secondary Assets

3.2.7.1 Voltage Regulators

The majority of the sites have two relatively new single phase regulators operating in open delta to give ± 10% regulation. Five older type 3 phase units remain in service. Seven of the regulator sites are at zone substations where regulators are used as a low cost alternative to on load tap-changers built into transformers (Awamate, Kaahu Tee, Nihoniho, Otukou, Tuhua, Waiotaka and Te Anga). One is at a point of supply; necessary for voltage stability.

The renewal programme, the growth that has occurred and the need to ensure compliance with regulations has resulted in the age of the regulator stock reducing substantially. Included in the planning period are allowances for the replacement of the remaining old units and the addition of more regulators in areas where voltage constraints exist or will exist as load increases.

Systemic issues leading to the premature replacement of regulators include:

- Problems with the control relays, particularly the older electro-mechanical systems.
- Problems with software/firmware in modern units.
- The mechanical internal systems sticking and failing.
- Operator error when by-pass switches are closed and units are not in the neutral position.

Table 3.12 provides a summary of voltage regulators. Figure 3.18 Illustrates the age profile of these assets.

Regulator Units	<100 Amp	150 Amp	200 Amp	**300 Amp**	**Total**
Single Phase	6	20	34	6	**66**
Three Phase	2	1		1	**4**
Total	**8**	**21**	**34**	**7**	**70**

TABLE 3.12: VOLTAGE REGULATOR SUMMARY

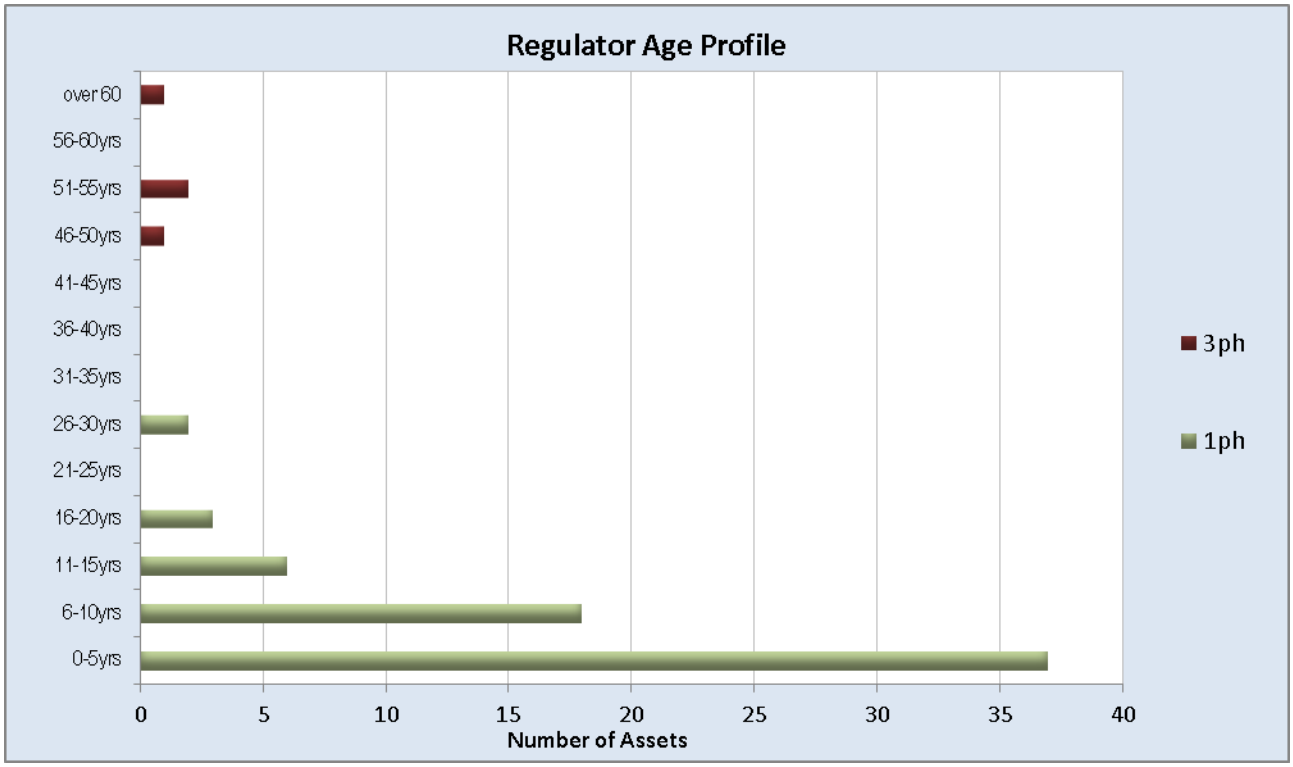


FIGURE 3.18: REGULATOR AGE PROFILE

3.2.7.2 Ripple Injection Systems

TLC operates two generations of ripple systems, one in the southern part of the network and a combination of new and old in the north. Both systems share the same controller, which is integrated into the SCADA system. The network controller decides on the need to shed and restore load. Telegrams are generated at the plant controller level.

Table 3.13 lists the injection plants, frequencies, and injection voltages.

INJECTION PLANT LOCATION, TYPE, FREQUENCY AND VOLTAGE			
Manufacture	**Frequency**	**Voltage**	**Notes**
Landis Gyr	725 Hz	11 kV	Located at Arohena, Gadsby Road, Maraetai, Te Waireka, Wairere and Waitete. All are aged but in operational condition.
Landis Gyr	317 Hz	11 kV	Ohakune only. Unit is in good condition.
Landis Gyr	317 Hz	33 kV	Hangatiki, Ongarue, National Park and Whakamaru units are all in good condition. Tokaanu is aged but operational.

TABLE 3.13: RIPPLE INJECTION PLANTS

The exchange from the 725 Hz relays with 317 Hz devices has been modified to allow the deployment of advanced meters incorporating a relay across the entire network so that customer demands can be fully measured. It is expected that the advanced meter deployment will take at least another two years. The priorities for this deployment have remain unchanged in that TLC needs to change frequency on the northern area to ensure all customers are receiving a reliable load control signal. The two new 33 kV injection plants at Hangatiki and Whakamaru are physically enclosed in 40 foot containers to ensure they are modular and have adequate security. The old Landis and Gyr plants will be decommissioned once the advanced meters have been installed.

The southern system injects into the 33 kV network, which has the advantage of removing any difficulty of adding 33/11 kV zone substations. The 317 Hz system also has the advantage of enabling good signal propagation throughout the downstream network. The present plant controllers and relays are not set up to allow load to be switched if the frequency begins to fall. There are little known harmonic interference problems with the southern plants. The northern regions are supplied by old 11 kV 725 Hz plants that provide marginal signal levels to many areas.

There are several areas (approximately 800 customers) that have no load control signal coverage and a similar number are estimated to have marginal coverage until the lower frequency relays incorporated in advanced meters are deployed. In the northern region, it is not possible to add additional 33/11 kV transformers and create new zone substations without the loss of load control signals. Figure 3.19 indicates the age of load control plants.

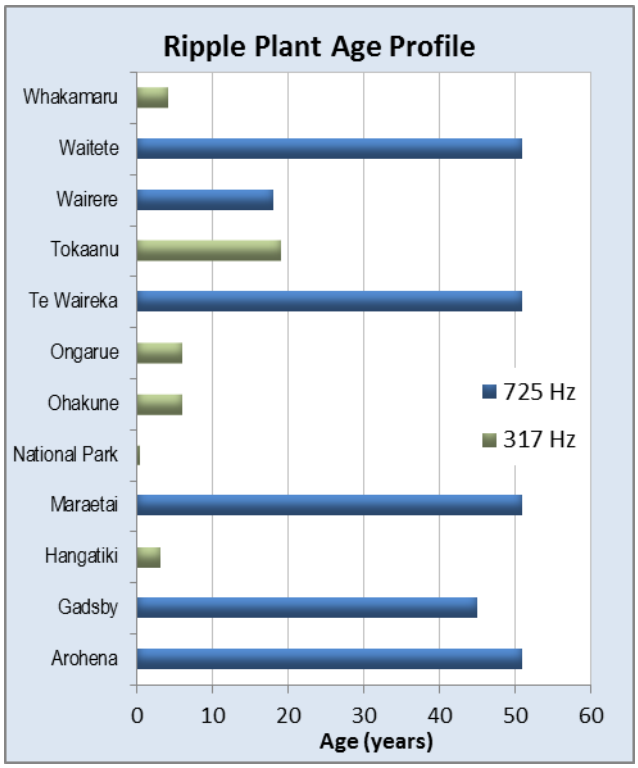


FIGURE 3.19: AGE PROFILES OF RIPPLE(LOAD CONTROL) PLANTS

The two new 33 kV injection plants at Hangatiki and Whakamaru will, in the long term, replace the six 725 Hz plants. Once achieved this will change the age profile.

There is no redundancy in any of the load control systems. A failure will result in loss of signal until a unit is repaired, i.e. there are no n-1 components in any of the plants.

Systemic issues leading to the premature replacement of load control plants or parts of them include:

1. Lack of signal at 725 Hz due to network complexity.
2. Loss of communication network
3. Failure in load rhythm generator due to software problems
4. Failure of plant hardware on older units
5. Resonance on SWER systems at 725 Hz
6. Load calculator software and hardware issues when upgraded or renewed

3.2.7.3 SCADA and Voice Radio

The TLC network uses a Lester Abbey central control system and RTUs to automate approximately 35 zone substations, 12 load control plants and about 89 field devices and two investor owned generators. It also displays information from the grid exits, the Waikato River system and 4 other investor owned generation sites. In addition to operation of field devices, the equipment performs the central summation of system load and dispatch of load control signals.

The amount of output from larger generators is also input into the system for the purpose of Transpower peak avoidance calculations and provision of information to the control room on the operating state of the network. Specifications are currently being developed in conjunction with Abbey Systems for a more improved load control calculator as part of TLC's move towards a more advanced network.

The network incorporates six E-Band (150 – 155 MHz), radio repeaters providing voice communication throughout the operational area. A further eight repeaters divided across three sub communication networks provide a complimentary low speed (1200bps) SCADA transmission platform to access the 100 plus remote terminal units.

One of the generator companies also uses the TLC SCADA system to communicate with its generation equipment and control a remote station. The system uses both a data UHF, voice VHF (radio) system and telephone line to communicate to field devices. The voice VHF system and the telephone line are only used in areas where it is difficult to get a data radio signal into.

The communications system is low speed, but robust and relatively low cost. The installation of additional links to provide diversity is part of proposals for long-term development of the system. Changes to the radio spectrum license requirements will be a major driver in the on-going direction of the system. Systematic connection of voice then data systems to 12.5 kHz band width digital systems is planned.

SCADA and load control central system computer uses the Lester Abbey Powerlink product. The system has proven to be reliable and is vital to the operation of the TLC network. For example, it is common during a storm event for more than 150 circuit breaker and other related commands to be issued by the controller. If staff had to be sent to these 150 sites to manually operate equipment, the costs and restoration times would be far greater than those able to be achieved with the use of this system. The system is being constantly renewed to ensure it is maintained in a reliable operating condition.

The SCADA system uses mostly an analogue polled data radio system to communicate with the majority of devices. There are also two links via Leased Direct Circuit (LDC) and two via TLC owned communication lines attached to overhead lines. The equipment and system is in good condition, considered reliable and low cost by industry standards.

The most common issues that cause the system not to operate include:

- Loss of communication due to lightning strike or power supply failure.
- Software or hardware failure.
- Installation configuration errors.

3.2.7.3.1 Data Communication

The UHF data communication system consists of a head end and 12 repeater sites (excluding individual RTU radios) operating on two channels. The data communication network is necessary for system automation. The system is a very simple, slow-speed network focused on circuit breaker and substation automation, not high-speed data and event gathering.

Equipment has been assessed and allowances are included in the Plan for constant renewal of equipment. Advice from communication specialists is that the system is appropriate and cost effective for the rugged TLC network environment. The existing analogue system will be converted to a low speed digital system over the planning period.

The SCADA and Voice Radio Equipment summary shown in Table 3.14 includes the site locations. Each site comprises radio componentry – all in good condition - and other ancillaries. The age of communication equipment will remain relatively constant.

3.2.7.3.2 Voice Radio Equipment

A frequency modulated voice communication system consisting of six repeaters, linking equipment and radios in the mobile fleet owned and operated by TLC. The radio repeater sites are necessary for voice communication throughout the region, with the use of other communication such as trunked radio and cell phone equipment not an option in the King Country because of incomplete coverage.

The overall system is reliable and an extensive maintenance and renewal programme is kept up. TLC has three voice repeater sites that need to be replaced due to the Ministry of Business, Innovation and Employment requirement to move from 25 kHz to 12.5 kHz wide channels. These upgrades are to be completed by 2015. The main cause of failure of voice radio equipment is external influences such as lightning strikes.

SCADA and Voice Radio Equipment Summary			
Location	**SCADA**	**Voice**	**Condition**
Kuratau Hut	✓		Aged but operational
Mahoe Road	✓		Average condition
Maungamangero		✓	Aged but operational
Motuoapa Reservoir	✓		Aged but operational
Ohakune	✓		Good condition
Pomerangi	✓		Good condition
Pukawa	✓	✓	Average condition
Pukepoto	✓		Average condition
Ranginui	✓	✓	SCADA is in average condition, Voice is aged but operational.
Taumarunui Depot	✓	✓	SCADA is in average condition, Voice is in good condition.
Taumatamaire		✓	Average condition
Te Kuiti Control	✓	✓	Aged but operational
Tuhua	✓	✓	Average condition
Waipuna	✓	✓	Average condition
Waituhi	✓	✓	Average condition
Whakaahu	✓		Average condition

TABLE 3.14: SCADA AND VOICE RADIO EQUIPMENT SUMMARY

The SCADA and Voice Radio Age Profile shown in Figure 3.20 includes the location of key sites. Network diagrams for these are shown in Figures 3.21 TLC SCADA Radio Network and 3.22 TLC Voice Radio Network respectively.

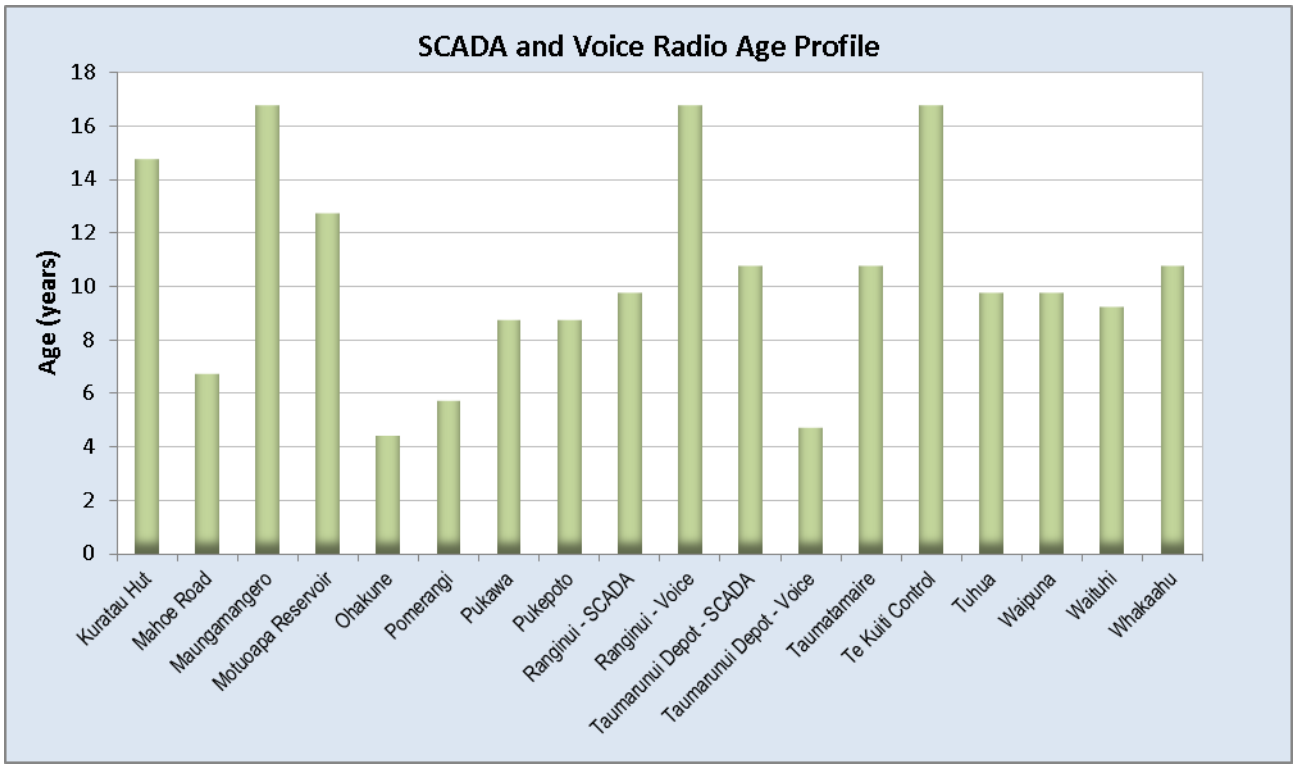


FIGURE 3.20: SCADA AND VOICE RADIO AGE PROFILE

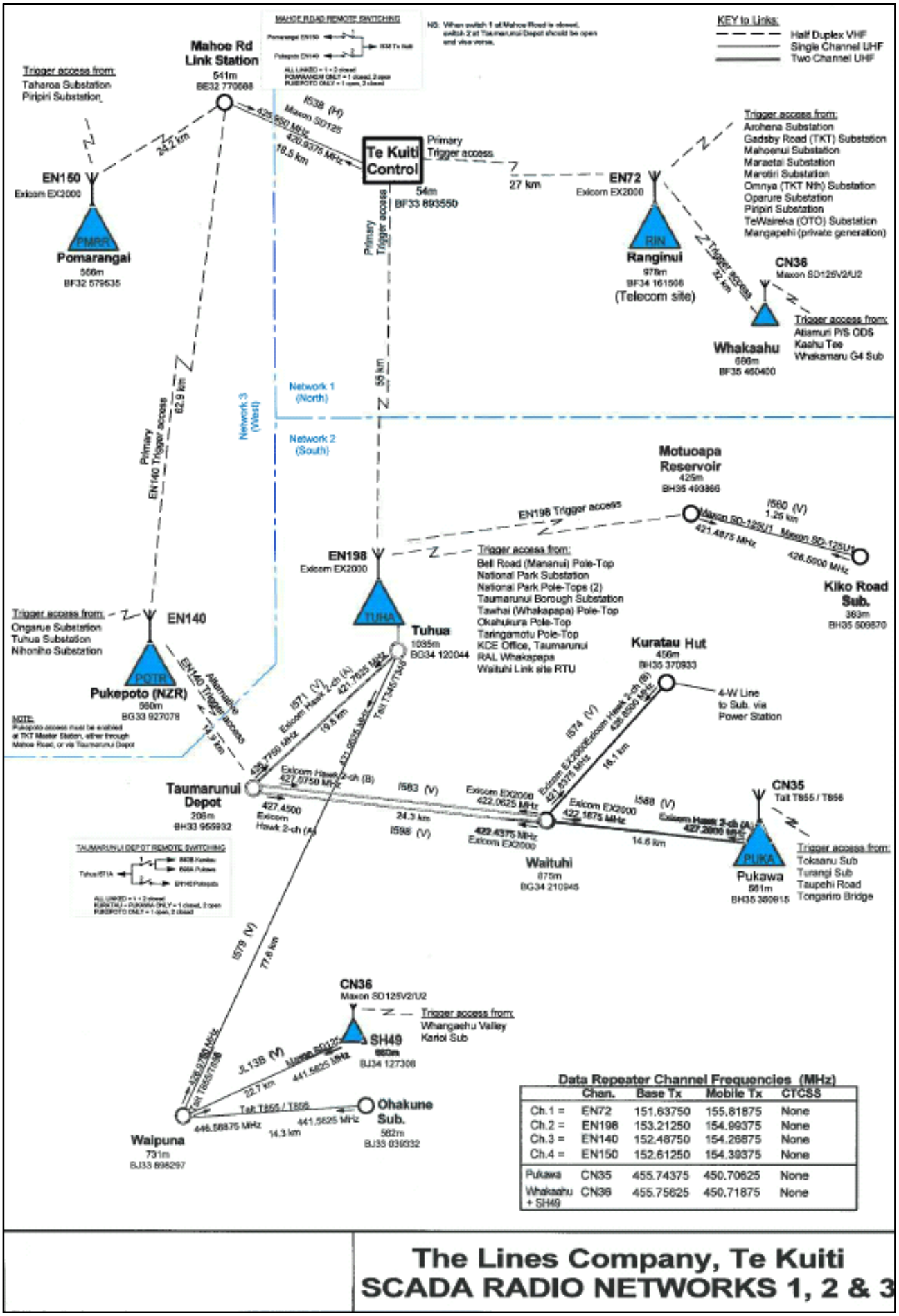
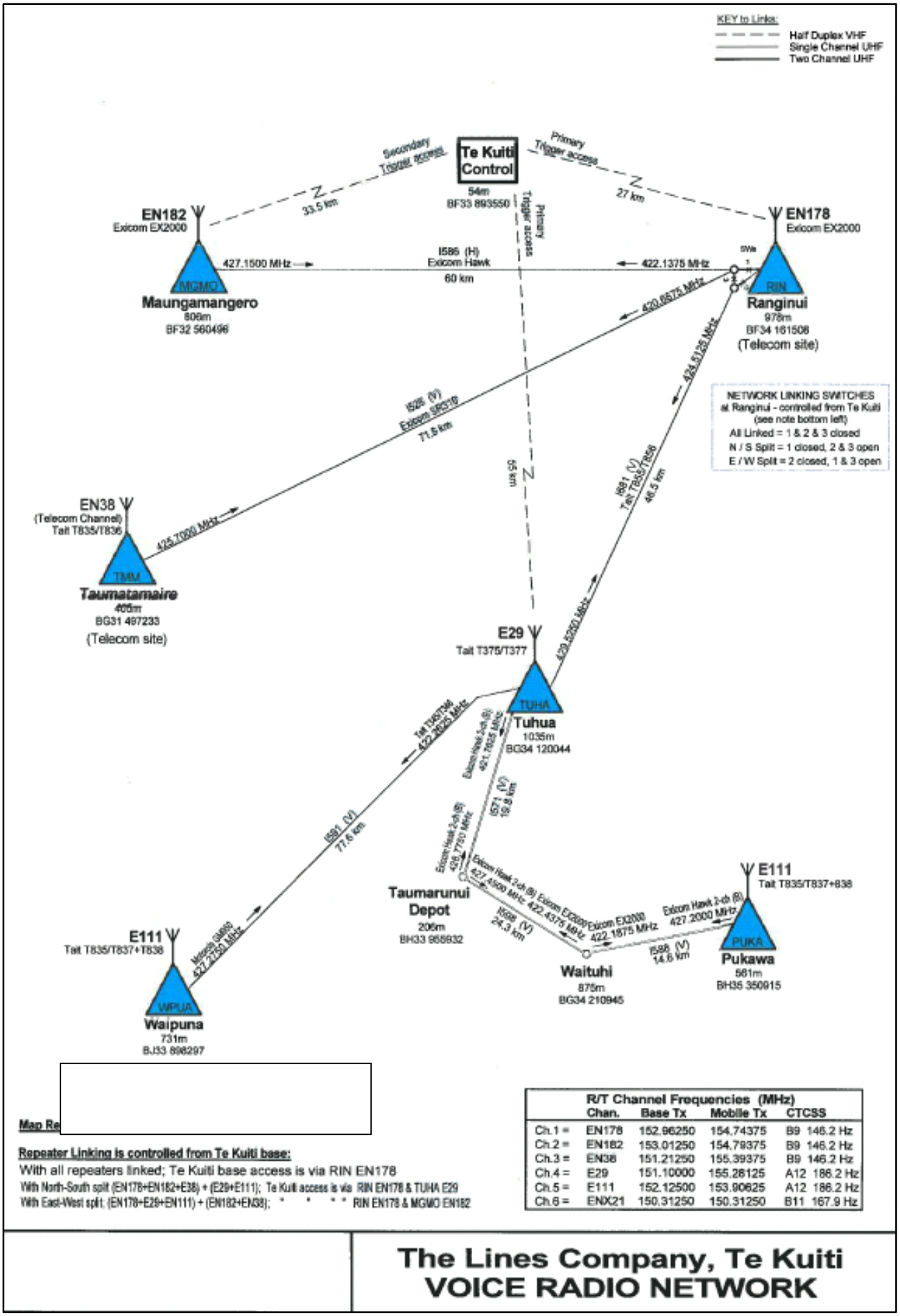


FIGURE 3.21: TLC SCADA RADIO NETWORK



Map Re

Repeater Linking is controlled from Te Kuiti base:

With all repeaters linked; Te Kuiti base access is via RIN EN178

With North-South split (EN178+EN182+E38) + (E29+E111); Te Kuiti access is via RIN EN178 & TUHA E29

With East-West split: (EN178+E29+EN111) + (EN182+EN38); " " " " RIN EN178 & MGMO EN182

R/T Channel Frequencies (MHz)				
	Chan.	Base Tx	Mobile Tx	CTCSS
Ch.1 =	EN178	152.96250	154.74375	B9 146.2 Hz
Ch.2 =	EN182	153.01250	154.79375	B9 146.2 Hz
Ch.3 =	EN38	151.21250	155.39375	B9 146.2 Hz
Ch.4 =	E29	151.10000	155.28125	A12 186.2 Hz
Ch.5 =	E111	152.12500	153.90625	A12 186.2 Hz
Ch.6 =	ENX21	150.31250	150.31250	B11 167.9 Hz

The Lines Company, Te Kuiti
VOICE RADIO NETWORK

FIGURE 3.22: TLC VOICE RADIO NETWORK

3.2.7.4 Mobile Units

3.2.7.4.1 Emergency Generator and Injection Transformer

TLC owns a mobile generator, protection transformer, and circuit breaker capable of injecting into the 11 kV network under emergency or shutdown conditions. The 11 kV / 400 Volt unit is mounted on an 8-ton carrying capacity truck.

The interconnection between the 11 kV circuit breaker is arranged so that further standard delta-star (Dy) connected transformers can be connected at the point between the circuit breaker and the star delta winding transformer. This allows larger generators to be connected and the Yd transformer to become a system protection earthing transformer. The machine has a communications system and the controller can remotely oversee and control the operation of the generator when it is connected to the network.

3.2.7.4.2 Capacitor Banks

TLC has an 11 kV mobile capacitor bank and 4 fixed capacitor bank units that are rated at 1MVAr.

The trailer mounted unit is used as an alternative network support tool to generators. It allows added capacity to backup supplies without the need to bring in expensive generators.

The 3 of the fixed capacitor banks are located on the Wharepapa, Huirimu and Pureora feeder. There is also a fixed capacitor bank at the Tuhua zone substation.

3.2.7.5 Metering Assets

TLC, through a subsidiary company, owns the majority of customer meters and relays. It also owns interconnection metering assets at Whakamaru, Mokai and Tangiwai (uncertified). About 40% of the domestic metering installations have two meters (controlled and uncontrolled). The remainder are a mixture of 2 phase and single meters.

As part of its demand billing initiative, TLC is deploying half hourly meters to domestic installations. These are read by both retailers (monthly or two monthly), and TLC (annual download of half hourly demands). These half hourly demands are reconciled with load control signals and customers' half hourly demands are used to calculate the annual demand component of their line charges.

The TLC owned relays are 80% of the modern programmable electronic type. The remainder are old and electro-mechanical relays. The channel segmentations of these relays is typically that of the legacy lines company load control systems, i.e. about 10 channels randomly deployed for water heater controls, 2 channels for street lighting, other channels for times controls and a few other channels mostly allocated for encouraging electrical energy usage programmes from the Electro Corp marketing strategies of the 1980's.

Looking forward, these channel layouts will be modified for the future to include more focus on demand billing, the fast load reduction frequency market and other activities involved with an advanced network.

The TLC network owns five grid exit point metering installations with half hour meter and remote reading equipment. These are Whakamaru supply site, Tangiwai Winstones Mill interconnection and three others associated with the Mokai Energy Park.

The meter type that TLC's connection code/standard specifies is of a type that has inbuilt relay functionality and various communications options plus it is loaded with TLC's demand charging firmware. The relay functionality is being used.

Section 4

4. Targets and Performance

TLC provides billed connections to about 23,500 electrical installations in the greater King Country. Its business is to provide a service to customers' expectations that produces income to fund the maintenance, renewal and development of this infrastructure in a sustainable and hazard controlled way. To ensure that it is providing a service in line with customers' expectations, TLC has consulted with customers through surveys, customer clinics, focus groups and other consultation meetings. TLC also consults with stakeholders and researches other industry performance.

A key objective of asset management planning is to match the level of service provided by the assets to the expectations of customers and other stakeholders. This is consistent with TLC's vision, corporate organisational objectives and goals as outlined in Section 2 of this Plan.

TLC carries out regular reviews of actual performance against targets, and of customers' feedback/expectations. The targets and expectations are also considered in day to day operational decision making.

The key performance targets are:

- Consumer oriented performance targets.
- Asset performance targets.
- Asset efficiency targets.
- Asset effectiveness targets.

The service performance targets in this section are used to:

- Measure the effectiveness of the actions taken in accordance with the AMP.
- Performance benchmark against industry peer groups.
- Measure service quality standards.
- Monitor and measure compliance with statutory and regulatory requirements.
- Inform customers of the proposed levels of service.
- Focus asset management strategies to an appropriate level of service.
- Enable customers and stakeholders to understand the suitability and affordability of the service offered.

4.1 Customer Oriented Performance Targets

TLC saw the need for a modular asset management system where there is correlation between assets, service levels and charges. To meet this, a system was created where assets are grouped and these groups are then aggregated up into service level areas and charging regions. These asset blocks are called asset groups and are sized so that they can be used to manage renewal and maintenance etc. As an example a typical 11kV feeder is broken into 10 asset groups.

All costs, reliability, valuations etc. are attached to asset groups in the asset management system. These asset groups all have attached service level performance targets and measuring criteria.

The service level areas are as follows:

- Urban service level A
- Rural service levels B, C and D
- Remote rural service levels E and F

Figure 4.1 illustrates the service level areas in geographical layout.

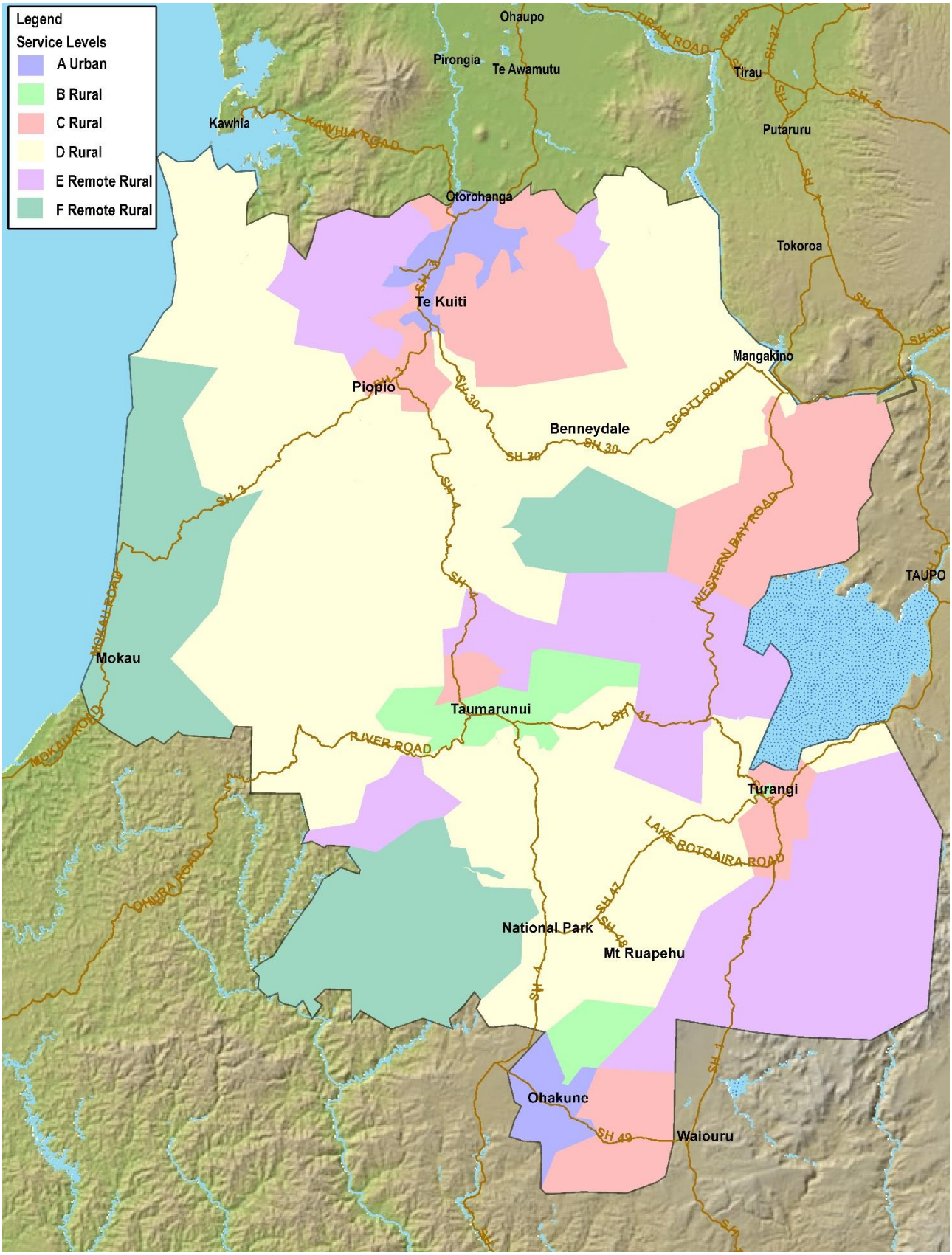


FIGURE 4.1 SERVICE LEVEL AREAS

Two charging density categories and six regional pricing zones sit above the service level areas to complete the feedback loop between service, costs and prices.

Criteria used to determine the service level areas include:

- Customers' remoteness from supply points and depots.
- Terrain and weather effects e.g. snow in southern areas.
- The number of back feed options available.
- Customer/stakeholders expectations.
- Past asset performance.
- Expected future performance given the strategies included in this Plan.

The customer service level targets were discussed and approved by customers at focus group meetings by stakeholders and other interested parties. They were originally set in 2003 and were reviewed in 2008. The customer service level targets form part of the Terms and Conditions of Supply.

In previous years, TLC had been contemplating undertaking a Customised Price-Quality Path (CPP) application in order to vary the SAIDI and SAIFI limits. The intention was that by gaining customer feedback on acceptable reliability targets, TLC could contain or reduce expenditure requirements and therefore costs to customers. After weighing the potential costs of a CPP process against the benefits to be gained, this course of action was curtailed in favour of retaining the application funds in the renewals and maintenance programmes.

Note: All customer oriented service related performance targets apply to TLC network assets. The effects of other asset owners' equipment, i.e. the effects of privately owned lines, are not included.

4.1.1 Customer Oriented Performance Targets: Asset Related

The following customer oriented performance targets (asset related) are used:

- SAIDI and SAIFI broken down by the 6 service level regions.
- Time to restore supply after an unplanned outage by the 6 service level regions.
- Maximum number of planned shutdowns per year by the 6 service level regions.
- Maximum number of long and short faults per year by the 6 service level regions.

These targets are consistent with business strategies and asset management objectives to operate a network that meets customer quality and reliability expectations.

The Commerce Commission Default Price-Quality Path (DPP) 2015-2020 has reset the levels of quality standards to be met. In addition, amendments to input methodologies have introduced new revenue-linked quality mechanisms (the Incremental Rolling Incentive Scheme, IRIS). Both of these regulations will come into effect on 1 April 2015.

The SAIDI and SAIFI limits from 2015 are set at one standard deviation above the 10-year historical average, which is the same for the SAIDI and SAIFI caps under the quality incentive scheme. The new regulatory SAIDI and SAIFI targets and incentive limits are outlined in Table 4.1 below. These SAIDI and SAIFI totals emphasise unplanned outages with planned outages being weighted at 50%. To limit the impact of severe weather events on the annual reliability measures the maximum daily SAIDI or SAIFI figures are limited to normalised values of 10.97 SAIDI minutes and 0.144 SAIFI.

REGULATORY TARGETS AS AT 1ST APRIL 2015			
	Collar	**Target**	**Cap**
SAIDI	**183.4**	**208.8**	**234.2**
SAIFI	**2.67**	**3.07**	**3.47**

TABLE 4.1 REGULATORY TARGETS AS AT 1ST APRIL 2015

The revenue linked incentive scheme is linked to the cap and collar limits outlined above. Under this scheme future revenue is adjusted linearly based above or below the target reliability level. If reliability is better than the target, then future revenues will be increased. Likewise, if reliability is worse than the

target, then future revenue will be reduced. If the cap is breached for either SAIDI or SAIFI in two-out-of-three consecutive years then TLC would be deemed non-compliant and subject to investigation as to the cause and possible penalties under section 87 of the Commerce Act.

4.1.1.1 SAIDI Targets and Performance

Table 4.2 lists the SAIDI targets by outage type and Table 4.3 lists the SAIDI targets by service level.

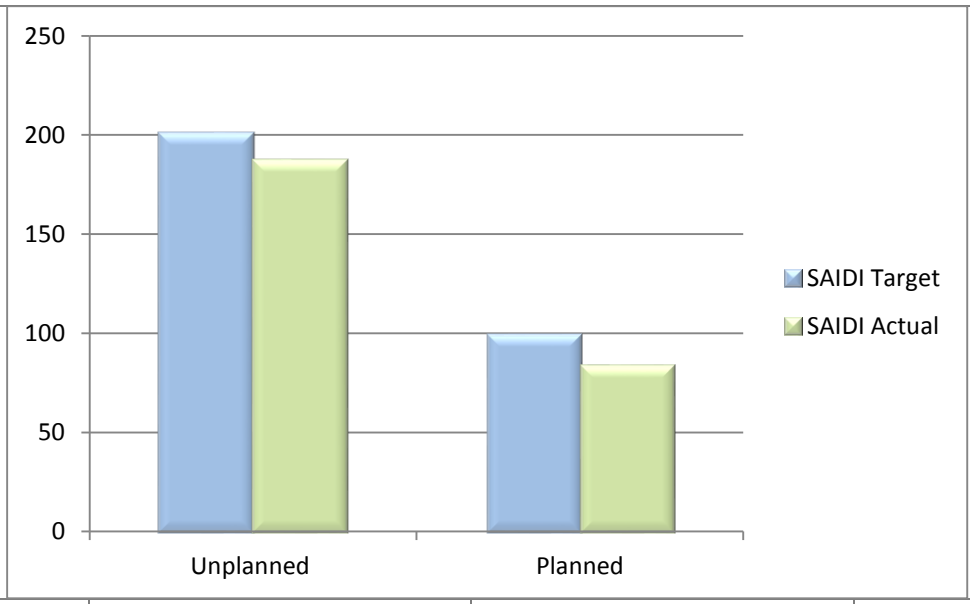
SAIDI TARGET BY PLANNED/UNPLANNED			
	Planned	**Unplanned**	**Total**
2014 Target	**90.7**	**217.0**	**307.7**
2015 Onwards Target	**58.9**	**149.9**	**208.8**

TABLE 4.2 SAIDI TARGETS BY PLANNED/UNPLANNED

SAIDI TARGETS BY SERVICE LEVEL							
	Urban A	**Rural B**	**Rural C**	**Rural D**	**Remote Rural E**	**Remote Rural F**	**Total**
2014 Target	**41**	**36**	**51**	**123**	**20.7**	**36**	**307.7**
2015 Onwards Target	**40**	**15**	**38**	**81**	**12**	**22.8**	**208.8**

TABLE 4.3 SAIDI TARGETS BY SERVICE LEVEL

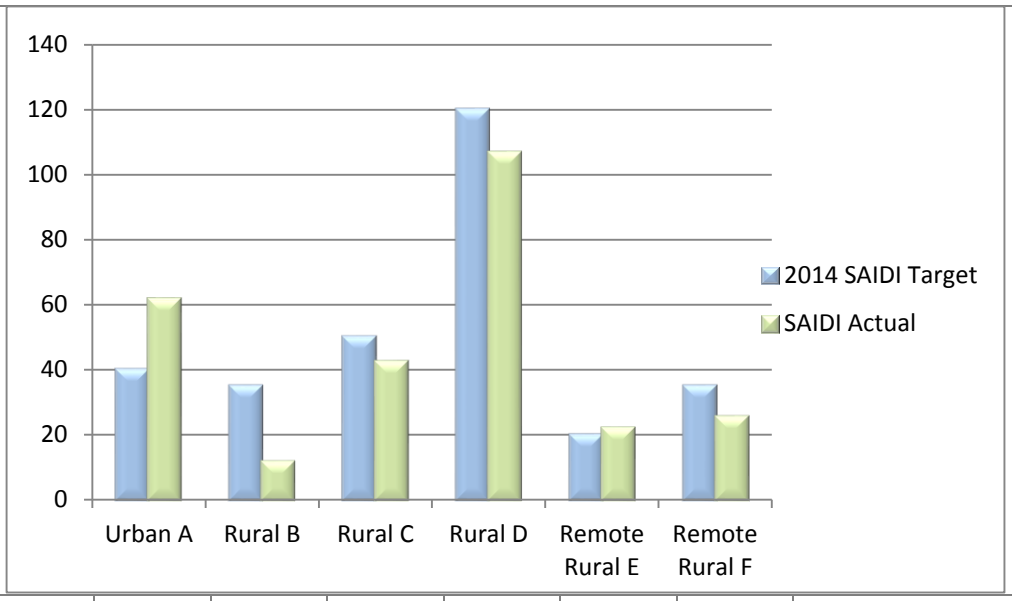
The SAIDI target will remain the same for the 2014/15 financial year, but due to the DPP determination these will change in 2015/16 financial year. The total SAIDI target going forward will be 208.8 minutes, with a split of 58.9 and 149.9 between planned and unplanned which has been identified using 10 years prior data. For the 2013/14 year the split between actual unplanned and planned SAIDI was 186.84 and 83.61 respectively. This compares against a target of 200.6 unplanned and 99.4 planned. Figure 4.2 illustrates this.



SAIDI Target	217.0	90.7	**TOTAL**	**307.7**
SAIDI Actual	186.84	83.61	**TOTAL**	**270.46**
Variance	6.86% (F)	15.88% (F)	**TOTAL**	**9.85% (F)**

FIGURE 4.2 SAIDI PERFORMANCE 2013/14 BY PLANNED/UNPLANNED

Figure 4.3 lists the SAIDI performance by service level areas.



SAIDI Target	41	36	51	123	20.7	36	**TOTAL**	**307.7**
SAIDI Actual	61.75	11.77	42.54	106.70	22.11	25.58	**TOTAL**	**270.46**
Variance	54% (U)	66% (F)	15% (F)	11% (F)	11% (F)	27% (F)	**TOTAL**	**9.85% (F)**

FIGURE 4.3 SAIDI PERFORMANCE 2013/14 BY SERVICE LEVEL

The main driver in the variances is the storm events in May, September, October and November months. The wind and lightning strikes in these months significantly delayed the restoration of supply to both remote and rural areas. A number of faults occurred in urban areas when staff were working on rural line renewals; in cases like this it takes time for them to mobilise back into urban areas.
TLC's on-going objective is to continue to target the rural service level regions through the planning period. A number of urban and rural areas are also being targeted for switch automation.

4.1.1.2 SAIFI Targets and Performance

The SAIFI target will remain the same for the 2014/15 financial year, but due to the DPP determination this will change in 2015/16 financial year. The total SAIFI target going forward will be 3.07 minutes, with a split of 0.45 and 2.62 between planned and unplanned which has been identified using previous year's data.

Due to the configuration and current capabilities of the Basix database the SAIFI target and performance has not been broken down to service level. At the time of the review, the Basix database was able to report on total SAIFI; however, it had not been configured to accurately report on SAIFI at service levels.

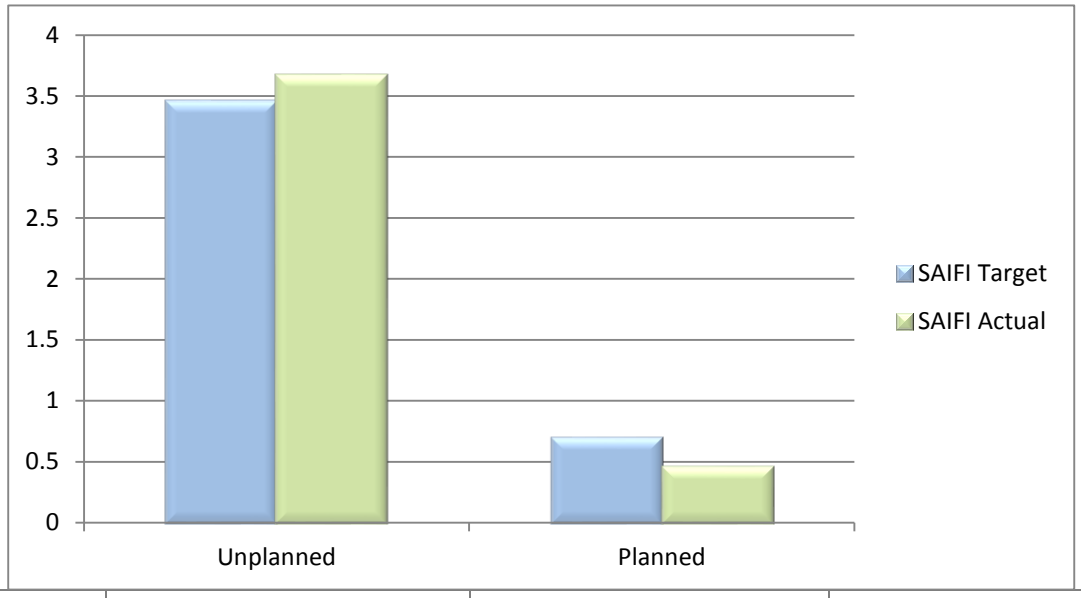
Table 4.4 lists the unplanned and planned SAIFI targets.

SAIFI TARGETS BY PLANNED/UNPLANNED			
	Planned	**Unplanned**	**Total**
2014 Target	**0.70**	**3.45**	**4.15**
2015 Onwards Target	**0.45**	**2.62**	**3.07**

TABLE 4.4 TARGETS FOR PLANNED AND UNPLANNED SAIFI

Both SAIFI and SAIDI will be sensitive to threshold compliance due to the nature of the TLC network. SAIFI will be driven up at a greater rate as opposed to SAIDI during periods when extensive use of generator by-pass for planned outages is used and extensive switching occurs during unplanned events.

Figure 4.4 lists the total SAIFI performance for the 2013/14 year. Column 3 lists the variance for the 2013/14 year. Wicked wonderful



SAIFI Target	3.45	0.70	**TOTAL 4.15**
SAIFI Actual	3.67	0.46	**TOTAL 4.13**
Variance	6.3% (U)	33.7% (F)	**TOTAL 0.5%** (F)

FIGURE 4.4 SAIFI PERFORMANCE FOR 2013/14

The SAIFI performance was better than the targets; however there was a slight increase in SAIFI compared to the previous year. This was mainly due to an increase in generator use and an increase in unplanned interruption during extreme storm events in May, September, October and November months. Storm events during this period is common, however the spells of bad weather lasted longer than in previous years.

TLC's on-going renewal programme will continue to improve SAIFI performance at the individual service level regions and overall levels. The use of generators to reduce SAIDI often has an effect of increasing SAIFI given that a short outage is often needed to connect or disconnect the generator. The key to the long-term control of the indices is an effective renewal and maintenance programme.

4.1.1.3 Time to Restore Supply

Table 4.5 lists the target and performance figures for maximum times to restore supply by service level. The measuring index of this target is based on the percentage of events that do not exceed the target time.

MAXIMIUM TIME TO RESTORE SUPPLY AFTER AN UNPLANNED OUTAGE (HOURS)						
Service Level Region	**Number of Asset Groups**	**Target Time (Hrs)**	**Total Number of Unplanned Events**	**Number of Events Where Target Time Was Not Met**	**Target %**	**Actual Performance**
Urban A	91	3	117	18	95	84.6% (U)
Rural B	17	6	55	2	90	96.4% (F)
Rural C	59	6	203	16	90	92.1% (F)
Rural D	131	6	396	47	90	88.1% (U)
Remote Rural E	22	12	76	2	90	97.4% (F)
Remote Rural F	18	12	63	7	90	88.9% (U)

TABLE 4.5 TARGETS AND PERFORMANCE FOR MAXIMUM TIME TO RESTORE SUPPLY

The main drivers for these variations were the significant storm events discussed above

There are a number of actions being taken to address and reduce the time to restore supply in urban areas. These are:

- Additional switchgear is being deployed into areas as a by-product of the hazard control programme. This will allow many of the "daisy chained" transformers to be isolated without causing extended outages when one section of the cable fails.
- Additional training is taking place on the use of generator by-pass.
- Further automation is being deployed, i.e. automation of a number of key ring main sites.
- Mobile capacitor banks are set up to increase the capacity of back feeds.

The control systems in TLC's emergency generators are also being improved to allow easier connection and operation.

4.1.1.4 Maximum Number of Planned Shutdowns per Year by Service Level

Table 4.6 lists the target and performance figures for the Maximum planned shutdowns per year by service level. Achieving this in all cases is not possible because of an extensive renewal programme and a large number of aged hazardous assets. Shutdowns are necessary to complete this work, especially when old hazardous assets are involved. The measuring index of this is based on the percentage of events that complied with this target.

PERFORMANCE TARGETS AND VARIANCES OF THE NUMBER OF PLANNED SHUTDOWNS PER YEAR					
Service Level Region	**Number of Asset Groups per Service Level**	**Target number of shutdowns**	**Number of asset groups where target exceeded**	**Targeted Compliance**	**Actual Compliance**
Urban A	91	2	4	95	95.6% (F)
Rural B	17	4	1	90	94.1% (F)
Rural C	59	6	1	90	98.3% (F)
Rural D	131	6	6	90	95.4% (F)
Remote Rural E	22	8	3	90	86.4% (U)
Remote Rural F	18	10	0	90	100% (F)

TABLE 4.6 TARGETS AND PERFORMANCE FOR MAXIMUM PLANNED SHUTDOWNS

The variances were within expected levels. Only the Remote Rural E region was below the target. The main driver for this variance was that the 3 asset groups that exceeded the target had all undergone major line renewal works.

There are several actions being taken to maintain the number of shutdowns per year within acceptable limits. It must be remembered that outages are often required to allow the renewal programmes to take place. The actions include:

- More detailed monitoring of outage applications from contractors. This has become less complex now that the new outage reporting system has been fully implemented.
- Use of by-pass generators and mobile capacitor banks to increase the capacity of back feeds.

4.1.1.5 Maximum Number of Unplanned Shutdowns per Year by Service Level

Table 4.7 lists the target and performance figures for the maximum number of short and long faults per year by service level. The measuring index of this is based on the percentage of events that complied with the target.

PERFORMANCE TARGETS AND VARIANCES OF THE NUMBER OF SHORT AND LONG FAULTS PER YEAR						
	Urban A	**Rural B**	**Rural C**	**Rural D**	**Remote Rural E**	**Remote Rural F**
Number of Asset Groups	91	17	59	131	22	18
Target Max number of Long Faults (Greater than 1 minute)	5	15	15	15	25	25
Number of Asset Groups that did not meet criteria	2	0	1	1	0	0
Target	**95%**	**90%**	**90%**	**90%**	**90%**	**90%**
Actual Performance	98% (F)	100% (F)	98% (F)	99% (F)	100% (F)	100% (F)
Target Max number of Short Faults (Less than 1 minute)	20	20	60	60	60	160
Number of Asset Groups that did not meet criteria	0	0	0	0	0	0
Target	**98%**	**98%**	**98%**	**98%**	**98%**	**98%**
Actual Performance	100% (F)	100% (F)	100% (F)	100% (F)	100% (F)	100% (F)

TABLE 4.7 MAXIMUM NUMBER OF SHORT AND LONG FAULTS PER YEAR

The variances were within expected levels. In the above performance the effect on downstream asset groups have not been included.

The numbers of faults affecting particular areas are monitored daily. When an event occurs, effort is put into tracking down the actual cause of the faults. This will often involve downloads of protection and ground and helicopter patrols. Tools such as ultrasonic discharge testers and corona cameras are often used to assist with this process.

Other more general strategies to address this include:

- Additional switchgear is being deployed into these areas as a by-product of the hazard control programme. This will allow many of the "daisy chained" transformers to be isolated without causing extended outages when one section of the cable fails.
- The automation and line renewal programmes particularly with a more of a focus on the urban areas.
- Feeder open points have been adjusted, and automated, in a few locations.

4.1.2 Customer Oriented Performance Targets – Service Related

The following customer oriented service related targets are used:

- Total telephone calls coming into the organisation through the various departmental queues. TLC is decoupled from retailers and receives all telephone calls locally.
- Total customer complaints recorded through the internal complaints process and as a percentage of that total, the number of deadlocked cases being lodged with the EGCC for resolution.
- Number of community meetings including regular updates to representative community interest groups.
- Number of customer clinics - TLC schedules meetings in regions where customers come and discuss collectively, or individually, their service concerns.

4.1.2.1 Telephone Calls Coming into the Organisation

The number of telephone calls TLC receives is a measure of the ability of the organisation to provide information and education to our customers. Experience has shown us that rather than attempt to minimise the number of calls into the organisation we should welcome customer contact and use this opportunity to provide demand response and energy efficiency advice. For the reporting years 2012/13 and 2013/14 we have reversed the focus of previous years and now require a minimum level of telephone calls to be handled by our various contact centre teams.

The target is to effectively handle between 4500 - 6000 telephone calls per month. Incoming calls are recorded by the telephone system and monthly reports detail call statistics. Due to a change in telephone system we no longer track "unanswered calls" as there is an effective call back system in place. All calls are, effectively, "answered".

Table 4.8 lists the targeted numbers of telephone calls coming into the organisation. These are compared to the actual.

COMPARISON OF ACTUAL TELEPHONE CALLS AND UNANSWERED CALLS AGAINST TARGETS (Averaged Per Month)							
Item	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**Target**	**Variation**
Number of Incoming calls	3785	4098	3932	4854	4798	**>4500**	7% (F)
Note : The numbers represent average per month							

TABLE 4.8 COMPARISON OF ACTUAL TELEPHONE CALLS AGAINST TARGETS

4.1.2.2 Unresolved Complaints

Unresolved (deadlocked) complaints cause customer frustration and extra costs (staff time and EGCC charges). This results in dissatisfied customers who are more likely to lodge a complaint with the Electricity and Gas Industry Complaints Commissioner. TLC has revised the target to not exceed a total of twenty deadlocked complaints per annum. The target has been set based on what is considered a realistic level given TLC's situation. The practice of charging customers direct for their distribution charges and using the concept of kW load rather than kW hours or units has resulted in an expected higher number of dead locked complaints than normal for a distribution company. The target has been adjusted to reflect the number of complaints that are not resolved by the customer service team and takes into account the actions of the very active lobby group that use the EGCC scheme to make complaints against the company on multiple occasions during the year.

4.1.2.3 Community Group Meetings

Local community interest groups meet regularly with executive members to discuss the issues that largely concern their members. Customers bring their local and other issues forward at these meetings and management usually prepare and present a summary of key current issues at these meetings. Regular meetings are held with the Greypower groups in Ruapehu and in Waitomo, Federated Farmers and Local Authorities.

From the 2014/2015 year full community public meetings are run in each of the main centres across the network. These are attended by the full Executive Team and provide an annual update on the Company direction and strategy. The Community Meetings will continue to be held regularly.

The most recent Community Group presentations have focused on access to rural land, upgrading shared assets and the smart meter rollout. In addition regular meetings are held to discuss the options for customers to gain more information on load management, energy efficiency, relief polices and sponsorship.

The previous target was to hold at least 5 meetings per year – this is to increase to 10 for the 2014/2015 year onwards taking into account the addition of regional public meetings. This target is measured by collating reports on meetings presented at the Board of Director's meetings. The target has been set based on the number of meetings that TLC can realistically handle given its present staffing levels.

4.1.2.4 Customer Clinics

Customer clinics are meetings that occur between customer services staff and customers throughout the area. They are intended to provide a TLC point of contact for customers that are geographically removed from TLC's main office. Advertisements are placed in local papers and appointments arranged. Discussions can be collective or individual depending on the issues. Most of the customers' requests are centred round billing issues. Any requests relating to assets are passed onto asset management and engineering staff.

The target is to have 12 customer clinics offered annually. This target is measured by logging the clinics into a database and has been set on the number of meetings that TLC can realistically handle given its present staffing levels.

Table 4.9 lists the targets and numbers of maximum number of deadlocked complaints annually investigated by the Electricity and Gas Complaints Commission (EGCC), the industry's complaints resolution organisation, community group meetings and customer clinics. Targets are compared to actual.

COMPARISON OF UNRESOLVED COMPLAINTS, FOCUS GROUP MEETINGS AND CUSTOMER CLINICS AGAINST TARGETS							
Item	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**Target**	**Variance**
Deadlocked Complaints	33	40	9	41	20	**20**	0% (F)
Community Group Meetings	5	11	6	8	7	**5**	40% (F)
Customer Clinics	30	26	19	17	53	**12**	77% (F)

TABLE 4.9 COMPARISON OF UNRESOLVED COMPLAINTS, FOCUS GROUP MEETINGS AND CUSTOMER CLINICS

Unresolved Complaints – Unresolved complaints exceeded expectations for three reasons;

i. A high number of complaints were associated with landowner and tenant issues. The landowners of installations that are connected to the TLC network are ultimately responsible for the line charges.

ii. The TLC policy of direct billing and billing on load continues to cause confusion throughout the customer base. The difference between meter measured load and formula loads has contributed to this confusion.

iii. There was a very active lobby group using the EGCC scheme requirements very effectively.

Community Group Meetings – This is above target and resulted as a consequence to customers' queries regarding TLC's pricing methodology and landlord/tenant and vacant installation billing issues. In addition, we received more customer queries with regard to the planned meter rollout programme.

Customer Clinics – There were more customer clinics than targeted.

The 2012/13 results increased as expected due to the changes in the pricing in 2012 and the introduction of a new customer profile. This had a flow on effect into the 2013/14 results, although this number decreased in this year due to more effective explanations around customer pricing and metering.

We plan to continue to find clear and simple ways to communicate what we do and why to our customers.

4.1.3 Justification of Customer Oriented Performance Targets

Table 4.10 summarises the justification for customer oriented performance target.

JUSTIFICATION OF CUSTOMER ORIENTED PERFORMANCE TARGETS	
Item	**Justification**
Consumer Considerations	Customers accept that outages happen from time to time but do not enjoy the inconvenience when they do occur. As a consequence TLC has set numerical limits as outlined above. These limits are set after analysing historic data and feedback from customers. TLC uses auto reclose schemes extensively throughout the network as a tool to reduce SAIDI times. The use of auto reclose schemes does mean customers see short faults. Auto recloses give warnings of potential problems on the network, these are then analysed by the engineering department. Switching and other surges on the network often destroy customers' electronic equipment. Measuring and setting targets that drive the design and operation of the network to eliminate these effects are important customer service considerations.
Statutory Considerations	There was a Statutory requirement for engagement with customers to discuss price/quality trade-offs. Customer clinics are one of the tools TLC uses to achieve this.
Regulatory Requirements	There is a Regulatory requirement to maintain SAIDI and SAIFI below the Cap threshold. If the cap is breached for either SAIDI or SAIFI in two-out-of-three consecutive years then TLC would be deemed non-compliant and subject to penalties under section 87 of the Commerce Act.
Stakeholder Considerations	Customer satisfaction and minimal disruption to businesses and individuals in the region is in the best interests of stakeholders. This has a direct effect on the economic and social well-being of the region.
Other Considerations	The targets are a balance between existing network performance, customers' expectations and the costs associated with improving network performance. Alternative supplies are often not practical and not cost justifiable for rural ICPs. As a consequence, rural customers see more unplanned events.

TABLE 4.10 JUSTIFICATION OF CUSTOMER ORIENTED PERFORMANCE TARGETS

4.2 Other Targets Relating to Asset Performance, Asset Efficiency and Effectiveness

4.2.1 Asset performance targets

The following targets are used to measure asset performance:

- Power Quality: -
  - » Voltage complaints.
  - » Legacy Voltage Issues.
  - » Voltage Surge Complaints.
  - » Harmonics levels in various key locations.
- System component performance.
- Environment performance.

These targets are consistent with business strategies and asset management objectives to operate a network that meets customer quality and reliability expectations.

4.2.1.1 Power Quality

TLC's Power quality objectives are to match the performance of assets with statutory requirements and the performance customers expect and are willing to pay for. Quality targets reflect industry accepted levels of voltage and harmonic distortion. TLC uses legislation, customer complaints, code of practice, historical experience and network studies to determine what is acceptable or tolerable.

4.2.1.1.1 Voltage Complaints

TLC receives voltage complaints as a consequence of network asset and customers' works/installations performance. There are many causes of voltage being outside limits. Some of the causes can quickly be eliminated by adjusting regulators or transformer taps. Other problems require either network or customer works/installation upgrades. The annual target level for voltage complaints is not more than 10 per year of proven long term complaints throughout the planning period. Complaint measurement does not include short term events, faults, customer works/installation problems, Transpower system events and similar events beyond TLC's control. The level was set based on the number of historic complaints.

4.2.1.1.2 Voltage Studies: Legacy Issues

Improved network analysis has identified parts of the 11 kV network that have operated outside of Regulatory limits for many years. These have been caused mostly by cumulative load growth and legacy issues. TLC has a number of legacy voltage constraints that have been identified and these determine the levels that load control equipment is set. The target has been set based on the number of additional regulators in the annual plan.

Table 4.11 lists the targets and performance for voltage complaints and Legacy voltage issues.

COMPARISON OF VOLTAGE PERFORMANCE ACTUALS AND TARGETS							
Item	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**Target**	**Variance**
Voltage Complaints	4	10	1	2	2	**10**	80% (F)
Resolved Legacy Voltage Issues	1	1	3	2	1	**2**	50% (U)

TABLE 4.11 ASSET PERFORMANCE: COMPARISON OF QUALITY TARGETS VERSUS ACTUALS

The voltage complaints were lower than the previous year and one legacy voltage issue was resolved.

One of the voltage regulators was installed in 2013/14 to overcome legacy voltage problems. The second was carried over into the next financial year due to resource issues. The need to target legacy voltage issues is on-going and one of the drivers behind network constraints and load controller settings.

Monitoring of voltage equipment via SCADA has been increased as part of improvements to customer service and compliance. (The voltage complaint numbers include those originating in customer owned assets).

4.2.1.1.3 Voltage Surge Complaints

Voltage surges can destroy appliances which cause inconvenience, nuisance and cost to customers. TLC has implemented a system of measuring the complaints and the related letters it has to send to customers when they claim this damage against their insurance policies. TLC has set a performance target to benchmark and measure these complaints. TLC has set a target to not exceed 80 voltage surge complaints per year. Table 4.12 lists the voltage surge targets and performance. (These are measured from the number of complaints and resulting insurance claim letters).

VOLTAGE SURGE PERFORMANCE ACTUALS AND TARGET			
	Actual	**Target**	**Variance**
Number of surge events (Measured and compared to numbers of customers)	42	**80**	48% (F)

TABLE 4.12 VOLTAGE SURGE PERFORMANCE

The variances were within expected levels. TLC uses engineering techniques and design criteria to ensure suppression devices are installed. For example, cabling is used between substation transformers and feeders with arrestors fitted.

4.2.1.1.4 Harmonic Levels in Various Key Locations

Harmonics are the by-products of modern electronics. They occur frequently when there are large numbers of personal computers (single phase loads), uninterruptible power supplies (UPSs), variable frequency drives (AC and DC) or any electronic device using solid state power switching supplies to convert incoming AC to DC. As a result of these, harmonics can cause a multitude of problems from increases in current to interference in the system.

TLC measures harmonic distortion via modern regulator equipment and annual spot checks at key points of the network. TLC closely monitors harmonic distortion, with maximum targets of 10% for 3-wire systems and 30% for SWER systems. TLC is concerned about harmonic levels due to amplification characteristics caused by lightly loaded rural lines and SWER systems.

As a consequence, TLC has set a quality performance objective to monitor these key sites and investigate further the increase of harmonic distortion. This target has been set based around information on actual measurements taken.

Table 4.13 lists the number of measurements taken for harmonic distortion and percentage of measurements where the levels have exceeded the targets. The objective of this performance target is to monitor the level from year to year, and ensure that levels are stable.

HARMONIC DISTORTION: ACTUALS AND TARGETS					
System	**Description**	**2010/11**	**2011/12**	**2012/13**	**2013/14**
Harmonic Levels 3-Wire Systems **Target is 10%**	Measured Sites	171	87	N/A	87
	Instance where target exceeded	8.19% (F)	6.89% (F)	N/A	2.30% (F)
Harmonic Levels SWER Systems **Target is 30%**	Measured Sites	21	60	N/A	62
	Instance where target exceeded	9.25% (F)	0% (F)	N/A	1.61% (F)

TABLE 4.13 ASSET PERFORMANCE: HARMONIC DISTORTION TARGETS AND ACTUAL

The variances were within expected levels. Harmonics are likely to increase as more power electronic equipment is connected to existing and new connections. TLC's terms and conditions of supply and connection standards control existing and new connections. Variances in the levels of harmonics (and voltage flicker) will be controlled by these standards being tightened.

4.2.1.2 System Component Performance: Failures

TLC monitors system component failures that have caused faults; this information forms the basis for setting the component failure target. The component failure target for 2015/16 onwards has been adjusted as a consequence of improved data coming from the outage reporting system. This measurement has given an indication of the number of events occurring. These events are mostly caused by old components deteriorating to failure.

The renewal programme should reduce the number of component failures that lead to faults. Previous performance and future targets are shown in Figure 4.5 below.

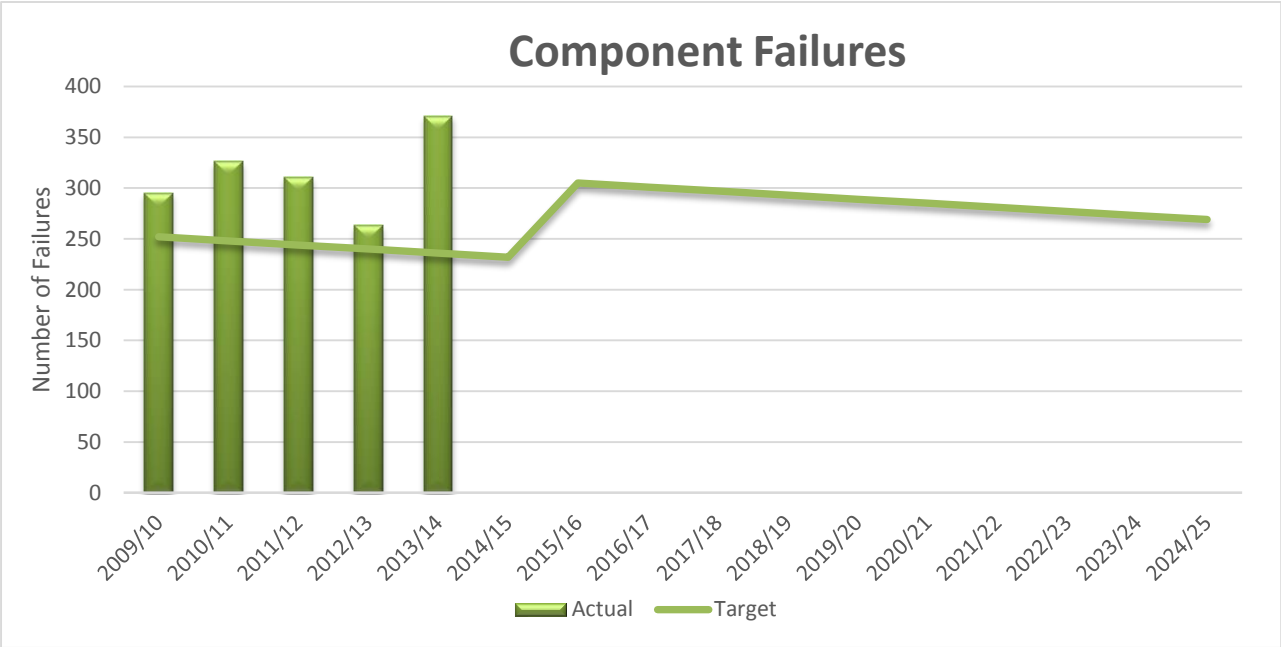


FIGURE 4.5 Component failures performance and targets

The system component failure performance was higher than the target by 57.2%; this is mainly due to better recording of outage causes in the outage reporting system.

TLC has a renewal programme in place that over the long term will address component failures due to age. TLC is continuing with a strategy of trying to follow up fault "warning signs" (such as auto recloses) before situations deteriorate to failure and renew assets that are in poor condition. TLC is also very focused on the quality of components that are used on the network.

4.2.1.3 Environmental Performance

The environmental performance is measured using two targets. The first target is to have zero prosecutions or abatement notices from environment control agencies. The second target is to ensure all environmental improvement works scheduled for a particular year (as detailed in this Plan) and the supporting works programmes are completed. The targets have been based on the works included in the Plan.

Table 4.14 lists the environmental impact targets for the next for years. There is no environmental impact work over the remainder of the planning period.

ENVIRONMENTAL PERFORMANCE TARGETS	
Year	**Environmental Impact Works Due For Completion**
2015/16	1
2016/17	2
2017/18	1
2018/19	1

TABLE 4.14 ENVIRONMENTAL PERFORMANCE TARGETS

In 2013/14 there were no environmental prosecution or abatement notices received from environment control agencies which meets the target of having no environmental impact events.

4.2.2 Asset Efficiency Targets

The following targets are used to measure asset efficiency:

- Network losses: Technical
- Network power factor.
- Load factor.

These targets are consistent with the objective to renew, develop and maintain a network that fulfils stakeholders' values and expectations.

4.2.2.1 Network Losses: Technical

TLC uses a network analysis model called ETAP that models technical losses down to distribution transformer level. This model calculates technical losses and was set up as a bench mark in the 2006/07 year.

Distributed generation and power flows (both active and reactive) influence losses significantly as does the location and variation of network loads. Setting a target for technical losses is not a straight forward process and the regions of the network in various states have to be considered. The technical loss factor is set based on power flow studies.

Table 4.15 lists the targets and performance for technical losses for contiguous network regions under heavy and light loads with the generation injecting at expected levels throughout the planning period.

COMPARISON OF TECHNICAL LOSS STUDIES BASED ON NETWORK REGION										
Region	**2011/12**		***2012/13***		***2013/14***		**Target**		**Variance**	
	Heavy	*Light*	*Heavy*	*Light*	*Heavy*	*Light*	***Heavy***	***Light***	*Heavy*	*Light*
North	5.08%	1.60%	5.19%	1.61%	5.29%	1.84%	**7.00%**	**2.00%**	1.71% (F)	0.16% (F)
Central	11.41%	1.90%	11.40%	1.90%	10.27%	1.74%	**8.00%**	**5.00%**	2.27% (U)	3.26% (F)
Ohakune	11.74%	0.81%	11.75%	0.81%	8.60%	0.61%	**9.00%**	**2.00%**	0.40% (F)	1.39% (F)

TABLE 4.15 TECHNICAL LOSS TARGETS AND PERFORMANCE BY REGION

The technical losses at light loads are below the target and technical losses at heavy loads are above the target in the Central areas. This is being driven by the strategy to increase capacity at the lowest possible cost; mostly through the increased use of regulators instead of increasing conductor sizes and voltages. The level of distributed generation including the related reactive power flows affects the central areas losses.

Long term, TLC is focusing on reducing losses by:

- Demand site management initiatives by the use of load control systems and charges.
- Upgrading metering technology to achieve compliance and improve accuracy.
- Designing to minimise losses.

- Requiring distributed generators to set plants to minimise losses and maximise power factor during RCPD periods.
- More innovative load control and network automation schemes.
- When necessary and practical, deployment of capacitors to reduce reactive power flows.
- In the case of Ohakune; upgrading of the network and the use of mobile capacitors during ski weekend times.

Averaging the target data in Table 4.19 gives an overall technical loss expectation of about 6 to 7 %. Analysis of electricity meter registry and TLC's SCADA data shows that the ratio of billed energy to energy coming into the network is showing combined technical and non-technical loss figures that do not make sense e.g. they can vary from 12% to -3%. Given that TLC has relatively firm data for the technical losses (subject to averaging assumptions) the loss factors disclosed to the market are considered to be the most accurate figures available.

4.2.2.2 Network Power Factor

The higher the network power factor the more efficient the transfer of energy. Power factor becomes a complex issue when the effects of distributed generation are added. TLC set a performance target to maintain grid exit power factors at present levels during transmission interconnection charge periods.

Table 4.16 lists the power factor targets and performance at grid exit supply points during regional peak periods. The target is based on 2010 national data set by the Electricity Authority and that the existing power flow is maintained.

COMPARISON OF GRID EXIT POWER FACTOR TARGETS AND ACTUAL					
Grid Exit	**2011/12**	**2012/13**	**2013/14**	**Power Factor Target**	**Variance**
Hangatiki	0.922	0.924	0.899	0.912	1.32% (U)
Ongarue	0.794	0.975	0.944	0.916	2.61% (F)
Tokaanu	0.996	0.997	0.996	0.992	0.00% (F)
National Park	0.998	0.994	0.998	0.990	0.81% (F)
Ohakune	0.990	0.993	0.998	0.991	0.91% (F)

TABLE 4.16 TARGETS AND PERFORMANCE FOR POWER FACTOR BY GXP DURING RCPD PERIOD

Note: The Ohakune grid exit is shared with Powerco.

The Hangatiki power factor is lower than the target and is as a result of the large industrial loads supplied from this site, notably New Zealand Steel has the most influence. TLC has been granted by Transpower an exemption from power factor during RCPD periods for the Hangatiki GXP. Transpower has granted this request via a variation agreement.

At a local level TLC is using its network models and working with generators to better adjust equipment to improve the RCPD power factor and to minimise losses. This is a relatively complex and time consuming process but can substantially improve power factor and reduce losses.

4.2.2.3 Network Load Factor

Load factor is an indicator of network investment efficiency; the higher the load factor the more efficient the utilisation is of the assets. Nationally over recent years load factor has been reducing as peak demand has been growing faster than the energy transported. An objective of TLC's demand based billing is to hold load and ideally improve load factor. The target is to maintain or improve on the current load factor of 60%. The target has been determined by historic data.

Figure 4.6 shows the historic load factor performance and the load factor target.

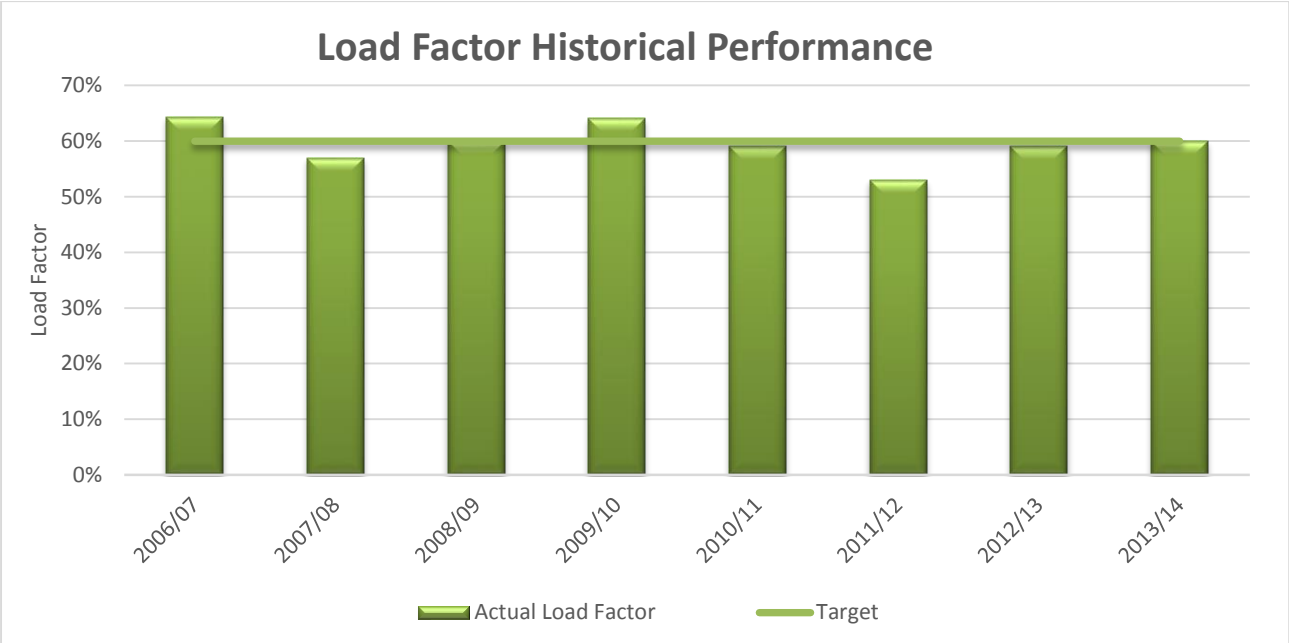


FIGURE 4.6 TARGET AND PERFORMANCE FOR NETWORK LOAD FACTOR

There is no variance between the load factor target and performance. The load factor is seen as an important network effectiveness indicator and the long term objective of demand charging is to improve the load factor over time.

4.2.3 Asset Effectiveness Targets

The following targets are used to measure asset effectiveness:

- Accidents/Incidents involving network assets.
- The number of asset hazards that are eliminated/minimised annually.
- Diversity factor.
- The ratio of total trees felled to trees worked on annually.

4.2.3.1 Accidents/Incidents Involving TLC Network Assets

TLC's objective is to minimise the accidents and incidents that are caused by or are associated with its network assets. Table 4.17 lists the targets and performance for accidents/incidents involving TLC network assets.

ACCIDENT/INCIDENT PERFORMANCE: ACTUAL COMPARED TO TARGET					
Event	**Actual 2011/12**	**Actual 2012/13**	**Actual 2013/14**	**Target**	**Variance**
Lost time - injuries involving Staff or Contractors	5	0	1	**5**	80% (F)
Average hours lost (per employee)	0.04	1.68	4.07	**<2.5**	63% (U)
Number of DOL notifiable accidents	0	0	0	**0**	0% (F)
Number of public injuries involving a TLC facility	0	0	0	**0**	0% (F)

TABLE 4.17 ACCIDENT/INCIDENT PERFORMANCE: ACTUAL COMPARED TO TARGET

The targets have been set based on historical data. The number of lost time injuries, average hours lost per employee, OSH notifiable accidents and the numbers of public injuries involving a TLC facility were at or above the target, this is due to employee injuries such as back and shoulder injuries

The following actions are being taken to minimise accidents/incidents involving TLC assets and ensure they are performing below target levels:

- Hazard control is a priority for all asset planning and designs.

- Assets inspected and the likelihood of them creating hazards is assessed.
- Hazard control renewal programme underway.
- Strong hazard control policies in place with clear non-negotiable criteria.
- Extensive control room and other hazard control systems and policies.
- Regular work crew auditing and feedback.
- On-going asset patrol and inspection programmes in place.
- Formal staff hazard awareness programme put in place.

4.2.3.2 Number of Asset Hazards that are Eliminated/Minimised Annually

Hazard control improvements make up a significant proportion of the renewal expenditure over the planning period. Many of the old TLC assets have hazard issues associated with legacy designs; TLC's target is to make sure that old equipment is being removed from the network. The targets have been set based on the number of improvements included in the Plan.

Table 4.18 lists the target for removing equipment that has been identified as hazardous during the planning period and included in the calculations of forward expenditure.

TARGETS FOR REMOVING HAZARDOUS EQUIPMENT SITES					
Year	Pillar Boxes	Two pole Structures	GMT	Switching Equipment	Total Hazards Eliminated/Minimised
2015/16	30	5	3	2	40
2016/17	0	6	3	2	11
2017/18	0	6	3	4	13
2018/19	0	7	3	2	12
2019/20	0	8	3	2	13
2020/21	0	7	4	6	17
2021/22	0	5	4	2	11
2022/23	0	6	3	1	10
2023/24	0	8	3	5	16
2024/25	0	0	3	3	6

TABLE 4.18 TARGETS FOR REMOVING HAZARDOUS EQUIPMENT SITES DURING THE PLAN PERIOD

Table 4.19 compares the target numbers of asset hazards that are eliminated/minimised as compared to actual.

ASSET HAZARDS ELIMINATED/MINIMISED: ACTUAL COMPARED TO TARGET			
Hazard Category	Actual 2013/14	Target 2013/14	Variance
Pillar Boxes	49	**50**	2% (U)
Two Pole Structures	5	**9**	44% (U)
Ground Mount Transformer	2	**3**	33% (U)
Switching equipment	3	**3**	0% (F)
Total Hazard Control	59	**66**	9% (U)

TABLE 4.19 ASSET HAZARDS ELIMINATED/MINIMISED: ACTUAL COMPARED TO TARGET

Hazard elimination/minimisation projects were slightly below target. This was due to a number of tasks being more complex and technical than anticipated and delivery delays associated with high voltage switchgear. The pillar box renewals fell short of its target due to difficulties within the contracting job management systems i.e. resources were diverted to other projects such as fault repairs.

Continuous improvement of the work management systems is taking place to ensure focus throughout the year is maintained on priority hazard renewals. (Faults, customer demands and the need to complete other priority emergent work can quickly take the focus away).

4.2.3.3 Diversity Factor

Diversity Factor is the probability that a particular piece of equipment will come on at the time of the facility's peak load. It is also a measure of how effective TLC's demand billing programme has been. It is an indication that customers have spread their load more effectively. Higher diversity means the individual maximum demands are less likely to occur at the same instants, which means a more efficient network asset utilisation. Diversity Factor target is set at 1.39. Table 4.20 lists the target and performance for diversity factor.

Diversity Factor						
2009/10	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**Target**	**Variation**
1.51	1.36	1.32	1.38	1.33	1.39	0.04 (U)

TABLE 4.20 DIVERSITY FACTOR: ACTUAL COMPARED TO TARGET

The performance is slightly lower than the target.

4.2.3.4 Ratio of Total Numbers of Trees Felled to Trees Worked on Annually

Vegetation control is TLC's greatest operating cost. Felling trees as opposed to trimming gives the best permanent solution. The target for the planning period is to keep the fell ratio above 70%, i.e. 70% of all trees or more are felled as opposed to being trimmed throughout the planning period.

Table 4.21 lists the actual annual ratio of the numbers of trees felled to the numbers of trees worked on.

RATIO OF TREES FELLED TO TREES WORKED ON							
	2009/10	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**Target**	**Variance**
Ratio of the Number of Trees Felled to Number Of Trees Worked On	79%	80%	77%	81%	88%	**70.00%**	25.71% (F)

TABLE 4.21 COMPARISON OF THE RATIO OF TREES FELLED TO TREES WORKED ON

The variation was within expectations. The fell rate was above target. Customers' understanding of the importance of allowing trees close to power lines to be removed to improve reliability and minimise costs is increasing. TLC is constantly striving to increase the fell rate to try and minimise its long term vegetation control costs and improve reliability.

4.3 Performance Against the Plan

Discussed in this section is the comparison between planned and actual expenditure, including the reasons for any variances. Table 4.22 below outlines overall capital expenditure compared with the budget for 2013/14.

2013/14 Capital Expenditure			
Category	**Actual $**	**Budget $**	**Variance**
Consumer Connection	597,939	580,626	3%(U)
System Growth	157,731	444,241	64%(F)
Asset Replacement and Renewal	5,719,803	6,157,729	7%(F)
Asset Relocations	2,924	16,648	82%(F)
Quality of Supply	1,753,001	1,897,436	8%(F)
Other Reliability, Safety and Environment	57,781		No Budget
Non System Fixed Assets - Routine	108,681	154,198	30%(F)
Non System Fixed Assets - Atypical	114,579	50,000	129%(U)
Total	**8,512,439**	**9,300,878**	**8%(F)**

TABLE 4.22 COMPARISON OF ACTUAL AND BUDGETED CAPITAL EXPENDITURE

The main reason for consumer connection being over budget is the greater than anticipated number of industrial new connections.

Figure 4.7 compares actual historical network expenditure with the forecast expenditure for the corresponding year.

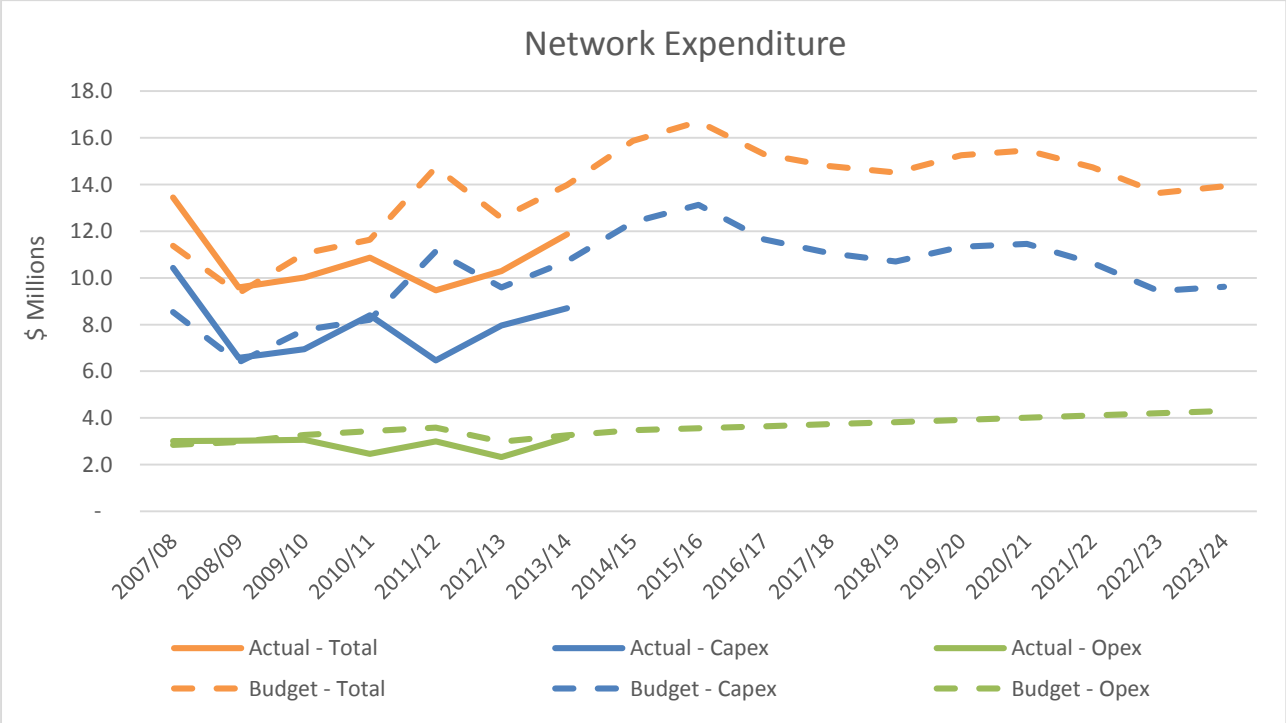


FIGURE 4.7 COMPARISON BETWEEN HISTORICAL ACTUAL AND FORECAST EXPENDITURE

The gap between budgeted expenditure and actual expenditure has decrease compared to previous years. As shown in Figure 4.7 2013/14 had the highest level of achieving implementation against the planned work than previous years.

Table 4.23 includes planned work that was allowed for in the budget for 2013/14.

Budgeted Work for 2013/14			
	Actual $	**Budget $**	**Variance**
Mokau 128-08 LV LR	40,705	6,539	522%
Hakiaha Tx 01A38 & 01A82 Switches (4 Bay Xiria)	123,265	55,494	122%
Mahoenui 113-03 LV LR	13,975	6,539	114%
Industrials New Connections	297,859	156,926	90%
Atypical System Development	93,748	50,000	87%
Manunui ZSub Tx Refurbishment	164,262	88,790	85%
Tawhai ZSub Tx Refurbishment	237,059	160,041	48%
Piopio 116-05 11kV LR	176,880	131,062	35%
LV Emergent	122,882	104,617	17%

TABLE 4.23 SIGNIFICANT VARIANCES FOR BUDGETED WORK IN 2013/14

There were more industrial new connections than anticipated for in 2013/14.

Both the Tawhai and Manunui zone sub transformer refurbishment were over budget due to the allowance for additional work that was not included in the initial scope. This includes the addition of new switchgear and overhead structures.

More work was required on the LV line renewals to get them up to standard than was initially anticipated.

Additional work was completed along with the installation of switchgear for transformers 01A38 and 01A82. This involved moving forward a project to add an LV tie between the two transformers.

The capital projects carried over from 2012/13 that went over the allocated budget are outlined in Table 4.24.

Carry Over Work from 2012/13			
	Actual $	**Budget $**	**Variance**
04I01 Ongarue 2-pole	29,122	8,000	264%
T4128 Ongarue 2-pole	28,658	8,000	258%
Waitete Zone Substation (Bunding and Earthquake restraints)	56,718	20,000	184%
Te Waireka Substation Project	278,217	103,076	170%
Maihiihi 111-08 11kV LR	180,688	90,164	100%
McDonalds 110-05 11kV LR	346,561	240,840	44%

TABLE 4.24 VARIANCE OF CARRY OVER WORK FROM 2012/13

The Te Waireka substation project was an evolving project designed to improve reliability and protection at Te Waireka zone substation. Due to limited availability for outages the majority of the work was completed in 2013/14.

The Waitete bunding and earthquake restraints was more complicated than anticipated. It was required that the transformers were lifted up to remove their wheels so they could be securely fastened to the plinths.

The majority of work for the 2 pole Ongarue two pole structures (04I01 and T4128) was planned to be completed in 2012/13, due to the availability of resources the work was not started until 2013/14.

Due availability of resources the majority of both the Maihiihi and McDonalds line renewals were conducted in 2013/14 instead on 2012/13.

4.4 Performance Benchmarking

TLC has undertaken a performance benchmarking review as part of a wider asset management review. The review was done using the 2013 financial year information disclosure figures. The purpose was to provide a modelled approach to replacement capex and compare it with the current approaches. The exercise compares TLC's asset management strategies to other electricity distribution business's (EDB's). This is the first year comparative performance has been evaluated. It will lead to further evaluation of TLC asset strategies.

4.4.1 Reliability

CAIDI is a measure of time to restore supply and is deduced by dividing SAIDI by SAIFI, This is a good indication on the overall impact that outages have on customers. Figure 4.8 shows that over the years CAIDI has been decreasing and this is a result of improved reliability across the network. The deployment of remote controlled equipment in key areas of the network has reduced the average interruption duration that customers experience.

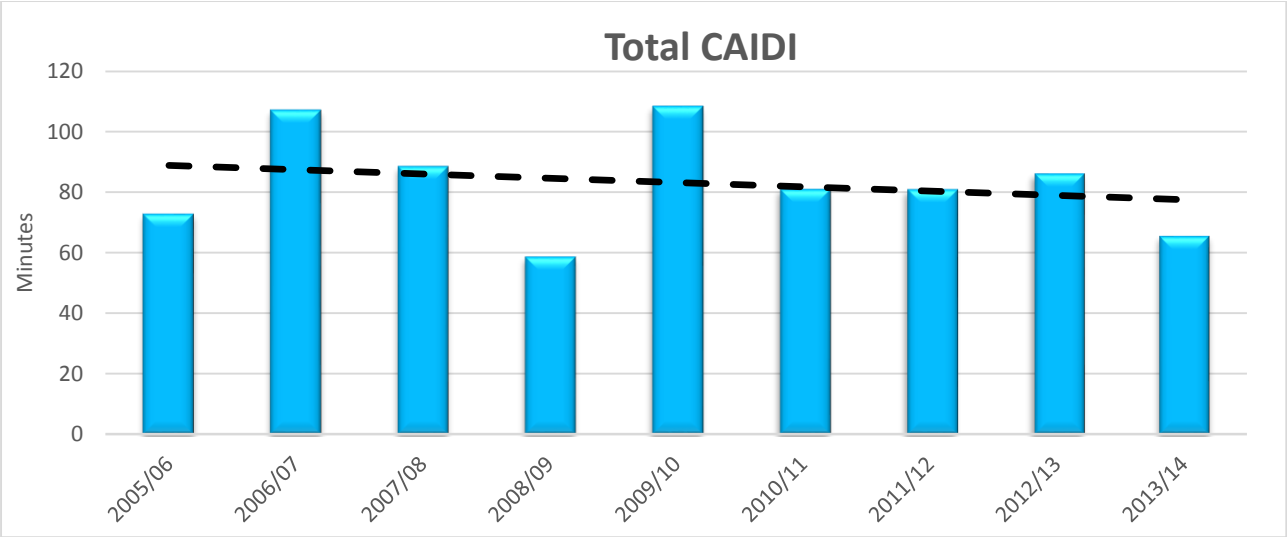


FIGURE 4.8 TOTAL CAIDI TRENDS

In comparison to other EDB's TLC has around mid-range CAIDI for unplanned work but very low planned CAIDI (Figure 4.9 and Figure 4.10). The low planned CAIDI is a result of a targeted plan to minimise the duration that customers are without supply.

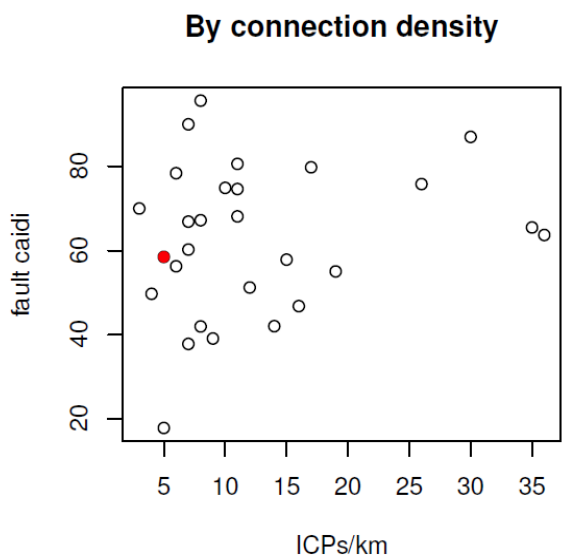


FIGURE 4.9 FAULT CAIDI BY NETWORK CONNECTION DENSITY

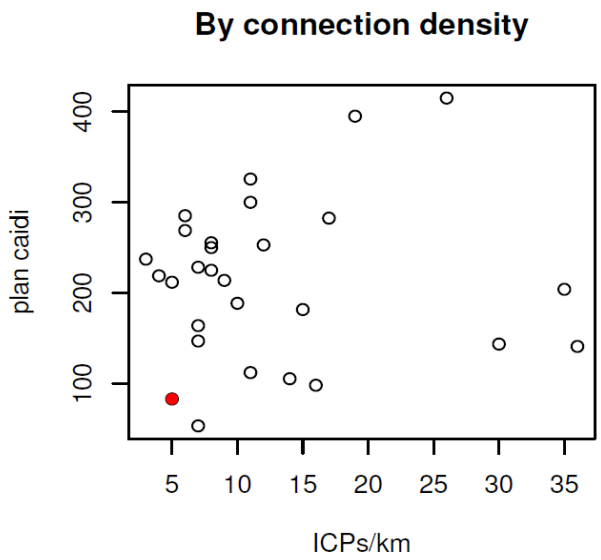


FIGURE 4.10 PLANNED CAIDI BY NETWORK CONNECTION DENSITY

Figure 4.11 shows that SAIDI is steadily improving. This trend of decreasing SAIDI is a good indication of the effectiveness of TLC's line renewal program and the deployment of report controlled equipment across the network. Performance in the 2012/13 year was exceptional in the history of the network with both indices under 65% of thresholds. SAIDI performance is on target for 2014/15.

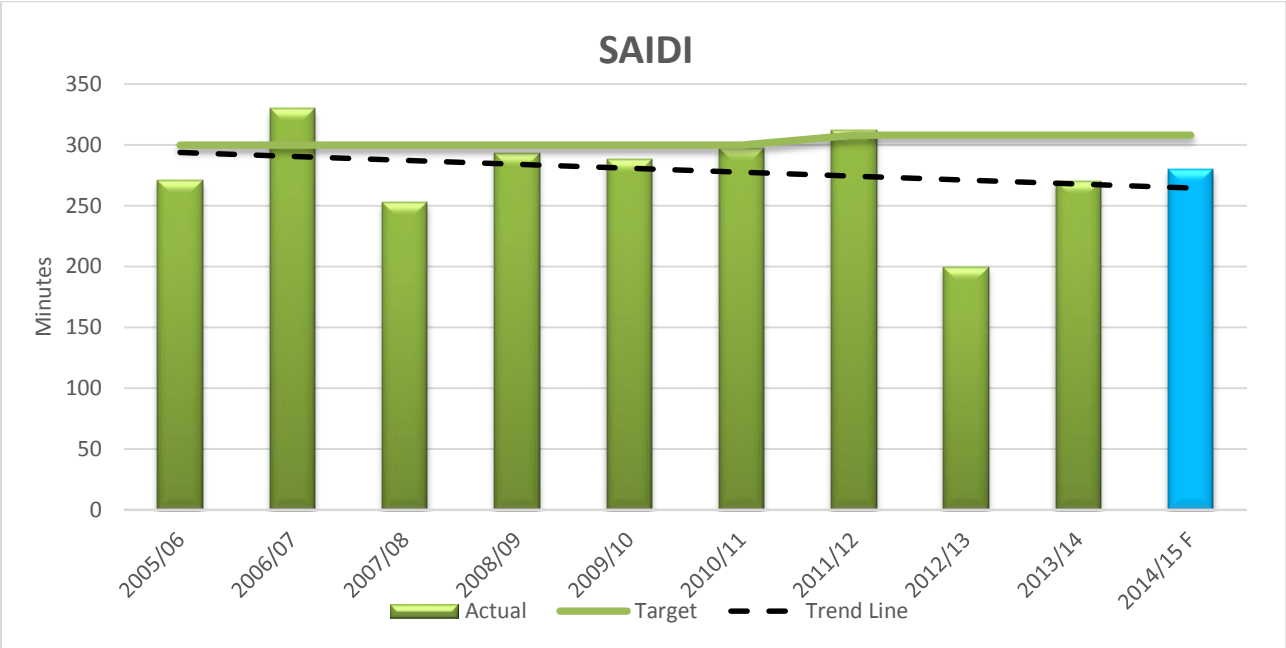


FIGURE 4.11 TOTAL SAIDI WITH 2014/15 FORECAST

Figure 4.12 Show and increase in asset related outage; post to 2011 the data collected on asset related outages has significantly improved in terms of data accuracy. The increase in asset related faults is driven by an increase in underground cable faults, conductor failures and switchgear failure (mainly transformer fuses). The renewal of underground cables, conductor and switchgear will be a key area that will be targeted in the upcoming years. Figure 4.14 to Figure 4.19 show the breakdown of defective equipment SAIDI. Along with underground cable and conductor related faults, customer service, switchgear and transformers have also had an increase in faults over the past nine years. While not entirely compensating for these increases in SAIDI, poles and cross arms are showing a pleasing reduction, this is a result of the 15 year line renewal program.

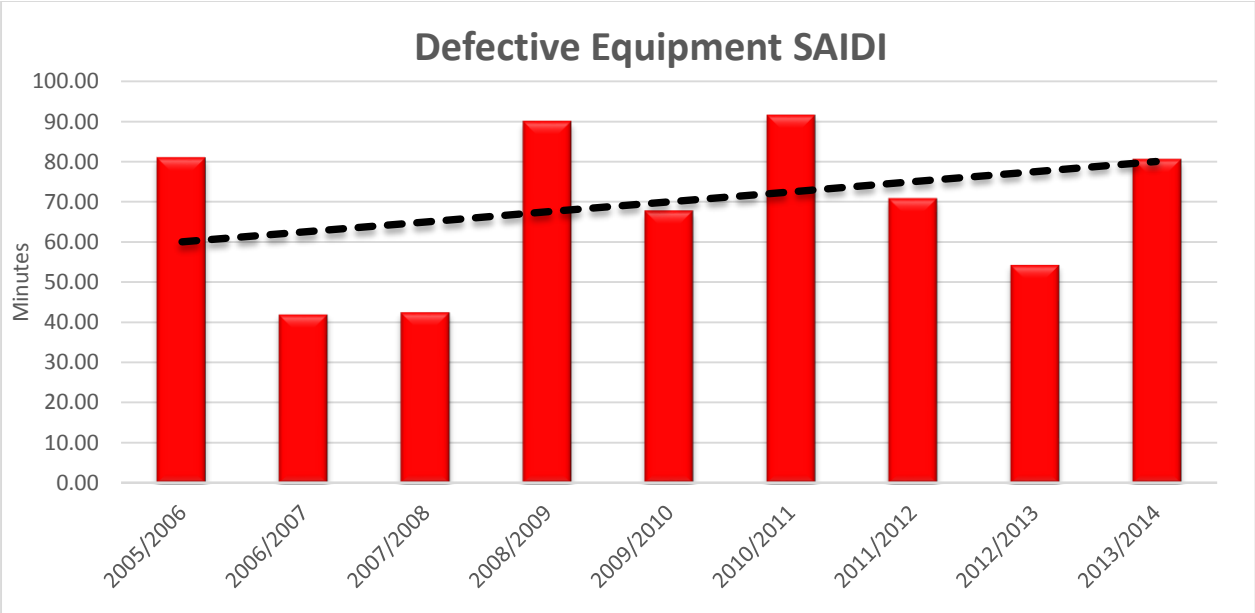


FIGURE 4.12 DEFECTIVE EQUIPMENT RELATED OUTAGES

Figure 4.13 indicates an increasing trend of SAIDI from vegetation.

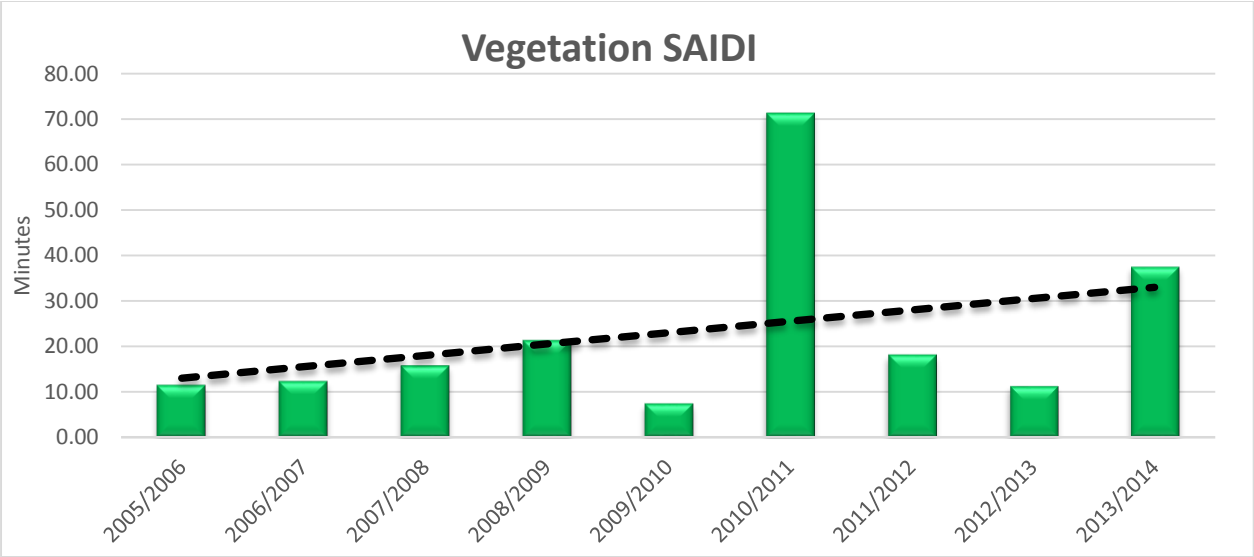


FIGURE 4.13 OUTAGES CAUSED BY VEGETATION

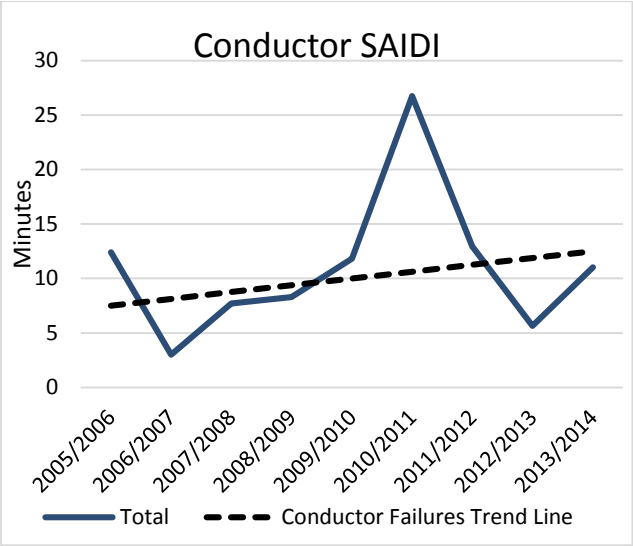


FIGURE 4.14 OUTAGES CAUSED BY CONDUCTOR FAILURE

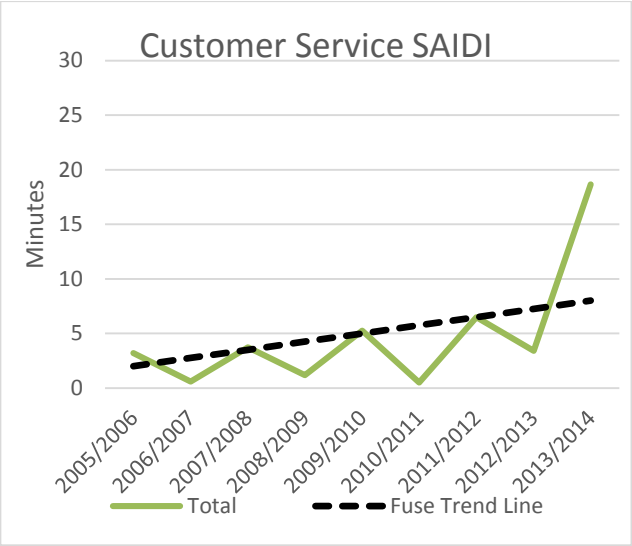


FIGURE 4.15 OUTAGES CAUSED BY CUSTOMER SERVICES

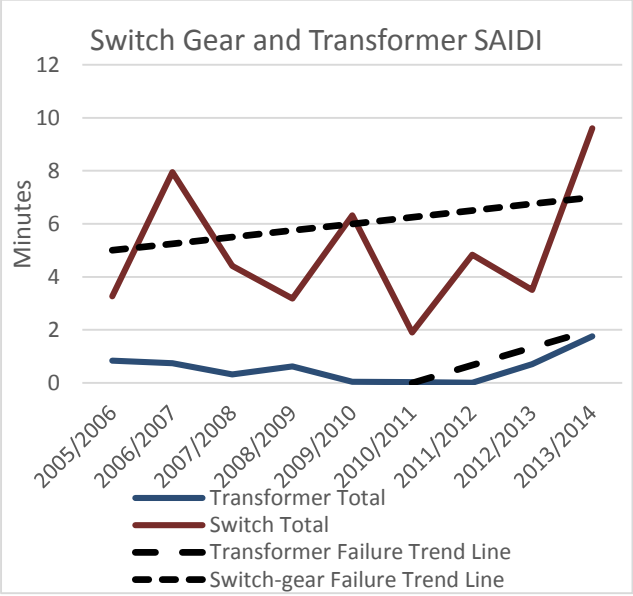


FIGURE 4.16 OUTAGES CAUSED BY SWITCH GEAR AND TRANSFORMER FAILURE

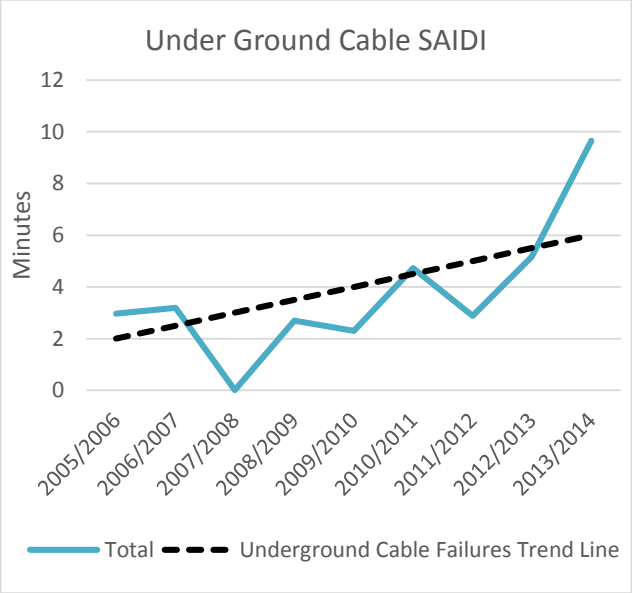


FIGURE 4.17 OUTAGES CAUSED BY UNDERGROUND CABLE FAILURE

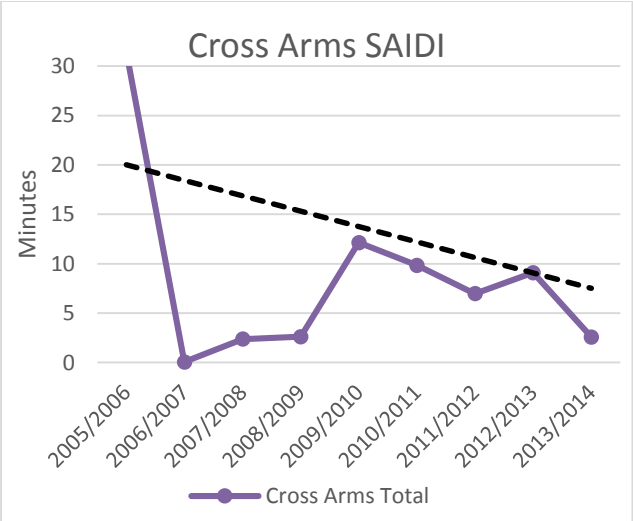


FIGURE 4.18 OUTAGES CAUSED BY CROSS ARM FAILURE

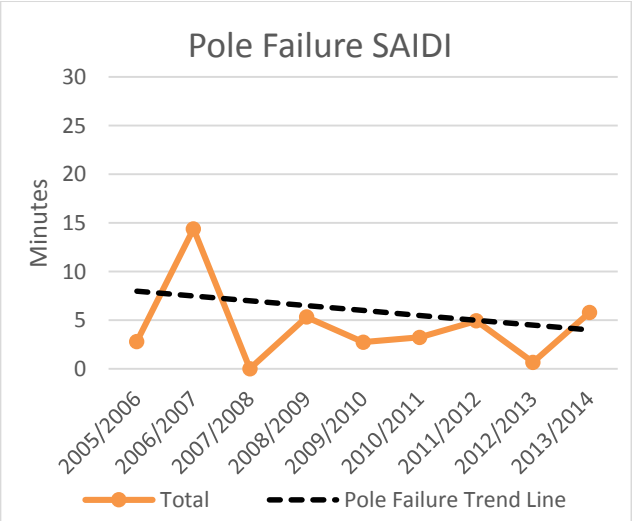


FIGURE 4.19 OUTAGES CAUSED BY POLE FAILURE

There is a small trend of increasing SAIFI (Figure 4.20). The overall SAIFI trend has been flat. The 2013/14 SAIFI was high due to a human related operation fault that affected the whole network. The high SAIFI in 2013/14 is also a result of a targeted plan to minimise the duration that customers are without supply. TLC has used a number of generators to keep supply to its customers; the use of these generators has a major impact on the SAIFI performance as the connection and disconnection process effectively involves and outage each time.

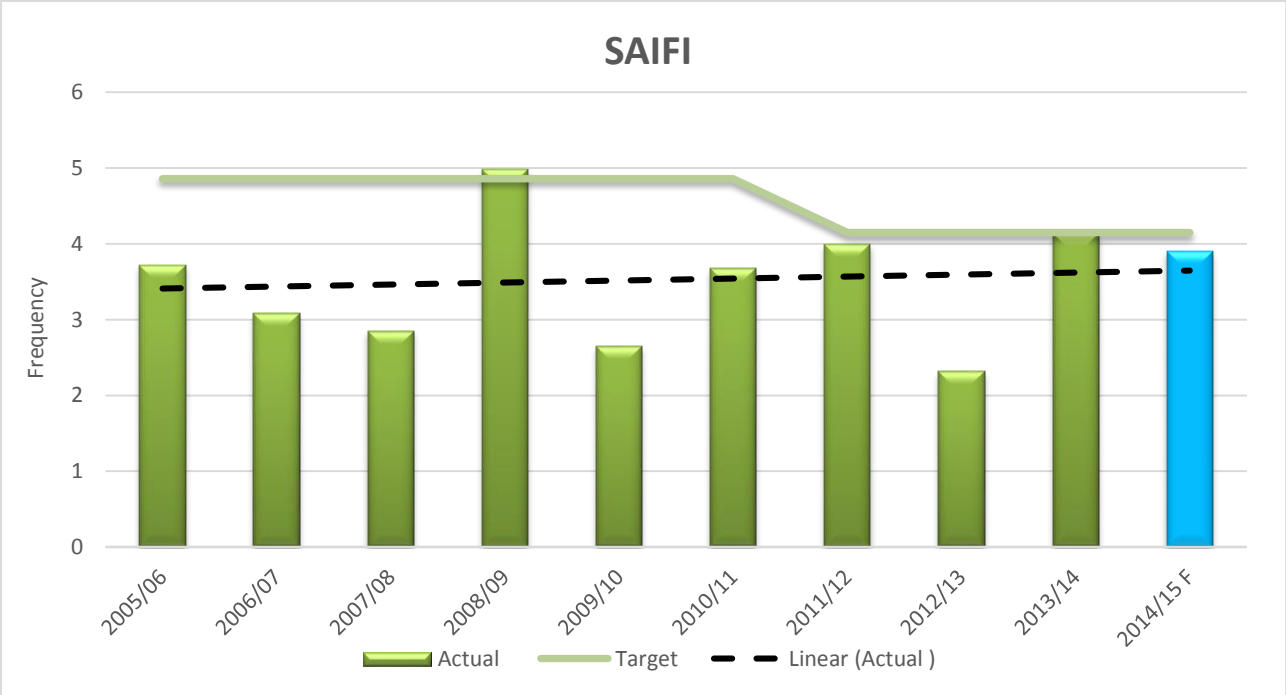
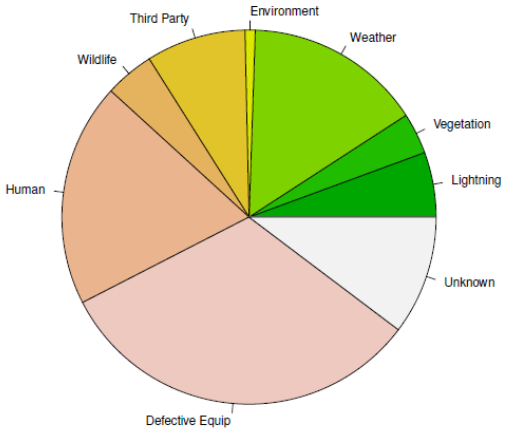


FIGURE 4.20 TOTAL SAIFI WITH 2014/15 FORECAST

Figure 4.21 compares TLC's fault break down by SAIFI to the industry average. TLC fault SAIFI has high weather and human components. 2013/14 was an unusual year for human impacts. The low level of Unknown outages compared to the industry average shows a concerted effort by all staff to identify and report fault causes. This improved level of data allows for more objective analysis and a targeted approach for reducing the impact of outages.

The Lines Company Ltd Fault SAIFI



Industry Average Fault SAIFI Make-up

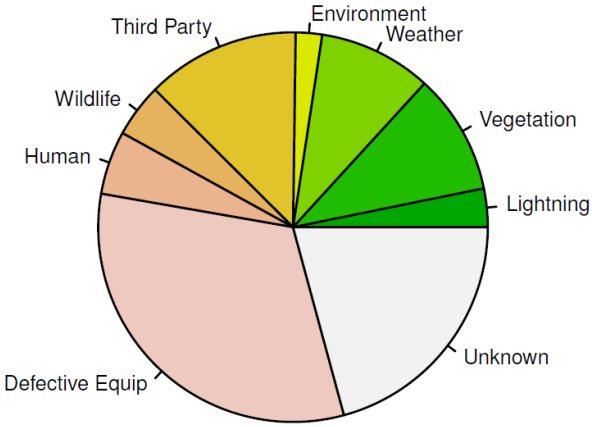


FIGURE 4.21 SAIFI BREAKDOWN COMPARISON

Figure 4.22 shows that TLC SAIFI is above the industry norm. As mentioned earlier it is believed this is due to the increased use of generators. This along with the slight trend of increasing SAIFI indicates that work needs to be done to find methods to improve SAIFI going forward.

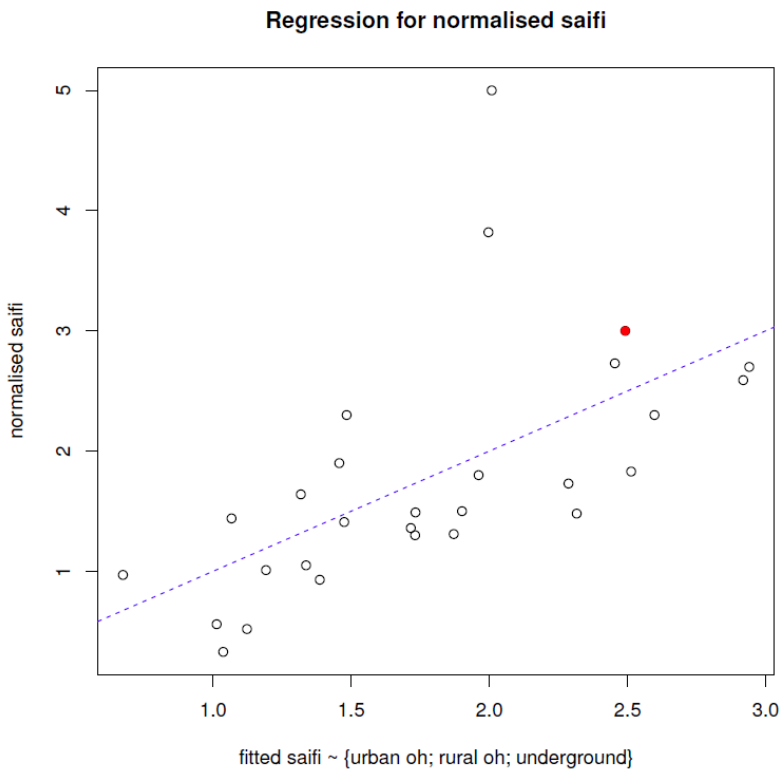


FIGURE 4.22 REGRESSION OF SAIFI ON NETWORK CHARACTERISTICS

4.4.2 Utilisation and Losses

TLC has utilisation within expected bounds for the density of the network and this is shown in Figure 4.23.

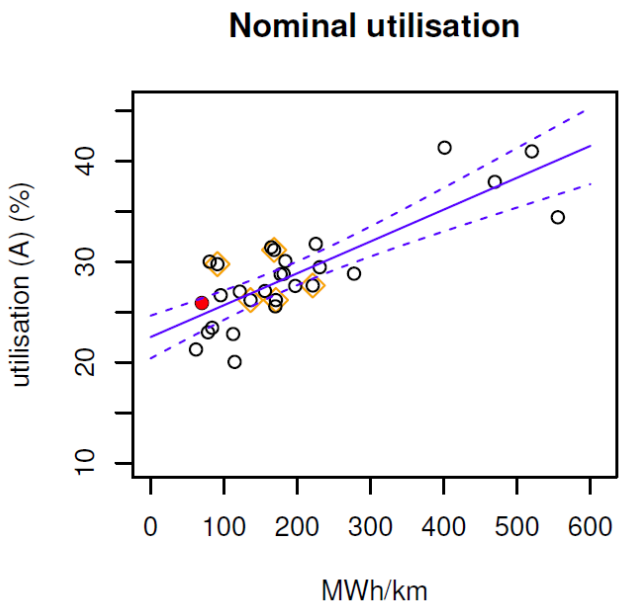


FIGURE 4.23 DISTRIBUTION TRANSFORMER UTILISATION

The chart below shows TLC has a high loss ratio. Network configuration optimisation and other cost effective solutions are being investigated in order to address this.

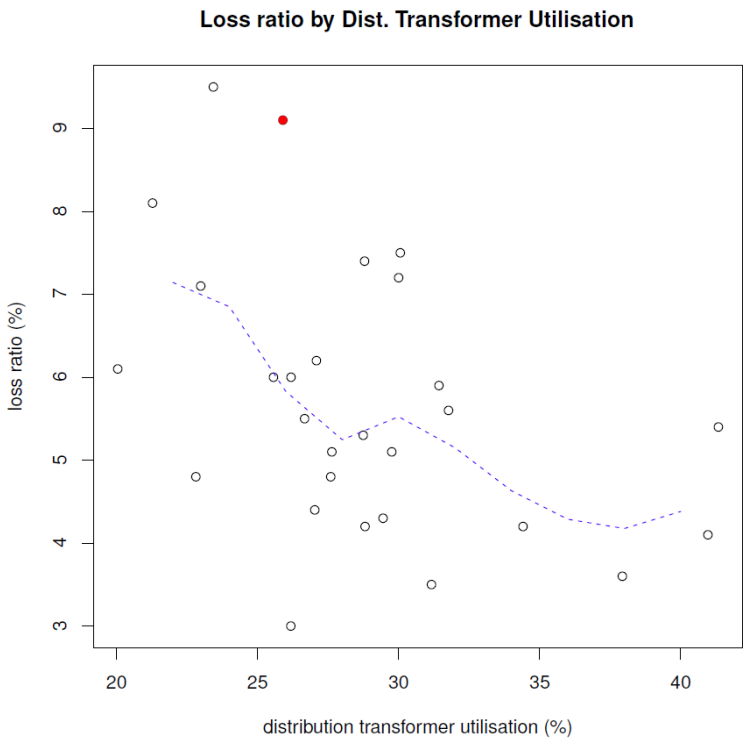


FIGURE 4.24 LOSS RATIO AND TRANSFORMER UTILISATION

4.5 Asset Management Improvement

TLC currently collects asset information through the inspection program; this is collated in the Basix database. The information collected to date has been largely subjective; the quality of the information has been average and has not been utilised to its full extent.

The history of the plan has revolved around a number of people who are no longer part of the asset management team. Asset management concepts and thinking has moved on since the plan was originally developed.

We are now revisiting where our asset management capabilities should be with a view to developing an appropriate improvement plan in the upcoming year. As part of revisiting our asset management capabilities TLC has engaged external consultants to review the following areas;

- Project management
- Benchmarking review
- Asset management review
- Health and safety review

The results of the review have highlighted a number of areas in which TLC requires improvements; these will form the basis of the improvement plan.

4.6 Asset Management Maturity Assessment Tool

The Asset Management Maturity Assessment Tool (AMMAT) has been developed to assess the maturity of EDB asset management systems. The tool consists of a self-assessment questionnaire which is derived from PAS55:2008. This has highlighted key areas in the asset management system that TLC will need to improve on. Engineering resources will need to be directed to developing the asset management system to show improvements. A full review of TLC capabilities against AMMAT will be undertaken through the development of the improvement plan.

Each question in the AMMAT is given a maturity rating (this must be a whole number between 0 and 4).

Table 4.25 below shows the AMMAT Maturity Rating Scale.

Maturity Score 0	Maturity Score 1	Maturity Score 2	Maturity Score 3	Maturity Score 4
Inadequate (Unaware)	Inadequate (Aware)	Average (Development)	Competent	Surpass the Standard (PAS 55:2008)

TABLE 4.25 AMMAT MATURITY RATING SCALE

Figure 4.25 shows TLC current self-assessed score for the 2013/14 AMMAT and forecast score for 2014/15.

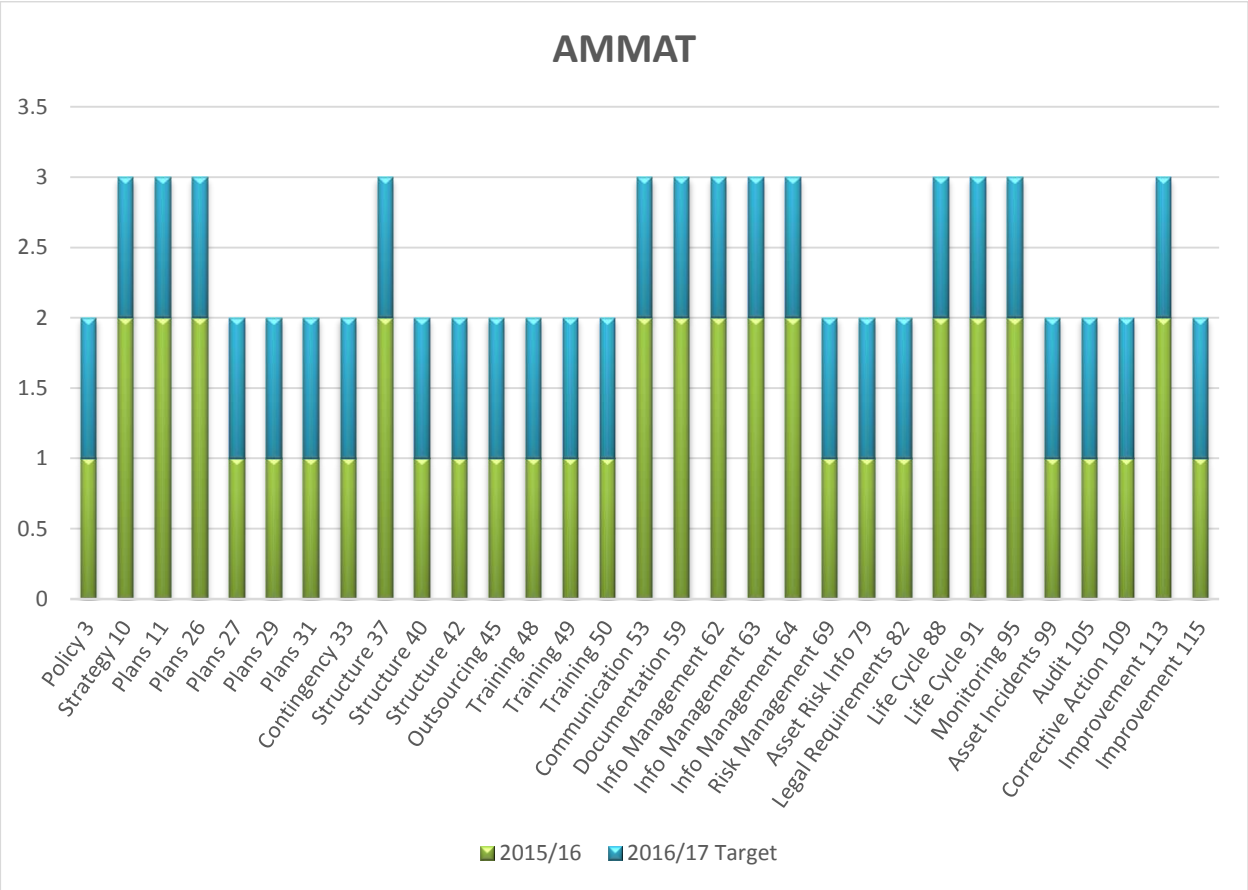


FIGURE 4.25 CURRENT SELF-ASSESSED SCORE FOR THE 2014/15 AMMAT AND FORECAST SCORE FOR 2015/16.

Section 5

5. Development Planning

5.1 Description of Network Planning Criteria and Assumptions

5.1.1 Introduction

Resourceful network development planning is critical in that TLC has to achieve the best results for its stakeholders and customers, yet still meet regulatory requirements and stay within the bounds of best industry practice.

TLC covers a large geographical area but has a small customer base that results in limited cash flow to fund the development that caters for load growth, achieving agreed customer service levels and providing a network that is stable with minimal outages.

TLC has a 10 year planning window. Each year TLC holds a planning meeting that reviews the proposed Plan and adjusts it as required. The review is based on facts from data collected and knowledge of network performance and where forecasts indicate that network will be constrained, planned customer development and load growth.

The basis for the development of the plan are detailed in this section, which discusses the assumptions made and the criteria used, prioritisation of development, forecasting methodology and the impact of uncertain development, generation and demand side management.

This section also gives details on the projects planned in the 10 year planning period, with an in-depth description for those projects that will be started in the coming financial year and to a lesser extent those in the following four years, followed by a high-level description of the projects included in the plan for the following five years.

5.1.2 Planning Assumptions

5.1.2.1 Performance Assumptions

- Customers will require reliability to the service level targets outlined in previous sections.
- Customers will require service to the levels outlined in previous sections.
- Customers will require quality to levels outlined in previous sections.
- Customers will accept pricing compliant with that approved by the Commerce Commission.
- Customers will accept other performance indicator results that are in line with those of other network companies that supply remote rural areas.
- Customers will require the network to be renewed, developed and maintained to be sustainable for the long term; including a hazard controlled network.
- Customers will demand increased service and innovative new products that will give them the opportunity for cost savings of on both energy and network services.

5.1.2.2 Economic Assumptions

- The organisation's pricing models (that are set up in compliance with the Commerce Commission requirements) shall be used for evaluating and setting revenue requirements for development proposals. (These models include capital evaluation formulae, rates of return and valuation in line with Commerce Commission guidelines.)
- If customers are not prepared to fund such development the projects will not take place unless some other sources of funding are found.
- Localised pricing models are set up and used to test the economics of most development projects. (The exception is new and upgraded network connections under 200 kVA.)
- Financial commitment will be required from customers before investing to minimise the risks of stranded assets or non-profitable assets.

- Customers in the King Country have a limited ability to pay ever increasing lines and energy charges. New products and services are needed to be able to offer them a better product at a lower cost.

5.1.2.3 Customer Load Growth Assumptions

- Customers are increasing the average household peak load, with the availably of heat pumps, spa pools and numerous electronic devices. This increase will be offset to a degree by the increasing energy efficiency of modern appliances, resulting in declining overall energy intensity.
- Customers require a more reliable supply to ensure electronic devices and lighting are not affected by the networks performance.
- Customers' expectations are much higher than those of 10 or even 5 years previously.
- The growth in electronic devices and compact florescent lighting increases the harmonics on the network.
- The uptake of alternative energy devices such as solar panels will increase as they become more affordable.
- There will be a timing gap between the reducing energy consumption effects of solar and the escalation of energy quantities associated with the penetration of electric vehicles.
- TLC will continue to use its demand approach to charging supported by a continuous improvement process.
- TLC will continue with its investment in education customers regarding their energy use and controlling their demand growth.

5.1.2.4 Business Environment Assumptions

- Low growth in urban areas and continuing drift from regional centres to large cities.
- Slow growth in holiday homes in National Park, Ohakune and Taupo lake areas.
- Some development around urban centres with lifestyle blocks.
- Underground conversion in urban centres is customer funded.
- Dairy farming growth will continue.
- Generally, there will be on-going farm rationalisation.
- The ski fields continue with on-going development.
- Industrial customers with high power consumption will vary their growth depending on the economic climate. Customer expansions are generally customer funded projects.
- The growth in small businesses is expected to be low. If any investment is made this will generally be customer funded and planning horizons are short.
- Continued growth of distributed generation.
- Penetration of electric vehicles in 10 to 15 years' time.

5.1.2.5 Asset Assumptions

- Assets are being run to their upper capacity limits to defer development investment as long as possible. Renewals continue to take the focus for the planning period.
- Environmental and hazard issues on the network are given a high priority.
- Improvement of the ripple control system and metering of customers, to promote Demand Side Management and reduce losses.
- The use of shunt capacitors is being investigated to provide voltage support. This cannot be developed fully until the ripple signal is fully converted from 725 Hz to 317 Hz and systems are implemented to prevent the capacitors interfering with the ripple signal. A number of banks have been installed to support voltage for limited times during backfeeds.
- Continue the promotion of advanced metering that can produce demand data.
- Ensure the network is capable of achieving targeted reliability, quality and hazard control performance.
- Reliability development improvements are designed to target improvement for lower performing areas.

- Build enough asset redundancy and back feed options that allow service to be maintained to customers when critical equipment is removed from service for maintenance, such as the annual Transpower outage at Ohakune, or in times of major faults on the network.
- Use simple but innovative ways to minimise development expenditure to alleviate pressure in growth areas. (Modular substations for example.)
- Network architecture to minimise the effects of network surges that can destroy electronic equipment.
- TLC's connection code and standards will require that metering and relays are installed that will meet the standard of network pricing methodologies.

5.1.2.6 Data and Network Analysis Assumptions

- Develop data systems to provide accurate regulatory reporting.
- Development of data systems that will read advanced meters and make this information available to customers, retailers and TLC for both planning and billing purposes.
- Develop data and information systems to support decisions that align network performance with asset development, renewal and maintenance.
- Continued SCADA development for more detailed data collection and monitoring.
- Network analysis using data collected and the network analysis program to model future network requirements, harmonics and protection requirements.
- Explore and develop self-healing network technologies, intelligent networks with automatic load shedding and real time monitoring.
- Develop information systems to be increasingly integrated including :
  - » Revenue models compliant with Commerce Commission guidelines.
  - » Financial systems.
  - » Asset data and information.
  - » Billing systems.
  - » Develop data systems to improve customer service information across the organisation, i.e. outage notification systems, metering and relay data, complaints and customers' enquiries, maintenance and capital plans, and other service related activities.
  - » Customer feedback and contact with the organisation.
- Planning and modelling to find ways to complete the necessary network renewals and development at the lowest possible cost.

5.1.2.7 Grid Exit Power Factor Assumptions

It is assumed that the present grid exit power factor requirements during Regional Co-Incident Peak Demand (RCPD) periods will be modified to consider reactive power flows as opposed to the present power factor figure. This will be required if the intent of the government's wish to promote distributed generation is to be fulfilled.

5.1.2.8 Equipment End of Life Assumptions

Equipment end of life disposal is considered when selecting equi1pment. Issues such as SF6 disposal and other toxic substances are considered when selecting equipment.

5.1.3 Planning Criteria

The planning criteria are focused on ensuring network performance will meet or exceed performance targets as detailed in Section 4. Most of the criteria listed below have a direct effect on the asset related customer service targets, asset performance targets and asset effectiveness targets.

The planning criteria have been aligned to the capital expenditure development categories as required by the disclosure regulations. These are:

- Capital Expenditure: Customer Connections.
- Capital Expenditure: System Growth. (Cumulative capacity)
- Capital Expenditure: Quality of Supply.
- Capital Expenditure: Asset Replacement & Renewal.
- Capital Expenditure: Asset Relocations.
- Capital Expenditure: Non Network Assets.

The planning criteria of each of these categories are discussed in the following sections.

5.1.3.1 Planning Criteria: Customer Connections

Most of these connection costs are funded by customers via line charges and capital contributions. The designs for these connections are completed to the various regulations and codes of practice that guide the industry.

Connections shall be made in such a way that they will be compliant with TLC connection code and standards.

Transformers are designed to typical industry earthing, strength, hazard controls and security standards. (The layout of these is described in more detail in Section 3.)

The design criteria for underground cables and associated overhead lines are to industry standards. It is an option for customers to own transformers, lines and cable or pay for these assets as dedicated assets in monthly line charges. Customer owned works must meet published standards before TLC will connect. The connections of assets associated with customer connections usually do not have backup security.

Other technical requirements are covered by TLC's Terms and Conditions of Supply, and commercial requirements.

5.1.3.2 Planning Criteria: Customer Connections: Subdivisions

The local body subdivision conditions generally require new subdivisions to be constructed using underground reticulation.

The capacity requirements of new domestic connections are assumed to be typically 5 kVA. (Line charges have a capacity component and customers may choose to vary this assumption to minimise charges.)

More detail of the design criteria for subdivisions is included in TLC's connection standards.

The key criteria include:

- Fuses at the point of connection to individual customers.
- Cabling to industry codes using industry preferred sizes.
- Low voltage protection on each circuit heading away from transformers.
- Links between low voltage circuit ends if practical.
- Low voltage panels to be insulated and to have transformer isolation and maximum demand indicators.
- High voltage switchgear (ring main type) should be fitted to all but the last spurred transformer. Each transformer and/or spur should be individually protected against over-current.
- Where practical and economic the high voltage cable network will be ringed.

- 11 kV cabling to be industry preferred size cables.
- All overhead to underground cable connections shall have isolation links and surge protection.
- Voltage drops in low voltage cables should not exceed 5% with a co-incident demand of about 5 kVA for domestic installations.
- Typical domestic average 3 hourly demands of 2 to 3 kVA will be assumed.

Experience has shown that when these design criteria are applied, subdivision reticulation will perform to the targets in Section 5 and hazards are controlled to acceptable standards.

TLC may model subdivisions using a pricing model or use standard criteria for the amounts it requires customers to fund. The standard criteria are for TLC to supply the transformer assets and for the developer to fund the remainder.

5.1.3.3 Planning Criteria: Customer Connections: Industrial Connections

Industrial connections are usually tailored for the customers' individual needs. Options like alternative supplies and additional security are discussed with customers and when necessary pricing models are developed to give customers cost implications. Capacities are tailored to customers' requests.

Design criteria that are not affected by customer requirements include:

- Earthing to industry standards.
- The need for all ground level components to be insulated, protected, and earthed to acceptable industry hazard control standards.
- The need for all equipment to be secure and have advanced hazard control features.
- All designs must meet or exceed industry hazard control standards.
- Installations designed to ensure voltage drops are less than 5%.
- Harmonics and voltage flicker to comply with NZECP36 and AS/NZS 61000 series of joint Australian and New Zealand standards.
- Surge suppression fitted to all 11 kV or 33 kV points of connection, (11 kV – 9 kV, SWER 11 kV – 18 kV and 33 kV – 27 kV arrestors respectively).

Experience has shown that designs to these criteria will meet network performance targets. (As outlined in Section 5 and in the assumptions above)

5.1.3.4 Planning Criteria: Customer Connections: Distributed Generation Connections

Distributed generation connections greater than 10 kVA are usually tailored for the customer's needs and the specific installation. Installations below this capacity level are likely to have insignificant effects. (This may exclude inverter connections on SWER or weak systems.)

The physical design criteria are as for small customer connections and industrial connections (dependant on the size of the installation). The additional design criteria include:

- Capacity: Capacity is determined by the maximum voltage rise at the point of connection that will not affect other customers. (Normally 11.2 kV on 11 kV system and depends on the tapping range of 33 kV zone substation transformers on the 33 kV network) at RCPD periods whilst maintaining a unity power factor injection.
- Protection: Protection to be set to ensure no damage to other customers and TLC's equipment.
- Power Factor: Equipment to be set to produce unity power factor during RCPD periods.
- Voltage: Voltage protection to be set to ensure generation trips when voltage varies typically more than ± 10%.
- Frequency: Frequency protection set to trip slightly outside the reach of national automatic under frequency load shedding (AUFLS) relays.
- Fault levels: Additional generation must not cause combined network fault levels that exceed the rating of existing equipment.
- Harmonics: Compliance with NZECP 36.
- Voltage flicker: Use of guidelines as in AS/NZS 61000 series.

- Reliability: Customers have to accept the reliability of existing lines. If they require a better level of reliability or security they have to fund this.
- Auto-reclosing: Connections have to be engineered to be able to withstand line auto-reclosing.
- Charges: In compliance with the Electricity (Distributed Generation) Regulations.

5.1.3.5 Planning Criteria: System Growth

As with new connections, system growth has to be funded from the additional income such investment creates. System growth is also closely related to security and reliability. Installing n-1 capacity and alternative supplies have to be funded by those who benefit from it either directly or through on-going revenue. Planning criteria for system security is in many ways embodied in the service level structure that specifies performance targets based on TLC's financial and logistic ability to deliver security of supply. There is, for example, a natural tendency to prioritise security for areas in the north of the network where there is a higher concentration of industrial customers and hence greater consequences of loss of supply as well as greater revenue to fund investment.

Funding growth from additional revenue forces the development and the criteria associated with it to be more focused.

5.1.3.6 Planning Criteria: System Growth: Modular Solutions

The planning criteria have to focus on the specific performance issues.

For example:

- Modular low cost substations that address capacity for 10 to 15 years as opposed to expanding existing sites or establishing large new ones with inherently greater long term capacity. (There are other advantages to the modular approach including diversification that improves reliability and control of fault currents.)
- Installing modular modern equipment such as switchgear in existing sites.
- Installing regulators and the like in the existing network to push the capacity of the existing assets.
- Tuning voltage levels and active/reactive power flows in the existing network to extend capacity. (This is often done in conjunction with distributed generation installation.)
- Modular break-up of SWER systems when the loading of existing configurations becomes high to the point that the operating earth potential rises are hazardous.
- Supplying SWER systems off three phase systems to use phase displacements to reduce earth currents.
- Incentives for customers to control their reactive power needs.

The equipment used must be:

- Standard and be able to be swapped to different sites.
- Simple to install, operate and maintain.
- Installed in such a way that it is easy to operate and repair.

Network capacity increases are designed to integrate and form long term solutions.

The technology chosen must form part of a longer term integrated solution. For example, regulator controllers must have the capability to control capacitor banks and reclosers must be able to provide synchronised switching. Both of these will be necessary as the network is further tuned and operated in a more automated and complex mode in the future. Equipment with these features can be supplied "off the shelf" at no extra cost.

<u>Note:</u> The installation of cable, conductors and equipment must take into account the fault levels on the network. Any new distributed generation application must consider the effect of the connection to TLC's network and local fault levels. (As noted above)

5.1.3.7 Planning Criteria: System Growth Funding

There are a number of areas in the network where the present revenue is not funding present operating and renewal costs. In these cases there is no additional income available to fund the modular incremental costs. As a consequence some areas within TLC's network are charged a connection fee based on the kVA load applied for, to provide funding towards securing upstream capacity and reliability in those areas. (For example, in the Mokau and Whakamaru regions, there is a capacity charge added to every new connection to the Network.)

These amounts are determined after detailed analysis using a pricing model based on the Commerce Commission's regulatory valuations and rates of return. As stated in other sections growth has to be self-funding.

5.1.3.8 Planning Criteria: System Growth: Security

The TLC network is relatively complex and there are few places where there is n-1 full capacity security. The design criteria intent is to have medium and light load backups for zone substations and in as many parts of the of the 11 kV network as practical with no or minimal cost. Section 3 gives more detail on the effectiveness and implementation of these criteria.

This plan includes a number of projects that create security improvements as a by-product of environmental, hazard control and other targets. The security implications of each development project are looked at on a case-by-case basis and related back to the performance criteria in Section 5.

The modular solutions discussed above are installed in such a way that at medium to light load times there is a backup supply. (For example, if a modular substation fails there is diversity such that other assets in the area can continue to supply customers.) TLC does not use probabilistic security planning techniques.

5.1.3.9 Planning Criteria: System Growth: Power Quality

Analysis of the power quality is included in the design criterion for system growth. This includes the investigation of voltage complaints, voltage surges, voltage and current studies and power factor and harmonic studies.

This satisfies the performance criteria outlined in Section 5 for power quality in maintaining regulatory requirements for voltage levels and ensuring current ratings of existing assets are not compromised.

5.1.3.10 Planning Criteria: Quality of Supply

5.1.3.10.1 Planning Criteria: Quality of Supply

A plan to improve quality of supply was embarked on in 2003. Reliability planning initiatives are aligned to focus on achieving the asset related customer services targets, asset performance targets and asset effectiveness targets as detailed in Section 5.

The criterion is to increase automation of network tie points and the installation of reclosers where there are relatively long spurs with a significant number of customers. The more critical locations, such as areas with long response times due to travelling time for fault personnel, are given priority and completed first.

Reliability is also a by-product of other design criteria and will change as hazard control and renewal works are completed. Outage data are also analysed and problem areas targeted.

All work for reliability and automation are planned with the future intention of developing a self-healing Network with automated load shedding.

5.1.3.10.2 Planning Criteria: Other Safety (Hazard Control)

Network hazard related control has two important streams. The first is about design and equipment selection to minimise the inherent network hazard levels. The second is the operation and maintenance of this equipment. Operation includes procedures, competence and the use of personnel protective equipment (PPE). Conceptually, design criteria being applied require two to three levels of incompetence or a concerted effort to break into a piece of electrical equipment before contact is made with energised equipment. TLC aims to minimise hazard related risks and operate a network that is considered to have reduced hazards to a tolerable level.

Arc flash analysis of equipment is carried out using the network analysis programs arc flash modules and appropriate signage installed for PPE requirements and procedures.

Two performance targets detailed in Section 5 are targeted specifically at hazard elimination by removing and replacing hazardous equipment and consequently minimising and eliminating accidents. Details of plans to achieve this are included later in this section.

5.1.3.10.3 Planning Criteria: Other Environmental

The planning criteria for environment projects are:

- End of use disposal must be considered.
- Risk of release of hazardous substances into the environment must be minimised or eliminated.
- Equipment must be able to withstand earthquakes.
- Transformer bunding and oil containment.
- Equipment must be out of Lahar paths and flood zones if possible.
- Equipment must be selected so that as far as practical it will operate through periods of volcanic ash fallout.
- Equipment must be selected that can withstand fertiliser applications in rural areas.
- Network designs should consider losses and decisions to increase losses should be avoided if possible.

Experience has shown that if equipment can perform under these environmental conditions the network performance targets will be achieved.

TLC's western coastal assets are subject to salt laden air; therefore, assets are chosen that perform well in this environment. Due to the high numbers of rural properties that apply fertiliser along with a number of lime works that create excessive dust deposit on insulators and equipment, TLC's standards and equipment selection specify components that are designed for high pollution environments. Other factors that TLC's designers take into consideration are ways of minimising the effects of a polluted environment.

Thermal areas, such as Tokaanu, require components that can be installed in hot ground. In one case TLC obtained special dispensation to not follow Taupo District Council District plan for underground reticulations in urban areas, as the ground was too hot for an underground cable. TLC also had to install wooden poles due to the corrosive nature of the gases in the thermal area that reduce the life of concrete poles.

5.1.3.11 Planning Criteria: Asset Relocation

Asset relocations are mostly associated with road works and other infrastructure activities. There are also a number of cases where assets have to be moved around slips or other environmental events.

The criteria for these types of works are to:

- Relocate assets as required by road controlling authorities.
- Renew assets while on site as per renewal policies.
- Reinstate the asset with similar capacity as previously.
- Secure funds from road controlling authorities in compliance with acts and regulations.
- Obtain land access easements for relocated works.

Experience has shown that following these criteria will achieve the performance targets as detailed in Section 4.

5.1.3.12 Planning Criteria: Asset Replacement and Renewal

Asset replacement and renewal means the capital expenditure associated with the physical deterioration of existing Network assets. Section 6 provides full details on the criteria for managing the asset replacement and renewal programme so that the asset is restored to its original service performance level.

The primary criterion for renewal is hazard control; the secondary criterion is to renew aged assets at the end of life.

A description of strategies or processes (if any) used by the **EDB** that promote cost efficiency including through the use of standardised assets and designs;

5.2 Prioritisation Methodology Adopted for Development Projects

The development and operation of assets is constantly being monitored and researched. This continuing quest to understand asset requirements to meet customer service levels, leads to a prioritisation methodology that is focused on controlling risk.

This includes:

- A feasibility study and assessment of the project.
- Consequences of not doing the project.

Figure 5.1 illustrates the process for prioritising risk driven needs.

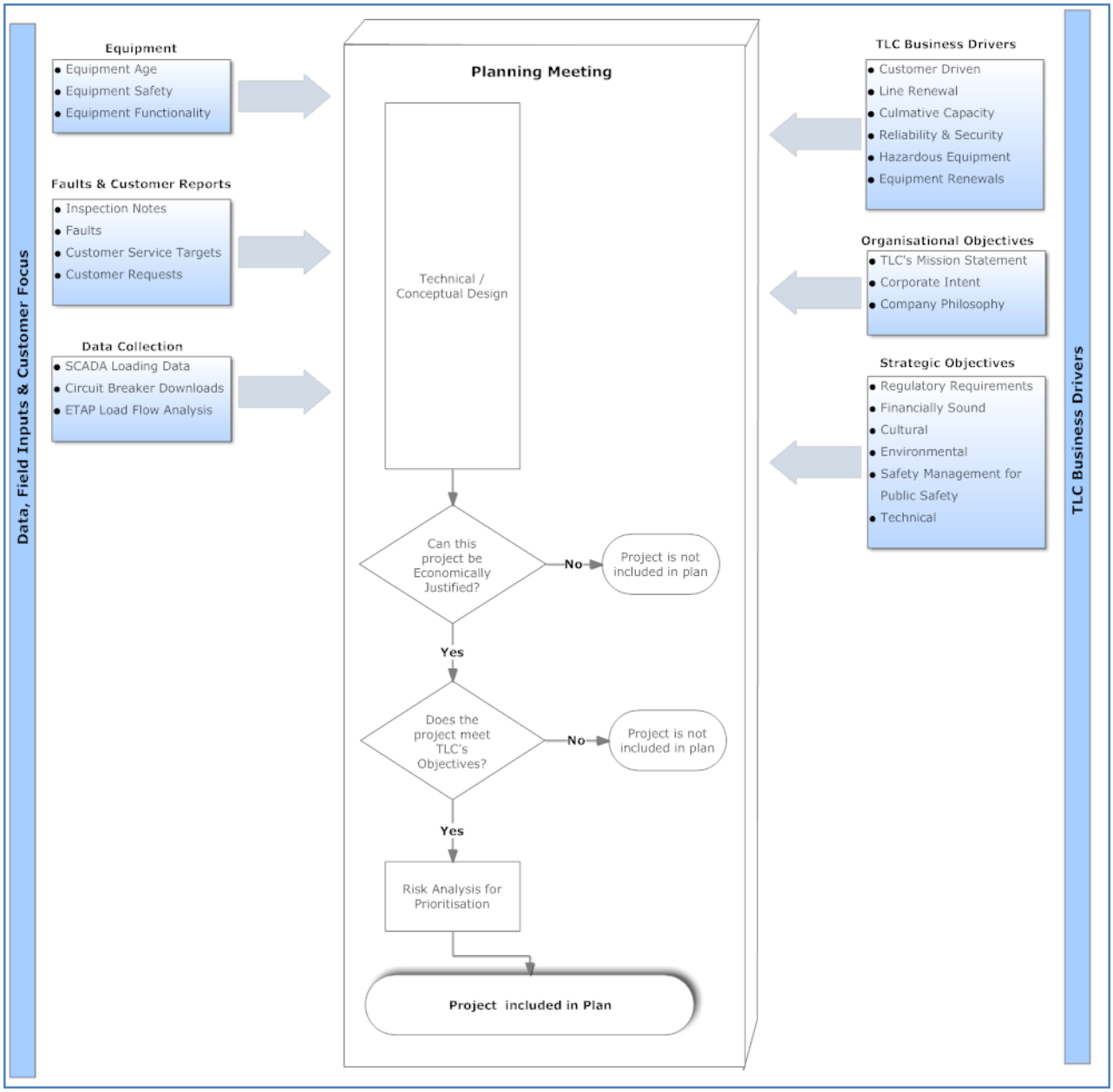


FIGURE 5.1: PLANNING METHODOLOGY

Figure 5.2 illustrates the process for prioritising risk driven needs, and Table 5.1 provides more details/guidelines on how the risk assessment across the project sets is undertaken.

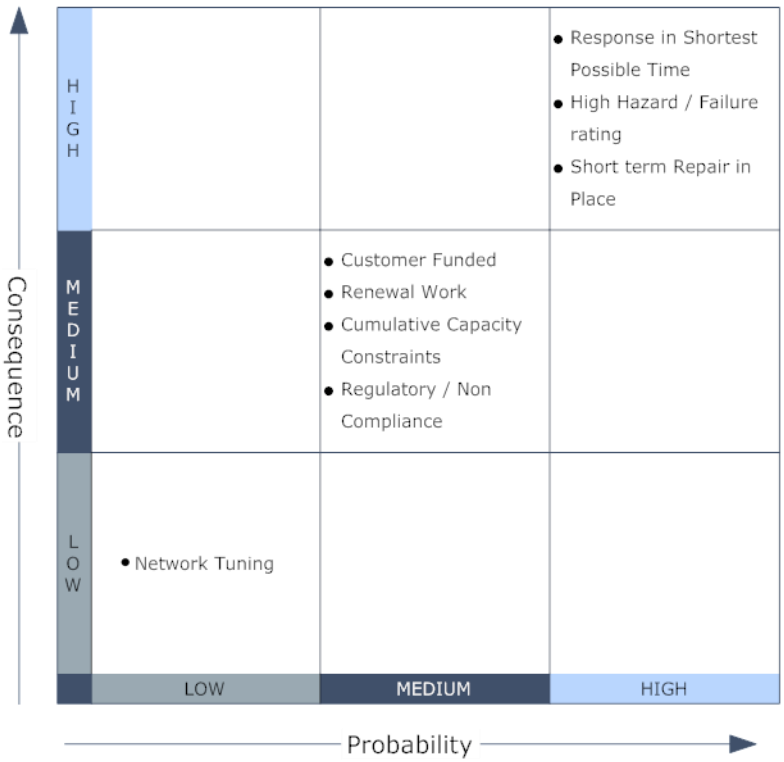


FIGURE 5.2: PRIORITISATION MATRIX FOR RISK DRIVEN NEEDS

The guidelines that are used in applying this approach include:

- Hazard elimination/minimisation, system security/reliability, growth demands, and environmental factors, the impact that a project may have on its customers, the security of supply, the urgency of the project, the resources availability to carry out the project and the impact on compliance.
- A sudden unplanned event can have a follow through effect on the prioritisation of projects and risk assessment is required in the planning of the projects. Any event that jeopardises TLC's ability to maintain their customer service levels and customer expectations needs to have a high priority (especially hazard control and SMS related activities).
- Customer Driven projects where the customer has a deadline that they wish to adhere to.

TLC has developed a database that enables planners to store planning and design notes, a time scale, cost estimation, and the options that have been considered for each project that is included in the 10 year plan. This database also enables the network planner's easy adjustment of the time scale as required. The database is packaged with the asset management database.

Ranking	Guidelines	Alignment with Company Objectives
High Consequence High Probability	» Response required in a shortest possible time to mitigate catastrophic failure. » High probability of hazard control breaches and or issues.	Renew, develop and maintain a network that does not exceed 208.8 SAIDI minutes or 3.07 SAIFI interrupts.
	» Short term temporary repair in place that has marginal hazard control features and if failure occurs there will be significant reliability / security and customer service problems. » Environmental damage event	Renew, develop and maintain a network that is considered non-hazardous by customers and professionals.
Medium Consequence Medium Probability	» Customer funded work that is needed for business or lifestyle activities.	Objectives above plus:
	» Medium hazard control risks. Examples are old fashioned metal switchboards, inadequate but secure barriers etc. » Equipment or sites that have the potential for environmental damage. » Cumulative capacity constraints.	Renew, develop and maintain a network that meets customer quality and reliability expectations.
	» Equipment with legacy legal and statutory non-compliance issues. » Medium risk of equipment failure. (For example lines that are on a slow moving slip). » The overall renewal programme work. » DSM programmes. » Reliability improvement projects.	Renew, develop and maintain a network that fulfils stakeholders' value expectations including their ability to pay and long term tenure, social and environmental responsibilities.
Low Consequence Low Probability	» Network tuning for long term sustainability i.e. regulator settings, distributed generation settings, phase loadings etc. » Harmonic and power factor control programmes » Other non time dependant projects that have been present for many years. (For example reducing current levels on overloaded SWER systems).	Minimising costs and improving efficiency through innovation

TABLE 5.1 SUBJECTIVE/OBJECTIVE ANALYSIS GUIDELINE FOR PRIORITY SETTING

5.2.1 Discussion on how Risk Assessment across the proposed set of projects is undertaken

5.2.1.1 System growth

Network growth is monitored by the collection of information on a number of growth factors.

This includes:

- New and increased load applications and the size of load required.
- Subdivision growth.
- Industrial growth applications are dealt with by an account manager.
- Feeder loading.
- GXP and distribution generation figures.
- Transformer numbers installed and the capacity of those transformers.

This data is used in growth forecasting and the resulting figures used in TLC's power flow programme to anticipate capacity constraints on the network.

Quality of supply is closely related to system growth and projects are prioritised in a similar manner. Projects are prioritised based on data collected using SCADA, switch history, live line power quality meters and other instruments. This data is reconciled with the network analysis package and the worst issues affecting the greatest numbers of customers on a frequent basis are given the highest priorities.

Planned work involves ensuring the customers' points of connection have a power quality that complies with regulatory requirements. Some quality of supply projects will be funded by additional customer charges or contributions.

Power quality is also improved as a by-product of work carried out to improve hazards and reliability. It is also factored into development work. Capacity and quality improvements are prioritised by the network performance targets. The targets will be compromised if the improvements are not completed and the ability to increase revenue will be hindered. (The network growth included in this plan assumes revenue increases.) This aligns with the objective to renew, develop and maintain a network that meets customer quality and reliability expectations.

5.2.1.2 Customer connections

Commercial arrangements entered into with customers will be negotiated to ensure they can be financed from borrowing and comply with Commerce Commission requirements.

Where customers are paying for a connection that is critical to their enterprise or lifestyle, projects are prioritised based on this customer requirement. There is no other subjective/objective analysis used. The risk of not providing this service is high, i.e. customers will complain and take action against the organisation. This sets the priority.

This is aligned with the need to fulfil stakeholders' value expectations including their ability to pay and long tenure, social and environmental responsibilities.

5.2.1.3 Reliability, Safety (Hazard Control) and Environment

5.2.1.3.1 Reliability

Data from previous outages, customer numbers, network architecture, and asset condition are used to make predictions on the reliability and economic impact projects will make. This information is used to prioritise reliability projects, including automation of switches, addition of feeder ties and low voltage ties.

Priority is given to projects in areas where there have been network performance problems, or it is obvious that there will be issues in the near future. Remoteness from depots and the length of time required to mobilise staff is also considered. This reliability improvement work makes up the majority of the discretionary network development projects included in the planning period.

5.2.1.3.2 Hazard Elimination/Minimisation

Projects associated with reducing the risk of high consequence, high probability events have the highest development priority. These projects are further prioritised in the order of:

1. Hazard elimination/minimisation
2. Environmental
3. System security/capacity and reliability
4. SMS impact.

This is aligned with the requirement to own and operate a hazard controlled and compliant network. (It also needs to be recognised that hazard elimination/minimisation projects enhance environmental, system security, capacity and reliability issues and vice versa.)

The network was originally constructed under budgetary constraints and less rigorous hazard control regulations leading to inherited hazard issues. The slow development of the area has meant that many of these sites have not been upgraded as part of evolutionary network development.

Contributors to identification and evaluation of hazards include:

- Simple obvious problems with equipment.
- Industry accident reports.
- The various acts, regulations, codes etc. that control the industry.
- The application of engineering principles on how equipment operates, and the associated risks.

The experience from investigating and being involved in various industry incidents is used to add a practical aspect to the outcomes of the initial analysis. Over 400 sites have been assessed for hazards by a qualified engineer and electrical inspector/technician as part of the preparation of this plan. Priority has been assigned to those works that remedy hazards and these have been included in the forward renewal and maintenance projections in the plan.

This priority is aligned to the business objective for a hazard controlled, sustainable network and SMS compliant.

5.2.1.3.3 Environmental

Substation inspection data highlights pending environmental risks and concerns. This data is used to prioritise environmental issues such as the likelihood of an oil leak and the impact it will have. Where issues are found, the risks are assessed and improvements programmed in accordance with the prioritising methodology and guidelines.

The long term plan includes a number of environmental projects with medium priority. High priority issues such as oil leaks in sensitive areas are addressed sooner than the medium term projects. This aligns with the objective to fulfil stakeholders' value expectations, including their ability to pay, long term tenure, social and environmental responsibilities.

The long-term renewal programmes include projects to improve oil separation and other environmental facilities. Oil separation and earthquake restraints are also brought up to modern standards when other major work at a site is undertaken.

Environmental factors are considered with most projects. These include:

- End of life disposal issues. The use of SF6 gas insulated equipment is avoided where possible. Recyclable materials and equipment are given priority.
- Compliance with Resource Management Act.
- Minimal cutting of natural vegetation.
- Solutions to minimise environmental impacts, particularly in the National Parks and on sensitive Maori land.
- Impact of natural events on assets.

5.2.1.4 Asset replacement and renewal

Assets are replaced and renewed to ensure the safe and reliable operation of the network. Knowledge and experience of inspectors form a crucial part of determining what equipment needs replacing. Empirical testing, data on failures and cost analysis of the renewal is combined with the knowledge of the inspectors to prioritise renewals. To ensure consistency various reviews take place before and after jobs to determine the accuracy of any assumptions made and make adjustment to future plans based on this information. The renewal work aligns with TLC's objective to meet customers' quality and reliability expectations.

TLC does not convert overhead systems to underground unless the customers are prepared to pay the difference between undergrounding and the expected renewal costs associated with TLC maintaining the present system, or some other funding mechanism is established. A section of the Turangi low voltage is an example where an outside funding mechanism has been used to change a project from upgrading the aging overhead system, which also has a number of tree issues, to an underground system.

Undergrounding, however, will be undertaken where it is no longer practical to have an overhead or the cost of an underground system is lower than the renewal of overhead system. Typically this results in short lengths of cable around obstacles. The tree in Figure 5.3 is one example of a short length of cable installed to remove the overhead wire that went through the middle of the tree; the tree had been trimmed to accommodate the conductor.

FIGURE 5.3: LINES THROUGH MIDDLE OF TREE

5.3 Network Demand Forecasts

5.3.1 Introduction

To ensure optimal efficiency, security and stability of the network TLC has forecasted the following:

- Loadings on TLC's Network.
- Demand imposed on each busbar from which it takes supply, or proposes to take supply, from Transpower's Network.
- The effects of proposed generation on TLC's Network.

The forecasts are used extensively in the planning and prioritisation of work proposed on the Network.

5.3.2 Typical factors considered when adjusting growth forecasts

5.3.2.1.1 Peak Demands

Figure 5.4 shows the peak demand trends for each of the six supply areas in the network.

Demands do fluctuate from year to year and the figure below indicates the trends from 2005. These are the instantaneous peaks in MW. The main base data used for load forecasts is the peak demand figures.

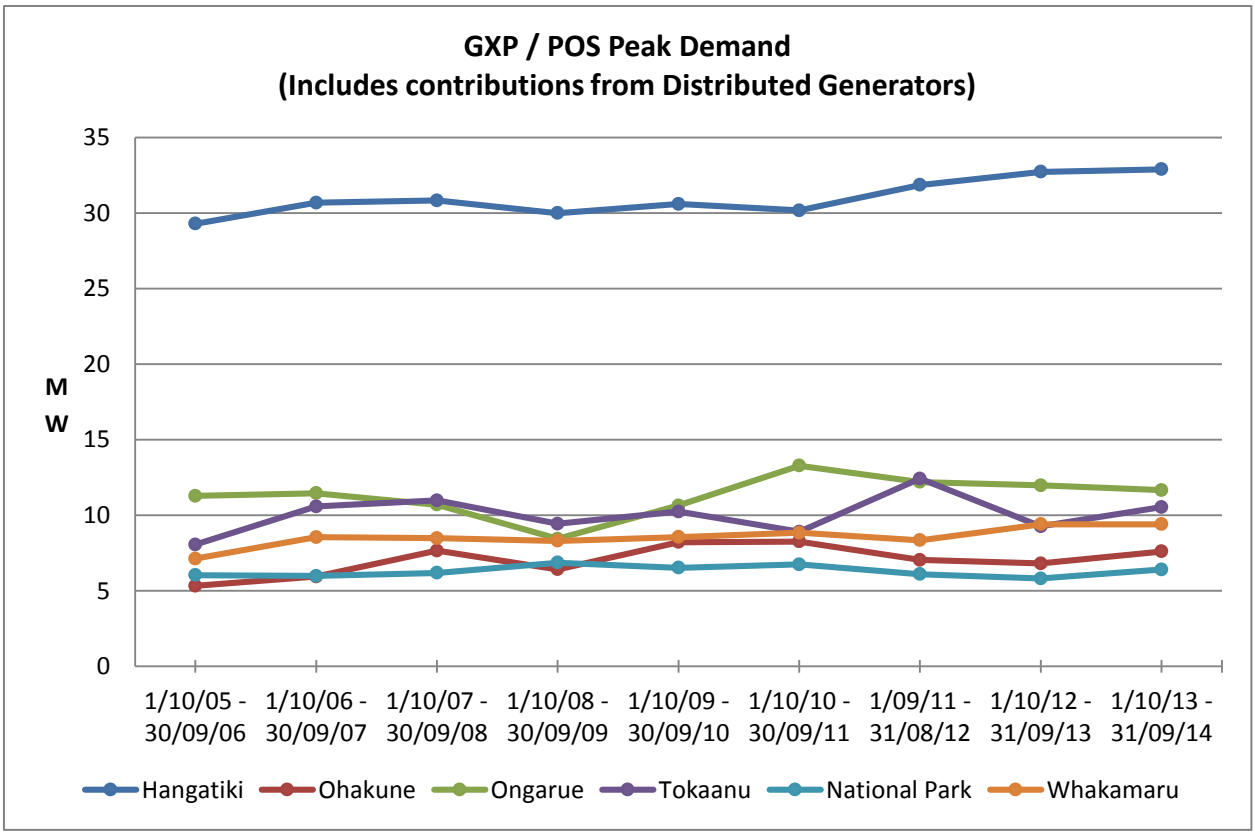


FIGURE 5.4: INSTANTANEOUS PEAK DEMAND TRENDS FROM 2005/06 TO 2013/14

There have been some movements in demand across the points of supply however they are insufficient to trigger significant departures from current planning. Of note, the Tokaanu maximum demand has fallen more into line with historical trends from 2011/12 outlier.

- Hangatiki continues to climb, albeit slower this year due to further dairy growth and industrial load.
- Ongarue demand continues to fall back to historic levels.
- Ohakune and National Park remain stable within annual variations around tourism and weather factors.
- Whakamaru maximum demand has remained consistent with the previous year's peak.

5.3.2.1.2 Energy Transported

Figure 5.5 shows the trends for the total energy transported for each of the six supply areas in the network.

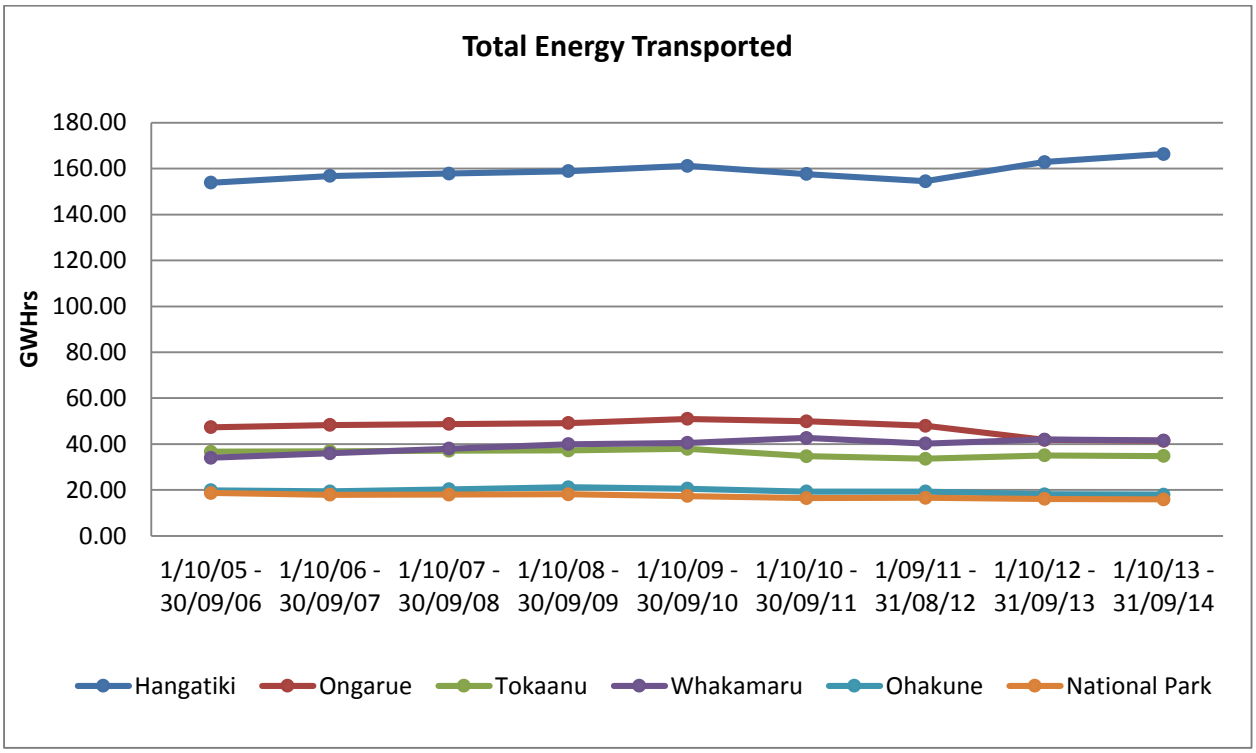


FIGURE 5.5 TOTAL ENERGY TRANSPORTED FROM 2005/06 TO 2013/14

There has been small movements in total energy transported over the last year. These small movements have not caused any significant changes from the current planning. All supply areas besides Hangatiki have shown little movement between 2012/13 and 2013/14. Hangatiki has seen a small increase in energy transported over 2012/13.

5.3.2.1.3 Applications for Load

Figure 5.6 illustrates the trend in applications for load development. Residential housing, businesses and holiday homes have shown a great downturn since the global financial crisis. However there are some signs of turnaround in both farming and particularly residential applications.

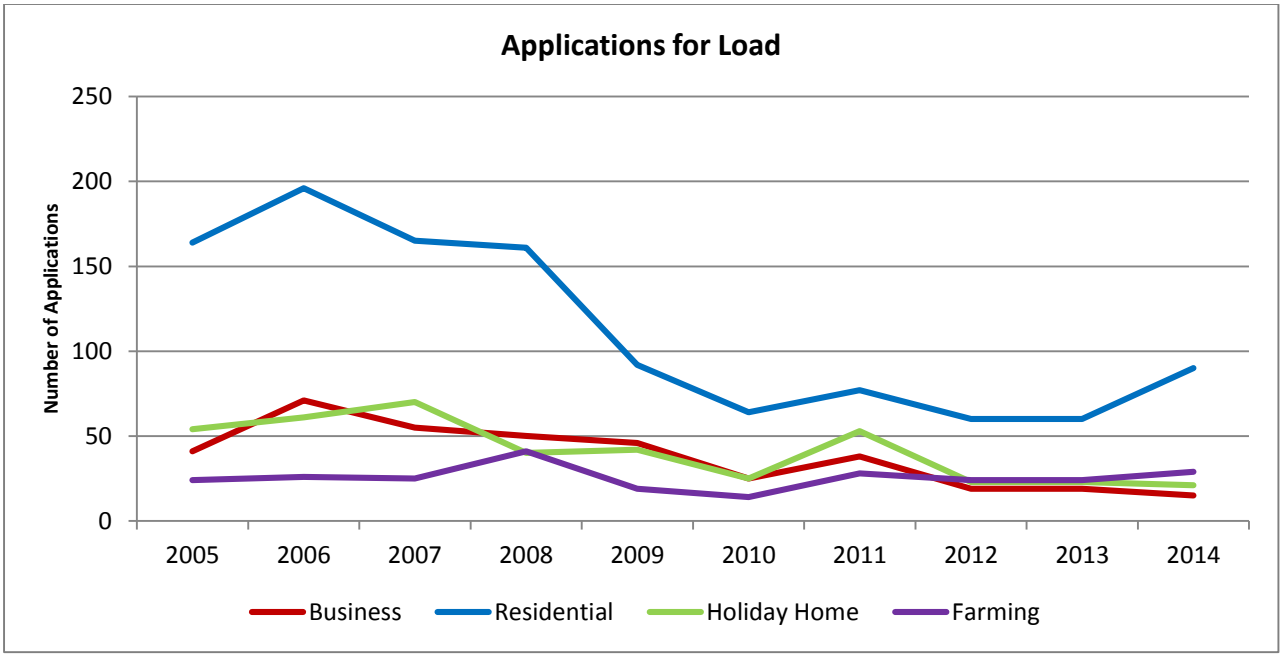


FIGURE 5.6: APPLICATIONS FOR CONNECTING LOAD ONTO TLC'S NETWORK

Further information that provides an indication of possible load growth changes include:

- Records of applications regarding electricity availability and subdivision information as required by councils for resource consent provision.
- Building consents.
- Pillar box records.
- Feeder and GXP loadings.

5.3.2.1.4 Effect of Embedded Generation

There are eight existing distributed generators of significance (about 28 machines) connected to the TLC network.

The factors taken into account when modelling generation includes:

- Output during periods of peak network loads.
- Output during periods of minimum network loads.
- Output during typical summer and winter network loadings.
- Expected operating power factors during the above periods.

It is anticipated that embedded generation output will remain relatively steady over the planning period.

5.3.2.1.5 Effect of Construction of a New Zone Substation

Forward estimates have included the effects of additional modular zone substations and the resulting feeder breakup. This will reduce the loading on the feeders that currently supply these areas.

5.3.3 Load Forecasting over the 10 Year Planning Period

Detailed below are the specific load forecasts and the associated reasons for the forecast, based on the methodologies and data included in Section 5.2 that details how TLC prioritises projects.

5.3.3.1 Supply Area Projected Demands

Figure 5.7 illustrates the forecast growth rate for the planning period in each supply area inclusive of existing generation. The grid exit loads are less than the system loads for the areas that are inclusive of distributed generation. The figures take into account the poor power factor at grid exits due to the effects of distributed generation.

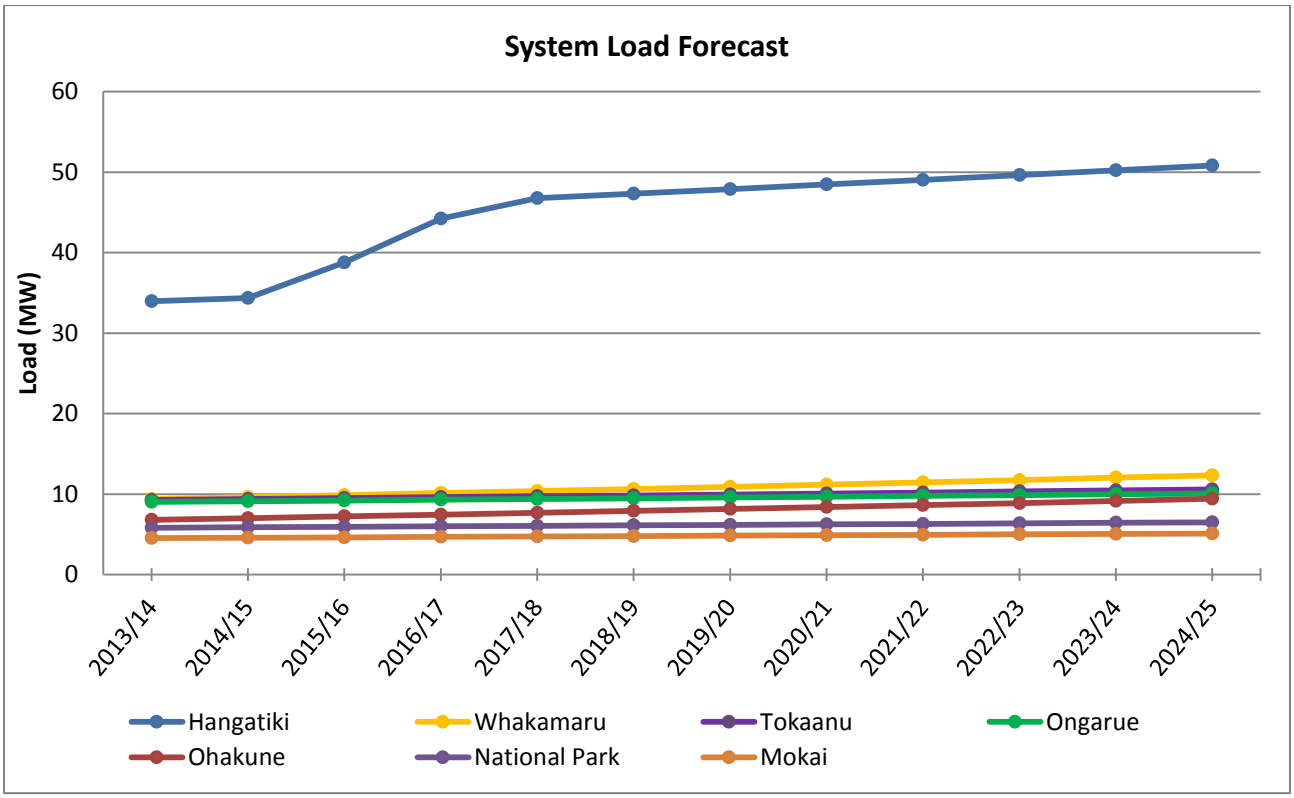


FIGURE 5.7: PROJECTED SUPPLY POINT ACTUAL AND 10 YEAR FORECASTED LOADS

Uncertainties associated with these projections:

- If the effects of demand billing and the demand side management initiatives encourage constrained demand growth then further "head room" will be achieved at Hangatiki.
- Ohakune estimates assume no stepped changes to ski fields or holiday home developments. The grid exit transformer has historically reached 95% of its capacity initially but with demand billing and demand side management, load has stayed within the transformers capacity. Transpower have commenced upgrading the GXP transformer to avoid further overloading.
- Tokaanu estimates assume continued but slow development in Turangi area. A prison expansion or other development associated with recreational activities will change this.
- There is adequate capacity at the Tokaanu supply point to provide for further growth unless there is an exceptional amount of development.
- National Park estimates assume no stepped growth on the Whakapapa ski field or National Park Village. The World Heritage Park plan controls growth in this area and as a consequence it is highly unlikely there will be stepped changes.
- Ongarue estimates assume a small amount of growth in the Taumarunui area associated with dairy farming and lifestyle development surrounding the township. Continued increase in heat pump loads could affect these assumptions.
- A new 10MVA substation (Point of Supply) is proposed for the Whakamaru area in year 2017/18 to accommodate increasing growth of local dairy farming and irrigation pumps along Waikato River. Furthermore, Atiamuri Zone transformer will be constrained in this planning period and a new substation will remove this constraint. There are a number of alternative options to address backup supply into this area. The main options are to install extra capacity at Atiamuri or to take supply directly from one of the nearby hydro generators (Maraetai or Whakamaru). This will require in depth analysis to determine the optimal solution.
- Hangitiki shows a significant increase early in the planning periods, due to proposed expansion at the NZ Steel iron sand extraction at Taharoa. At the time of writing, negotiations were well advanced to confirm this as proceeding.

5.3.3.2 Zone Substation Projected Demands

The forecasts (Table 5.2 and Table 5.3) assume the adoption of the development plan included in later sections and the upstream projects described in other sections taking place. Green boxes indicate a change in system operating conditions. Orange boxes indicate a potential overloading of the transformers.

Site	Rating (MVA)	Number of Transformers (MVA)	Forecast MD's (MW) for year ending March 31										
			2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Arohena	3	1 x 3.0	2.14	2.16	2.17	2.18	2.19	2.20	2.21	2.22	2.23	2.24	2.25
Atiamuri	10	1 x 10.0	9.68	9.97	10.27	5.29	5.45	5.61	5.78	5.95	6.13	6.32	6.51
Gadsby Rd	5	1 x 5.0	3.44	3.48	3.51	3.55	3.58	3.62	1.66	1.67	1.69	1.71	1.72
Omya	2.4	1 x 2.4							2.00	2.01	2.02	2.03	2.04
Hangatiki	5	1 x 5.0	3.60	3.63	3.67	3.71	3.74	3.78	3.82	3.86	3.90	3.94	3.97
Kaahu Tee	2.4	1 x 2.4	1.55	1.57	1.59	1.62	1.64	1.67	1.69	1.72	1.74	1.77	1.80
Mahoenui	3	1 x 3.0	0.94	0.95	0.96	0.98	0.99	1.00	1.01	1.02	1.03	1.04	1.05
Maraetai	5	1 x 5.0	4.43	4.47	4.51	4.56	3.46	3.50	2.03	2.05	2.07	2.09	2.12
Ranginui Road	2	1 x 2.0							1.50	1.51	1.53	1.54	1.56
Sandel Road	2	1 x 2.0					1.14	1.15	1.17	1.18	1.19	1.20	1.21
Marotiri	3	1 x 3.0	2.48	2.51	2.54	2.57	2.60	2.62	2.65	2.68	2.71	2.74	2.77
Miraka	7.5	1 x 7.5	2.99	3.05	3.11	3.18	3.24	3.30	3.37	3.44	3.51	3.58	3.65
Oparure	3	1 x 3.0	1.54	1.56	1.58	1.59	1.61	1.63	1.65	1.66	1.68	1.70	1.72
Taharoa	15	3 x 5.0	11.37	15.00	20.00	22.00	22.44	22.89	23.35	23.81	24.00	24.00	24.00
Te Anga	2.4	1 x 2.4	2.20	2.21	2.22	2.24	2.25	2.26	2.27	2.28	2.29	2.30	2.31
Te Waireka Rd	20	2 x 10.0	11.28	11.41	11.55	11.69	11.83	11.97	12.12	12.26	12.41	12.56	12.71
Wairere	5	2 x 2.5	3.05	3.09	3.12	3.16	3.19	3.23	3.26	3.30	3.33	3.37	3.41
Waitete	15	3 x 5.0	9.28	9.39	9.49	7.59	7.68	7.76	7.85	7.93	8.02	8.11	8.20
UBP Limited	2.4	1 x 2.4				2.00	2.02	2.04	2.07	2.09	2.11	2.14	2.16

TABLE 5.2 NORTHERN ZONE SUBSTATION FORECAST MAXIMUM DEMANDS

Site	Rating (MVA)	Number of Transformers (MVA)	Forecast MD's (MW) for year ending March 31										
			2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Awamate Road	2	1 x 2.0	1.21	1.21	1.22	1.22	1.23	1.24	1.24	1.25	1.26	1.26	1.27
Borough	10	2 x 5.0	7.87	7.95	8.03	8.11	8.19	8.27	8.35	6.94	7.01	7.08	7.15
Northern	2	1 x 2.0								1.50	1.51	1.53	1.54
Kiko Rd	3	1 x 3.0	1.42	1.43	1.44	1.45	1.46	1.47	1.48	1.49	1.50	1.51	1.52
Kuratau	3	1 x 3.0	2.47	2.48	2.49	2.51	2.52	2.53	2.55	1.56	1.57	1.57	1.58
Little Waihi	2	1 x 2.0								1.00	1.01	1.02	1.03
Manunui	5	1 x 5.0	2.16	2.18	2.20	2.22	2.24	2.27	2.29	2.31	2.33	2.36	2.38
National Park	3	1 x 3.0	1.83	1.85	1.86	1.88	1.90	1.92	1.94	1.96	1.98	2.00	2.02
Nihoniho	1.5	1 x 1.5	0.62	0.63	0.64	0.65	0.66	0.67	0.68	0.69	0.70	0.71	0.72
Ohakune	10	1 x 10.0	6.90	6.99	7.08	7.17	7.27	7.36	7.46	7.55	7.65	7.75	7.85
Otukou	0.5	1 x 0.5	0.25	0.25	0.25	0.25	0.25	0.26	0.26	0.26	0.26	0.26	0.26
Tawhai	5	1 x 5.0	4.00	4.08	4.17	4.25	4.33	2.21	2.25	2.30	2.35	2.39	2.44
Tawhai 2nd Tx	5	1 x 5.0 (2019)						2.21	2.25	2.30	2.35	2.39	2.44
Tokaanu	1.25	1 x 1.25	0.17	0.18	0.18	0.19	0.19	0.19	0.20	0.20	0.20	0.21	0.21
Tuhua	1.5	1 x 1.5	0.79	0.79	0.79	0.80	0.80	0.80	0.81	0.81	0.82	0.82	0.83
Turangi	10	2 x 5.0	4.62	4.62	4.62	4.63	4.63	4.14	4.14	4.15	4.15	4.16	4.16
Waiotaka	1.5	1 x 1.5	0.52	0.52	0.53	0.54	0.54	1.05	1.06	1.07	1.08	1.09	1.10

TABLE 5.3 SOUTHERN ZONE SUBSTATION FORECAST MAXIMUM DEMANDS

5.3.3.2.1 Zone Substation Demand assumptions

- **Tawhai** – Load at Whakapapa slowly developing such that an additional transformer is needed at Tawhai in 2019/20. If the development of the ski field does not eventuate there will be little impact other than an additional transformer will not be required. (Existing transformer is proposed to be run into overload due to low ambient temperatures when loading is greatest.)
- **Little Waihi** – Establishment of a modular substation at Waihi to backup Kuratau and holiday home developments in 2021/22. It is likely that the project can be delayed if large growth does not occur in the area.
- **Sandal Road** - It is assumed a substation will be needed in Sandal Road about 2018/19 to service increasing development in the Whakamaru area.
- **Ranginui Road** – It is assumed a substation will be needed in Ranginui Road about 2020/21 to service increasing development at the Crusader Meat Plant. (This will be needed to reduce loading on the Maraetai transformer, voltage drop on the Pureora feeder and conductor loadings.) The greatest demand is from the dairying in the area and from the meat processing plant whose peak time is through the summer months. If the Crusader Meat Plant were to reduce in size and farm development in the area were to stop then the need for an additional modular substation would not be alleviated due to the cumulative increasing load on the Maraetai zone substation. It would however, be likely that the project would be delayed beyond the planning period as it presently exists. Alternatively a new 33kV line could be built from Waitete substation out to a substation closer to Crusader Meats yard.
- **Lime Processor Industrial** – Lime processors in Te Kuiti/Otorohanga area opting for a modular substation in 2020/21 to improve plant reliability and increase capacity. If the Te Kuiti industrials choose not to expand and fund this project then the status quo would exist. The 11 kV feeders would be under pressure at times and this pressure would have to be alleviated by demand side initiatives such as power factor improvement.
- **Meat Processing Industrial** – Industrial load creep at meat processors' plant in Te Kuiti requiring an additional container substation in 2017/18. This project will not be needed if plants close or reduce load. The timing is dependent on a combination of industrial load creep and demand side management (mainly power factor improvement) no longer being able to work together and maintain supply quality and security at a level acceptable to industrial customers. The status quo will likely remain until these criteria are triggered.
- **Okahuharu** – An additional container sub north of Taumarunui in 2021/22. This is to minimise the flood risk at the Borough substation. The loading on the Northern feeder is expected to continue to increase as more heat pumps displace log fires in the northern part of Taumarunui.
- **Taharoa** – Planned development occurs at New Zealand Steels iron sands mine.
- Transformer replacement as proposed in the forward plan does occur.

5.3.3.3 11 kV Distribution Feeder Projected Demands

The significant events that could affect distribution feeder forecasts include:

- The changes to the sub transmission network as described in earlier sections.
- The existing TLC network configuration will largely remain unchanged.
- Lime processors partially funding modular substation to create new 11 kV feeder in Old Te Kuiti Road. If this does not take place, the existing network will remain in place until there is some form of external trigger point. It is likely to be when industrial load growth coupled with demand side management (mostly power factor control) is no longer able to provide the quality and security of supply that customers require.
- Distributed generation projects that are not included in forecasts and likely to proceed in the planning period.
- A change in the historical growth patterns in the Taumarunui area. If this takes place there will be pressure on sub transmission and distribution assets. A solution will be more modular substations and a point of supply out of the Transpower Taumarunui substation. If this were to occur the existing Ongarue grid supply point would likely be decommissioned.

- Continued growth in ski fields. Any sudden additional growth to be partly covered by demand side generation on ski fields. The cost of upgrading and supplying extra capacity to the ski fields will be substantial. As a result of this, it is likely that all the capacity in the present system will be used and then demand side generation used for peak control during the planning period.
- Continuing industrial load growth for areas around Te Kuiti. This is dependent on the demand for the primary products (meat, timber and lime) that the industrial processors produce.
- Continued dairying expansion in the Mangakino area.

Table 5.4 and Table 5.5 outline the projected maximum demand forecasts for 11kV distribution feeders.

Feeder	Feeder Number	Forecast MD's (A) for year ending March 31										
		2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
McDonalds	110	174	177	179	181	183	186	188	191	193	196	198
Gravel Scoop	109	115	115	116	116	116	116	117	117	117	117	118
Otorohanga	112	191	193	195	197	200	202	204	206	209	211	213
Maihiihi	111	213	216	220	223	226	230	233	237	240	244	247
Coast \ Te Anga	125	119	120	122	123	124	125	127	128	129	130	132
Mokauiti	115	53	53	53	53	53	53	53	53	53	54	54
Mahoenui	113	23	23	23	23	23	23	23	23	23	23	23
Piopio	116	69	70	70	71	72	73	73	74	75	76	77
Te Mapara	117	21	21	22	22	22	22	23	23	23	23	24
Aria	114	27	27	28	28	28	28	29	29	29	29	29
Benneydale	103	243	245	248	146	147	149	151	152	154	156	157
Proposed Meat Processing Industrial					105	106	106	107	107	108	108	109
Te Kuiti Town	105	53	53	54	54	55	56	56	57	57	58	59
Te Kuiti South	104	40	41	41	42	42	43	43	44	44	45	45
Rangitoto	106	139	140	141	142	143	144	145	146	147	148	149
Hangatiki East	102	168	170	172	173	175	73	74	75	110	111	112
Proposed Limestone industrial							104	105	105	106	106	107
Caves	101	47	47	48	48	49	49	50	50	51	51	52
Oparure	107	182	184	186	188	190	192	194	196	199	201	203
Waitomo	108	139	140	142	143	145	146	148	150	151	153	155
Mangakino	118	39	40	40	41	41	42	42	43	43	44	44
Huirimu	121	36	36	36	36	36	36	36	36	36	36	36
Wharepapa	122	91	93	94	96	97	98	100	101	103	104	106
Pureora	119	157	160	162	165	147	149	72	74	75	76	77
Whakamaru	120	123	123	123	123	84	84	84	84	84	84	84
Proposed Ranginui Road								79	80	81	83	84
Proposed Sandel Road						60	61	61	62	63	63	64
Tirohanga	129	82	83	85	86	87	89	90	91	93	94	95
Mokai	123	89	91	92	93	95	96	98	99	101	102	104
Tihoi	124	57	57	58	59	59	60	60	61	62	62	63
Rural	126	39	39	40	40	40	40	40	41	41	41	41
Mokau	128	49	49	50	50	51	51	52	52	53	54	54
Paerata	130	43	44	44	45	45	46	46	47	47	47	48
Miraka	131	128	129	131	132	134	135	137	139	140	142	144

TABLE 5.4 FEEDER LOAD FORECAST FOR NORTHERN FEEDERS

Feeder	Feeder Number	Forecast MD's (A) for year ending March 31										
		2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Hakiaha	401	94	94	94	94	94	95	95	95	95	95	95
Northern	402	158	159	160	161	163	164	165	87	88	88	89
Proposed Okahukaru									79	80	81	82
Western	403	67	68	69	70	71	72	73	74	75	77	78
Matapuna	404	180	182	185	188	191	194	196	199	202	205	208
Motuoapa	425	32	32	33	33	33	33	34	34	34	34	35
Oruatua	417	43	44	44	44	45	45	45	45	46	46	46
Hirangi	405	62	63	63	63	64	64	64	65	65	65	65
Turangi	423	112	112	112	112	113	113	113	113	113	113	113
Rangipo-Hautu	424	137	137	137	138	138	112	112	112	112	112	112
Waiotaka	427	24	25	25	25	25	52	52	53	53	54	55
Manunui	408	60	60	61	62	62	63	64	64	65	66	67
Southern	409	48	49	49	50	50	51	51	52	52	53	54
Ongarue	421	25	25	25	26	26	26	26	26	26	26	26
Tuhua	422	27	27	27	28	28	28	28	28	28	28	29
National Park	411	123	125	126	127	129	130	132	133	135	136	138
Raurimu	410	33	34	34	34	35	35	35	36	36	36	37
Otukou	418	13	13	13	13	13	13	13	14	14	14	14
Turoa	415	233	237	241	244	248	251	255	259	263	267	271
Tangiwai	416	102	103	104	106	107	108	109	110	111	113	114
Ohakune	414	152	153	155	157	158	160	162	164	166	167	169
Waihaha	426	28	28	28	29	29	29	29	29	29	29	30
Kuratau	406	108	108	109	109	110	110	111	61	62	62	62
Proposed Little Waihi									50	51	51	52
Chateau	419	235	239	244	249	254	259	264	269	275	280	286
Tokaanu	420	10	10	11	11	11	11	11	12	12	12	12
Nihoniho	412	6	6	6	6	6	6	6	6	6	6	6
Ohura	413	24	24	24	24	25	25	25	25	25	25	25

TABLE 5.5 FEEDER LOAD FORECAST FOR SOUTHERN FEEDERS

5.3.4 The Impact of Uncertain but Substantial Individual Projects on Load Forecasts

5.3.4.1 Wind Farm Projects

The effects of the wind farm generation have not been included in the forecasts due to no activity on the current two large proposed wind farm projects that TLC has received applications for. It is anticipated that in the short to medium term there is a low likelihood of wind generation growth.

5.3.4.2 Hydro Generation

Distributed generation has a dynamic effect on the network and there is a lot of uncertainty as to where and when developments will take place. As a consequence it is not practical to factor into future load predictions all possible effects. Currently there are no new projects being developed that will have an effect on the network.

5.3.4.3 Industrial Site Expansions

TLC has a number of industrial sites that have approached TLC with upgrade and expansion plans. For those sites near a 33 kV line, TLC has programmed into the forecasts a modular substation that will allow the industrials the capacity to expand.

These include:

- A lime works where a modular substation will reduce the demand on Hangatiki East feeder and the transformer at the Hangatiki zone substation
- A meat works where a modular substation will reduce the demand on Benneydale feeder and the transformer at the Waitete zone substation.
- A second meat works where a modular substation will reduce the demand on Pureora feeder and the transformer at the Maraetai zone substation
- An iron sands mine that would require the upgrading of transformers at the Taharoa zone substation and the upgrading of the Hangatiki GXP transformers.

If these industrial developments do not occur the modular substations proposed for the industrial site will be removed from the plan.

5.3.4.4 Dairy Farming & Irrigation

TLC has two modular substation planned for rural areas where irrigation has taken place. If the development continues with increase in demand than the proposed modular substation can be brought forward to avoid any voltage constraints.

There is an expected increase in load due to more stringent milk refrigeration requirements that are expected to come into effect in 2016. The effect of these changes are already coming in to effect with a number of increased load applications from dairy farms for milk chilling.

5.3.4.5 Effects of Electric Vehicles

It is recognised that the introduction of electric vehicles has the potential to have a significant effect on the TLC network. In the longer term it may be that the energy transported to charge these vehicles will increase as they become more main-stream.

The demand effects, if this were to occur, would likely be significant. If the vehicle batteries were set up to assist demand side management by supplying power in peak times and absorbing power in off peak times, there could be a decline in peak growth. Alternatively, if no demand side management is implemented, peak demand could increase rapidly. It is hoped that demand billing would strongly encourage the former option. If the batteries assist demand management by supplying power directly from their reserves, the network fault level within the system could rise due to the additional sources of energy that would feed into network faults when they occur.

The timing of these vehicles turning up and the extent of penetration into the rural TLC environment is unknown. There are several penetration timing scenarios prompted by various motoring experts. A common theme amongst them is that electric vehicles are more likely to be adopted in urban areas as opposed to rural. Many of these writers suggest that electric vehicle penetration into rural areas will take a long time to develop given the current technological status of the batteries.

For example, the most likely vehicles that will be suitable for rural use are hybrids that use a combination of petrol/diesel and electric motors with some battery storage.

For the purposes of the 2015/16 plan, the effects of electric vehicle penetration on the network have not been included.

5.3.5 Equipment or Network Constraints Anticipated in the planning period

TLC uses Electrical Transient Analyser program (ETAP) to predict where constraints will occur if the forecast load growth occurs. The network is modelled with the projected loadings and the program produces reports that highlight the assets within TLC's network that are likely to have unacceptable voltage levels; similarly, ETAP reports can be used for current constraints.

The report can be used to highlight sections of the network that are below or close to the minimum supply of 94% of rated voltage. Areas identified with low voltage are slated for voltage regulators or conductor upgrades in the planning period.

Current constraints are identified in the report by comparing the maximum load current with the conductor's current rating.

TLC uses these reports to assist in planning and identifying areas of constraint. An analysis of the network constraints is summarised in the following sections, given the predicted system demands listed in the sections above.

5.3.5.1 Supply Points Constraints

Hangatiki - The constraining factor on the present load off-take from Hangatiki is the capacity of the two 110 kV/33 kV banks. These have a summer/winter rating of 22/24 MVA for one unit and 25/26 MVA for the other. It is often difficult during day light hours to reduce load to the 22/24 MVA level to allow Transpower to remove a unit from service to carry out maintenance. A failure or a fault in a unit will mean that a number of dairy farmers, meat processors, and lime processors will have to stop production.

If the load increase at Taharoa goes ahead then the capacity will have to be upgraded in the first half of the planning period to accommodate the extra load. Transpower in conjunction with TLC, have commenced planning for this replacement.

Waipa Networks have proposed to build an 110kv line out of Hangitiki. This will add to the load requirements at Hangitiki and it will also aid in the cost reduction of GXP charges. Further impacts of this new 110kV line are being investigated through continued engagement with Transpower.

A new ripple injection plant has been installed at Hangatiki. However, it is expected that the change out of all the relays will take another 5 years and the present plants will be decommissioned in 2017 or a little later, (dependent on the rollout of advanced meters). In addition to historic load control, signals are essential for customer demand side management under TLC's charging structures.

Ohakune – The capacity of the shared Ohakune GXP transformer (shared with PowerCo) has reached 95% of capacity in 2007, 2009 and 2010. From 2011 onwards load management has been used to limit the peak which has stayed below 80% of the transformer capacity. As a result of this high loading Transpower has moved forward their plans to upgrade the Ohakune GXP transformer to 2015. The new transformer will have double the capacity and improved reliability associated with modern power transformers at negligible extra cost.

Tokaanu - There are no capacity constraints at the Tokaanu point of supply.

National Park - Continued development at the Whakapapa ski field and National Park village will drive load demands at this grid exit point. Models are saying that the grid exit transformer capacity will be adequate to the end of the planning period. It is likely a non-asset solution in conjunction with the development of the ski field will be pursued when its transformer capacity is fully utilised. There are a number of potential hydro sites in the area that, if developed, would alter the National Park grid exit loads.

At the beginning of 2014 the new containerised zone substation and ripple injection plant were commissioned at National Park, this has allowed for the removal of one Transpower circuit breaker which will reduce annual costs from this site.

Transpower has commenced replacement of the National Park transformer at the time of writing. Load controlling philosophy meant this is an age and reliability driven replacement rather than capacity. The outcome will be improved asset condition over the whole site (TLC and Transpower) with improved reliability and capacity at negligible increases in transmission charges that will be offset by the removal of one of Transpower's circuit breakers.

Ongarue - The Ongarue point of supply has sufficient capacity for all likely development during the planning period. This may change towards the end of the planning period if potential hydro in the region is developed. The connection charges for the site are high and it is possible to reduce these by rationalising the number of outgoing feeder circuit breakers. As with other sites above, Transpower has agreed to work with TLC to modernise and rationalise the site to better produce outcomes that both organisations require. These will be addressed in planning work following the completion of Ohakune and National Park projects.

Whakamaru / Atiamuri – The capacity of the 10 MVA backup supply out of Atiamuri will be at its upper limit during this planning period. There is a plan for either a new point of supply at Whakamaru, an increase in capacity at Atiamuri or a new supply directly from a hydro generator in 2017/18 that will provide an improved backup supply.

More planning and thinking is required in this area as we get to understand developments in and around the Mokai Energy Park and changes in dairying load in the region.

The present primary load control system for the area downstream of the Whakamaru/Atiamuri supply is old and based on an injection frequency of 725 Hz. The plants themselves inject at 11 kV. Over time load has grown and the signal propagation levels have attenuated resulting in unreliable relay operation. There is also a zone substation without an injection plant. The consequence of this is little signal level downstream of this site.

A new ripple injection plant has been installed at Whakamaru GXP. It is expected that the present plants will be decommissioned in 2016 following completion of the advanced metering rollouts in the area. In addition to historic load control, signals are essential for customer demand side management under TLC's charging structures.

5.3.5.2 Zone Substation Constraints

There are transformers at two zone substations that will be constrained due to capacity in this planning period. Atiamuri supply transformer will be at capacity during this planning period. There is planned work for 2017/18 that will alleviate this constraint. With the planned increase in load at the iron sands mine an upgrade of the existing transformer arrangement at Taharoa is planned for 2015/16.

Oil tests on the Kuratau transformer indicate that is in a deteriorated condition. This will be replaced with a refurbished transformer that is being swapped out of Mahoenui.

There is an environmental constraint due to a potential flood risk at the Borough zone substation. This will be mitigated with the establishment of a new modular zone substation that can back up supply to Taumarunui.

5.3.5.3 33kV Line Constraints

TLC's sub-transmission network will not encounter any capacity constraints within this planning period. Assuming that the existing network configuration will be maintained in the Taumarunui and Kuratau areas. The Nihoniho 33 and the Kuratau/ National Park lines have reliability and hazard constraints caused by their age and inherent low strength design.

If the load increase at Taharoa goes ahead then the Taharoa A and B line will be running at full capacity and future upgrades on the line are being considered.

Included in the plan is the relocation and undergrounding of the Lake Taupo 33kV which runs through Turangi Town. The primary reasons for this are that the line runs through the main street of Turangi and it is susceptible to damage from surrounding tree.

5.3.5.4 Distribution Feeder Constraints

Table 5.6 to Table 5.11 list the distribution feeders and the constraints. Note: The hazards in these tables are being controlled as part of the asset management process and addressed in this plan. The references to the constraints are explained in notes following the tables. The feeders have been listed under each point of supply.

Hangatiki Point of Supply						
Feeder	**Current Constraint**	**Access Constraint**	**Reliability Constraint**	**Extreme Weather Constraint**	**Voltage Constraint**	**Hazard Constraints and Comments**
Aria	OK	3	2	3	None within this planning period.	Rural feeder. Reliability constrained by long spans and polluted insulators. SWER lines.
Benneydale	OK	4	3	2	There are 4 regulators on this feeder and distributed generation. Without generation the voltage can dip at the end of the feeder.	Distributed generation. Very long feeder with some large industrial and rural customers. SWER lines.
Caves	OK	3	3	3	Due to the small conductor size, ends of long rural spurs are constrained.	Long spans towards end. SWER lines. Voltage regulator proposed for the end of the planning period.
Coast	OK	4	4	3	Marokopa and the Kiritehere could see constraint due to small conductor size. However none within this planning period.	Rural feeder with distributed generation and SWER system.
Gravel Scoop	OK	1	4	2	Gravel Scoop constraints towards the end of the planning period.	Rural supply with dairying load. High fault currents near zone substation. Regulator is proposed for year 2024/25.
Hangatiki East	OK	1	2	2	Due to a large lime industrial site this feeder is at its upper limits.	Industrial & dairying load.
Mahoenui	OK	4	3	3	Mahoenui constraints towards the end of the planning period.	Long rural feeder. Reliability constrained by long spans and polluted insulators. SWER systems.
Maihiihi	OK	3	4	2	Two regulators on this feeder providing voltage support. Mangaorongo and Maihiihi Road junction is at upper limits.	Long urban and rural feeder with mainly dairy farming load. High fault currents near zone substation.
McDonalds	OK	1	4	2	None within this planning period.	Rural feeder with lime works connected. High fault currents near zone substation.

Feeder	Current Constraint	Access Constraint	Reliability Constraint	Extreme Weather Constraint	Voltage Constraint	Hazard Constraints and Comments
Mokau	OK	4	4	4	Two regulators on this feeder.	Significant amount of overhead line in exposed coastal environment. Conductor renewal is planned for 2016/17. Four separate SWER systems into the remote rural areas.
Mokauiti	OK	4	3	3	SWER systems at end of feeder are at upper limit.	Rural feeder. Reliability constrained by long spans and polluted insulators. Two SWER systems into remote areas. Regulator proposed for 2021/22
Oparure	OK	3	4	2	Ends of long rural spurs are constrained.	Long rural feeder with fertiliser polluted insulators.
Otorohanga	OK	1	4	4	None within this planning period.	Mainly urban supply with some very rugged rural spans. High fault currents near zone substation. Number of ground mounted transformers.
Piopio	OK	3	3	3	Piopio is currently stable but will constraint at the end of the planning period.	Rural feeder. Reliability constrained by long spans and polluted insulators. Regulator is proposed for year 2018/19.
Rangitoto	OK	4	3	2	None within this planning period.	Long feeder with industrial and rural loads. Has one small SWER system. Recent line renewal has strengthened lines.
Rural	OK	4	4	3	None within this planning period.	Small coastal feeder.
Te Kuiti South	OK	3	2	2	None within this planning period.	Urban and rural supply with a number of ground mounted transformers.
Te Kuiti Town	OK	OK	1	1	None within this planning period.	Mostly urban supply with number of ground mounted transformers.
Te Mapara	OK	3	3	3	SWER systems at end of feeder are at upper limit.	Rural feeder. Reliability constrained by long spans and polluted insulators. SWER systems.
Waitomo	OK	1	3	1	None within this planning period.	Urban and rural supply. Has large sawmill connected.

TABLE 5.6 CONSTRAINTS ON FEEDERS SUPPLIED BY HANGATIKI POS

Whakamaru Point of Supply						
Feeder	**Current Constraint**	**Access Constraint**	**Reliability Constraint**	**Extreme Weather Constraint**	**Voltage Constraint**	**Hazard Constraints and Comments**
Huirimu	OK	4	3	2	Voltage constraint at end of feeder at the end of this planning period.	Rural feeder supplying dairy load.
Mangakino	OK	OK	2	2	None within this planning period.	Ex dam construction town. Low 2 pole structures and low voltage in poor condition.
Mokai	OK	4	3	3	Voltage constraint along Whangamata and Karangahape Road.	Rural feeder with dairying, subdivision and industrial load growth. Regulator proposed in 2015/16 year.
Pureora	OK	5	3	2	Two regulators on this feeder. Load increase for Crusader Meats constrains the feeder.	Long rural feeder with meat processor on end. Two regulators proposed for year 2016/17 and year 2022/23.
Tihoi	1 (SWER)	4	3	3	Western Bay Road constraints before and after SWER sub.	Long rural feeder with growth. SWER system.
Whakamaru	OK	3	3	2	Regulator installed in 2012/13 due the increased load (irrigation pumps). No foreseeable constraints.	Rural feeder supplying dairy load. Old cabling and lack of switchgear in underground system at what was the hydro village at Whakamaru.
Wharepapa	OK	4	3	4	This feeder has three regulators.	Long rural feeder supplying dairy load.
Tirohanga	OK	3	3	2	None within this planning period.	Rural feeder with many trees along route.

TABLE 5.7 CONSTRAINTS ON FEEDERS SUPPLIED BY WHAKAMARU POS AND MOKAI STATION

Ongarue Point of Supply						
Feeder	**Current Constraint**	**Access Constraint**	**Reliability Constraint**	**Extreme Weather Constraint**	**Voltage Constraint**	**Hazard Constraints and Comments**
Hakiaha	OK	OK	3	3	None within this planning period.	Mostly urban feeder in Taumarunui with many GMT substations.
Manunui	1 (SWER)	4	3	3	Long small conductor SWER lines.	Rural feeder with a number of SWER systems.
Matapuna	OK	2	3	3	Due to small cable sizes this feeder is nearing its upper limits.	Mostly urban feeder in Taumarunui. Small cable.
Nihoniho	OK	5	4	4	None within this planning period.	Old feeder into very remote rugged country with SWER.
Northern	OK	4	4	3	Voltage constrains in rural areas.	Long rural feeder SWER systems. Old switchgear. Regulator proposed for year 2021/22.
Ohura	OK	5	4	4	None within this planning period.	Old feeder into very remote rugged country. Five separate SWER systems.
Ongarue	4 (SWER)	5	3	3	Due to small conductor voltage drops South of Tangitu. SWER systems also at upper limits.	Rural feeder in rugged remote country with high current SWER systems. Regulator is proposed for 2017/18.
Southern	OK	4	3	3	Without generation the feeder constrains at South of Owhango during peak loads. SWER transformers also constraints during peak load.	Six separate SWER systems supplying remote areas. Embedded generation.
Tuhua	OK	5	3	3	None within this planning period.	Rural feeder in rugged remote country. High current SWER systems.
Western	ok	4	4	4	Growth of lifestyle blocks close to Taumarunui may see this feeder with voltage constraints at the end of the planning period.	Long rural feeder with high current SWER systems. Regulator is proposed if load growth occurs.

TABLE 5.8 CONSTRAINTS ON FEEDERS SUPPLIED BY ONGARUE POS

Tokaanu Point of Supply						
Feeder	**Current Constraint**	**Access Constraint**	**Reliability Constraint**	**Extreme Weather Constraint**	**Voltage Constraint**	**Hazard Constraints and Comments**
Hirangi	OK	OK	1	OK	None within this planning period.	SWER feeder close to Turangi.
Kuratau	OK	3	4	4	No constraints at present, lake side development may change this situation.	Feeder supplying Kuratau holiday area. Underbuilt and U/G systems. Long SWER systems. Low strength poles, renewal programme has replaced many of these poles.
Motuoapa	OK	2	2	2	None within this planning period.	Low structures & LV systems. Many improvements to minimise/eliminate hazards, more needed.
Oruatua	OK	3	2	2	None within this planning period.	SWER systems. Low structures. Improvements required minimising hazards.
Rangipo / Hautu	OK	2	2	3	None within this planning period.	Many improvements to eliminate/minimise hazards; more needed.
Tokaanu	OK	OK	2	1	None within this planning period.	Many improvements to minimise/eliminate hazards.
Turangi	OK	OK	4	2	None within this planning period.	Ground mounted transformers (GMT) in inadequate enclosures and old switchgear. Underground cabling reaching end of life.
Waihaha	OK	4	4	4	No constraints at present, development on Karangahape Road will change this situation.	Feeder with long SWER systems connected. Many of the low strength poles have been replaced in the line renewal programme.
Waiotaka	OK	OK	1	1	None within this planning period.	Short feeder supplying Hautu Prison and SWER system to a Māori incorporation farm.

TABLE 5.9 CONSTRAINTS ON FEEDERS SUPPLIED BY TOKAANU POS

National Park Point of Supply						
Feeder	**Current Constraint**	**Access Constraint**	**Reliability Constraint**	**Extreme Weather Constraint**	**Voltage Constraint**	**Hazard Constraints and Comments**
Chateau	2	4	2	1	There are 2 regulators on this feeder providing voltage support.	Switchgear on the mountain. Many improvements to eliminate/minimise hazards; more needed.
National Park	OK	3	3	4	Remote lines with small conductor south of National Park.	Hazard concerns include long spans of single phase along SH4. Environmental concern in World Heritage Park.
Otukou	OK	3	3	3	None within this planning period.	Heavily forested, most of feeder is SWER.
Raurimu	1 (SWER)	5	3	3	None within this planning period.	Feeder with three very long SWER systems into remote rugged country. These systems have high current loadings.

TABLE 5.10 CONSTRAINTS ON FEEDERS SUPPLIED BY NATIONAL PARK POS

Ohakune Point of Supply						
Feeder	**Current Constraint**	**Access Constraint**	**Reliability Constraint**	**Extreme Weather Constraint**	**Voltage Constraint**	**Hazard Constraints and Comments**
Ohakune Town	OK	1	3	4	The small conductor and heavy loads over the ski season have put this feeder at its upper limits.	Work needed to remove hazard constraints with LV and switchgear and to meet growth. Conductor size small in some areas.
Tangiwai	3	3	3	3	One regulator installed at Tangiwai. At heavy loading this feeder constrains from the town's boundary.	Renewal work over the last few years to improve pole strengths. Snow area.
Turoa	OK	3	3	2	Four regulators installed on this feeder.	Supply to ski fields. Has old switchgear.

TABLE 5.11 CONSTRAINTS ON FEEDERS SUPPLIED BY OHAKUNE POS

Current and Access Constraints

Current constraints are determined by using the network analysis program to forecast the expected currents on conductors. These are then checked against the existing conductors rating. The constraint priorities in Table 5.12 to Table 5.13 are defined on a scale of 1 to 5, five being the most concerning. The definitions of priority are set out in these tables.

CURRENT CONSTRAINTS	
Constraint Grade	**Current Constraints on 11 kV Feeders for predicted loads over 10 year planning period**
1	Current of 100% of a section conductor rating.
2	Current of 110% of a section conductor rating.
3	Current of 120% of a section conductor rating.
4	Current of 130% of a section conductor rating.
5	Current of 140% or greater of a section conductor rating.

TABLE 5.12 CURRENT CONSTRAINTS

Access constraints are determined from the line inspection information and local knowledge.

ACCESS CONSTRAINTS	
Constraint Grade	**Access Constraints on 11 kV Feeders**
1	Up to 20% of the feeder must be fault patrolled and accessed with a helicopter.
2	Up to 40% of the feeder must be fault patrolled and accessed with a helicopter.
3	Up to 60% of the feeder must be fault patrolled and accessed with a helicopter.
4	Up to 80% of the feeder must be fault patrolled and accessed with a helicopter.
5	Up to 100% of the feeder must be fault patrolled and accessed with a helicopter.

TABLE 5.13 ACCESS CONSTRAINTS

Reliability Constraints

Reliability problems due to age, construction, span lengths, tree numbers, numbers of alternative feeds, numbers of reclosers, other automated controls, known fault current problems, distances from depots, amount of feeder that is a radial feeder, local terrain, i.e. how rugged and remote the area is, previous history and likely problems have been considered to assign a reliability constraint.

The severity of these constraints is listed as in Table 5.14.

RELIABILITY CONSTRAINTS	
Constraint Grade	**Reliability Constraints on 11 kV Feeders**
1	Above issues are expected to cause problems or likely to cause problems every 2 years.
2	Above issues are expected to cause problems or likely to cause problems every 12 months.
3	Above issues are expected to cause problems or likely to cause problems every 6 months.
4	Above issues are expected to cause problems or likely to cause problems every 3 months.
5	Above issues are expected to cause problems or likely to cause problems monthly.

TABLE 5.14 RELIABILITY CONSTRAINTS

Extreme Weather Constraints

Constraints due to extreme weather conditions rise as wind speed accelerates (Table 5.15). For example, winds between 40 - 60km/hr have little effect on the network; whereas wind speeds above 80km/hr start to have a significant effect on our 11 kV feeders.

EXTREME WEATHER CONSTRAINTS	
Constraint Grade	**Extreme Weather Constraints on 11 kV Feeders**
1	Winds greater than 40 km/hr.
2	Winds greater than 60 km/hr.
3	Winds greater than 80 km/hr.
4	Winds greater than 100 km/hr.
5	Winds greater than 120 km/hr.

TABLE 5.15: EXTREME WEATHER CONSTRAINTS

5.3.6 Impact of Distributed Generation on Forecasts

Post the global financial crisis, the national demand and supply position has changed considerably. Completion of significant geothermal power plant construction in the Central North Island and reducing demand has meant an uplift in the supply side of electricity. This has resulted in considerable downward sliding of wholesale energy prices. Developers of distributed generation and major retailers, have shelved the majority of any further generation projects.

As such, activity in the distributed generation market has subsided. While we are aware of the majority of potential distributed generation projects, none are anticipated to come on-stream within the planning period.

5.3.7 Impact of Demand Management Initiatives on Forecasts

5.3.7.1 Effect of Auxiliary Generation on Peak Demand Reduction

Ruapehu Alpine Lifts (RAL) has installed a generator to bolster the supply during peak load periods such as snow making on a winter's night on its Turoa ski field. The company is also proposing another similar installation at Whakapapa.

The Turoa installation has only been used occasionally to reduce peaks due to the practical issues associated with getting enough fuel up to the ski field to the site. There are also clauses in the World Heritage Park Plan that will make running this plant for extended periods difficult. There is still an amount of capacity in the existing supply to both ski fields and demand side management savings via power factor improvements are potentially possible.

As a consequence of this the forward models have assumed expansion of loads on the ski fields until all of the existing capacity is used and then loads have been seen to not increase further. It has been assumed that by this time the current difficulties with the auxiliary generation will be overcome and it will be used to constrain load for the remainder of the planning period.

Auxiliary generation over peak periods on the ski fields has been assumed to delay the need to upgrade the Tawhai transformer.

A number of smaller businesses in the Ohakune area also operate generators to reduce peak demand. Due to the small size of the generators they have a negligible effect on the network.

5.3.7.2 Effect of Load Control on Peak Demand Reduction

TLC uses a load control system to reduce loading during peak periods. The load control targets are set to align as best as possible with Transpower's regional peaks and network constraints.

Customers have a ripple relay that controls hot water and other assigned loads. Each ripple relay is assigned a channel and, TLC's SCADA system is programmed to automatically shed load based on the forecast loadings at peak times.

Load control through peak times delays the need to upgrade system capacity. Comparisons of loads in the network analysis program indicate that a number of assets would be constrained at peak loading time much earlier in the planning period.

5.3.7.3 Effect of Peak Demand Billing on Peak Demand Reduction

TLC utilises a Demand Billing methodology to influence customer energy usage, in particular network peak demand. TLC sets one billing rate for peak load over the year, based for most customers on the amount of energy consumed through the peak period. This is re-assessed each year after the peak demand period is over, at the end of September.

To get the full benefits of Demand Billing, customers need to have an advanced meter installed. This metering registers that a ripple signal is received and monitors the load consumed throughout the load control period. Customers also need to be aware of what appliances have high power consumption and if

possible transfer these onto the control relays. TLC is rolling advanced meters to all customers over the next 2 years.

The data from these meters are used to set the customers charges for the following year. The signal to customers is to reduce their consumption through the peak period, when TLC is shedding load.

Initial work has produced calculations have shown that demand will have increased in the range of 0.2% to 1.3% greater than if financially driven demand side management had not been introduced. These percentages have been included in the growth rates and trend lines have been adjusted accordingly.

5.3.7.4 The Implications of Demand Side Management Initiatives

5.3.7.4.1 On Supply Points

5.3.7.4.1.1 General Discussion on Demand Side Management Effects on Substations

Figure 5.8 shows the estimated reduction in peak demand as a result of demand side management.

Hangatiki - Demand side management creates headroom. There is also a likely associated implication in that it will be difficult even at light load times to get the larger of the two transformers out for maintenance. With demand side management we may be able to delay the upgrade of the Hangatiki transformers.

Ohakune – Demand growth is driven by the ski season. Demand charging has delayed any significant investment by Transpower and TLC due to capacity constraints. That is, peak demand has been managed successfully without impinging on availability of supply for the economic growth of the area.

Tokaanu and Ongarue - It is predicted that if present growth in demand figures continue, then growth will be delayed by six and seven years respectively at these two sites. There are no supply point constraints on the planning horizon for either of these two sites.

National Park - Demand growth is being driven by the ski field. Similarly to Ohakune demand charging has delayed any significant investment by Transpower and TLC due to capacity constraints. That is, peak demand has been managed successfully without impinging on availability of supply for the economic growth of the area. Again, as with Ohakune, it is likely that without demand charging, growth would have been greater. It is known that the ski lodges for example have become more focused on demand control.

Whakamaru/Atiamuri/Mokai – Without demand side management the Atiamuri supply transformer that backs this area up will be operating beyond acceptable loadings about one to two years sooner.

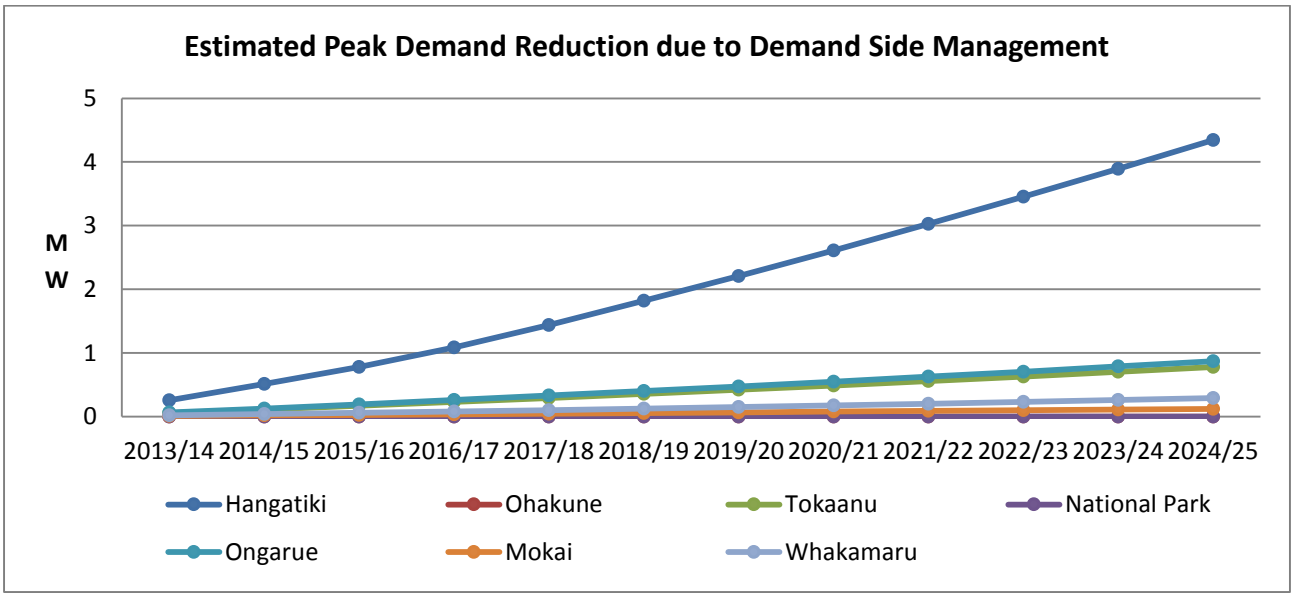


FIGURE 5.8 EFFECTS OF DEMAND SIDE MANAGEMENT ON SYSTEM ESTIMATED PEAK DEMANDS

5.3.7.4.1.2 The Effect of Maximum Demand Tariff's on Supply Point Loadings

The following are cost reductions that are handed on to customers as a result of maximum demand billing:

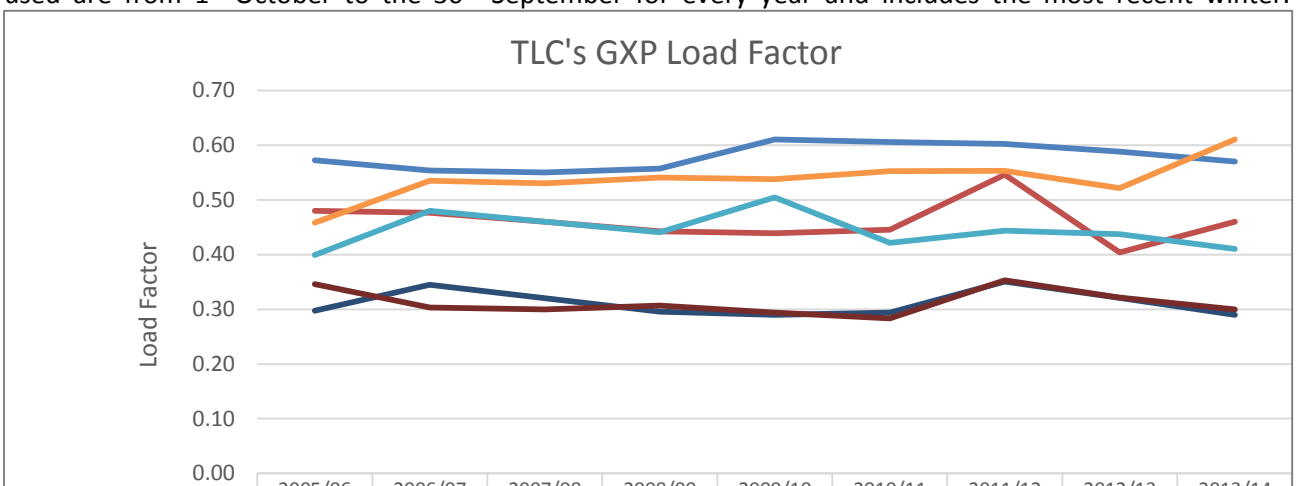
- A reduction in Transpower charges. TLC is able to reduce its loading during the Lower North Island electricity peaks thus reducing the transmission charges imposed on it.
- By reducing the peak loading on network assets this will increase life expectancy and reduce failures caused by electrical deterioration, which is aggravated by excess heating. Thereby asset replacement is pushed further out.
- Benefits may be gained through the deferral of capacity upgrades. These occur at all levels from transmission through to distribution. For example, TLC is outgrowing several National Grid assets that will cost several million to replace such as the Hangatiki 110/33kV transformer bank. These assets have not yet reached their life expectancy and could be replaced prematurely due to overloading. Their replacement will be expensive to both TLC and its customers.

Load factor is used to estimate the effects of TLC's maximum demand pricing options.

The load factor is the ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. It is a percentage derived using the following formula.

$$\text{Load Factor} = \frac{\text{Actual Energy Consumed}}{\text{Maximum Demand x Time in hours of period}}$$

Figure 5.9 outlines the change in load factors for each of the different systems in the network. The figures used are from 1st October to the 30th September for every year and includes the most recent winter.



	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Hangatiki System	0.57	0.55	0.55	0.56	0.61	0.61	0.60	0.59	0.57
Ongarue System	0.48	0.48	0.46	0.44	0.44	0.45	0.55	0.40	0.46
Tokaanu	0.40	0.48	0.46	0.44	0.50	0.42	0.44	0.44	0.41
Whakamaru	0.46	0.53	0.53	0.54	0.54	0.55	0.55	0.52	0.61
Ohakune	0.30	0.34	0.32	0.30	0.29	0.29	0.35	0.32	0.29
National Park	0.35	0.30	0.30	0.31	0.29	0.28	0.35	0.32	0.3

FIGURE 5.9: LOAD FACTOR AT EACH SUPPLY POINT FOR THE TLC NETWORK

A load factor that is improving indicates that there is better utilisation of the systems assets in moving peak demand from the peak times. Ideal is a load factor of 1.

5.3.7.4.2 On 33 kV Lines

Without demand side management, the conductors would be approaching their rated capacity at the end of the planning period.

5.3.7.4.3 On Zone Substations

Table 5.16 and Table 5.17 show the estimated reduction in forecast zone substation loadings due to the effects of demand side management. The following assumptions can be made about the impact of demand side management initiatives:

- The Atiamuri transformer is forecast to exceed full load at the end of the planning period but with demand side management realistic operating capacity limits are just being reached. The Plan includes an additional supply from Whakamaru in years 2016/17 which will alleviate this constraint.
- Taharoa and Te Anga show no effects from demand side management as the maximum demands on these substations are effected by a growing industrial load and distributed generation respectively.
- Due to the small peak demands at Otukou and Tokaanu it is difficult to discern the impact of demand side management on these zone substations.

Site	Rating (MVA)	Number of Transformers (MVA)	Forecast MD's (MW) for year ending March 31										
			2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Arohena	3	1 x 3.0	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.05	0.05	0.06	0.06
Atiamuri	10	1 x 10.0	0.07	0.09	0.11	0.07	0.08	0.09	0.11	0.12	0.14	0.16	0.17
Gadsby Rd	5	1 x 5.0	0.08	0.13	0.17	0.22	0.27	0.33	0.37	0.40	0.43	0.47	0.50
Omya	2.4	1 x 2.4							0.01	0.01	0.02	0.02	0.03
Hangatiki	5	1 x 5.0	0.08	0.13	0.18	0.23	0.29	0.34	0.40	0.46	0.52	0.58	0.65
Kaahu Tee	2.4	1 x 2.4	0.03	0.03	0.03	0.04	0.04	0.05	0.05	0.05	0.06	0.06	0.07
Mahoenui	3	1 x 3.0	0.02	0.04	0.05	0.06	0.08	0.09	0.11	0.12	0.14	0.15	0.17
Maraetai	5	1 x 5.0	0.05	0.06	0.07	0.08	0.08	0.09	0.08	0.09	0.09	0.10	0.10
Ranginui Road	2	1 x 2.0							0.01	0.03	0.06	0.08	0.10
Sandel Road	2	1 x 2.0						0.02	0.03	0.04	0.05	0.05	0.06
Marotiri	3	1 x 3.0	0.03	0.04	0.04	0.05	0.05	0.06	0.07	0.07	0.08	0.09	0.09
Miraka	7.5	1 x 7.5	0.15	0.25	0.35	0.46	0.58	0.71	0.84	0.98	1.14	1.30	1.47
Oparure	3	1 x 3.0	0.04	0.06	0.08	0.10	0.13	0.15	0.17	0.20	0.23	0.25	0.28
Taharoa	15	3 x 5.0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Te Anga	2.4	1 x 2.4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Te Waireka Rd	20	2 x 10.0	0.03	0.07	0.10	0.14	0.18	0.21	0.25	0.29	0.34	0.38	0.42
Wairere	5	2 x 2.5	0.04	0.07	0.10	0.14	0.17	0.21	0.24	0.28	0.32	0.36	0.40
Waitete	15	3 x 5.0	0.12	0.24	0.37	0.50	0.61	0.73	0.85	0.97	1.10	1.23	1.36
UBP Limited	2.4	1 x 2.4					0.03	0.05	0.08	0.11	0.14	0.17	0.20

TABLE 5.16 NORTHERN ZONE SUBSTATION ESTIMATED MAXIMUM DEMANDS REDUCTION THOUGH DEMAND SIDE MANAGEMENT

Site	Rating (MVA)	Number of Transformers (MVA)	Forecast MD's (MW) for year ending March 31										
			2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Awamate Road	2	1 x 2.0	0.01	0.01	0.02	0.03	0.03	0.04	0.05	0.05	0.06	0.07	0.07
Borough	10	2 x 5.0	0.13	0.18	0.23	0.28	0.33	0.38	0.44	0.49	0.54	0.59	0.64
Northern	2	1 x 2.0								0.01	0.01	0.01	0.01
Kiko Rd	3	1 x 3.0	0.02	0.03	0.04	0.05	0.05	0.06	0.07	0.08	0.09	0.10	0.11
Kuratau	3	1 x 3.0	0.03	0.04	0.06	0.07	0.09	0.11	0.12	0.14	0.15	0.16	0.17
Little Waihi	2	1 x 2.0								0.01	0.02	0.02	0.03
Manunui	5	1 x 5.0	0.04	0.05	0.07	0.09	0.10	0.12	0.14	0.16	0.17	0.19	0.21
National Park	3	1 x 3.0	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Nihoniho	1.5	1 x 1.5	0.01	0.02	0.02	0.03	0.03	0.04	0.04	0.05	0.06	0.06	0.07
Ohakune	10	1 x 10.0	0.09	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.10
Otukou	0.5	1 x 0.5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tawhai	5	1 x 5.0	0.11	0.14	0.17	0.21	0.24	0.14	0.16	0.18	0.20	0.22	0.24
Tawhai 2nd Tx	5	1 x 5.0 (2019)						0.14	0.16	0.18	0.20	0.22	0.24
Tokaanu	1.25	1 x 1.25	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Tuhua	1.5	1 x 1.5	0.01	0.01	0.02	0.02	0.03	0.03	0.04	0.05	0.05	0.06	0.07
Turangi	10	2 x 5.0	0.03	0.06	0.08	0.11	0.14	0.17	0.20	0.22	0.25	0.27	0.30
Waiotaka	1.5	1 x 1.5	0.00	0.01	0.01	0.01	0.02	0.02	0.03	0.03	0.04	0.05	0.05

TABLE 5.17 SOUTHERN ZONE SUBSTATION ESTIMATED MAXIMUM DEMANDS REDUCTION THOUGH DEMAND SIDE MANAGEMENT

5.4 Analysis of Network Development Options Available

The solutions listed below are after consideration of non-asset solutions including the gains made by demand billing and distributed generation.

5.4.1 Voltage Regulator Installs in the Development Plan to Counteract Voltage Constraints

As stated in other sections TLC's network analysis package has been analysed to loadings expected in 2024/25. This exercise has identified a number of legacy and future voltage constraints. These constraints, present and predicated, have been caused by both legacy issues and future cumulative capacity load growth.

The analysis models have been developed based on assumptions for critical issues such as power factor and reactive power flows in line with present measurement and expectations. If demand based charges are more successful than predicted, some of these installation may be delayed.

The proposed voltage regulator sites often need further investigation after the initial network analysis is carried out, for example SWER systems are difficult to model correctly and further field tests are often required. The results of these checks and annual review of load growth may alter the timing of proposed voltage regulators in future AMPs.

The regulator expenditure has been allocated to the cumulative capacity expenditure category. Once many of the relays are upgraded to advanced meters in the northern area it may be possible to substitute some of the regulators for slightly less expensive capacitor banks. A major driver for needing to install the regulators is the need to comply with the Electricity (Safety) Regulations.

11 kV REGULATORS (Cumulative Capacity Allocation)			
Supply Point	**Feeder**	**Planning Notes for Voltage & Quality of Supply Improvements**	**Year and Cost Estimate**
HANGATIKI	Caves	Depends on tourism growth in area	105K in 2023/24
	Gravel Scoop	Install regulator after switch 622 to support Lurman Rd area and for back feeding Maihiihi.	105K in 2019/20
	Gravel Scoop	Install regulator on Otewa road just before Barber Will mainly be used when tieing to Rangitoto and Maihihi.	105K in 2024/25
	Mahoenui	Mainly for backup of Mokau Feeder when 33 kV is out. Install new regulators	105K in 2020/21
	Mokauiti	Install regulator near switch 1710 to lift voltages in the Mokauiti Valley.	105K in 2020/21
	Piopio	Install new regulator before switch 1340, if growth continues in this area.	105K in 2018/19
	Rangitoto	Install regulator near Switch112, to boost voltages before regulator 30.	105K in 2022/23

11 kV REGULATORS (Cumulative Capacity Allocation)			
Supply Point	**Feeder**	**Planning Notes for Voltage & Quality of Supply Improvements**	**Year and Cost Estimate**
ONGARUE	Northern	By High School Depends on load growth.	105K in 2021/22
	Ongarue	Install Regulator at State Highway 4 near switch 6640.	105K in 2017/18
	Southern	Growth in dairying and irrigation along state highway. Install regulator just before Otapouri Road. Will help lift voltage at Owhanga for subdivision growth.	105K in 2024/25
	Western	Install regulation to accomadate increased load due to the subdivisions of land for lifestyle blocks along River Road.and the surround areas.	105K in 2022/23
WHAKAMARU	Mokai	Install regulator on Waihora road before intersection of Whangamata Road so benefits both directions along Whangamata Road.	105K in 2015/16
	Mokai	Replace Tirohanga Road Regulator	105K in 2023/24
	Pureora	Near switch 785 just after Ranginui Road on SH 30.	105K in 2015/16
	Pureora	Close to Crusaders Meats 4th Regulator for deer plant.	105K in 2022/23

TABLE 5.18 VOLTAGE REGULATORS FOR VOLTAGE CONSTRAINTS

5.4.2 Upgrades of conductor sizes in the Development Plan

The overhead conductor upgrades listed in Table 5.19 are cumulative capacity upgrades. Additional conductor renewal pertaining to line replacement (as opposed to upgrade) have been included in the line renewal programme.

CONDUCTOR UPGRADE PROJECTS (EXCLUDING LINE RENEWALS)						
Feeder	**Asset**	**Conductor Size**	**Year**	**Constraint**	**Estimated Length**	**Estimated Cost ($)**
Maihiihi	FED111	Jaguar	2016/17	Current & Voltage	1.0km	315k
Mokai	FED123	Mink	2018/19	Current & Voltage	7.0km	772k
Ohakune Town	414-01	Ferret	2016/17	Current & Voltage	1.5km	82k
Turoa	415-04	Mink	2020/21	Current & Voltage	5.5km	607k
Whakamaru	FED120	Dog	2019/20	Current & Voltage	1.0km	105k

TABLE 5.19 PROPOSED CONDUCTOR UPGRADES FOR CUMULATIVE CAPACITY

5.4.3 Analysis of Distribution Transformers and Specific Locations where constraints are expected

The focus of the analysis of distribution transformers is hazard minimisation improvements. The results of this analysis have contributed to the lists of programmed work in the preceding sections.

5.4.3.1 Pole Mounted Transformers and Equipment (Distribution and SWER Isolation) Analysis

Historically, the structures for 2 pole distribution transformers and SWER isolation transformers were constructed low to the ground. All structures have been measured and assessed for hazards, including in particular, ground to live bare conductor clearances, and the ease of climbing up onto transformer mounting platforms. Other potential hazards such as the closeness of high voltage jumpers to low voltage fuse operating positions have also been considered.

The solutions include allowances for modifying the incoming and outgoing circuits to eliminate hazards and make the connections more straightforward and understandable by fault staff. The plan includes the on-going renewal of these structures starting from the worst. At this point TLC is about half way through the sites initially highlighted as hazardous. Each site has been assessed for its needs and estimates have been put together that sum into capital and maintenance plans for the planning period.

Sites were assessed for hazards using two independent parties. An electrical inspector viewed all photographs and prioritised. An engineer also went through the data and photographs allocating points based on the prioritisation policies described in this plan. The two approaches were reconciled and the plan finalised. This plan is reviewed annually to ensure it continues to align with safety objectives.

5.4.3.2 Ground Mount Distribution Transformer Analysis

The focus of the analysis of ground mounted transformers and enclosures, was to identify all security, operating, and potential points of contact with live terminal hazards. Each site has been assessed for its needs and estimates have been put together that sum into capital and maintenance plans for the planning period. Sites were assessed for hazards using two independent parties. An electrical inspector considered all photographs and prioritised. An engineer also went through the data and photographs, allocating points based on the prioritisation policies described in this plan. The two approaches were reconciled and the plan was finalised. This plan is reviewed annually to ensure it continues to align with safety objectives.

5.4.4 Low Voltage System Underground and Overhead

The low voltage lines in the TLC network are of the same vintage as the 11 kV lines (old and in need of renewal). Many are well under current codes of practice height. The poles supporting many of these lines are often under strength and in poor condition. Most conductors are bare, and arcing, and clashing is common. This causes outages and the related surges may damage customers' equipment.

It is likely that aerial bundled conductor will be used for many of the renewals in rural villages. There are also poorly integrated underground and overhead systems that are creating hazards and require renewal to control these.

The design and planning process for each of these projects varies, being dependent on the local area issues. Low voltage renewal often involves customers' service lines and urban streets. As a consequence of this the design process involves discussions with landowners and road controlling authorities.

5.4.4.1 Underground Service Box Analysis

The constraint with low voltage service boxes is that they age and are subjected to vehicle and other damage. The result of this damage is that they often become insecure and the tops can be removed by members of the public. The damage is usually such that the service box needs to be renewed. The only other option is to leave them in a hazardous condition.

The option TLC chooses is to eliminate or minimise the hazard. An electrical inspector checks and tests service boxes on a five yearly cycle. Priorities are then set by this work.

5.4.5 Analysis of Related Systems (Load Control, SCADA, Communication) and Specific Locations where constraints are expected

All related systems have been analysed and predicted future needs to meet customer service levels have been included in spend plans.

The load control system in the northern area cannot provide the required customer service levels without renewal. New 317 kHz plants have been installed.

The estimates assume continuation of present strategies with SCADA. On-going and renewal and development of the SCADA equipment is included in forward estimates.

TLC is currently in the process of upgrading the radio network to meet new spectrum requirements. This includes adding new repeater sites to improve radio coverage.

5.5 Description and Identification of the Network Development Programme 2015/16

This section covers the planned expenditure for capital projects for the following 12 months.

Capital Expenditure Summary 2015/16		
	Budget	**Total**
Capex Network1 NXC: Consumer Connection		
Sub & 33 Dev - 33kV Lines	$ 120,750	
Sub & 33 Dev - Substations	$ 2,625,000	
Transformers - General Connections	$ 225,225	
Transformers - Industrials	$ 184,590	
Transformers - Subdivisions	$ 99,645	**$ 3,255,210**
Capex Network2 NXS: System Growth		
11kV Fdr Dev - Feeder Development	$ 262,500	
Regulators	$ 105,000	**$ 367,500**
Capex Network3 NXR: Asset Replacement and Renewal		
11kV Fdr Dev - Switch Automation and Renewal	$ 94,500	
11kV Planned Line Renewals	$ 4.321.065	
33kV Planned Line Renewals	$ 498,225	
Equipment Renewals	$ 1,168,125	
LV Planned Line Renewals	$ 748,125	
Relay Changes	$ 320,828	
Sub & 33 Dev - Substations	$ 102,900	
Sub & 33 Dev - Supply Points	$ 150,000	
Tx & Service Boxes - GMT	$ 128,100	**$ 7,531,868**
Capex Network4 NXL: Asset Relocations		
Equipment Relocations - Miscellaneous	$ 10,710	**$ 10,710**
Capex Network5 NXEQ: Quality of Supply		
11kV Fdr Dev - Switch Automation and Renewal	$ 273,000	
Sub & 33 Dev - Substations	$ 52,500	**$ 325,500**
Capex Network7 NXEO: Other Reliability, Safety and Environment		
11kV Fdr Dev - Switchgear for Safety	$ 52,500	
Sub & 33 Dev - Substations	$ 445,200	
Tx & Service Boxes - 2 Pole Structures	$ 212,100	
Tx & Service Boxes - Capital Pillar Boxes	$ 66,150	
Tx & Service Boxes - GMT	$ 141,750	**$ 917,700**
Capex Non-Network8 NXNR: Non System Fixed Assets - Routine		
Eng & Asset Capital - Data Systems	$ 96,390	
Eng & Asset Capital - Metering	$ 2,800,000	
Eng & Asset Capital - Misc Equip	$ 10,710	
Eng & Asset Capital - Office Area	$ 21,420	
Eng & Asset Capital - Vehicle Replacements	$ 68,250	**$ 2,996,770**
Capex Non-Network9 NXNA: Non System Fixed Assets - Atypical		
Eng & Asset Capital - Building Re-structure	$ 1,500,000	**$ 1,500,000**
Total		**$ 16,905,258**

TABLE 5.20 SUMMARY OF CAPITAL EXPENDITURE FOR 2015/16

5.5.1 Overview of Network projects for 2015/16

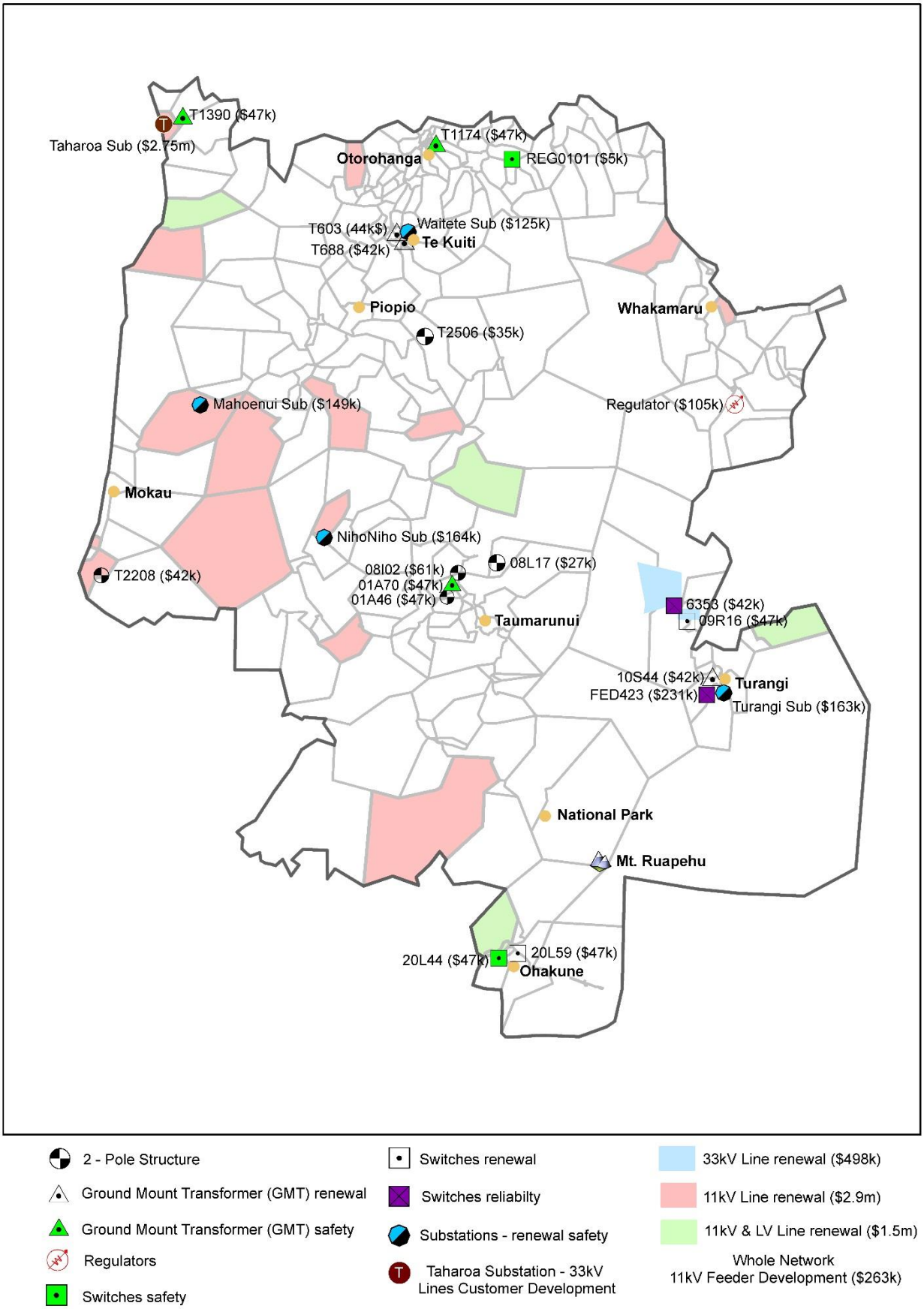


FIGURE 5.10 OVERVIEW OF THE LOCATION OF NETWORK PROJECTS FOR 2015/16

5.5.2 Customer Connection Development Programme 2015/16

5.5.2.1 Customer Connection Project Details

5.5.2.1.1 General New Connections Contributions - $225,225

This allowance is to fund distribution equipment costs associated with new customer connections and includes transformers and fusing at the connection point and other costs. This amount covers the cost of TLC's contribution to new connections. Generally, TLC has a policy of supplying a transformer and substation (including earthing) as its economic contribution to a new connection. These items are included in TLC valuation registers.

The investment is recovered by each customer's low voltage capacity or dedicated transformer charges. The amount of the allowance expended is dependent on the number of new connections.

5.5.2.1.2 Subdivision New connection Contributions - $99,645

TLC supplies transformers and substation components as its capital contribution to new subdivisions. The developer funds the remainder. The substation components are those defined in the 2006 Valuation handbook. The amount of the allowance used is dependent on the number of new subdivisions and the allocation has been reduced due to the downturn in lifestyle and holiday home demand.

The alternative option available to reduce this cost is to install the smallest transformer possible. The TLC charging structure means that customers have initial and on-going incentives to minimise capacity and reduce peaks. The charging structure also encourages the connection of more than three ICPs per transformer.

5.5.2.1.3 Industrial New Connection Contributions -$184,590

TLC supplies various items and recovers these as part of on-going charges to customers when expansions and alterations are taking place. The amount of the allowance used is dependent on the level of industrial development.

The alternative options available to reduce this cost include installing the smallest transformer possible and supplementing with other energy options. The TLC charging structure means that customers have initial and on-going incentives to minimise capacity, reduce peaks and improve power factor. Alternative options for customers include providing energy requirements from alternative sources or providing their own transformers and earthing. Modular substation funded by the customer could be considered.

5.5.2.1.4 Taharoa Expansion -$2,625,000

<u>Scope</u>

The iron sands mine at Taharoa are expanding their operations and require increased security of supply and capacity to meet their needs. This includes both substation ($2,625,000) upgrades and work on the 33kV lines ($120,750). The focus will be upgrading of the supply transformers and switchgear at Taharoa zone substation and improving the reliability of the 33kV lines.

<u>Justification</u>

This project is to meet customer expectations and will be funded in collaboration with the customer. There are two drivers for this; the first being that the iron sands require an increased supply. The second is that the Iron Sands will require an improved level of reliability. This upgrade will also remove hazards associated with the aged existing equipment.

<u>Alternative Options:</u>

There are no alternative options to customer driven development projects.

5.5.3 System Growth Development Programme 2015/16

5.5.3.1 System Growth Project Details

5.5.3.1.1 Conductor Assessment Project- $262,500

Scope

To analysis conductor condition and improve records of what conductor is used across the network. The conductor condition will be analysed by removing small sections to visually inspect.

Justification:

This review is being conducted as a first step in a plan to ensure that the conductor on the network is maintained in a safe and reliable condition.

Alternative Options:

Continue with limited conductor condition information.

5.5.3.1.2 11kV Regulator on Mokai Feeder - $105,000

This is a long feeder supplying dairy load. The increasing dairy load will mean that potentially voltage will drop below regulatory limits. The regulator is planned to be installed on Waihora Road to support the sagging voltage along Whangamata Road.

Voltage regulators are a cost effective method of lifting the voltage on the feeder to alleviate the voltage problems. This is a legacy voltage issue that has to be addressed for compliance.

Justification:

The voltage is getting down to below regulatory limits during peak demands.

Alternative Options:

- Re-conductor with larger conductor; this is an expensive option (About 10km at $100K per Kilometre would be required).
- Install capacitors; however, these will interfere with the present ripple signal.

5.5.4 Other Asset Replacement & Renewal (Excluding Line Renewals) Projects for the 2015/16 year

5.5.4.1.1 Ground Mount Transformer Renewal - $128,100

Three transformers that are reaching end of life are planned to be changed out with modern ground mounted transformers.

The three transformers are:

- 10S44
- T603
- T688

5.5.4.1.2 Transformer Switch Renewal - $94,500

Scope

Two transformers are being replaced with transformers that include RTE switches. This will allow cable sections and the transformers to be isolated. The transformers are:

- 09R16
- 20L59

Justification

At present the transformers cannot be individually isolated. This means that extensive outages are necessary to do relatively minor works. Experience has shown that staff, when faced with this situation, often take risks. A by-product of this project will be improved reliability given that the transformers will be able to be more easily isolated.

Alternative Options

The sites could be left as is.

5.5.4.1.3 Mahoenui Zone Substation- Refurbish - $102,900

Scope

The project involves removal of the transformer to perform a half-life service and replace the rusted fins. The ex-National Park transformer will replace the current transformer that will be serviced. The transformer replacement will coincide with work to install a new circuit breaker.

Justification

Cheaper than letting the transformer rundown and need replacing.

Alternative Options

Replace transformer.

5.5.4.1.4 Ohakune Ripple Control Plant Upgrade - $150,000

Scope

Upgrade the Ohakune Ripple Control Plant to cater for the larger point of supply transformer being installed at Ohakune.

Justification

Without upgrading the ripple control plant the ends of the feeders supplied from Ohakune point of supply will not receive ripple control. This will limit the ability to control load at times of constraint. Load control signals also form an integral part of customer demand side management.

Alternative Options

The plant could be left as is.

5.5.4.1.5 Equipment Renewals - $1,168,125

Equipment renewals covers general non-specific individual equipment renewal contingencies.

5.5.4.1.5.1 Tap-offs with new connections - $35,700

This is a contingency amount set aside each year for the installation of fuses on private line tap-offs or new connections. This protects the network from private line faults. It is a renewals bought forward allowance – i.e. if a tap-off pole needs to be replaced to facilitate a new connection, then TLC may contribute to this via this allowance if the pole was likely to be replaced as part of the next renewal cycle. It is considered unfair to expect a customer to fund the total renewal of a pole if it is in poor condition and likely to be renewed as part of the next cycle of the renewal programme.

5.5.4.1.5.2 Radio Specific - $630,000

TLC is upgrading is radio communication sites. This equipment upgrade is being completed to comply with the regulations of changing from 25 kHz bandwidth to 12.5 kHz bandwidth. The equipment that is used to achieve the upgrade is capable of switched between analogue and digital. An upgrade programme has been prepared by a communications consultant.

5.5.4.1.5.3 Radio Contingency - $12,075

This is a sum set aside per annum to cover any unforeseen capital work on the radio system. TLC owns and operates 20 repeater sites for data and voice communications throughout the network. Each of these sites contains various numbers of radios, batteries, chargers, aerials and other electronic equipment that need to be replaced on an on-going basis as the equipment ages. The data radio system is the backbone of network automation and in recent times there have been a lot of additional remote circuit breakers, substations and other controlled equipment added.

If the radio network fails, communication with various items of remote equipment is lost. When this occurs, load control inputs and signals cannot be sent and automated equipment cannot be communicated with. Potential cost increases come from loss of load control during peaks. When failures occur, various options are considered. The refurbish/renew decision is based on the policies and issues outlined in the preceding sections.

5.5.4.1.5.4 SCADA Contingency - $18,375

This is a sum set aside per annum to cover any unforeseen capital work on the SCADA system. TLC now has automation in some form at approximately 30 zone substations, a distributed generation site, 11 load control plants and about 80 field devices. In addition to operation of field devices the equipment provides the central summation function of system load, generation and dispatch of load control signals.

5.5.4.1.5.5 SCADA Specific – $44,100

This is work to ensure the SCADA system is using the latest software and computers. The organisation has two options with SCADA equipment: either maintain and renew it on an on-going basis or let it run its course and complete a total replacement at the end of the equipment life.

The equipment is at the heart of the operating of the network and the rundown option would have many negative flow-on effects as reliability decreases. Increasing SAIDI would be one of these effects plus increased costs from having to send staff to various sites. The option of maintaining the equipment in a reliable state is currently being followed.

5.5.4.1.5.6 Transformer Renewals $357,000

This is a contingency amount set aside for distribution transformer failure through lightning strikes or either damaged or old units that are uneconomic to refurbish. This allowance also covers refurbishment of recycled transformers.

5.5.4.1.6 Protection & Voltage Relays - $12,075

A contingency amount set aside per annum to cover any protection equipment failure. This contingency is to mostly renew but sometimes refurbish in service equipment on failure. The TLC network has about 150 relays plus a similar number of other tripping and alarming relays in service. Over the past few years a number have failed or been found to be working incorrectly.

5.5.4.1.6.1 Distribution Equipment – $58,800

A contingency amount set aside per annum to cover any distribution equipment failure. TLC owns, and still has in service, some very old switchgear, regulators and other distribution equipment. From time to time units fail and parts to repair the equipment are no longer available. When these events occur, the purpose of the equipment is reviewed and if it is still needed it is replaced with a modern equivalent.

5.5.4.1.7 Load Control Relays - $320,828

One of the weaknesses identified in the constraints section and in earlier AMPs was the implications of old high frequency ripple injection into the Hangatiki and Whakamaru supply points. A full report was put to Directors in July 2008 and they approved the plant renewal in the 2009/10 programme.

The report included a full discussion of operational and financial evaluation. In summary the conclusions were:

- That reliable load control and demand based charges would not be possible without renewal.
- All smart metering solutions deployed to date in New Zealand have continued to use load control systems.
- The long term financial benefit of replacing the plants outweighed the option of not renewing.
- The best technology option was to replace the existing system with a lower frequency ripple system.

The new load control plants are in place and the programme now moves onto relay replacement. It is envisioned that the programme will continue for the next 4 years.

The load control replacement programme was originally planned to start in the 2010/11 year; however, this was delayed due to the intent to combine it with TLC's advanced meter programme rollout. The cost of advanced meters which now include load control relays are such that the installation of a combined unit is similar to that of a legacy relay.

Advanced meter firmware has now been developed to the point that it will read both retailer and TLC demand based charging data and includes the capabilities for future communications and in-home displays.

The allowance included in this Plan is based on the amount it would cost to replace the relays. It is based on a model of a typical relay replacement programme and will form a contribution to the meter rollout; the numbers and costs are not fully funding the meter rollout.

Justification and Scope

TLC requires meters that will operate with the load control signal of the new ripple plants 317Hz decabit signal, which will improve TLC's ability to use demand side management load control.

The network must fund the renewal of relays and the associated administration systems to control these assets. The metering on the network is also substantially owned by a subsidiary company. These meters largely need recertification and renewal under the Electricity Authority's rules. There are about 5500 relays in the northern area that are affected by the load plant change out.

Note: This allocation is a notional amount given that the meters are now inclusive of relays. The notional amount is for the like for like replacement of relays.

For the purpose of planning, the relay exchange cost of $210 per relay inclusive of administration has been included in estimates.

Alternative Option

The alternative options include:

- Not replacing relays and allow the effectiveness of the load control plant to reduce.
- Replacing the mains signal load control system with some other system. Analysis of options has shown that the lowest cost and most effective option is to replace the system with lower frequency load control equipment.

Non Asset Solution

The objective of load control and network constraint signalling is to create the opportunities for non-asset solutions. A non-asset solution may have been to go to some other form of signalling but, at the time the decisions were made, there were no alternative technologies that could provide reliable and effective load control for the TLC network.

5.5.4.1.8 Asset Replacement & Renewal - Line Renewal Expenditure for the next 12 months

The line renewal capital expenditure is primarily associated with replacement and refurbishment of existing lines. This work is to maintain the network and equipment to meet target levels of service. Section 6 covers the full details of the line renewal process and the line renewal schedule. Table 5.21 summarises planned renewal expenditure.

ASSET RENEWAL AND REPLACEMENT LINE RENEWAL CAPITAL EXPENDITURE PREDICTION 2015/16	
Project	**Estimate**
33 kV Line Renewal (includes emergent)	$498,225
11 kV Line Renewals (includes emergent)	$4,321,065
LV Line Renewals (includes emergent)	$748,125
TOTAL	**$5,567,415**

TABLE 5.21 SUMMARY OF LINE RENEWAL CAPITAL EXPENDITURE PREDICTIONS

5.5.5 Asset Relocation Development Programme

This expenditure is primarily associated with relocating assets for road controlling authorities to carry out road works. The amount spent depends on the locations of road works.

A contingency allowance of $10,710 has been included in estimates for 2015/16.

Note: This expenditure may be varied due to the changing legislation for access to railway and road corridors.

5.5.6 Quality of Supply Development Programme

5.5.6.1 Reliability & Security

Programme Objective

The objective of the reliability improvement programme is to bolster reliability and reduce operating costs. Staffing rural depots is expensive and providing efficient workflows for periods when faults are not occurring is difficult. Increased skills specialisation is adding to this difficulty. Network automation speeds restoration and takes away the need to maintain high staffing levels in rural depots to service faults.

The risk assessment analysis indicated that the contingencies are needed for new and end of lifecycle equipment. The ability to support the network with a generator during fault conditions and maintenance projects improves the reliability of the supply to customers, reducing unacceptable outages and producing a saving in customer minutes. Mobile reactive power units are a lower cost way of doing this.

Automation Options

The automation of breakers improves network outage statistics, and has a hidden benefit in that it provides better data for on-going network analysis, including revenue reconciliation, and reduces operating costs.

Projects are aligned with the need to meet reliability objectives and service level standards as detailed in earlier sections. The last customer survey also highlighted customers' expectations of continuously improving supply reliability.

In recent times attracting staff to rural areas and meeting the costs of retaining these people to cover standby rosters have become difficult issues. Three of TLC's rural depots (Ohakune, Turangi and Whakamaru) no longer have enough staff to cover full rosters and the areas have to be covered on alternative week. This means at least a two hour mobilisation delay for the weeks when there is no local cover.

5.5.6.1.1 Turangi Town – 11kV Feeder Tie - $231,000

Scope

Develop an 11 kV link for the Turangi Town Feeder through to Rangipo Hautu 11 kV by bridge on SH 1. This will involve installing an 11kV cable and two automated ring main units.

Justification:

This will give an alternative option to back feed for Turangi town. Further saving will be made by allowing the control room to remotely control the switch and speed fault finding if there is a cable fault in the Turangi area.

Alternative Options

The site could be left as it is. This would mean that TLC would not be able to meet its target service level and improve Network performance.

5.5.6.1.2 Kuratau – Install New Recloser 6353 – $42,000

Scope

The existing sectionaliser at this site means that the whole feeder experiences an auto reclose if the fault is beyond 6353. An automated recloser would allow Kuratau village to be unaffected by faults beyond this recloser.

Justification

Kuratau village is affected by rural outages. An improved level of service will be beneficial to these customers. The installation of a recloser will allow quicker power restoration to more densely populated areas. Further saving will be made by allowing the control room to remotely control the switch and decrease the fault-man's travelling time when fault finding and sectionalising.

Alternative Options

The site could be left as it is. This would mean that TLC would not be able to meet its target service level and improve Network performance.

5.5.6.1.3 Waitete Zone Substation – 33kV Circuit Breaker - $52,500

Scope

Install 33kV circuit breaker at Waitete zone substation.

Justification:

Te Kuiti Town is affected by outages on the Waitete 33kV line from Hangatiki. The additional circuit breaker will allow for the full advantage of the current closed ring configuration. This will allow for uninterrupted supply to Waitete zone substation when there is a fault on either 33kV line.

Alternative Options

The site could be left as it is. This would mean that TLC would not be able to meet its target service level and improve Network performance.

5.5.6.2 Hazardous Equipment Renewals (Safety)

Hazardous equipment renewals include renewals for reliability, safety and environmental reasons but does not cover line renewal.

5.5.6.2.1 Zone Substation Hazard Minimisation Projects

5.5.6.2.1.1 Nihoniho Zone Substation – Replace 11kV switchgear and install 33kV circuit breaker – $163,800

Scope

The 11kV aerial bus at Nihoniho is deteriorating and has become a safety concern. This will be replaced with new 11kV switchgear. A new 33kV circuit breaker is to be installed on site.

Justification

The current aerial 11kV switch gear is old and unable to be easily repaired. There is currently no 33kV protection on site, installing this along with the 11kV switchgear will bring the site up to modern protection standards.

Alternative Options

There are no alternative options if we are going to have reliable protection at zone substations.

5.5.6.2.1.2 Turangi Zone Substation – Upgrade 11kV switchgear – $163,800

Scope

Add additional 11 kV switchgear. Install 4 way ring main unit and leave existing reclosers. Upgrade protection schemes to ensure primary and backup protection is reliable.

Justification

The present switchgear arrangement is complex, non-standard and consists of old components not designed for the job they are doing. This upgrade will minimise hazards and improve reliability.

Alternative Options

Leave as is with confusing arrangement for field staff.

5.5.6.2.1.3 Waitete Zone Substation – Replace fence – $72,450

Scope

Replace zone substation fence.

Justification

The current fence is aging and further deterioration could cause a security breach.

Alternative Options

There are no alternative options to maintain a safe and secure site.

5.5.6.2.1.4 Mahoenui Zone Substation – Install new 33kV breaker – $46,200

Scope

Install new 33kV breaker in conjunction with swapping out the transformer that needs to be overhauled due to corroding cooling fins.

Justification

The 33kV breaker will allow for more reliable protection at site.

Alternative Options

There are no alternative options if we are going to have reliable protection at zone substations.

5.5.6.2.2 Feeder and Switchgear Hazard Minimisation Projects – $52,500

There are two switchgear related hazard minimisation projects for 2015/16. The first involves installing a ring main unit at 20L44. This is break up the daisy chained transformers that cannot be individually isolated.

The second is to install bypass protection on Regulator 1 on the Maihiihi feeder. This involves installing a fuse before the bypass switch to prevent excessive currents if the switch is mistakenly closed while the regulator is not in the neutral tap. Without protection the regulator is likely to be damaged.

5.5.6.2.3 Two Pole Structure Hazard Minimisation Projects – $212,100

Low two pole structures have been identified and prioritised for renewal given that they present hazards to staff and the public. They support equipment that is low to the ground, close to fences and the like, that can be climbed and are hazardous for staff to work on. Priority has been given to sites in residential areas.

The following two pole structures will be upgraded in the first year:

- 01A46 Northern Feeder
- 08I02 Northern Feeder
- 08L17 Manunui Feeder
- T2208 Mokau Feeder
- T2506 Benneydale Feeder

5.5.6.2.4 Ground Mounted Transformer Hazard Minimisation Projects – $141,750

There are a number of ground mounted transformers that need to be replaced due to safety concerns. These transformers are either old ground mounted transformers with exposed unprotected cables or pole mount style transformers with exposed bushings installed in small sheds. Priority is given to transformers in residential areas and where there is higher chance of public exposure.

The following transformers will be upgraded in the first year:

- 01A70 – Turangi Feeder – Transformer replacement
- T1174 – Otorohanga Feeder – Transformer replacement
- T1390 – Rural Feeder – Transformer replacement

5.5.6.2.5 Pillar Box Hazard Minimisation Projects – $66,150

There are 30 sites planned for renewal in the 2015/16 year. TLC owns 4020 pillar boxes; these pillars are inspected every 5 years. Those pillars that do not comply with TLC's current standards are programmed into the renewal programme, which targets the worst of the pillar boxes first. These pillars are renewed with a ground mounted pillar that can be padlocked or, if the location of the pillar is one that is repeatedly struck by vehicles, then a flush type pillar is selected.

5.5.7 Non-System Fixed Asset

The scope of work for non-system fixed assets is associated with upgrade and procurement of the asset management systems, office equipment, motor vehicles, tools and plant. TLC cannot forward plan for these.

An Allowance of $196,770 p.a. has been included for the planning period.

5.5.7.1 Meter Purchase – $2,800,000

An allowance of $2,800,000 is included for the continuation of the roll out of advanced meters onto the network.

5.5.7.2 Atypical Non-system Fixed Assets – $1,500,000

This provision of $3,000,000 split over two years for either renovating the existing office or establishing a new building. It is possible that the refurbishment costs for the current building to reach building code requirements that allow for security of a control room environment will exceed that of new construction.

5.6 Summary Description of the Projects Planned for the next 4 years (2016/17 to 2019/20)

5.6.1 Unknowns

The unknowns that will affect plans are:

- Distributed generation development – if new schemes will be developed.
- Customer development – rural, residential, industrial and ski field.
- Network unknowns – An aged network will have unplanned and unexpected problems.
- Project unknowns – weather, landowners, resource shortage, access, and other factors will affect projects.
- Industry issues – compliance etc.
- Customers' ability to pay increased charges to fund the renewals.
- Political and other influences such as economic cycles.
- Other events unknown at this time. (e.g. natural disasters)

The estimates will be influenced by levels of economic activity and future energy prices. For example, there are unknowns with the distributed generation proposals and the network upgrades that would be required to connect this plant.

5.6.2 Summary of Expenditure Predictions 2016/17 to 2019/20 in disclosure categories

A summary of the disclosure categories expenditure predictions (without inflation) is listed below (Table 5.22).

Capital Expenditure Summary 2016/17 to 2019/20				
	2016/17	2017/18	2018/19	2019/20
Capex Network1 NXC: Consumer Connection				
Sub & 33 Dev - Substations	$ 2,625,000	$ 420,000	$ -	$ -
Transformers - General Connections	$ 274,995	$ 274,995	$ 274,995	$ 274,995
Transformers - Industrials	$ 229,845	$ 229,845	$ 229,845	$ 229,845
Transformers - Subdivisions	$ 132,930	$ 132,930	$ 132,930	$ 132,930
	$ 3,262,770	**$ 1,057,770**	**$ 637,770**	**$ 637,770**
Capex Network2 NXS: System Growth				
11kV Fdr Dev - Feeder Development	$ 711,900	$ 147,000	$ 771,750	$ 105,000
Regulators	$ 105,000	$ 105,000	$ 105,000	$ 105,000
Sub & 33 Dev - 33kV Lines	$ 299,250	$ -	$ -	$ -
Sub & 33 Dev - Substation			$ 483,000	$ 742,500
Sub & 33 Dev - Supply Points		$ 1,575,000	$ 420,000	
	$ 1,116,150	**$ 1,827,000**	**$ 1,779,750**	**$ 934,500**
Capex Network3 NXR: Asset Replacement and Renewal				
11kV Fdr Dev - Switch Automation and	$ 669,900	$ 52,500	$ 94,500	$ 47,250
11kV Planned Line Renewals	$ 4,022,025	$ 5,434,590	$ 4,974,165	$ 4,968,915
33kV Planned Line Renewals	$ 701,925	$ 1,050,000	$ 1,236,900	$ 2,102,100
Equipment Renewals	$ 1,000,125	$ 582,225	$ 582,225	$ 702,975
LV Planned Line Renewals	$ 631,575	$ 597,450	$ 783,825	$ 301,350
Relay Changes	$ 68,828	$ 37,328	$ 16,328	$ -
Sub & 33 Dev - Supply Points	$ 714,000	$ -	$ -	$ -
Tx & Service Boxes - GMT	$ 123,900	$ 130,200	$ 164,115	$ 130,200
	$ 7,932,278	**$ 7,884,293**	**$ 8,013,758**	**$ 8,252,790**
Capex Network4 NXL: Asset Relocations				
Equipment Relocations - Miscellaneous	$ 10,710	$ 10,710	$ 10,710	$ 10,710
	$ 10,710	**$ 10,710**	**$ 10,710**	**$ 10,710**
Capex Network5 NXEQ: Quality of Supply				
11kV Fdr Dev - Switch Automation and	$ 183,750	$ 194,250	$ 210,000	$ 183,750
	$ 183,750	**$ 194,250**	**$ 210,000**	**$ 183,750**
Capex Network7 NXEO: Other Reliability, Safety and Environment				
11kV Fdr Dev - Switchgear for Safety	$ 52,500	$ 147,000	$ 52,500	$ 52,500
Sub & 33 Dev - Substations	$ 49,350	$ 47,250	$ 17,850	$ -
Tx & Service Boxes - 2 Pole Structures	$ 253,050	$ 221,550	$ 216,300	$ 263,550
Tx & Service Boxes - GMT	$ 164,850	$ 145,950	$ 105,000	$ 144,900
	$ 519,750	**$ 561,750**	**$ 391,650**	**$ 460,950**
Capex Non-Network8 NXNR: Non System Fixed Assets - Routine				
Eng & Asset Capital - Data Systems	$ 96,390	$ 96,390	$ 96,390	$ 96,390
Eng & Asset Capital - Metering	$ 2,800,000	$ 1,500,000	$ -	$ -
Eng & Asset Capital - Misc Equip	$ 10,710	$ 10,710	$ 10,710	$ 10,710
Eng & Asset Capital - Office Area	$ 21,420	$ 21,420	$ 21,420	$ 21,420
Eng & Asset Capital - Vehicle Replacements	$ 68,250	$ 68,250	$ 68,250	$ 68,250
	$ 2,996,770	**$ 1,696,770**	**$ 196,770**	**$ 196,770**
Capex Non-Network9 NXNA: Non System Fixed Assets - Atypical				
Eng & Asset Capital - Building Re-structure	$ 1,500,000	$ -	$ -	$ -
	$ 1,500,000	**$ -**	**$ -**	**$ -**
Total	**$ 17,522,178**	**$ 13,232,542**	**$ 11,240,408**	**$ 10,894,590**

TABLE 5.22 SUMMARY OF CAPITAL EXPENDITURE FORECAST 2016/17 TO 2019/20

5.6.3 Overview of Network projects for 2016/17 to 2019/20

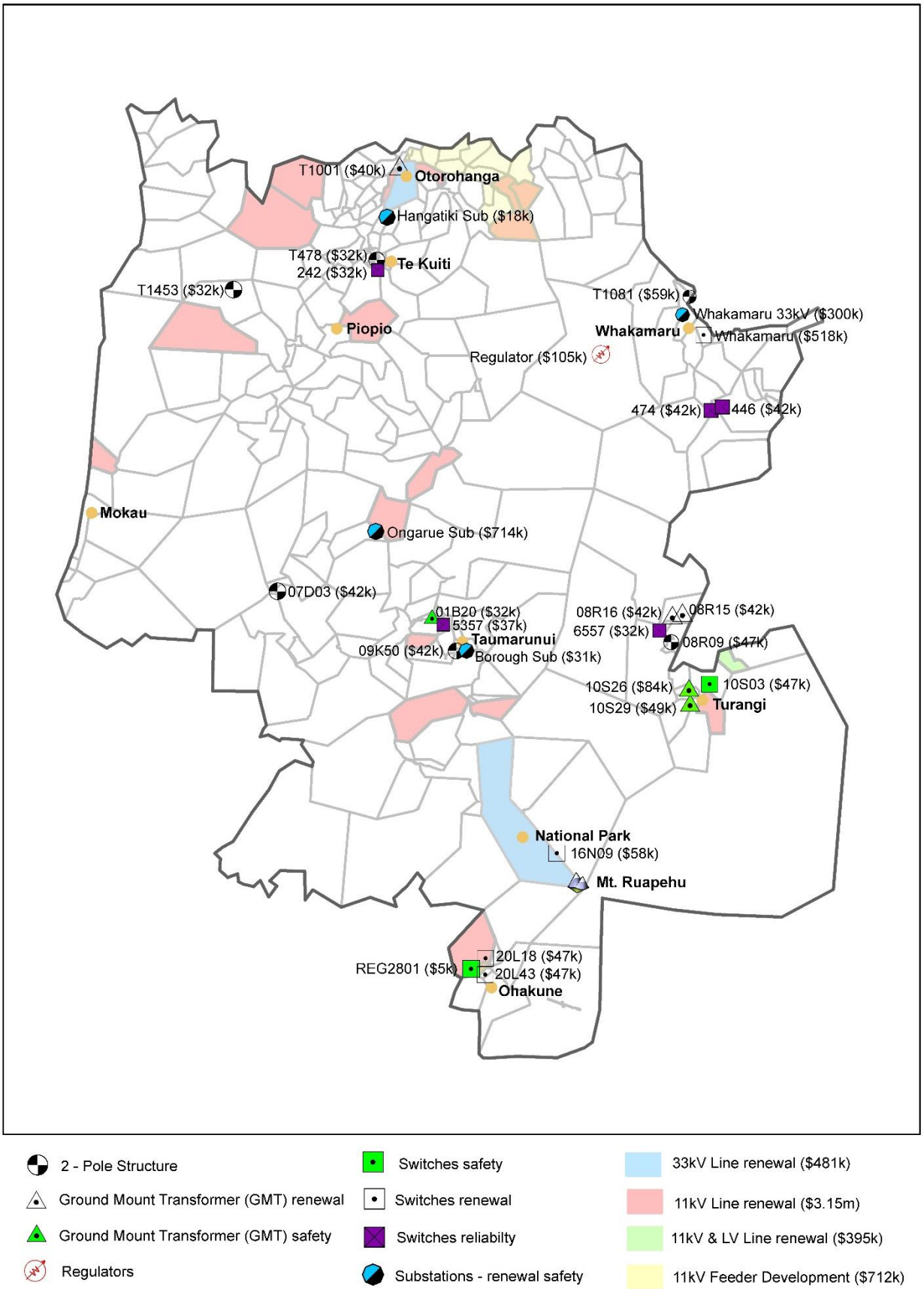


FIGURE 5.11 OVERVIEW OF THE LOCATION OF NETWORK PROJECTS FOR 2016/17

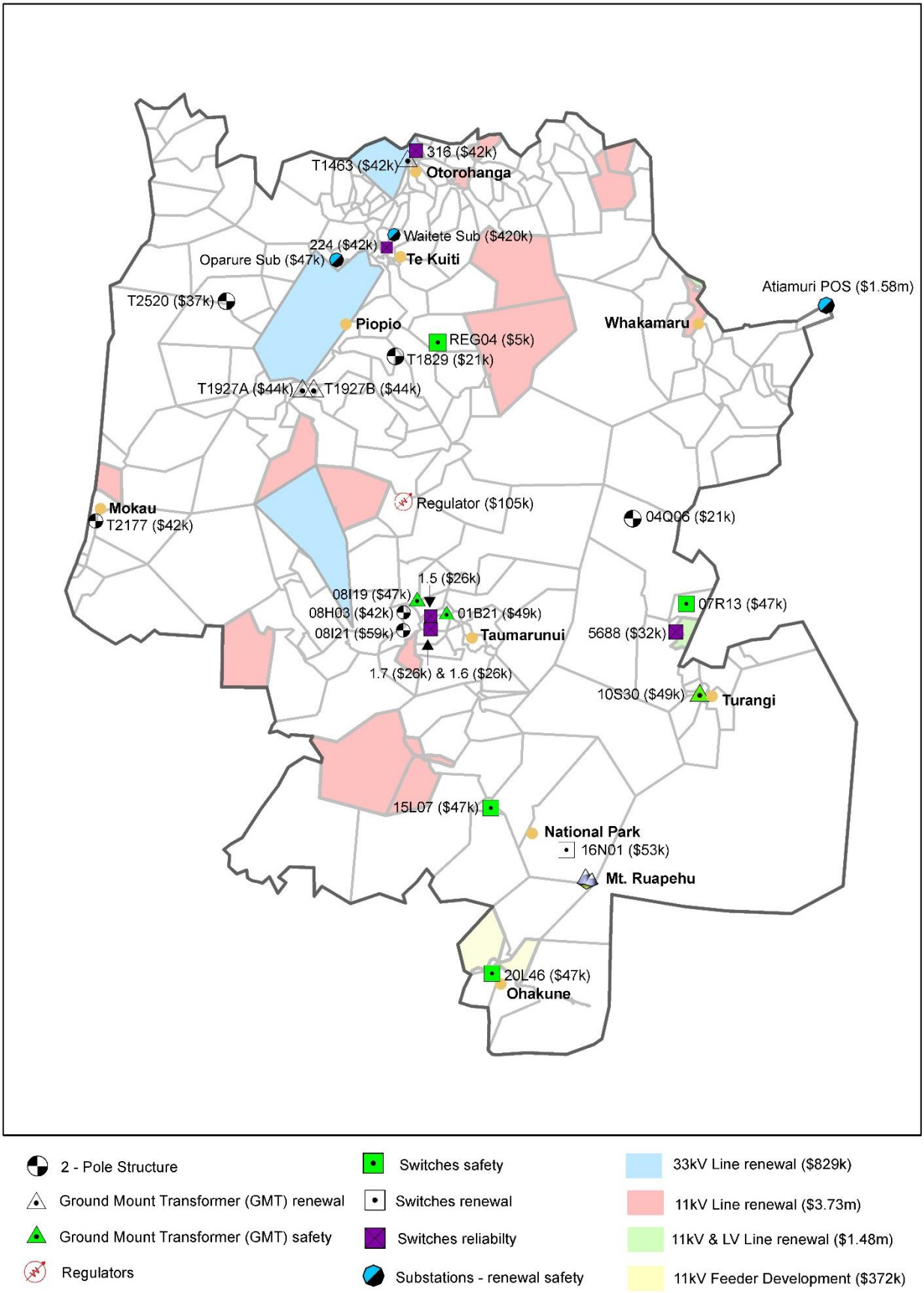


FIGURE 5.12 OVERVIEW OF THE LOCATION OF NETWORK PROJECTS FOR 2017/18

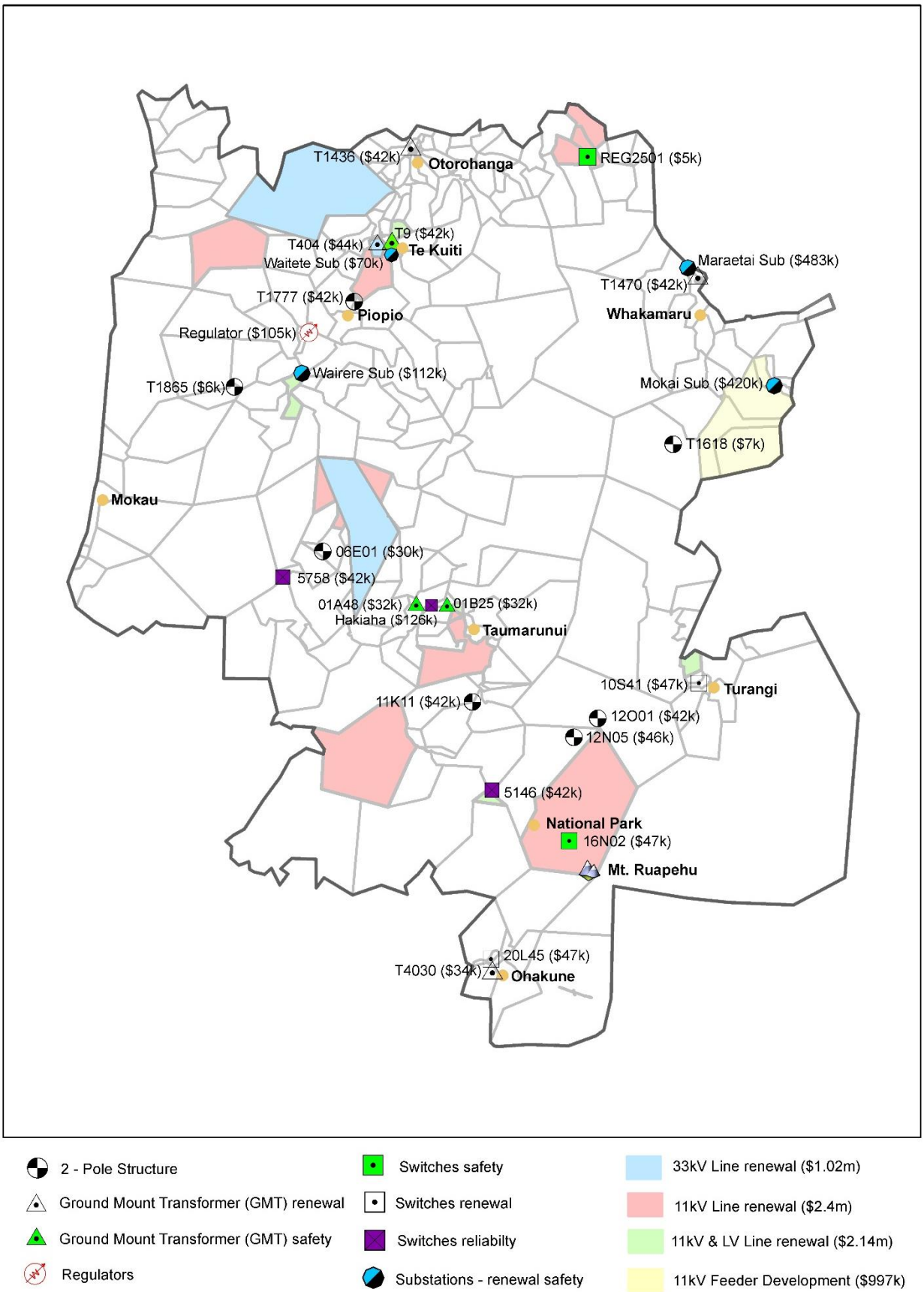


FIGURE 5.13 OVERVIEW OF THE LOCATION OF NETWORK PROJECTS FOR 2018/19

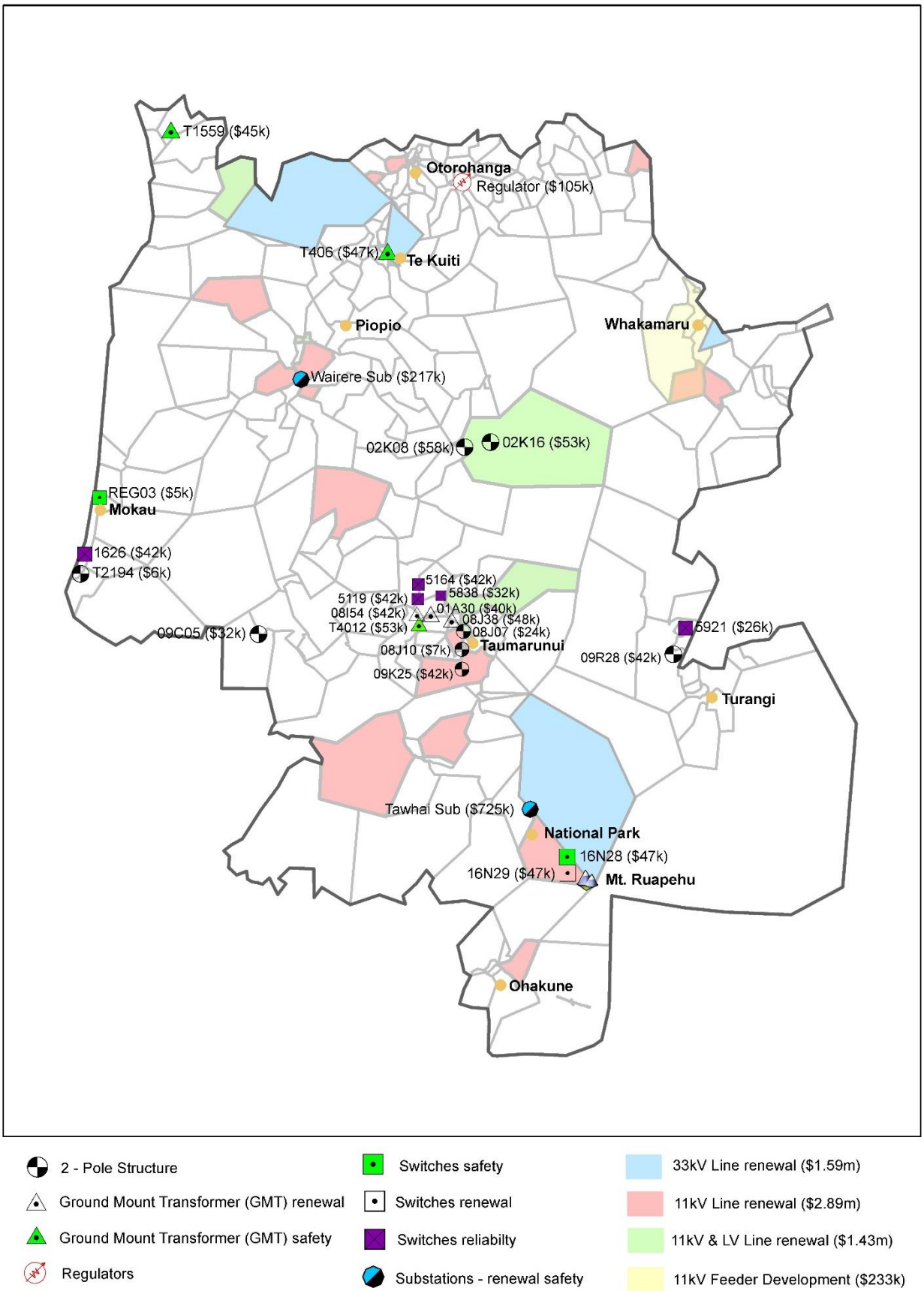


FIGURE 5.14 OVERVIEW OF THE LOCATION OF NETWORK PROJECTS FOR 2019/20

5.6.3.1 Customer Connection Capital Expenditure Predictions

5.6.3.1.1 Customer Connection – Substations

5.6.3.1.1.1 Taharoa Zone Substation – $2,625,000 – 2016/17

An allowance has been included for the continuation of the upgrading of Taharoa substation in conjunction with an expanded and a more reliability critical Iron Sand operation.

There are two drivers for this; the first being that the iron sands require an increased supply. The second is that the Iron Sands will require an improved level of reliability. This upgrade will also remove hazards associated with the aged existing equipment.

5.6.3.1.1.2 Waitete Zone Substation – $420,000 – 2017/18

An allowance has been included for the installation of a modular substation to supply industrial sites, this is contingent on customer expansion plans.

5.6.3.1.2 General Connections, Industrials and Subdivisions

General, Subdivision and Industrial Connection Expenditure includes earthing, substations, points of connection, isolation/protection, transformers, switchgear and other items associated with general, subdivision and industrial new connections. The allocation for connections have been rolled forward at expected levels ($637,770 per annum).

5.6.3.2 System Growth Capital Expenditure Predictions

5.6.3.2.1 Scope of Specific Projects for 2016/17

5.6.3.2.1.1 11kV Feeders – $711,900

Maihiihi Feeder – Upgrade conductor at the start of the feeder to improve feeder strength and voltage profile.

Ohakune Town Feeder – Renew aging cable in Ohakune Town.

5.6.3.2.1.2 33kV Feeders – $299,250

Install an additional voltage regulator on the Whakamaru 33 kV line near Maraetai zone substation to boost the voltage, especially when back feeding from Atiamuri supply point.

5.6.3.2.1.3 Regulators – $105,000

An allowance for an additional voltage regulator on the Pureora feeder to improve the voltage at the end of the feeder that supply's Crusader Meats.

5.6.3.2.2 Scope of Specific Projects for 2017/18

5.6.3.2.2.1 11 kV Feeders – $147,000

Turoa Feeder – Upgrade Cu 16mm Cu XLPE cable between Magnefix switch 6420 and transformer 20L18 to a feeder strength sized cable. This is to allow effective back feeding to Ohakune Town Feeder.

Turoa Feeder – Redesign over LV and HV configuration for Rangataua. Check loading of all transformers including 20M09. Assess LV wire size and extending LV. Work to alleviate Low voltage problems and possible development of empty sections.

Ohakune Town – Re-conductor from ferret to dog between 6644 and 6444 on Ayr Street. This is to address voltage drop issues in Ohakune town during peak loading.

5.6.3.2.2.2 Regulators – $105,000

An allowance for a regulator on the Ongarue feeder to support voltage towards the end of the feeder.

5.6.3.2.2.3 Supply Point – $1,575,000

Due to limited backup supply in the Whakamaru area a supply from Transpower at Whakamaru on the 220 kV or Mokai's 110 kV supply connection at Whakamaru has been included in the plan. This will allow for continued expansion in the area that is currently limited by the backup supply capacity from Atiamuri. An alternative option would be to upgrade the transformer at Atiamuri although this would also require an upgrade of the conductor to supply the higher capacity. An alternative option that will be considered is taking a supply directly from one of the nearby hydro generators (Maraetai or Whakamaru). This will require in depth analysis to determine the optimal solution. A non-network solution is the use of generators during peak loadings. A new point of supply at Whakamaru is the most cost effective solution.

5.6.3.2.3 Scope of Specific Projects for 2018/19

5.6.3.2.3.1 11kV Feeders – $771,750

Mokai Feeder – Re-conductor Tirohanga Road near injection pumps to Okama Rd. 7 km of line to Mink. This allows for better back feed options and more security of supply.

5.6.3.2.3.2 Regulators – $105,000

An allowance for a regulator on the Piopio feeder to support growth in Piopio town and surrounding area.

5.6.3.2.3.3 Substations – $483,000

The allowance is for a modular substation on Sandel Road in Whakamaru to alleviate the voltage problems in the surrounding area. A non-network option includes the use of generators to support voltage during heavy loading. A modular substation is the most cost effective long term solution.

5.6.3.2.3.4 Supply Points – $420,000

Install a load control plant at Mokai, to provide load control when supplying the network from Mokai.

5.6.3.2.4 Scope of Specific Projects for 2019/20

5.6.3.2.4.1 11kV Feeder Development – $105,000

Whakamaru Feeder – An allowance to renew the conductor at the start of the feeder. To improve the voltage profile of the feeder.

5.6.3.2.4.2 Regulators – $105,000

Gravel Scoop Feeder – An allowance to install regulator to support Lurman Rd area and for back feeding Maihiihi Feeder.

5.6.3.2.4.3 Substations – $742,500

An allowance to install a second transformer at Tawhai if the load on the Whakapapa ski field continues to increase. This will also provide N-1 security outside of peak demand periods. A non-network option considered is the use of generators to support the load during peak times.

5.6.3.3 Asset Replacement & Renewal excluding Line Renewal Capital Expenditure Predictions

5.6.3.3.1 Ground Mount Transformer Renewal

Transformers that are reaching end of life are planned to be changed out with modern transformers.

5.6.3.3.1.1 Ground Mount Renewals 2016/17 – $123,900

- 08R15 – Waihaha Feeder
- 08R16 – Waihaha Feeder
- T1001 – Mc Donalds Feeder

5.6.3.3.1.2 Ground Mount Renewals 2017/18 – $130,200

- T1927A – Otorohanga Feeder
- T1927B – Otorohanga Feeder
- T1463 – Mokauiti Feeder

5.6.3.3.1.3 Ground Mount Renewals 2018/19 – $161,700

- T404 – Otorohanga Feeder
- T4030 – Whakamaru Feeder
- T1470 – Tangiwai Feeder
- T1436 – Oparure Feeder

5.6.3.3.1.4 Ground Mount Renewals 2019/20 – $130,200

- 01A30 – Hakiaha Feeder
- 08I54 – Northern Feeder
- 08J38 – Manunui Feeder

5.6.3.3.2 Transformer Related Switch Renewal

The scope of works and justification for the following transformer related switch renewals is in line with what is discussed earlier in this section.

Installation of ring main units in association with transformer replacements:

- 16N09 – Chateau Feeder – 2016/17
- 16N01 – Chateau Feeder – 2017/18

Installation of ring main units:

- 20L18 – Ohakune Town Feeder 2016/17

Installation of new transformers with RTE switches:

- 20L43 – Tangiwai Feeder – 2016/17
- 10S41 – Turangi Feeder – 2018/19
- 20L45 – Tangiwai Feeder – 2018/19
- 16N29 – Chateau Feeder – 2019/20

Other works include major reticulation renewal work planned for the Whakamaru old hydro village in 2016/17. The reticulation is old and hazardous. The houses are directly connected to the low voltage reticulation with no isolation equipment at the point of supply. The proposal is to address this issue and also install a 300 kVA transformer at site T2523 and remove units T2524 and T2521. Through-joint at T2523 and 2525 and replace LV cable around village with 4c Cable and pillar boxes.

5.6.3.3.3 Substation Renewals

5.6.3.3.3.1 Waitete – $69,615 in 2018/19

Replace bulk oil circuit breakers due to age, reliability and condition. Spare parts are no longer able to be obtained to maintain these circuit breakers.

5.6.3.3.3.2 Wairere – $94,500 in 2018/19

Refurbish transformer T1 to increase its expected life cycle and to ensure continued reliability. This is more cost effective than replacing the transformer.

5.6.3.3.4 Equipment Renewals

General non-specific individual equipment renewal contingencies for the next four years are summarised in Table 5.23.

EQUIPMENT RENEWAL CAPITAL EXPENDITURE PREDICTIONS 2016/17 to 2019/20				
Category	**2016/17**	**2017/18**	**2018/19**	**2019/20**
Radio Specific	$462,000	$44,100	$44,100	$44,100
Radio Contingency	$12,075	$12,075	$12,075	$12,075
SCADA Specific	$44,100	$44,100	$44,100	$44,100
SCADA Contingency	$18,375	$18,375	$18,375	$18,375
Tap-offs with new connections	$35,700	$35,700	$35,700	$35,700
Load Control				$120,750
Transformer Renewals	$357,000	$357,000	$357,000	$357,000
Protection	$12,075	$12,075	$12,075	$12,075
Distribution Equipment	$58,800	$58,800	$58,800	$58,800
TOTAL	**$1,000,125**	**$582,225**	**$582,225**	**$582,225**

TABLE 5.23 EQUIPMENT RENEWAL EXPENDITURE FORECAST FOR 2016/17 TO 2019/20

5.6.3.3.4.1 Radio Specific

On-going upgrade of the radio system to comply with new spectrum requirements. This will involve upgrading TLC communications to a digital network.

5.6.3.3.4.2 Radio Contingency – $18,375 p.a.

This is a contingency amount per annum for replacing radio equipment on failure. From time to time water gets into aerials and lightning destroys repeaters.

5.6.3.3.4.3 SCADA Specific – $44,100 p.a.

Annual allowance based on recommendations from SCADA experts to keep equipment up to date.

5.6.3.3.4.4 SCADA Contingency – $18,375 p.a.

This is a contingency amount per annum for replacing failed SCADA equipment.

5.6.3.3.4.5 Tap-offs with New Connections – $35,700 p.a.

This is a contingency amount per annum to cover brought forward renewals associated with replacing poles when new customer connections are taking place.

5.6.3.3.4.6 Load Control – $120,750 in 2019/20

This is an amount for renewals and upgrades to the load control plants.

5.6.3.3.4.7 Distribution Transformer Renewals – $357,000 p.a.

This is a contingency amount per annum for renewal of transformers that are uneconomic to repair. Typically units are renewed when repair cost is greater than regulatory value: see earlier sections for criteria details.

5.6.3.3.4.8 Protection – $12,075 p.a.

This is a contingency amount per annum for replacing relays and voltage control equipment on failure.

5.6.3.3.4.9 Distribution Equipment Contingency – $58,800 p.a.

This is a contingency amount per annum for failed equipment. (Typically circuit breakers and regulators.)

5.6.3.3.5 Load Control Relays

Expenditure is for the continuation with the upgrade of relays to the advanced meter type within TLC's network as described in the preceding section.

5.6.3.3.6 Supply Points – $714,000 in 2016/17

Expenditure is for the rationalisation of the number of outgoing feeder breakers in 2016/17. This reduces the number of circuit breaker from 3 to 2 by putting breakers on Taumarunui and Tuhua and removing Nihoniho. This allows splitting of feeders and isolation of Transpower Supply. The alternative to this is to maintain the current network configuration.

5.6.3.4 Asset Replacement & Renewal – Line Renewal Capital Expenditure Predictions

The Line Renewal planning process and schedule is detailed in section 6. A summary of the proposed expenditure for the next four years is shown in Table 5.24.

ASSET RENEWAL AND REPLACEMENT – LINE RENEWAL EXPENDITURE PREDICTIONS 2016/17 to 2019/20				
Projects	**2016/17**	**2017/18**	**2018/19**	**2019/20**
33 kV Line Renewal (includes emergent)	$701,925	$1,050,000	$1,236,900	$2,102,100
11 kV Line Renewals (includes emergent)	$4,022,025	$5,434,590	$ 4,974,165	$4,968,915
LV Line Renewals (includes emergent)	$631,575	$597,450	$727,125	$301,350
TOTAL	**$5,355,525**	**$7,082,040**	**$6,938,190**	**$7,372,365**

TABLE 5.24 ASSET REPLACEMENT AND RENEWAL – LINE RENEWAL CAPITAL EXPENDITURE FORECAST FOR 2016/17 TO 2019/20

5.6.3.5 Asset Relocation Capital Expenditure Predictions

The scope of works for asset relocations is associated with road re-alignments and relocations of lines when slips occur. TLC cannot forward plan for these.

An allowance of $10,710 p.a. has been included for the planning period.

There are usually no non-asset solutions that can be used for asset relocations. Projects are justified as part of compliance.

5.6.3.6 Quality of Supply Capital Expenditure Predictions

5.6.3.6.1 Quality of Supply

There are no known non-asset solutions for automated switches. The justification for the projects is that customers expect a reliable supply and these sites will improve reliability for customers in the area.

5.6.3.6.1.1 Scope of Specific Projects for 2016/17 – $183,750

- 474 – Mokai Feeder – Upgrade to modern recloser
- 446 – Mokai Feeder – Upgrade to modern recloser
- 5357 – Matapuna Feeder – Automate switch
- 6557 – Kuratau Feeder – Automate switch
- 242 – Oparure Feeder – Automate switch

5.6.3.6.1.2 Scope of Specific Projects for 2017/18 – $194,250

- 224 – Rangitoto Feeder – New recloser
- 316 – Otorohanga Feeder – New recloser
- 5688 – Kuratau Feeder – Automate switch
- 1.5, 1.6 and 1.7 – Matapuna – Replace SDAF with modern ring main unit

5.6.3.6.1.3 Scope of Specific Projects for 2018/19 – $210,000

- 11 kV tie in Taumarunui between Matapuna and Hakiaha Feeders adjacent to rail bridge where the feeder come within a few metres of one another.
- 5758 – Ohura Feeder – Replace sectionaliser with recloser
- 5146 – National Park Feeder – New recloser

5.6.3.6.1.4 Scope of Specific Projects for 2019/20 – $401,100

- Wairere zone substation – Install 5MVAR of capacitor to support voltage during heavy load times.
- 5119 – Northern Feeder – Upgrade to modern recloser
- 5164 – Northern Feeder – Upgrade to modern recloser
- 1626 – Mokau Feeder – Replace sectionaliser with recloser
- 5838 – Matapuna Feeder – Automate switch
- 5921 – Kuratau Feeder – Automate switch

5.6.3.6.2 Hazard Elimination/Minimisation (Safety)

There are no non-asset alternatives to the network having to be hazard controlled for the public and staff. The following projects have very similar scopes and justifications to safety projects discussed earlier in this section.

Scope of Specific Projects for 2016/17 – $470,400

Two pole transformer structures programmed for safety improvements include:

- 07D03 – Ohura Feeder
- 08R09 – Kuratua Feeder
- 09K50 – Southern Feeder
- T1081 – Mangakino Feeder
- T1435 – Mahoenui Feeder
- T478 – Te Kuiti South Feeder

Ground mounted transformers programmed for safety improvements include:

- 10S26 – Turangi Feeder – Includes replacement of switchgear on site.
- 01B20 – Matapuna Feeder
- 10S29 – Turangi Feeder

Switches to be installed in association with transformers programmed for safety improvements include:

- 10S03 – Rangipo / Hautu Feeder
- REG 28 – Turoa Feeder

Scope of Specific Projects for 2017/18 – $514,500

Two pole transformer structures programmed for safety improvements include:

- 04Q06 – Waihaha Feeder
- 08H03 – Western Feeder
- 08I21 – Western Feeder
- T1829 – Te Mapara Feeder
- T2177 – Mokau Feeder
- T2520 – Mahoenui Feeder

Ground mounted transformers programmed for safety improvements include:

- 01B21 – Matapuna Feeder
- 08I19 – Northern Feeder
- 10S30 – Turangi Feeder

Switches to be installed in association with transformers programmed for safety improvements include:

- 07R13 – Waihaha Feeder
- 15L07 – National Park Feeder
- 20L46 – Tangiwai Feeder
- REG 04 – Benneydale Feeder

Scope of Specific Projects for 2018/19 – $373,800

Two pole transformer structures programmed for safety improvements include:

- 06E01 – Nihoniho Feeder
- 11K11 – Southern Feeder
- 12N05 – National Park Feeder
- 12I01 – Otukou Feeder
- T1618 – Tihoi Feeder
- T1865 – Mahoenui Feeder
- T1777 – Te Mapara Feeder

Ground mounted transformers programmed for safety improvements include:

- 01A48 – Northern Feeder
- 01B25 – Matapuna Feeder
- T9 – Oparure Feeder

Switches to be installed in association with transformers programmed for safety improvements include:

- 16N02 – Chateau Feeder
- REG 25 – Wharepapa Feeder

Scope of Specific Projects for 2019/20 – $460,950

Two pole transformer structures programmed for safety improvements include:

- 02K08 – Ongarue Feeder
- 02K16 – Ongarue Feeder
- 08J07 – Manunui Feeder
- 08J10 – Manunui Feeder
- 09C05 – Ohura Feeder
- 09K25 – Southern Feeder
- 09R28 – Kuratau Feeder
- T2194 – Mokau Feeder

Ground mounted transformers programmed for safety improvements include:

- T1559 – Rural Feeder
- T4012 – Western Feeder
- T406 – Waitomo Feeder

Switches to be installed in association with transformers programmed for safety improvements include:

- 16N28 – Chateau Feeder
- REG 03 – Mokau Feeder

5.6.3.6.3 Environmental

There are no known non-asset solutions. The justification is environmental compliance and TLC being a responsible corporate citizen. Oil spills into nearby rivers would also attract fines and clean-up costs. The following zone substations are programed to have oil separation installed:

- Borough Zone Substation – 2016/17 – $31,500
- Hangatiki Zone Substation – 2016/17 – $17,850
- Oparure Zone Substation – 2017/18 – $47,250
- Wairere Zone Substation – 2018/19 – $17,850

5.6.3.7 Non-System Fixed Asset

The scope of work for non-system fixed assets is associated with upgrade and procurement of the asset management systems, office equipment, motor vehicles, tools and plant. TLC cannot forward plan for these. An Allowance of $196,770 p.a. has been included for the planning period.

$2,800,000 and $1,500,000 have also been allocated in 2016/17 and 2017/18 respectively for the continuation of the advanced meter roll out.

$1,500,000 has been allocated in 2016/17 for the continuation of the building replacement or renewal.

5.7 High Level Description of Projects Being Considered for Remainder of Planning Period

A detailed constraint analysis of the network is included in earlier sections of the Plan. These projects are modelled in detail for the 10 year planning period. Earlier sections provide in depth detail of this programme for the 2015/16 year and summary for the 2016/17 to 2019/20 years. The final years of the planning period are summarised in Table 5.25 below. Major projects for the final years of the planning period are outlined in the following sub sections. These are either financially significant projects (>$400,000) or projects that will significantly affect network configuration or operation.

Capital Expenditure Summary 2020/21 to 2024/25					
Capital Expenditure	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**
Capex Network1 NXC: Consumer Connection	637,770	1,057,770	637,770	637,770	637,770
Capex Network2 NXS: System Growth	1,459,500	1,128,750	899,850	1,277,850	1,181,250
Capex Network3 NXR: Asset Replacement and Renewal	7,860,825	8,024,100	8,340,465	6,715,275	7,025,025
Capex Network4 NXL: Asset Relocations	10,710	10,710	10,710	10,710	10,710
Capex Network5 NXEQ: Quality of Supply	236,250	220,500	189,000	215,250	173,250
Capex Network7 NXEO: Other Reliability, Safety and Environment	1,015,350	895,650	436,800	862,050	597,450
Capex Non-Network8 NXNR: Non System Fixed Assets - Routine	196,770	196,770	196,770	196,770	196,770
Total	**$11,417,175**	**$11,534,250**	**$10,711,365**	**$9,915,675**	**$9,822,225**

TABLE 5.25 SUMMARY OF CAPITAL EXPENDITURE FOR 2020/21 TO 2024/25

5.7.1 Overview of Network projects for 2021/22 to 2024/25

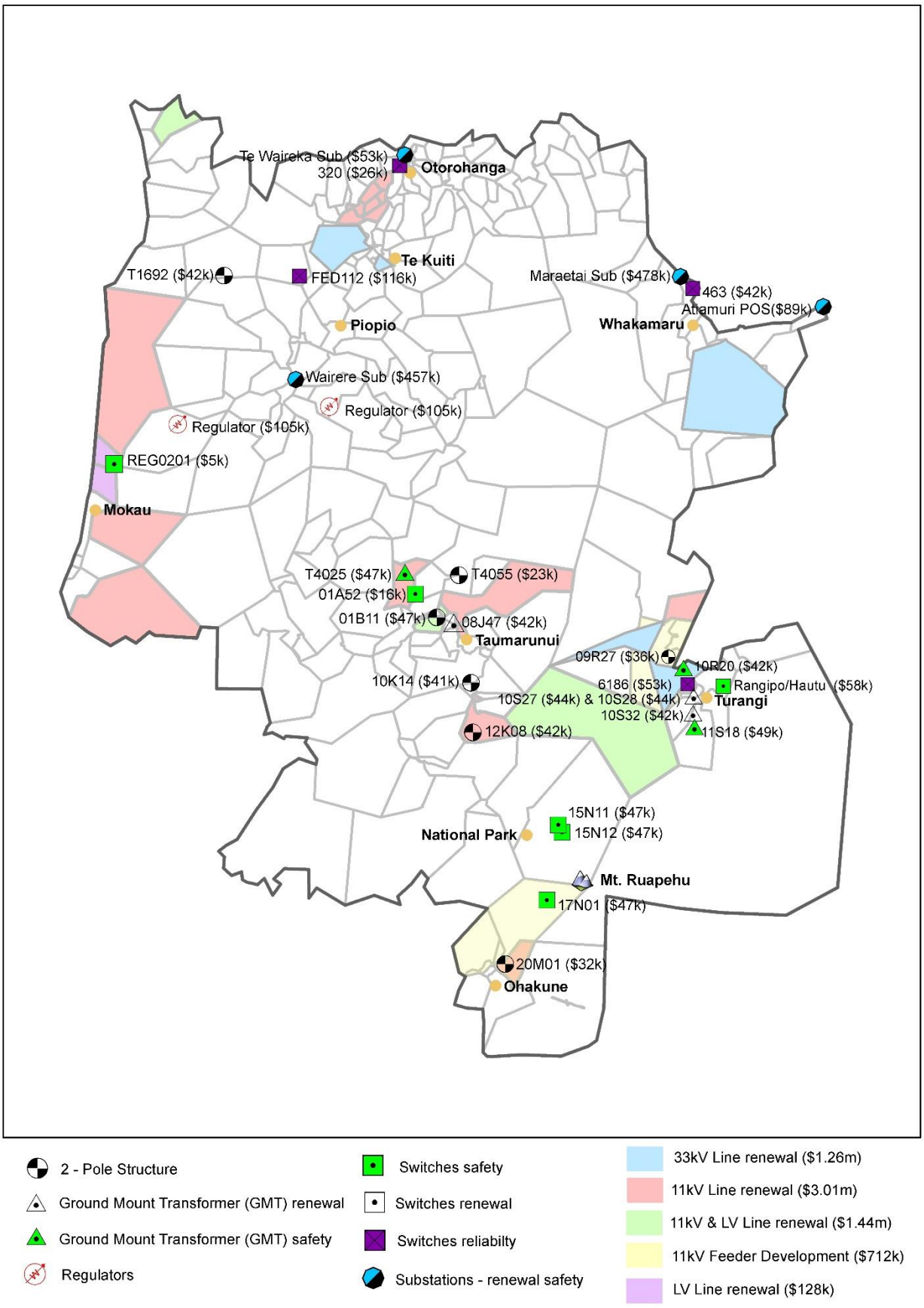


FIGURE 5.15 OVERVIEW OF THE LOCATION OF NETWORK PROJECTS FOR 2020/21

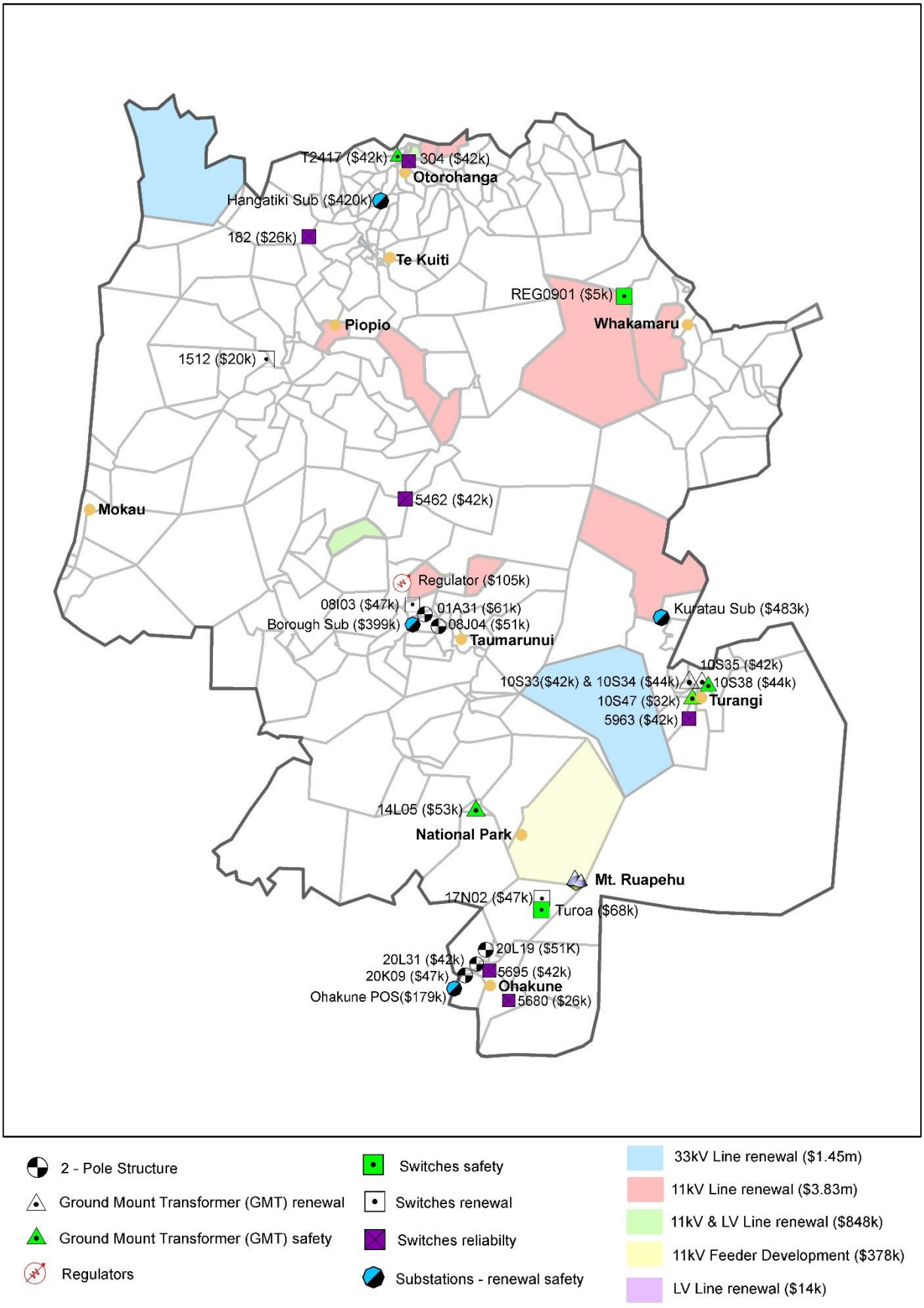
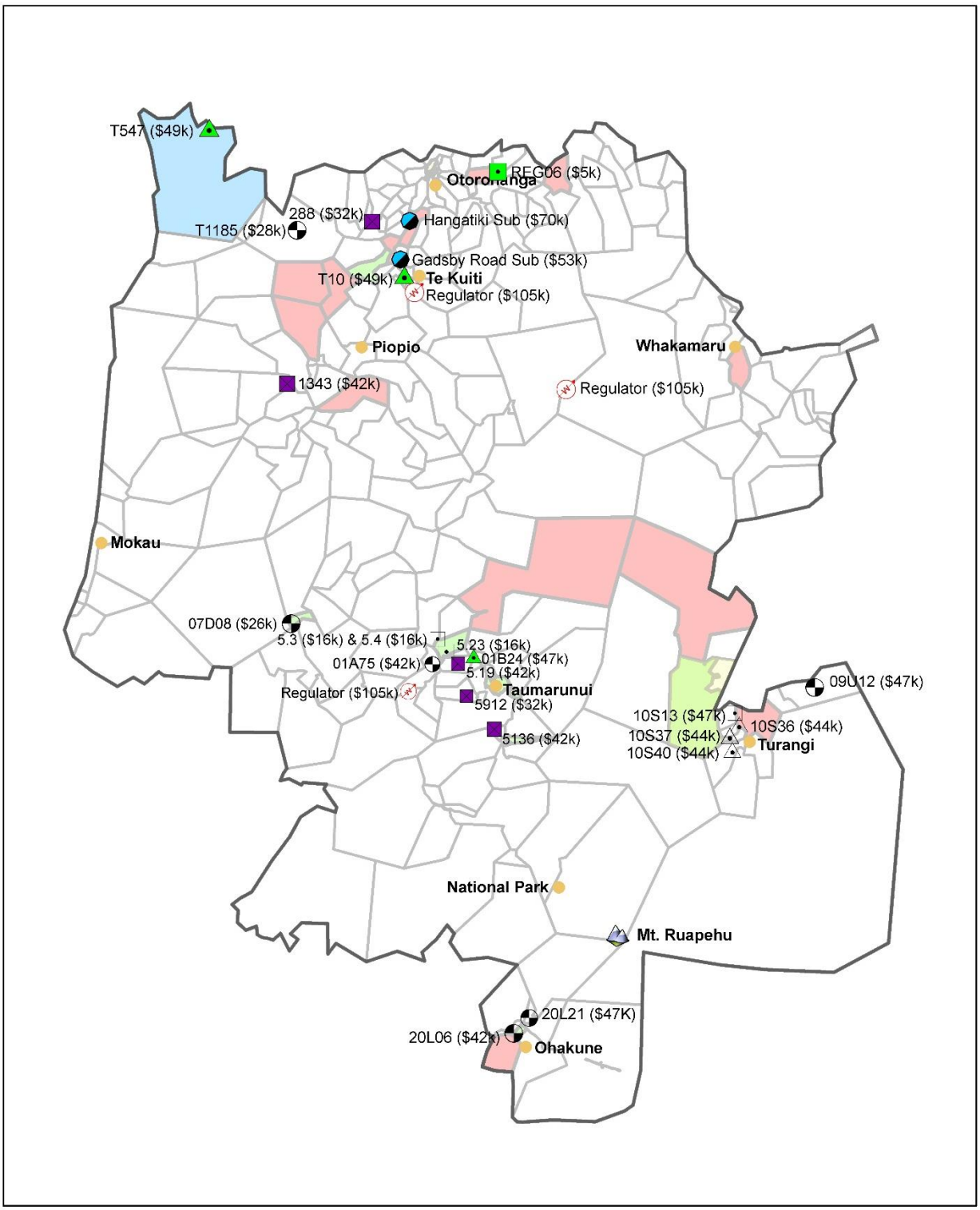
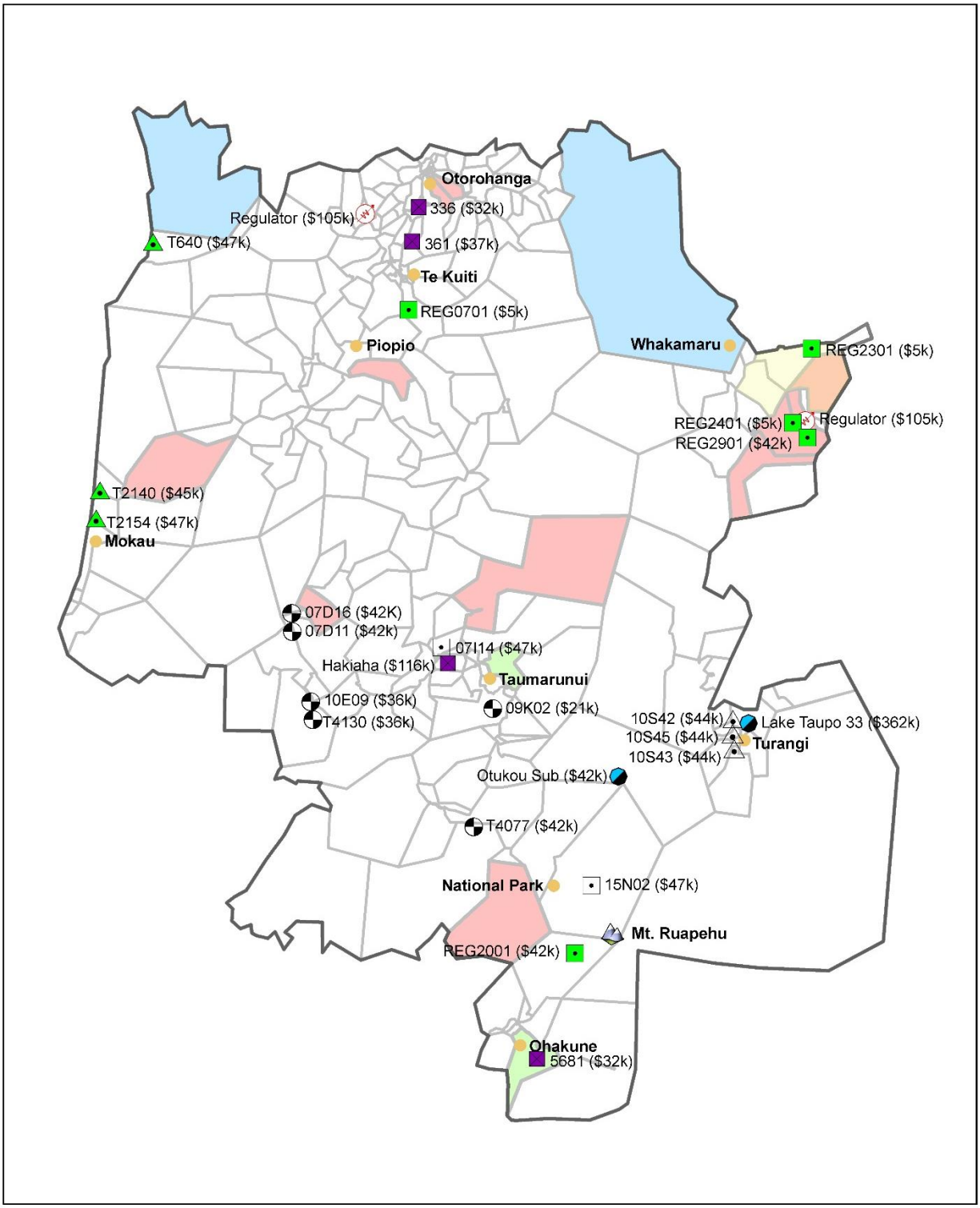


FIGURE 5.16 OVERVIEW OF THE LOCATION OF NETWORK PROJECTS FOR 2021/22



2 - Pole Structure
Ground Mount Transformer (GMT) renewal
Ground Mount Transformer (GMT) safety
Regulators
Switches safety
Switches renewal
Switches reliabilty
Substations - renewal safety
11kV Line renewal ($3.35m)
11kV & LV Line renewal ($2.82m)
11kV Feeder Development ($628k)

FIGURE 5.17 OVERVIEW OF THE LOCATION OF NETWORK PROJECTS FOR 2022/23



2 - Pole Structure
Ground Mount Transformer (GMT) renewal
Ground Mount Transformer (GMT) safety
Regulators
Switches safety
Switches renewal
Switches reliabilty
Substations - renewal safety
33kV Line renewal ($544k)
11kV Line renewal ($4.03m)
11kV & LV Line renewal ($606k)
11kV Feeder Development ($1.13m)

FIGURE 5.18 OVERVIEW OF THE LOCATION OF NETWORK PROJECTS FOR 2023/24

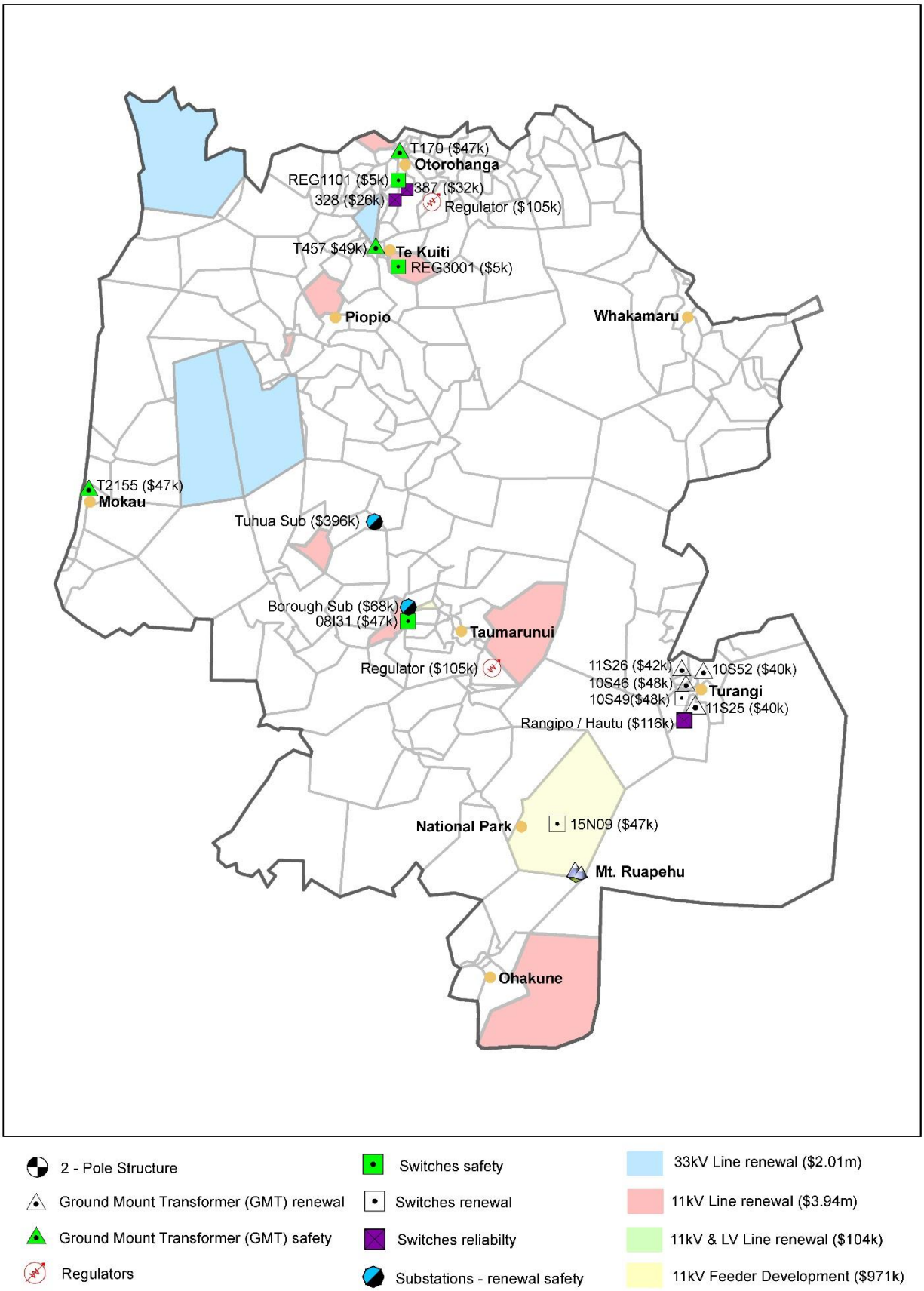


FIGURE 5.19 OVERVIEW OF THE LOCATION OF NETWORK PROJECTS FOR 2024/25

5.7.2 Customer Connection Projects

This expenditure will track to the number of new customers requiring connections. It will track up and down dependent on economic activity. Funding will come from the revenue these new connections will generate.

The scope of works includes supplying and installing TLC owned assets associated with new connections. The specific details of elements of this cost are listed below:

5.7.2.1 Sub transmission Customer Connection Related Development

Significant projects and summary scopes of work allowed for in the planning period 2020/21 to 2024/25 include:

- Industrial modular substation in the Hangatiki area for customer to meet plant expansion.

It is assumed that customers will use various technologies to reduce peaks and use non-asset solutions such as power factor correction.

5.7.2.2 General Connections Transformers and Earthing

This assumes a continuance of new connection activities and levels of funding in line with present policies. The scope of works includes supplying and installing new transformers, substations and fuses associated with new connections and upgrades of existing connections.

5.7.2.3 Subdivision Development

Assumes a continuing modest level of subdivision development. The scope of works includes supplying and installing new transformers, substations and fusing associated with subdivisions.

5.7.2.4 Industrial Development

Assumes a continuing level of industrial activity compared to previous years. It is assumed that customers will continue to consider peak reduction and on site non-asset solutions. The scope of works includes supplying and installing new transformers, substations, switchgear, cabling and fusing associated with industrial development.

5.7.3 System Growth Projects

This expenditure is for new and increased load. Projects will not be started or will be deferred if growth does not take place. Funding will come from the revenue these new connections will generate.

5.7.3.1 Sub Transmission System Growth Capital Expenditure

Significant projects and summary scope of works allowed for in the planning period 2020/21 to 2024/25 include:

- Modular substations at Kuratau/ Waihi for proposed distributed generation.
- Modular substation in Ranginui Rd area for meat industry and dairying growth in the area.
- Modular substation at Mine Rd area for dairy growth in the area.

It is assumed TLC will continue to promote demand side management and advise customers on non-asset solutions, such as power factor correction.

5.7.3.2 Voltage Support

We are continuing with the deployment of regulators, and possibly capacitors, to support network voltage. Individual sites have been identified by network analysis models. It is assumed TLC will continue to promote demand side management and advise customers on non-asset solutions.

The scope of work for most of these installations involves installing a high strength pole and two single phase regulators. Depending on the changes that occur in customer needs and our increasing understanding of network performance it is likely there will be a number of sites where capacitors will be deployed for voltage support to complement regulators.

5.7.3.3 Feeder Development

Summary scope of works allowed for in the planning period 2020/21 to 2024/25 includes:

- Second cable from Tawhai Substation to Whakapapa Ski Field.
- Conversion of SWER systems to 3 phase lines as part of holiday home development in the Kuratau and Waihaha areas.
- Cable renewal in Taumaranui
- Cable renewal in Te Kuiti Town
- Cable renewal in Otorohanga

These projects assume increasing success of demand side management schemes by customers including the deployment of generators, (active and reactive power), for peak reduction.

5.7.4 Asset Replacement and Renewal Projects

5.7.4.1 Equipment Renewals

Major projects programmed for these years include:

- Refurbishment of Wairere zone substation transformers.
- Renewal of circuit breakers at Atiamuri POS
- Renewal of aging indoor oil circuit breakers at various zone substation.

5.7.4.2 General Equipment Renewals

Equipment renewal expenditure includes contingency amounts per annum to cover equipment failure and refurbishment, these categories are:

- SCADA
- Radio & Data communications
- Distribution Transformers renewals
- Tap-offs with new connections

- Protection, relays and equipment
- Distribution Equipment

There are specific amounts set aside for load control, Radios and SCADA for planned upgrades.

5.7.4.3 Line Renewals

Programmes based on 15 year cycle for 33 kV, 11 kV and LV lines.
The full details of the line renewal and replacement programme are discussed in section 3 (Lifecycle Asset Management Planning) of this document.

5.7.5 Asset Relocation Projects

Asset relocations are typically associated with road realignment and slips. TLC cannot forward plan for these; an allowance of $10,710 p.a. has been allocated.

5.7.6 Quality of Supply Projects

5.7.6.1 Quality of Supply

The projects allowed for in the planning period 2020/21 to 2024/25 include a continuing programme of increasing network automation at a rate of about five new items of equipment annually. The specific sites have been identified and are included in plans. High level designs, evaluations and justifications have been completed. The scope of works includes automating existing switches and reclosers. Major projects include adding low voltage ties in Otorohanga (2020/21), Taumarunui (2023/24) and Turangi (2024/25).

5.7.6.2 Hazard Elimination/Minimisation (Safety)

The programme focuses on eliminating/minimising hazards in equipment and network architecture. This mostly includes low or hazardous 2 pole structures, ground mounted transformers, service boxes and distribution switchgear. All of this equipment has been inspected, photographed and prioritised. The expenditure predictions are based on the costs of eliminating or minimising these hazards and bringing the sites up to present day industry standards. Practical and likely ways incidents or events could happen when the overall network architecture in the area is considered have also been included in the prioritisation process.

The challenge for TLC is to complete this renewal work for costs that are lower than the estimates included in this section by increasing operational efficiency and being innovative with designs and equipment selection.

The projects allowed for in the planning period 2020/21 to 2024/25 include working through the programme of listed priority equipment. The scope of works includes renewal of sub transmission components, pole structures supporting equipment, ground mounted transformers, service boxes, switchgear and other hazardous equipment.

The specific sites have been evaluated and concept designs completed. These include adding switches to underground reticulation, rebuilding hazard free transformer structures, replacing ground mounted distribution substations that have inadequate enclosures, uncovered bushings and/or poorly designed LV racks.

Major projects programmed for these years include:

- Lake Taupo 33 kV river crossing.
- A modular substation at Tuhua zone substation.
- Renewal of switchgear at Wairere zone substation.

5.7.6.3 Environmental

The projects allowed for in the planning period 2020/21 to 2024/25 include working through the list of non-compliant equipment. These items of equipment are listed in the earlier constraints section.

The scope of work includes mostly the installation of oil bunding/separation and earthquake restraints.

The major project programmed for this period is a modular substation north of Taumarunui as the Borough substation is in a flood zone.

5.8 Distributed Generation

5.8.1 Policies for the Connection of Distributed Generation

5.8.1.1 General Policies

The policy on distributed generation is to allow the connection of distributed generation where it meets the costs of dedicated assets. The criteria for connection includes protection against the generation causing network hazards and impacting on network operating and other standards, including existing revenue flows.

TLC will encourage investors to provide network support by providing financial incentives aligned to the network savings that distribution generation produces.

All costs associated with collective and individual distributed generation connections shall be funded by the generators in accordance with the Electricity (Distributed Generation) Participation Code.

5.8.1.2 Capacity Policy

The capacity of generation that can be connected to any part of the network is determined by a number of factors. The most significant factor that affects capacity is the voltage rise when the network is in a normal state during an RCPD period with the plant operating at unity power factor. Policy is that the voltage rise should not exceed 2% (for 11 kV and LV networks) above the normal voltage. TLC will follow the requirements of the Codes in implementing this policy.

5.8.1.3 Applications for Connection Policies

The processes for considering applications follow those detailed in the Electricity (Distributed Generation) Participation Code. The fees charged for considering applications are those prescribed in the distributed generation regulations. The generators have to fund the full costs associated with preparing and submitting their initial and final applications.

Much of the work for new connections involves investigating options for capital upgrades so that cost indications can be given to potential investors. These upgrades often go deep into the network and can be complex.

In at least two recent cases, several parties wish to connect to the existing lines that only have capacity for one plant. Issues such as this pose questions such as deciding which one should be connected or how costs should be allocated. TLC's experience is that distributed generation issues often absorb considerable engineering time. This input must be funded from charges on an on-going basis for the connection of distributed generation.

5.8.1.4 Charging Structure for Distributed Generation Policies

There are two possible options for generators if the requirements of the Electricity (Distributed Generation) Participation Code are followed. These are the default regulated terms as listed in the Electricity (Distributed Generation) Participation Code, or a fixed fee approach. The regulated terms result in uncertainty to generators by having the provision for an annual reset on pricing and no capacity rights. The

fixed fee is a contract outside of the Participation Code whereby TLC, for a set fee, can give the generators more certainty in pricing and, for a fixed amount, take the uncertainties away from generators.

Most of the generators connected to, and wanting to connect to, the TLC network want the fixed fee approach provided the charges are realistic. The main reason for this is that the investor generators do not have technical knowledge and they want all of the complex electrical engineering taken off their hands while they focus on the environmental and mechanical issues associated with running plant.

TLC on the other hand is exposed to increased risk with this flat fee approach because of the uncertainty, for example, the possibility of complex grid exit power factor liabilities and the implications of operating outside the Electricity (Safety) Regulations.

The charging principle for the fixed fee and regulated approach is based on the following components:

A fixed fee for the capacity connected to cover the cost of administration, engineering and system operation associated with the connection of distributed generation.
A variable component with credits and charges associated with network benefits and non-benefits.

Credits are for:

- Transpower demand avoidance.
- Reduction in SAIDI minutes/SAIFI frequency. If plant is positioned in a place on the network, and has suitable controllers that will actually achieve SAIDI/SAIFI reduction, then TLC will pay a credit.
- Reduction in system losses (these payments will come from the market).
- Deferring of any capital expenditure by removing network constraints.

Charges are for:

- Inability to auto-reclose. TLC will instigate this charge if it cannot auto reclose within 5 seconds of a line tripping.
- Costs of power factor improvement required to be funded by TLC.
- Dedicated assets.
- Engineering time when a plant is modified, expanded or has an on-going operational problem.
- Any costs for destroyed appliances due to incorrect operation of the plant. (These will usually be direct claims from insurers or the owners of destroyed equipment.)

5.8.1.5 General Technical Issues with Distributed Generation that cause the need for Site Specific Conditions and Polices

As discussed in other sections of this plan, TLC has a long history of experience with distributed generation connected to the network. TLC's experience with distributed generation has highlighted the following issues:

<u>Power Factor</u>

The laws of physics are such that as power is transmitted through networks there are three components; active (kW) and reactive (kVAr) and apparent (kVA). Power factor is the ratio of real power flowing to the load to the apparent power of the network.

Whenever distributed generation is connected, active power is injected. In rural networks such as TLC's it is generally difficult to inject reactive power because of voltage rises. Figure 5.20 illustrates the impact of distributed generation on the network.

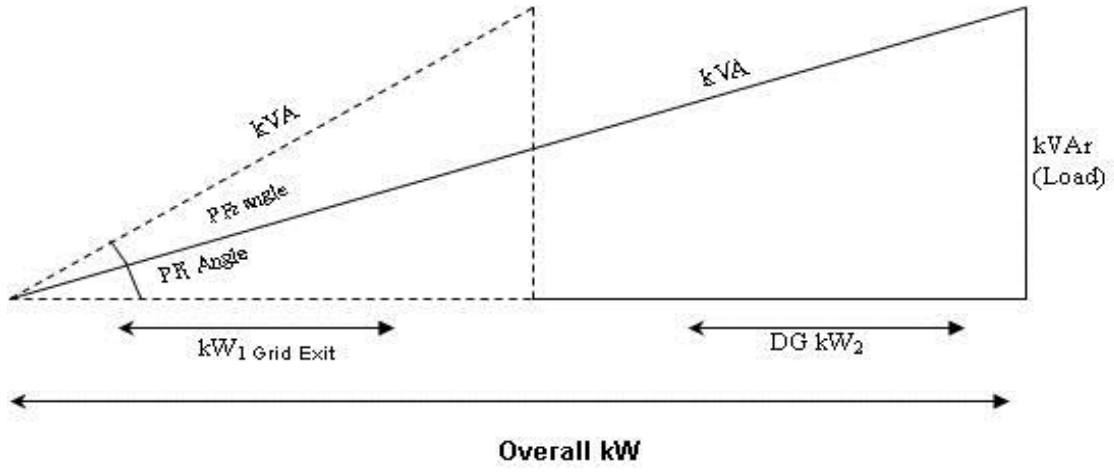


FIGURE 5.20 ILLUSTRATION OF EFFECT OF DISTRIBUTED GENERATION

Overall kW, kVA and kVAr are the components customers take out of a grid exit as shown by the solid lines. This diagram assumes that no distributed generation is connected. If distributed generation is connected and injects DG kW2, then the triangle is modified and becomes that shown by the dotted lines. The effect is that the power factor angle becomes greater; (PF2 angle within dotted triangle as opposed to PF1 angle within solid lines).

In the case of Hangatiki, DG kW2 comes from Wairere Falls, Mokauiti, Mangapehi, Marokopa, Speedys Road and other small generators.

Stability

Distributed generation does cause voltage and line tripping stability problems. TLC has investors' plant connected to the network that fights with other investors' plants on line tripping. This causes voltage and frequency swings on islanded network sections that have destroyed electronic appliances.

Resonance

TLC has had one case where the way an investor's plant was connected turned a 40km long 11 kV feeder into a sub 50 hertz oscillator. This had the potential to destroy appliances in at least 500 homes.

Current Flows/Protection

The plant characteristics and the way they are connected can cause various negative and zero sequence currents. TLC has had a number of cases where the zero sequence currents have biased and affected earth fault protection. Fault current levels also vary dependant on whether or not generation is connected. This makes protection settings more complex.

Auto Reclosing

Distributed generation plant can be damaged when a feeder is auto-reclosed. As a network company, SAIDI minute performance is a major measure. Distributed generation can be counter-productive to auto-reclosing to improve SAIDI performance.

Voltage Regulation

Distributed generation adds complexity to voltage control schemes. Distributed generation tends to run only when fuel sources are available. Often this time does not coincide with heavy feeder loadings. Distributed generation can cause a voltage swing that requires the installation of additional voltage regulators to hold network voltage. (Historic voltage control regulators typically have a 15% boost 5% buck range and the buck range sometimes has to be extended by the addition of extra regulators.)

Metering

Technically, metering is simple. However analysts reconciling distributed generation in the electricity market often have difficulty understanding the issues. Star points on the HV side of metering transformers can also cause interference problems with power systems. (TLC has experienced ferroresonance).

Islanding (Operate Isolated from Grid Connections)

Synchronous machines will island (or try to). When they island, TLC's experience is that frequency and voltage are not accurately maintained. This has destroyed electronic equipment and this has to be protected against.

Rules for Liability

Distributed generation and the interaction with the network is complex. When things do go wrong, electronic appliances can be destroyed. There are currently no rules for clearly determining these liabilities.

Loss Factors

Distributed generation connected to networks can reduce losses. They can also substantially increase losses and swing between the two extremes as network load changes. The electricity market requires a single figure for a loss factor. Calculating this is complex especially where there are a number of generators connected.

Self-Excitation

Rotating induction plant will self-excite when injecting into lightly loaded lines. It is important to get these machines quickly disconnected when they become isolated on a section of network.

Harmonics

At this time TLC is not experiencing any harmonic problems associated with distributed generation, but it is monitoring inverter sites. With the diverse TLC network, the risk potential for issues related to harmonics is high.

Voltage Flicker

As per the harmonics section above. TLC has to impose conditions and polices for applications to overcome these effects. These tend to be site specific.

Arc Flash

TLC has not experienced any serious arc flash incidents. However TLC is making steady progress in implementing arc flash policies for the safety of staff.

5.8.1.6 Effects of Power Factor Impeding Future Connections of Distributed Generation

Detail was included above on the theory associated with the effects on grid exit power factor of distributed generation. Figure 5.21 illustrates an example based on actual data from the Hangatiki grid exit.

Figure 5.21 Illustrates power factor every half hour during the year 1st April 2013 to 31st March 2014. Figure 5.22 shows the periods that Electricity Authority rules, Part F; say must be greater than 0.95 during RCPD periods.

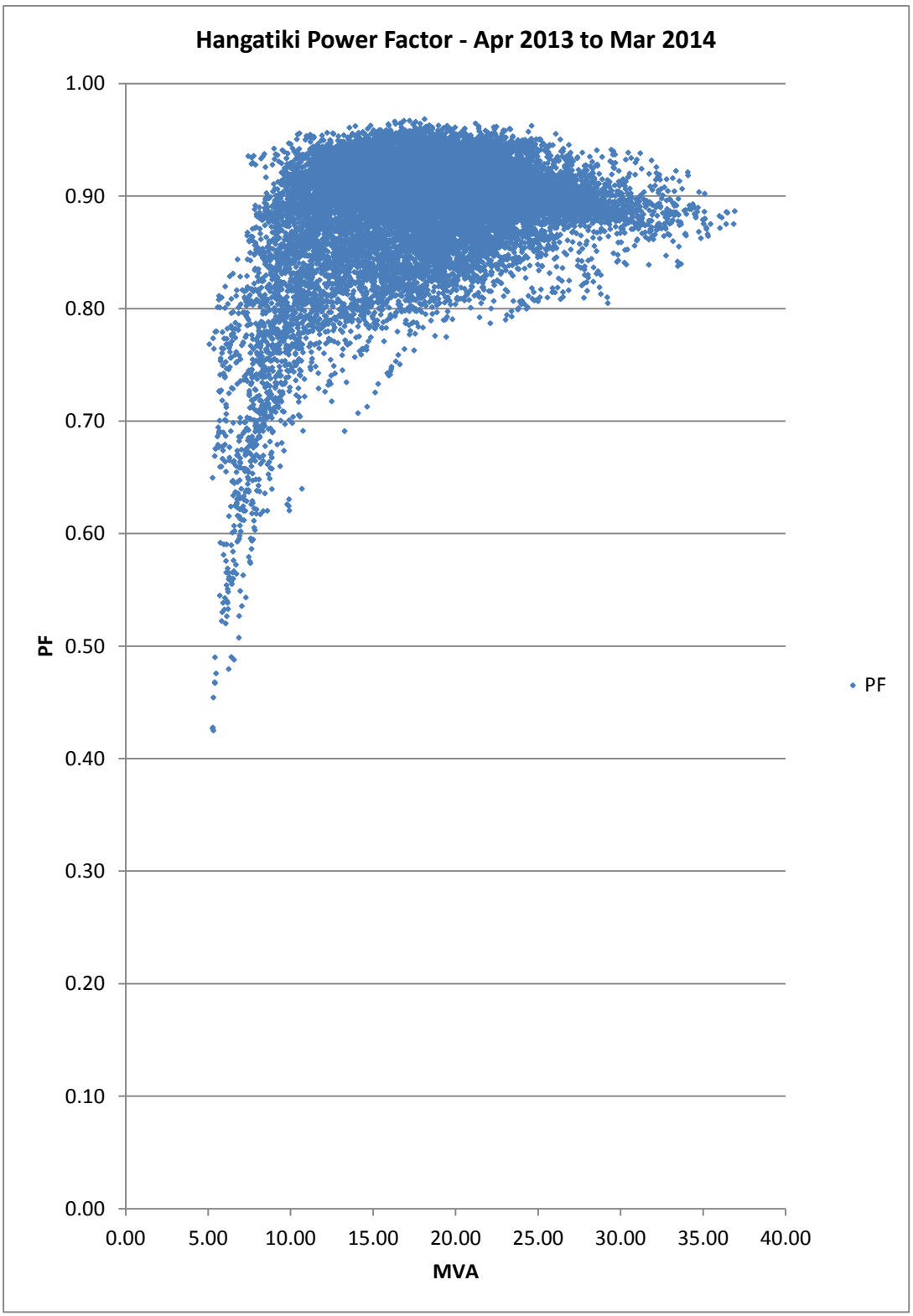


FIGURE 5.21 HANGATIKI POWER FACTOR

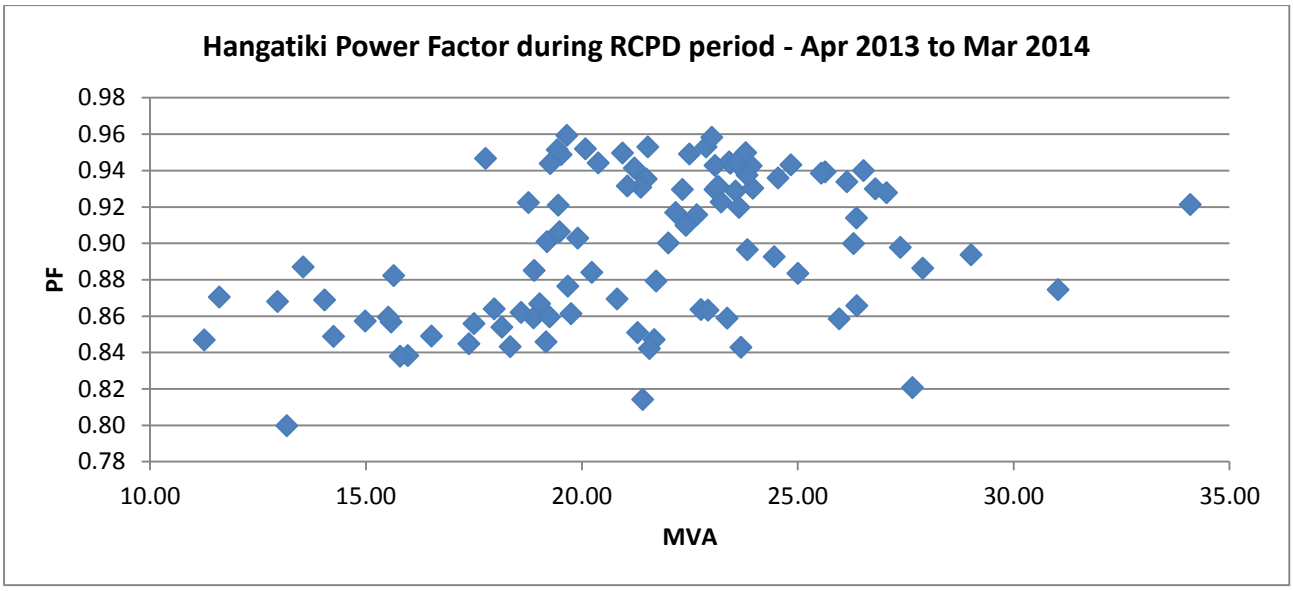


FIGURE 5.22 HANGATIKI POWER FACTOR DURING TOP 100 RCPD PEAKS

Figure 5.22 shows the power factor is rarely above 0.95. It also shows that at the peak times when the codes apply, Hangatiki power factor can get down to 0.80.

As a comparison, Figure 5.23 shows the Ohakune power factor, which is above 0.99. Ohakune does not have distributed generation connected. However this power factor is for the Ohakune GXP which includes TLC and PowerCo loads.

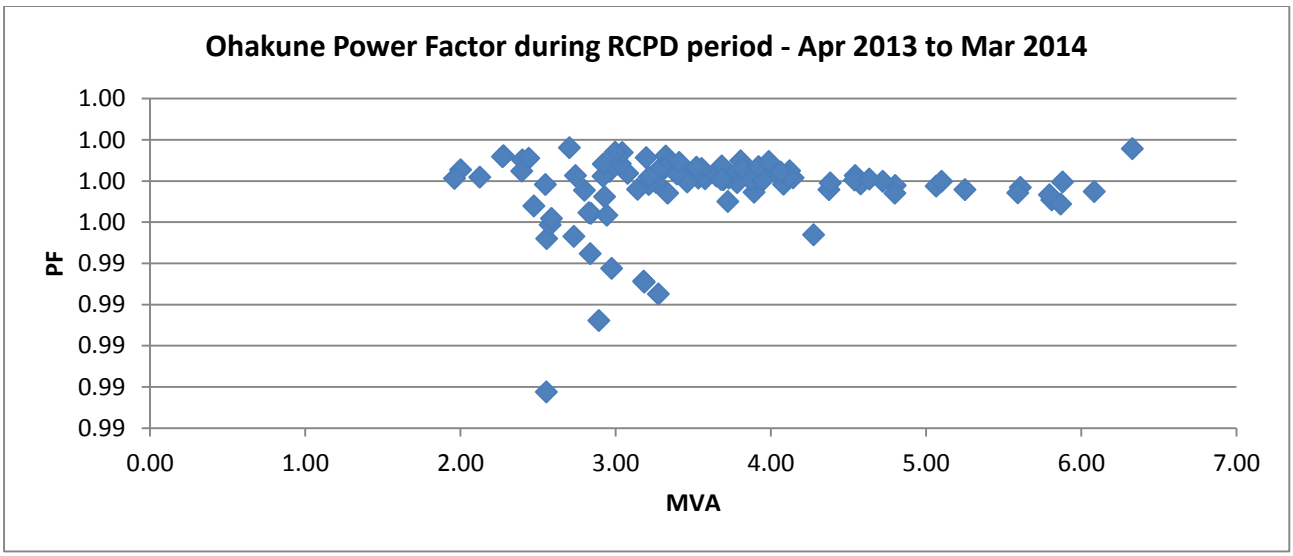


FIGURE 5.23 OHAKUNE POWER FACTOR DURING TOP 100 RCPD PEAKS

The intent of present documents produced by the Electricity Authority is to pass on the costs of correcting to 0.95 or unity at grid exits to network companies. Network companies have to recover this cost from somewhere. They have two choices: load taking customers or generators. Load taking customers are encouraged by TLC's demand based charges to correct power factor. Many do and are operating at 0.95 or better.

The generators could pay, but this will effectively penalise generators connected to distribution networks as opposed to the transmission grid. It also defies the intent of government policy to encourage distributed generation.

Given this difficult situation the solutions range from ignoring the power factor issue as has happened over the last eighty years or working towards a full reactive power market. The full reactive power market would be a good outcome as it would place a full value on reactive power. It would encourage the

generation of this and, in an ideal world, allow greater value to be placed on demand side active power generation. Customers would be free to generate reactive power similar to that for active power.

While this concept is good, the technical issues are not so straightforward. For example, resonance is always a possibility around capacitor sites, either from harmonics or at the fundamental frequency. Any such market would also be complex and add overall cost to the industry.

The capacity of generation that can be connected is heavily influenced by reactive power flows. The suggested solution to this issue is to focus on reactive power flows at grid exits, not power factor. The amount of reactive power that should be allowed at a grid exit should be that which would flow if no generation was present. The amount of generation capacity that could be connected would then be more defined, i.e. the amount that, if it operates at unity, would not cause excessive voltage rises on that part of the network.

5.8.2 Impact of Distributed Generation on Network Development Plans

5.8.2.1 Existing Generation

A summary significant existing distributed generation connected and injecting into the network can be found in section 3.

TLC also owns a mobile generator and injection transformer that is used to reduce planned and unplanned SAIDI events. The unit is also regularly used to support network voltage when only limited capacity back feeds are available.

5.8.2.2 Network Support

TLC has two mobile capacitor banks that are used to support network voltages during planned and unplanned events. Hire generators are also used from time to time to support the network or to provide supply during large outages.

TLC is also investing in the development of distributed generation through a wholly owned subsidiary called Clearwater Hydro.

5.8.2.3 Projects Directly Affected by Proposed Distributed Generation not going ahead

The following projects may be affected by distributed generation:

- Voltage regulators on the Wairere/ Gadsby 33 kV line.
- Waihi modular substation is dependant of the re-development of the hydro site at Waihi near Kuratau.

5.8.2.4 Impact on Sub-transmission Network of Distributed Generation

5.8.2.4.1 Grid Exits

The present transformers do not have n-1 capacity and are heavily loaded during peak demand periods without the availability of distributed generation. The problem with currently connected generation is that it is all run of the river and, as such, is rain dependent and is not necessarily available during periods of peak load.

5.8.2.4.2 33 kV Lines

Distributed generation and demand side management has the potential to ease the loading on the Whakamaru 33 kV, Taumarunui to Ongarue 33 kV and Te Waireka/Te Kawa 33 kV lines. Distributed generation proposals have the potential to cause upgrades of Te Kuiti and Mahoenui 33 kV lines.

5.8.2.4.3 Zone Substations

Distributed generation and demand side management have the potential to ease the loading on the following zone substations and their transformers and prolong the period before an upgrade is required:

- Marotiri
- Kuratau
- Tawhai
- Hangatiki
- Gadsby Road
- Maraetai
- Borough
- Waitete
- Atiamuri

5.8.2.4.4 Distribution Feeders

Distributed generation can assist with supporting loadings on distribution feeders. However, during periods of light load on a relatively long and high impedance system it can push voltages high. Inductors or absorption of reactive power can be used to control this, but these actions can have a detrimental effect on overall network power factors and system stability.

5.9 Policies on Non-Network Solutions

5.9.1 Non-Network Solutions processes

The general processes that TLC applies to identify and pursue non-network alternatives to its plans include:

- Price to ensure customers are aware of the cost of their:
  - » Capacity;
  - » Peak demand;
  - » Dedicated assets.
- This ensures customers are financially motivated to look at options that drive their network and non-network decisions, i.e. generators versus grid connection: gas versus the use of electrical energy.
- A high-level look at the alternatives and advice to the customer on these. Where the work involves renewals, cumulative capacity, hazard control or reliability development, the options for both network and non-network options are looked at.
- The option selected is based on the criteria of optimum cost and planning risk.
- There are a number of customers who select alternative power supplies for new connections.
- Technologies that can provide the energy intensity required for activities such as continuous water pumping and dairying are often more complex and backed up by diesel generators.
- A number of customers use single phase to three phase converters or generators to milk and the existing supplies to cool milk when supply capacity is not available. This typically occurs when there is only a single phase supply in the area.
- Financial analysis based on regulatory asset values and Commerce Commission return guidelines are completed for most capacity upgrade proposals. This analysis may include several engineering solutions including non-asset approaches such as the use of generators to provide short term demand until growth provides a stable income platform to fund asset network upgrades.
- Encourage the development of distributed generation to alleviate capacity constraints. Part of this encouragement is mostly given by the pricing structures put in place.
- Any customer who has a critical load is encouraged to make provision for its own standby generation and/or install generation to meet peak demand. For example during power outages:
- Ruapehu Alpine Lifts (RAL) has generators installed so that in the case of a power failure they are able to run the lifts to clear people stranded on the chair lifts.
- A number of dairy farms have generators that they run from the tractor Power take off (PTO) which enables them to continue milking in times out power outages. See Figure 5.24, which illustrates a generator at a cowshed for this purpose.
- Customers are informed of the need to install demand side surge protection and are given simple plug in surge diverters through various promotions.
- TLC promotes power factor improvement to all customers. Charges are based on kVA when metering is available to record this. As discussed in other sections TLC is annually surveying network power factor and using this data to reconcile actual values to its models.

FIGURE 5.24 GENERATOR BACKUP INSTALLED AT COWSHED

- Detailed, accurate technical models are used for all development, customer and other projects to look for options. These models, as stated in other sections, include protection, harmonics and fault current features that allow more than just the impacts of power flow to be considered.
- Consideration of how automation and controls could be applied to minimise the asset investment for customer requests and network development.

For example: Is it possible to use intelligent control systems to control and distribute load to maximise the utilisation of existing assets? (TLC has implemented several schemes. The most complex solution pushes a connection back and forward across the end of two feeders from different supply points, one of which has a distributed generation connection.)

- Information is made available from models to customers and retailers to encourage energy efficiency and minimise losses.
- Network security and reliability information is considered for all network and customer solutions. Often these factors influence the ability to use non-asset solutions.
- Encourage large industrials with high load demand to consider the alternative of installing a modular substation supplied from TLC's extensive 33 kV transmission network. This alleviates the capacity pressure on the 11 kV feeders and allows TLC to develop a currently constrained feeder further out in the network.
- Install capacitors to support the voltage. TLC is exploring this option and to date due to ripple signal interference has decided not to install permanent site. Instead TLC is developing a mobile capacitor bank that can be used to support the voltage when using generators on the network or in a back-feed situation where the voltage is dropping away.
- Mobile generators to support the network in fault situations or when supply is limited from the supply point, such has when MRP has its maintenance shutdowns at Whakamaru.

Once the best solution option is identified, TLC pursues this. Often considerable discussion must be held with the stakeholder parties and extensive financial analysis of the options completed. Medium to longer term solutions for a particular part of the network or site are considered and included in plans. For example: TLC has developed long term solutions for the ski fields. Each time modifications are made they progress the long term plan. The final network configuration will take about ten years to achieve.

TLC is committed to encouraging non-network solutions and sees this as a key pricing strategy, both for peak demand management and power factor correction. Customer incentives and education are seen as the most effective tools to encourage solutions at the load, thereby maximising the utilisation of existing assets and deferring investment. TLC believes that non-network solutions to minimise electricity costs (both lines and energy) for the end customer are a key to its overall operation strategy and giving customers long term value.

The forecasting section discusses TLC's understanding of the impact of demand billing and its encouragement of demand side management non-asset solutions. The analysis in this section illustrates the impact of these initiatives. The CAPEX estimates also illustrate the difficulty TLC would have funding upgrades as well as its renewal programmes without demand side management. At this time no dedicated cost benefit analysis of the savings that demand (or load) based charges are achieving has been done.

5.9.2 Strategies Being Deployed to Promote Non-asset Solutions

5.9.2.1 Integration of Demand Side Management and Pricing Strategy

TLC encourages the implementation of policies and measures to reduce electricity demand, through the use of pricing strategy, high efficiency equipment and good operating practice. Over recent years, the demand on the TLC network has been growing at a faster rate than the energy transported. Peak demand is the defining factor for network upgrades and hence investment level. Controlling peak load is seen as an important initiative for TLC to minimise cumulative capacity network development and the escalation of customer charges.

TLC is the only lines company in New Zealand to introduce universal demand billing and to send separate bills to customers to ensure maximum impact of these pricing signals. This concept dates back to the 1950's when load control was extensively deployed in New Zealand. Demand and combined energy charges were passed down to large commercial customer level. In the past the demand measuring meters involved complex mechanical devices and it was likely that this did not allow the concept to be applied at a lower level during these times. The arrival of electronic time of use meters at lower cost have changed this. A control period is a period commencing when a load control signal is sent to control demand and finishing when a further load control signal is sent to restore supply to the controlled demand.

Time of use meters to measure peak demands have started to be deployed and installation of these is being co-ordinated with relay and 2015 meter compliance requirements. Customers are charged for their peak demand during periods when load control is implemented. TLC's demand billing thereby encourages its customers to shift their peak usage to "off peak" periods. TLC has embarked on a programme to educate its customers on the billing structure and ways to reduce their electricity costs.

TLC's charging policy is based on components as outlined in other sections.

- A fixed charge based on the capacity made available. For a typical dwelling, this equates to 5 kVA or in dollar terms, approximately $250 p.a. for an urban dwelling after discount and exclusive of GST.
- A demand charge (about $200 to $250 per kVA).
- Charges for dedicated assets such as lines and transformers. This creates incentives for sharing assets and recuperates real costs for installation and maintenance.
- A customer service charge (for large industrial customers only).

Note: The capacity charge is also affected by customer density and is higher in rural areas. (These density bands reconcile with service level regions as discussed in Section 4.) Customers with other dedicated assets face additional charges associated with these assets. This structure allows customers the option of reducing capacity and demand.

5.9.2.1.1 Where demand meters are installed

FIGURE 5.25 "SWITCHIT"

Demand calculations are likely to be changed as a result of public consultation and recommendations provided by the Sapere review, from a single three hour period when TLC is load controlling to the average of six two hour periods when load controlling. There can be two periods in any single day recorded provided that there is at least five hours from the end of one control period to the beginning of the next.

In addition to fixed wired load control relays customers are using plug in relays for controlling appliances. Figure 5.23 show a "switchit" relay in use, the green light indicates that TLC is not load controlling the load control channel that the house is programmed to. The light is red on when the channel has been controlled and the appliance connected to the switch is disconnected. (The "switchit" have to be programmed to the same channel as the meter box relay to be effective, but are often a lower cost option that does not require wiring alterations.)

5.9.2.1.2 Where no demand meters are installed

Until half-hourly meters are installed in all installations a statistically derived formulae is used to calculate demand from uncontrolled energy meter readings. All load connected to the control relay is not included in this calculation as this will be disconnected during control periods. Reducing their total consumption will have a direct effect on the demand portion of their lines bill. Considerable savings can also be made by moving load onto the controlled load relay where this is installed as kWh consumption on the controlled meter is not included in the demand calculation.

5.9.2.1.3 Results

This structure has produced positive results amongst commercial customers where there is a high percentage of demand and time of use meters installed. This has been attributed to:

- A TLC initiative to hire consultants for commercial sector (mostly accommodation and tourism) to educate larger customers on how to reduce their demand and hence their costs.
- Commercial customers tending to be more aware of their costs than domestic customers and as a consequence understanding the ways to reduce charges.
- A push to get industrial customers to improve their operating power factor.
- PR campaigns and other customer awareness programmes.

TLC's programme of Customer Focus Groups and public meetings are beginning to show results through its domestic customers, and there is a greater understanding of load demand charging and why TLC has to build lines to take the maximum load, and that the infrastructure to carry that load has to be maintained to achieve the service levels that they, the customers, expect.

5.9.2.2 Generators Installed to Reduce Peak Demand

RAL has invested in a generator to bolster the supply in times of heavy use such as snow making on a winter's night on its Turoa ski field. Other large industrials that have critical load are encouraged to consider the same techniques.

Dairy farmers and small business are also encouraged to have a backup generator supply to enable them to carry on with their business in times of power outages.

TLC has two generators, the largest of which is 165 kVA, to allow it to supply areas that are disconnected by a fault or for maintenance where no back feed supply is available.

5.9.2.3 Distribution Network Capacitors

TLC, at this time, does not have any permanently mounted power factor correction capacitors connected to its network. Consistent with its demand side management and pricing strategy, TLC believes that the most effective and efficient place for power factor correction is at the customer's load. Hence intelligent billing is used in lieu of capacitors as the preferred means of power factor correction at this time.

Industrial customers are provided with free engineering advice as how to best control their power factor and loads. They are also charged based on kVA demand rather than kW, which gives further incentive to improve their power factor. Pricing has been set at a level where power factor correction pay backs are typically in the 2 to 5 year range.

TLC, however, recognises that there are locations where the future use of capacitors on the network will likely be the most cost effective way of maintaining voltage and meeting the Electricity Commission grid exit power factor requirements. Deployment at the present time is complicated by the old high frequency ripple injection plants and has been avoided. Rising harmonic levels may also add future complexity. As a shorter term solution the mobile active and reactive power unit concept is being developed.

5.9.2.4 Use of Intelligent Systems and Network Tuning

TLC has in place the base data systems required to move to an intelligent network. The base data in the existing systems are now at a level of detail, consistency and correctness where the data can be incorporated with other data sets. The strategy has been to use systems that have accessible data formats that can be integrated with other products.

TLC is investigating an upgrade of network analysis program to include the Smart Grid and/or Real Time modules that will interact with the SCADA data. Some of the benefits from introducing this system could be to provide more intelligent load shedding, switching, advanced monitoring, demand-side management and advanced forecasting features. The system is modular and therefore the purchase of packages will depend on cost-benefit analysis of each package.

This philosophy is integrally related to work to automate remote switches and a focus on flexibility for new projects. This automation and improving in the SCADA system is taking TLC closer to be able to start introducing a self-healing network. In many instances security of supply for a customer also equates to operational flexibility for TLC. There are cases where savings can be made via the optimisation of:

- Load distribution.
- Reactive power flow.
- Losses.
- Voltage (higher voltages leading to lower losses).
- Phase balance.

TLC is currently using its network analysis software to understand and tune network power flows to minimise losses and maximise the benefits of distributed generation and existing asset capabilities (e.g. regulators). Some of these optimisations can be achieved by an intelligent SCADA system. Some are implemented/encouraged in the Distribution Connection Code and pricing strategy. For example, it is possible to maximise distributed generation impacts and minimise the negative power factor effects by optimising generator control. One generator connected to the TLC network replaced controllers and indications are that technical network losses can be reduced by tuning these settings. Implementation of these savings is a multifaceted task and will require engineering time to determine where and how policy, investment or operational intervention is most effective.

5.9.2.5 Advanced (Smart) networks and TLC's positioning

Elements of advanced networks are available now and these technologies will have a cumulative effect as time goes on.

At this time the potential cumulative effect is a vision for TLC, and the key elements that we have in place to build on include a firm base of data, network analysis, direct based charging and other initiatives. The challenge is to bring these together in a planned way to provide improved service at a price customers are willing to pay. These initiatives must align with the strategic objective of being the best supplier of capacity to remote rural areas.

5.9.2.5.1 Definition of Advanced or Smart Networks

The definition that was adopted by an Electricity Networks Association working group is "The application of real time information, communication and emerging trends in electricity delivery to improve capacity utilisation, asset management practices and reliability on the modern network thereby optimising network investment to the benefit of all stakeholders."

This group concluded that the elements of an advanced network can be usefully grouped into three distinct layers. Figure 5.26 (on the following page) illustrates these layers and what they are.

The group went on to explore the cost benefits and concluded that "cost/benefit assessments indicate that the benefits of advanced networks substantially outweigh the cost at a national level". It is also considered that industry-wide policy settings may impede the deployment of advanced network technologies and identified a range of regulatory policies that prevent EDBs from deploying these technologies.

It is also recognised there is "no such thing as a representative EDB. Every EDB's advanced network investment would be different. The technology deployed is changing quickly and the cost established today will likely be out of date very quickly."

These latter points are very pertinent to TLC given that TLC is in a unique position given its direct charging strategies and remote rural environment.

Referring to the diagram in Figure 5.26 each of the layers are outlined and expanded on in the following sections.

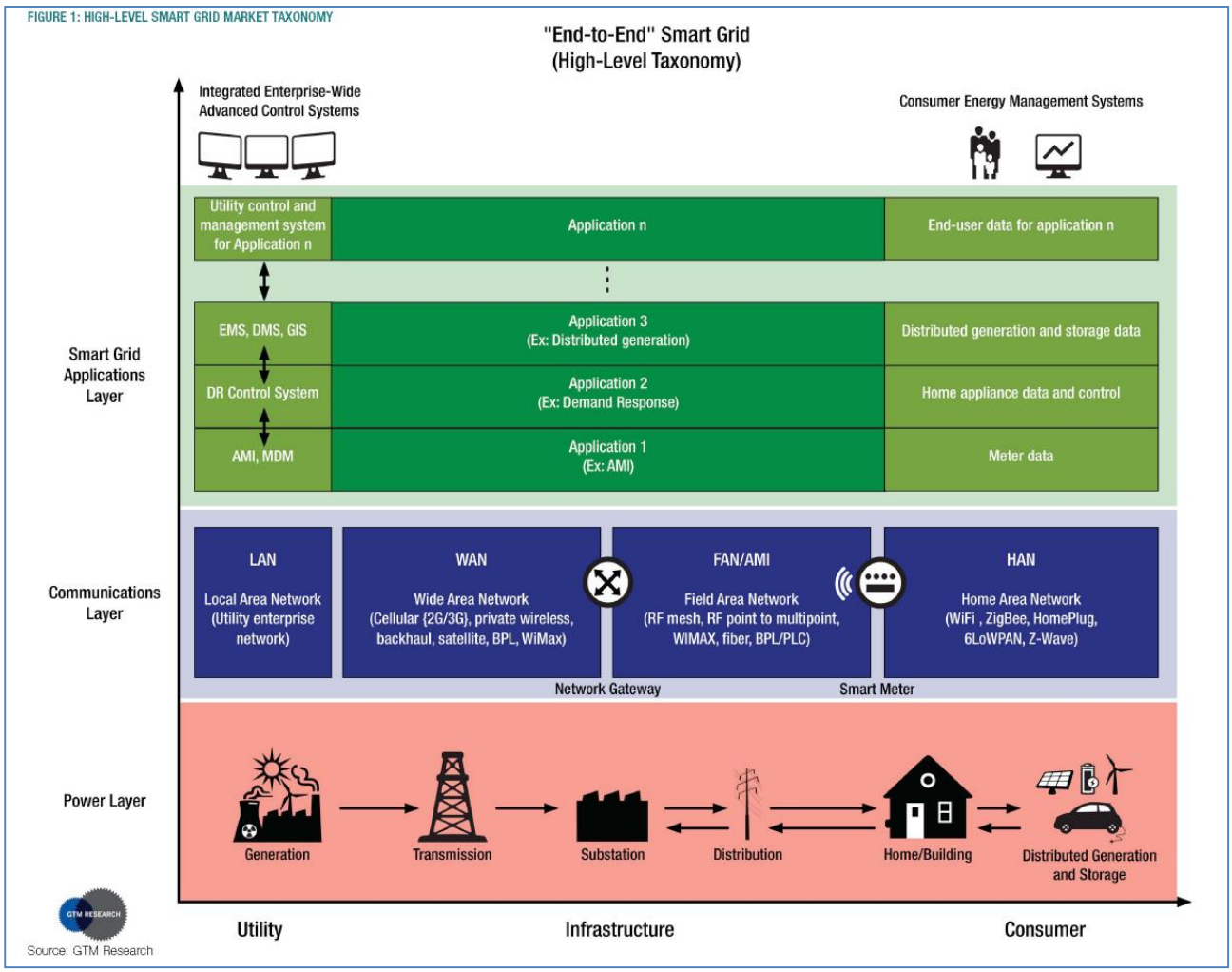


FIGURE 5.26 THREE DISTINCT LAYERS ASSOCIATED WITH AN ADVANCED NETWORK

5.9.2.5.2 Smart Grid Application Layer

At the heart of the applications layer lays a central element of an advanced network. It is the ability to:

i. Monitor condition, consumption and injection across the network, preferably in real time.
ii. Control the controllable functions in the way load control does now. However, this will become more complex and may include such things as charging for electric cars and signalling to smart appliances in a future smarter world.
iii. Signal to customers the necessary information for them to make choices.
iv. Recover the value of investments.

The communications layer covers the technologies and developments that facilitate a smart transformation. It includes metering developments, communications developments and information management.

The physical world may change as a result of more distributed generation, electric vehicles and other storage devices. The basic system will still deliver energy to load centres from large generating stations but the net demand from the network will be more volatile. The key physical impact of these developments will be greater two-way electricity flows on the distribution network and transmission grid. By itself this feature would necessitate a more active network operation approach.

Elaborating on these layers and relating them back to the TLC network: The strategies/tools and development vision TLC currently has for these are summarised in the following Table 5.26.

CONTROL LAYER	
Item	**Comments**
Energy Market	TLC is in the network business, not the Energy Markets business. It is disconnected because of direct billing from retail. TLC has options going forward that can impact on the energy markets and distributed generators; specifically, there are parts of the network that are and can shift energy among supply points to benefit customers and generators. TLC is also concerned that energy markets can only focus on active power not reactive power. TLC's network transports about 66% active power and 33% reactive power; so the effects of reactive power are significant, i.e. it absorbs a lot of available capacity. TLC's direct charging approaches have been designed to focus on ensuring that the customers who require reactive power to be transported, and as such reduce the network capacity to transport active power, pay for the reactive power transport service.
Reserves Market	The relays TLC owns are all capable of operating in the reserves market. What it does not have is the resources to bid, control and administer this potential income stream. It also notes that there is uncertainty in this market and that the industry is likely to develop it further in the future. TLC will enter this market when it can provide firm cost benefit.
Ripple Receivers	TLC owns the present stock of which about half are operating on a less than optimal frequency. New plants are in place; however, the change out will have to be co-ordinated with a meter rollout given that the next generation meters and relays are integrated. The plan going forward is to split the channel allocations into feeder groupings so that TLC and Transpower network constraints can be individually signalled.
Load Management	The objective is to have more information and better use of this to make decisions. Specifically half hour metering, better price signalling ability to control more load; not withstanding some set time undertakings. The present load management controller takes inputs from supply points and compares these against one present target for a specific half hour. These targets have been broadly set to try and minimise Transpower interconnection charges and networks under constraint periods. Looking forward the load control calculator has to get more complex and capable of sending signals that are more localised as well as global. Over the next period TLC will further investigate the options for this and develop the most justifiable alternatives. This is an area that will get finer and more detailed as load management is controlled to an advanced network standard. The actual costs are not known at this time and as such are only included in forward estimates as contingencies under SCADA development. Forward load projections have assumed an on-going improvement in load factor where the demand growth is lagging energy growth by about 1%, as discussed in other sections. The costs and savings may be greater or less that these amounts.
SCADA Network Analysis, Asset Management, Technical Records, Billing and Accounting	TLC presently has SCADA, network analysis, asset management, technical records, billing and accounting packages/systems as described in other sections. A need for these systems going forward will be for them to have more visibility and control of all distributed assets to provide improved service, quality and security and be aware of revenues and costs. This will require data and application integration among SCADA, network analysis, asset management, technical records, billing and accounting packages. These systems will address all manner of things, the detail of which is currently being given consideration by TLC. The cost implications of these are unknown at this time; however, there are some allowances for this development in SCADA estimates.

CONTROL LAYER	
Item	**Comments**
Commercial and Domestic Applications	Power and information systems downstream of the meter will be needed by the customer. The communications layer will be key to these as will be the ability to draw information out of TLC systems via the internet and directly from the meter. The initial advanced meters being deployed by TLC do have a Zigbee communication system and in-premises displays tailored to the meter are planned to be made available. It is recognised that from a customer perspective this is key data/information and the options available will advance quickly. The architecture of these systems is currently being given consideration by TLC. The cost implications of these are unknown at this time and are not included in this Plan.

POWER LAYER	
Item	**Comments**
Distributed Generation	As outlined in other sections TLC already has significant distributed generation connected to its network and, as a consequence, it is well aware of the issues and has systems in place to accommodate these connections; however, significant tuning is required to take these forward and maximise the benefits. Connecting distributed generation to a network does introduce a number of complexities and more advanced control systems (tying back to the control layer) are required. (Many of these are discussed in other sections.) The present distributed generation requirements under Electricity Authority participation codes are limiting in terms of recovering the costs from generations for more advanced networks. At this time we have developed control systems for the existing network and the architecture has been built up around this. Further development of this architecture is currently being given consideration by TLC. The cost implications are unknown at this time; however a number of improvements will be covered by the existing allowances in SCADA and communications contingencies/allowances.
Automated: Self-healing Networks	TLC currently has not invested in automated self-healing networks. It has been focussing on getting the basic remote controlled equipment installed. Due to the radial nature of the network there are not as many potential options for the deployment of this technology as some other networks have. There are sites where the deployment may be useful and these will be researched and developed. As outlined in other sections it is a selection criteria for the equipment being purchased to have functions that will allow the deployment of some of these options. TLC's engineering structure is currently being adjusted to provide a level of additional resource to be able to carry out some additional research in this area. At this time there are no specific allowances in favour of estimates for the deployment of this technology; however, some of the contingency amounts in the communications and SCADA areas will likely go some way to achieving the "low hanging fruit" in this activity.
Reactive Power and Voltage Control	Over the last nine years TLC has been busy deploying modern technology assets (see Section 3) to ensure compliance with the electricity regulations. Similarly there are a number of deployments planned going forward. The recent upgrade of the injection plants in the Northern area has also meant that the deployment of capacitors is now an option. Also, as outlined in other sections, TLC is sending a message to customers via its charging to minimise reactive power flows. The intent is to increase the level of network tuning going forward. Forward expenditure predictions have been increased to cover off a level of increased engineering to research and develop more advanced schemes. The additional hardware and software investment is not included in forward estimates at this time.

POWER LAYER	
Item	**Comments**
Capacity	There are a number of things TLC could do to extract more capacity out of existing assets, particularly given the capability of things such as modern regulators, better information systems and reactive power flow initiatives. The implementation of these will likely be on an area-by-area basis. Such initiatives will require mostly technical labour type input plus some sensors and more advanced modelling.
Asset Management Information	The use of more advanced asset management information and the inter-relationships associated with this are perhaps part of the control layer but they also have a direct impact on the management of the power layer. An important part of running the power layer in a more advanced manner is to have individual, sectored combined asset data and connectivity models from supply points to end customers. TLC has in place as asset management system to do this; however, as time goes on more and more requests will be made of these systems and the information they contain will be integrated. It is likely that these systems will become critical for reporting and the needs for continuous improvements for customer service associated with the power layer. TLC's present business planning allows for investment in these systems each year. At present the system is continuing to be developed and the need to complete a more visionary plan for the asset management system in conjunction with other systems is recognised.
Inspections and Testing	The inspection and testing of the power layer is critical for controlling the hazards and risks associated with its operation. Advanced networks will have some capability to remotely and automatically carry out a level of inspections, tests and measurements to ensure control of hazards, quality, security and risks. Advanced networks will also require a range of different types of tests and inspections as compared to existing networks. At this time we are unsure of the details and estimates so these items have not been included in the Plan.
Load Control Signalling	Advanced networks will likely start off utilising the legacy injection and signalling equipment, however going forward this will be substantially expanded and or replaced/supplemented with other signalling systems. At this time we have only assumed a continuation of the existing injection systems in forward expenditure estimates.
Fault Data from Field Services and Analysis of this to Automatically Dispatch to the Likely Fault Site	It will be possible with an advanced network to combine SCADA and network information to send staff to the likely site where a fault has occurred or is likely to occur. This capability has been recognised by TLC; however, at this time equipment and system detail needed to be able to implement this has not been researched or set up.
Reactive Power, Load Factor and Losses (Environmental Effects Inherent in a Power System)	With an advanced network some of the technical information that will become available in real time that is associated with operating efficiency and environmental effects includes reactive power flows, load factor and losses. How this information is applied is only very visionary at this time and will require considerably more research. No cost implications or benefits have been considered.

POWER LAYER	
Item	**Comments**
Transmission, Sub-transmission and Substation Interfaces	Advanced networks will make use of a lot more data and information from transmission, sub-transmission and substation interfaces. At this time no research has been done on the potential and how this information may be used.
Security	With the increasing value of copper, thefts and interference with power layer equipment is becoming more common. Advanced networks will likely have features that will increase security and related monitoring. This area is still to be researched.

COMMUNICATIONS LAYER	
Item	**Comments**
Ripple Signal	Ripple signal has the advantage that it reliably can send signals to large numbers of customers quickly and efficiently without involving a secondary communication system. This unique feature means that it has significant advantage. It cannot be used for 2-way network communication and as a consequence, given the hilly nature of the TLC network, it has been assumed it will be around for some time.
Voice Radio, Data Radio, Internet Protocols, Mesh Radio	The way the various communication mediums will be needed and develop as part of an advanced network is unknown at this time.

TABLE 5.26 STRATEGIES, TOOLS AND DEVELOPMENT VISIONS TLC HAS FOR THE LAYERS ASSOCIATED WITH AN ADVANCED NETWORK

5.9.2.6 Large Industrial Customers Encouraged to Install Modular Substations

TLC has an extensive 33 kV transmission network to supply the widely scattered zone substations. If a large industrial approaches TLC with a proposed load increase the possibility of installing a modular substation to supply the installation is investigated. This increases both security and quality of supply for the customer.

In 2006, Hautu prison was the first large customer to which the modular substation principle was applied. In this case a 33/11 kV substation was installed by teeing in to an existing 33 kV line and tying into the existing 11 kV feed to the prison. As such the prison is no longer dependent on a rural feeder that would otherwise have to be upgraded to meet their demand and reliability expectations. This supply, can however be used as backup (at a reduced load). As the 33 and 11 kV lines come from different points of supply, redundancy is achieved. The substation was customer funded, and lower cost than an 11 kV upgrade.

The modular nature of the substation means that, if it becomes redundant, it can simply be moved to the next desirable location. The success of this solution is obviously dependent on location and capacity of surrounding circuits but has, in at least one case, met the needs of both the customer and TLC at a reasonable cost.

TLC also has large industrial customers in the northern area where planning is in place to provide them with a modular zone substation supplying the industrial directly from the 33 kV network.

5.9.2.7 Ripple Control and Load Shedding

5.9.2.7.1 Peak Demand Load Shedding

TLC uses its ripple system to avoid RCPD peaks and reduce/signal network constraints. In 2010 the renewal of the old ripple system in the northern area operating on 725 Hz to a new system operating on 317 Hz began. The progressive replacement of customer relays over the next 3 years will see a significant improvement in the control TLC has over load at peak times.

As mentioned earlier, TLC is evaluating a package provided in conjunction with the network analysis program and will need to justify the initial cost against the proposed savings in reduced GXP costs, power factor penalties, MW and MVAr losses, and avoidance of network upgrades.

A key to further enhancing demand side management will be to implement systems for load control at feeder level and below. This will require intelligent load control systems.

5.9.2.7.2 Under Frequency Load Shedding

TLC has Automatic Under Frequency Load Shedding (AUFLS) relays which is a requirement from the Electricity Commission to ensure that the national grid does not experience total system instability and fail. TLC has devised a system where, if an under frequency event should occur, blocks of load are disconnected from the system.

5.9.2.8 Alternative Supplies for Remote Rural Areas

TLC has investigated and will continue to investigate the use of alternative supplies for remote rural areas. Work to date (that is supported by independent studies) shows that most customers prefer grid supply for sites that are permanently lived in or where dairying is taking place.

Alternative technologies are often used to supplement supplies. For example dairy farms are often established in areas where there is only a single phase supply. Often these farms connect to the single phase supply for vat cooling and install generators for the dairy milking times. Similarly woolsheds are often supplied by generators.

The reality is that farming today is a complex and busy business. Farmers need to focus on this, not running alternative electricity supplies. As a consequence of this most want a reliable grid supply to support their activities.

5.9.2.9 Solar Panels and Domestic Wind Turbines

While TLC encourages customers to support their own power usage through the installation of photoelectric solar panels, solar hot water boosters and small wind turbines, TLC at this time does not have sufficient resources to assist in the development of these types of small business or domestic power supplies. TLC encourages customers to use the technical advisors associated with the distributors of these products. However, customers who do install alternative generation and reduce their peaks do benefit from lower network fees under the Demand Billing system. A number of customers have these devices connected.

5.9.2.10 Surge Arrestors and Surge Suppression

In order to minimise damage to customers' equipment connected to the network, surge arrestors are installed on the network. In addition to this a TLC promotion was run to issue vouchers for surge protectors to customers. Surge protectors are also given out by faults staff, lines inspectors and as part of promotions.

5.9.2.11 Network Non-technical Losses

TLC has evidence of a significant variation between actual losses and losses derived by retailers from the difference between metering data at GXPs and that used for billing at the customer ICPs. The technical losses have been calculated by modelling and make up about 55% of the losses. To get accurate data on the remaining 45% (approx.), is very difficult, with the non-technical losses being caused by metering, meter reading and retailer billing errors.

Losses are funded by customers when retailers add these costs back into energy rates. Improving the accuracy of billing does involve working with retailers to minimise non-technical losses. TLC has worked with its test house and found that about 20% of meter exchanges lead to errors in meter data/readings. For example there have been instances where meter readers have substituted reactive power for active power readings. Blown or disconnected VTs and reverse connected CTs also frequently lead to metering errors – usually underestimation of consumed kWh.

TLC believes the best solution for these kinds of errors is to improve metering technology. Remote meter reading will not be simple in the King Country due to geographic communication difficulties. However, deployment of improved metering (for example handheld units that read and record data automatically) as part of the 2015 compliance and TLC's demand metering needs will likely significantly reduce meter reading error.

5.9.2.12 Demand Side Management Summary

TLC uses as many approaches as possible to ensure customers' capacity and cost expectations are met. These tools include the construction of capacity, generation and demand side management initiatives.

Due to the remote nature of the TLC network and that it is sparely populated, the cost of capacity construction can be high and often customers' ability to pay is limited. As a consequence of this, TLC is leading the way nationally in its charges that are designed to promote demand side management. It is acknowledged however, that demand control was used extensively in the 1950's and early 1960's. At that time though the technology such as electronic half hourly meters was not available to make this concept accessible to all customers. This technology is now possible.

TLC is in the process rolling out advanced demand meters to all customers to improve the ability of customers to monitor their demand.

TLC's forward asset management plans are relying heavily on demand side management to control demand and alleviate the need for investment in development while larger renewal programmes are in place. The use of capacitors and generators are to postpone the need to upgrade the network and TLC has installed (and is planning more) voltage regulators on its feeders to push the ageing and small volume feeders to their limits, however, the forward expenditure for TLC will need to include conductor and system upgrades to manage the system growth in the long term.

5.10 Non-System Fixed Assets Capital Expenditure Forecast

Table 5.27 outlines the Capital expenditure for non-system fixed assets.

Non-System Fixed Assets Capital Expenditure										
	2015/16	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**
Building Re-structure	$ 1,500,000	$ 1,500,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Data Systems	$ 96,390	$ 96,390	$ 96,390	$ 96,390	$ 96,390	$ 96,390	$ 96,390	$ 96,390	$ 96,390	$ 96,390
Metering	$ 2,800,000	$ 2,800,000	$ 1,500,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Misc Equip	$ 10,710	$ 10,710	$ 10,710	$ 10,710	$ 10,710	$ 10,710	$ 10,710	$ 10,710	$ 10,710	$ 10,710
Office Area	$ 21,420	$ 21,420	$ 21,420	$ 21,420	$ 21,420	$ 21,420	$ 21,420	$ 21,420	$ 21,420	$ 21,420
Vehicle Replacements	$ 68,250	$ 68,250	$ 68,250	$ 68,250	$ 68,250	$ 68,250	$ 68,250	$ 68,250	$ 68,250	$ 68,250
Total	**$ 4,496,770**	**$ 4,496,770**	**$ 1,696,770**	**$ 196,770**	**$ 196,770**	**$ 196,770**	**$ 196,770**	**$ 196,770**	**$ 196,770**	**$ 196,770**

TABLE 5.27 CAPITAL EXPENDITURE FOR NON-SYSTEM FIXED ASSETS

Note: The vehicles listed in Table 5.27 Capital Expenditure for Non-System Fixed Assets

are asset management vehicles and do not include TLC Contracting or other organisational vehicles.

5.11 Summary Description of Non-network Assets

5.11.1 Information and Technology Systems

TLC has a number of information and technology system that are used for network analysis, line design and mapping. Table 5.28 below outlines TLC's Information and Technology Systems.

DESCRIPTION OF TLC'S INFORMATION AND TECHNOLOGY SYSTEMS.	
Information and Technology System	**Description**
Electrical Transient Analyser Program	The Electrical Transient Analyser Program (ETAP) is a fully integrated AC and DC electrical power system analysis tool. ETAP is used for load flow, fault current, circuit breaker sequencing, distributed generation, harmonic and arc flash modelling. TLC has configured ETAP to represent the predicted growths of TLC's network. This allows TLC's planners to factor future capacity requirements into their equipment selection for the growth anticipated. Protection setting data has being put into ETAP to simulate circuit breaker, recloser and fuse operation under fault conditions. Harmonic levels and arc flash ratings are also calculated from ETAP.
CATAN	CATAN is an integrated design package that provides accurate solution to overhead power line design. The software removes the tedium and inaccuracy of manual data entry and manual calculation. TLC is currently in the process of inputting pole data, pole location, circuit lengths, and conductor types etc. into the software to make line design more accurate and efficient.
MicroStation	MicroStation is a CAD software program used for designing and drafting. MicroStation provides interaction with 3D models and 2D designs to produce precise drawings, its robust data and analysis capabilities enable performance simulation of designs. TLC currently use MicroStation for detailed engineering design, mimic updates and line design.
ESRI GIS system	Currently TLC has an ESRI GIS system for designing and managing solutions through the application of geographic knowledge. Assets are broken down into components and the asset type, capacity are recorded along with a considerable number of other data fields. Geographical locations are recorded and inputted into the GIS system.

TABLE 5.28 DESCRIPTION OF TLC'S INFORMATION AND TECHNOLOGY SYSTEMS

5.11.2 Asset Management Systems

The asset management system is based on BASIX software over an SQL server database. The BASIX system contains asset data for the whole TLC network and is used to calculate reliability statistics and valuations. It also produces reports that align with the network performance criteria in Section 4 of this Plan. The system is being extended further to include asset related customer service data.

The BASIX system is also used for many other asset related activities as detailed in subsequent sections. There has been a considerable amount of progress on the development of the system over the last 24 months and there is an extensive amount of development planned going forward. This will likely include things such as improved outage notification systems and the changed NZCC22 disclosure requirements.

5.11.3 Office Buildings, Depots and Workshops

TLC's main office is located on King Street East of Te Kuiti town. The office is a two story building which was commissioned in 1958. TLC recently had a seismic assessment completed though an external consultant. The conclusion to the assessment was that the building is not earthquake safe and needs strengthening and reinforcement. Building renewal projects are planned for 2015/16 and 2016/17.

5.11.4 Other Non-Network Fixed Assets

TLC, through a subsidiary company, owns the majority of customer meters and relays. It also owns interconnection metering assets at Whakamaru, Mokai, and Tangiwai (uncertified). About 40% of the domestic metering installations have two meters (controlled and uncontrolled). The remainder are a mixture of 2 phase and single meters.

As part of the demand billing initiative, TLC is deploying advanced meters to domestic installations. These are read by both retailers (monthly or two monthly), and TLC (annual download of half hourly demands). These half hourly demands are reconciled with load control signals and customers' half hourly demands are used to calculate the annual demand component of their line charges.

The TLC owned relays are 80% of the modern programmable electronic type. The remainder are old and electro-mechanical relays. The channel segmentations of these relays is typically that of the legacy lines company load control systems, i.e. about 10 channels randomly deployed for water heater controls, 2 channels for street lighting, other channels for times controls and a few other channels mostly allocated for encouraging electrical energy usage programmes from the Electro Corp marketing strategies of the 1980's. Looking forward, these channel layouts will be modified for the future to include more focus on demand billing, the fast load reduction frequency market and other activities involved with an advanced network.

5.11.5 Other Organisation Non-system Fixed Assets

TLC uses Navision which is well established Microsoft ERP system which well supported in the market. Navision is used extensively to maintain the accounting general ledger and sub ledger modules. Navision is interfaced with other core operating systems, including Gentrack (billing).

TLC uses Gentrack which is a well-established billing and customer services software product used widely in the electricity sector. Gentrack is used for customer invoices, debtor management as well as customer services management. Gentrack is interfaced with other core operating systems, including Navision (general ledger). The company operates a highly customised version of Gentrack which places constraints on updates and maintenance of the software. Gentrack currently does not deliver the full width of functionality required by TLC and further significant customisation of the product is not deemed cost effective.

Section 6

6. Lifecycle Asset Management Planning (Maintenance and Renewal)

6.1 Description of Maintenance Planning Criteria and Assumptions

Detailed in the following sections are the key drivers for maintenance for the various asset categories. Maintenance is planned to allow the network performance to meet the targets listed in Section 4. The following maintenance planning criteria are used to ensure these performance standards are met:

Hazard Elimination and Minimisation - Ensure equipment is installed, labelled, maintained, fit for purpose and secured to eliminate or minimise hazards to staff, the public and the environment. It is assumed that stakeholders, regulators and other interested parties require equipment to be maintained to eliminate and minimise hazards. This is also required for compliance with TLC's SMS and HSE policies.

Reliability - Ensure equipment will reliably operate to produce the outcomes it was purchased and installed for. It is assumed stakeholders and other interested parties require equipment to be maintained in a reliable state.

Operation - Ensure equipment is maintained, used, and operated in the way that it was designed for.

This maintenance criterion assumes stakeholders will wish equipment to be used in a way that does not cause hazards, failure ahead of time or is overrated for a particular application.

Life Span - Ensure equipment is installed, operated, and maintained in a way that it reaches or exceeds its expected life span. It is assumed that equipment should be managed to ensure its expected life span is achieved.

Simplicity - Maintenance periods, policies, and criteria that are easy to understand, realistic and achievable.

Experience has shown that complex non-standard equipment or procedures leads to confusion, an increase in hazards and increased costs. It has been assumed these should be avoided.

Renewal - Equipment should be renewed when it is no longer suitable for its intended function. It is assumed that continuing with equipment that is not reliable, constitutes and environmental risks does not control hazards, or for which parts are no longer available, is not cost effective. Where it will not do the job it is intended for, it should be renewed. The renewal decisions should consider the criteria listed above against commercial, pragmatic, and customer considerations.

The commercial considerations include:

- Cost of maintenance versus renewal.
- Income the equipment assists in generating.

The pragmatic considerations include:

- Will it work and meet customers' expectations?
- Will it be accepted by the people who have to operate it?
- Is it reliable?
- Is there any environmental implications?
- Are any hazards associated with the equipment in line with current stakeholder expectations? (public or staff)
- How long will it last?
- If things change, can it be used elsewhere in the network?
- Is there good supplier support?

The customer considerations include:

- Will it work and provide a solution that allows customers to get on with their business?
- Are they prepared to fund the solution either directly or indirectly?

6.2 Description and Identification of Routine and Preventative Maintenance Policies, Programmes or Action to be taken for each Asset Category including Associated Expenditure Predictions

6.2.1 Summary of Maintenance Schedule

The key maintenance schedules are summarised in Table 6-1

MAINTENANCE SCHEDULE SUMMARY	
Item	**Maintenance Framework**
All Categories	» Follow up after faults, defects and hazard reports (including "Red Tagged poles"). The resulting work will include minor maintenance through to renewal.
Overhead Lines and Cables (Excludes Ski Field Areas), Distribution Poles	Patrols: » 18 monthly drive or foot patrol through urban areas and schools looking for potential problems including vegetation. (11 kV and LV.) » 3 yearly helicopter patrols of rural areas looking for potential problems including vegetation. (11 kV and LV.) » 12 monthly helicopter patrols of 33 kV lines looking for potential problems including vegetation. » Fault patrols of all lines after a series of auto-recloses, tripping's or other reports. When these fault patrols involve a 33 kV line, a corona camera survey may be included. Most of these rural patrols are done from a helicopter. Inspections: » 15 yearly detailed inspection and renewal cycle. Emergent: » Renewals and maintenance as required to maintain supply and eliminate/minimise hazards. Emergent work often occurs as a result of following up after an event and includes a SMS hazard report.
Cables (Ski Field Areas)	Patrols: » Annual foot patrols through the low valley areas, stream beds, rock movement areas, in/around tracks and high hazard areas looking for potential problems. » 3 yearly foot patrols of cables and visual inspections of till box integrity. Inspections: » 15 yearly detailed inspections of cables and till boxes.
Vegetation	» 3 yearly patrol cycle for rural areas and 18 months for townships and schools (compliance driven). Emergent cutting to eliminate hazards or restore supply.

MAINTENANCE SCHEDULE SUMMARY	
Item	**Maintenance Framework**
Zone Substations	» 2 monthly routine maintenance checks. » 12 monthly detailed checks. Actions include earth tests. » 2 yearly oil tests for major transformers. » 3 yearly maintenance of active oil filled circuit breakers. » 5 yearly tap changer oil and maintenance on major transformers. » 15 yearly major maintenance cycles, which include SCADA recalibration, busbar cleaning, circuit breaker timing checks, detailed inspections, earth testing, painting, protection checking and extensive cleaning of the site. » Hazard elimination/minimisation projects as detailed in Section 5 of this AMP. Emergent: » Renewals/maintenance necessary due to failures or damage. Other equipment renewals/refurbishment as detailed in Section 5 of this AMP. » Oil refurbishment based on the results of 2 yearly oil tests.
Pole Mounted Transformers	» Renewal after failure - often caused by lightning or other damage. » Exchanged with renewed or maintained unit as part of the 15 yearly line renewal programme if the unit is in a decayed state, i.e. Rusty lid, poor paintwork etc. » Testing of earths and renewing of earthing systems as necessary. (Earth is tested as part of 15 year line inspection programme.) » Renewal or exchange with a maintained unit triggered by customer's need for more or reduced capacity.
Ground Mounted Transformers and Ground Mounted Switchgear	» 12 monthly security check and minor urgent maintenance. » 15 year major maintenance cycle. » Hazard elimination/minimisation projects as detailed in Section 5 of this AMP. » Emergent renewals/maintenance necessary due to failures or damage. » Renewals/upgrades triggered by changed customer demands.
Service Boxes	» 5 yearly inspection and renewal cycle. » Planned hazard elimination/minimisation projects as detailed in Section 5 of this AMP. » Emergent renewals/maintenance necessary due to failures or damage (typically vehicle impacts). » Renewals/upgrades triggered by changed customer demands.
SCADA and Communication	» Maintenance repairs when the system, or parts thereof, do not operate. » Renewals of software and hardware with modern equivalents on failure. » Planned renewals to keep software and hardware up to date.
Load Control	» 3 monthly inspection of rotating plants and equipment room cleaning. » 2 yearly vibration analysis of rotating plants. » 12 monthly inspections of static plants and cleaning. » Planned renewals of plant as recommended by the supplier. » Hazard elimination/minimisation projects as detailed in Section 5 of this AMP. » Emergent renewals/maintenance necessary due to failures or damage. » Changes to control software triggered by changes to customer charging policies (driven by demand side management initiatives).

MAINTENANCE SCHEDULE SUMMARY	
Item	**Maintenance Framework**
Three Phase Reclosers, Automated Switches and Voltage Regulators	» 12 monthly inspections. » Emergent renewals/maintenance necessary due to failures or damage. » Relocations and refurbishment of equipment to fit in with the long term development plan as detailed in Section 5 of this AMP.
SWER Systems	» 2 yearly inspections of reclosers and sectionalisers, and testing of isolation transformer earths. » 15 yearly inspections and testing of distribution transformer earths. (Lines are patrolled 3 yearly and inspected 15 yearly as part of lines programme.) » Emergent renewals/maintenance necessary due to failure or damage - mostly earthing systems.
Fault Inspections	» 33 kV lines after recloses or tripping's. » 11 kV lines after recloses or tripping's. » Many fault inspections will be by helicopter as this is the most efficient way of patrolling in the rugged King Country terrain.
Other Inspections	» On-going roving. » Quality – Annual harmonic checks of key areas of the network, in particular 33 kV lines, industrial areas and a number of SWER systems. » Asset Efficiency – Annual power factor checks of key areas of the network, in particular 33 kV lines, industrial areas and adjacent to distributed generation sites.

TABLE 6.1: SUMMARY OF MAINTENANCE / RENEWAL STRATEGIES

Note: All patrols, inspections and works are recorded against the assets in the Basix asset management system.

6.2.2 Overhead Lines

Overhead lines form the highest value asset category owned and operated by TLC.

6.2.2.1 Overhead Lines: Inspection, Testing and Condition Monitoring Practices

6.2.2.1.1 Patrols – Inspection, testing and condition monitoring practices

Patrols are used to find and overcome obvious immediate asset problems and follow the schedule as listed in Table 8.1. Most of the rural patrols are done from a helicopter. Identified problems are photographed, the asset identifying numbers recorded and the location physically recorded with GPS co-ordinates. A report is completed after each patrol and data verifying that a patrol has taken place is recorded against each asset. Tools such as helicopter flight path recording via Google earth are used as additional references for the locations of defects.

The use of a corona camera has been successful in finding damaged insulators on 33 kV lines when carrying out helicopter patrols. Most of these faults are caused by insulator flashover from fertiliser build-up. In the extreme they escalate to cross arm failure. The corona camera has not proved successful for finding problems on 11 kV lines.

Helicopter patrols are cost-effective and provide a quick way to cover long lengths of lines in rugged country. The average cost is $35 to $55 per km. They are also a good way of ensuring customers know TLC is concerned about their supply, with most rural customers appreciative of a low level helicopter check after a series of auto recloses. The biggest negative to helicopter patrols is stock disturbance, particularly when intensive break feeding of cattle is taking place. Staff are stock conscious and keep a watch ahead of flight paths for potential stock and other issues. High level fly overs are often undertaken to check for stock before low level inspections. Where possible we advise farmers of patrols ahead of time.

Helicopter patrols are not possible in urban areas and around places such as schools where more detailed shorter cycle patrols are required. Urban and school areas are patrolled from the ground on an 18 month rotation to identify problems and potential hazards.

Other special one-off patrols are also completed from time to time. For example, if a 33 kV line is to be used as an alternative supply while Transpower has a grid exit point out of service for maintenance, the line will be patrolled beforehand. Key lines are often patrolled preceding special events such as long holiday weekends.

Patrols may take place after a series of auto recloses to try and identify the cause of the tripping's. Patrols are also completed after customers express concern or report some type of problem with equipment.

6.2.2.1.2 Inspections - Inspection, testing and condition monitoring practices

Inspections are used to take a more detailed look at assets and drive the longer-term preventative maintenance and renewal programmes.

The inspection assessment includes:

- Travelling to each pole and assessing the condition of all hardware, cross-arms, conductors etc.
- Testing the pole - if practical and access is possible - with a mechanical strength tester.
- Photographing the pole and associated hardware.
- Plotting the position by GPS.
- Measuring span lengths.
- Checking vegetation and recording any other issues associated with line security.
- Visually checking the integrity of the transformer and equipment earthing.
- Visually checking all earthing at transformer and equipment sites. Testing is also completed.
- Visually checking all HV fuses and air break switches. This includes visually checking and testing the earthing system.
- Checking all switch and fuse labelling and re-labelling if they are not readable.

- Checking pole labelling and re-labelling with new asset numbers as required.
- Checking all transformers and other equipment labelling.
- Completing data sheets.
- Establishing walking access to pole sites. This may involve cutting a track through bush, scrub etc.
- Initial renewal specifications, and design when renewal is being proposed by the inspector. The inspectors' assessment and specified renewal requirements are desk top checked and calculations are completed.
- Site access details are recorded for renewal recommendations.
- Recording and specifying any minor maintenance needs.

6.2.2.2 Overhead Lines: Processes for ensuring overhead line defects identified by the Inspection and Condition monitoring programmes are rectified

6.2.2.2.1 Patrols – Ensuring defects are rectified

Data from the patrols are returned to the asset and engineering management section for processing. Data and defect reports are reconciled to asset database and the types of assets. The locations of assets are verified along with any other information stored against the asset. Vegetation data are separated out and forwarded to vegetation control and follows the process detailed in later sections.

Repairs and renewal instructions from the patrollers are then checked and instructions to field staff are prepared. For larger problems, detailed designs may be included and financial approval from Directors may have to be secured. Once the appropriate specifications, designs and approvals are obtained, works orders are issued to the internal Service Provider. The Service Provider then schedules and completes the work. Once notification is received that work has been completed, it may be audited (particularly larger jobs) by a lines inspector/designer before final payment is approved. Asset records are updated as part of the final settlement process. The auditing ensures work is completed to the specifications and that all assets are correctly labelled.

6.2.2.2.2 Inspections – Ensuring defects are rectified

The following processes are used for rectifying defects and ensuring data are correct after detailed inspections:

- Appropriately qualified and experienced staff conduct the inspections.
- Inspections are reconciled against the asset data records.
- Gathered data and photographs are loaded into databases.
- Strength calculations on selected assets are carried out using a line design package.
- Field inspector's designs are reviewed and modified as necessary.
- Co-ordinate renewals and maintenance with other works.
- Investigate the outages needed to do the work and the implications of the outages.
- Put together work packages and specifications including specifying requirements to eliminate or minimise hazards.
- Notify landowners and discuss proposals.
- Prepare, obtain and check cost estimates. This includes reconciling industry current cost survey data.
- Issue work to contractors.
- Receive and process applications from contractors to work on network. Police contractors to ensure they eliminate/minimise hazards, are approved to work on network and have hazard control programmes in place.
- Receive notification from contractors that works are complete and audit work for compliance with the specifications.

- Review private line connections and ensure customers understand their liabilities under the Electricity Act and its regulations. In extreme cases for private lines that pose a significant hazard, details are forwarded to Energy Safety for follow up. (The Electricity (Safety) Regulations 2010 impose significant liability for private lines on the line owners. At this time the various government bodies do not appear to have co-ordinated their activities in this area, nor understood the implications of the liabilities the Regulations place on the rural communities.)
- Re-audit and where required issue further network instructions.
- Accept invoices and reconcile to original estimates.
- Carry out line owner follow-ups.
- Settle any outstanding landowner or line owner issues.
- Ensure all as built data and databases are updated.

6.2.2.3 Overhead Lines: Systemic Problems and Solutions

Table 6.2 summarises the systemic problems associated with lines and the steps taken to address these. Some of these issues were discussed in Section 3.

OVERHEAD LINE SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problems	**Steps to Address**
Insulator failures advanced by fertiliser build up and magpies.	» Taller insulators with longer creepage distances.
Air Break Switch failures due to poor manufacturing and connections.	» Greater quality focus on connections and use of proven switch types.
Tree and other environmental issues such as flooding and slips.	» Tree programme in place. » Equipment located away from flood prone land. » Slips continually watched during helicopter patrols and inspections. Poles moved to less hazardous locations.
Wire clashing.	» Greater focus on line design, fault current control designs and wire spacing/tension.
Insulator wire ties breaking due to vibration and loading.	» Greater focus on quality of hardware. » Larger size binder wire used. » Galvanised steel pre-form wire ties that tend to corrode are not used.
Connection failure due to dissimilar metal reactions.	» Greater focus on the quality of connectors and types used. They must be straight forward and simple to apply, yet robust and able to handle dissimilar metals.
Drop out fuse failures.	» Careful component selection. » Attention to corrosion, connections and clearances for hazard elimination/minimisation.
Pole cross-arms and other hardware problems.	» Focus on component workmanship quality and design, in particular making sure correct pole and component strengths are used. » Planned renewal programme and making sure reported problems are followed up. This is critical for improving reliability, SMS, security and hazard control.
Private responsibility overhead lines interfering and causing problems with TLC assets.	» Increased fusing of private lines. » Increase publicity to owners to improve their awareness and understanding of the complex issues for compliance with Electricity Regulations. » Better data systems including more detail on ownership and responsibility for lines.

TABLE 6.2 SYSTEMIC PROBLEMS ASSOCIATED WITH LINES

6.2.3 Cable (Ski Field Areas): Inspection, Testing and Condition Monitoring Practices

6.2.3.1 Patrols – Inspection, testing and condition monitoring practices

Foot patrols are used to find and overcome obvious immediate asset problems. Identified problems are photographed, the asset identifying numbers recorded and the location physically recorded with GPS co-ordinates. A report is completed after each patrol and data verifying that a patrol has taken place is recorded against each asset.

Annual Foot patrols are conducted in low valley areas, stream beds, rock movement areas, in/around tracks and high hazard areas. A foot patrol of the whole cable length is done over 3 years (the cable length is split into 3 sections and each section is done once in the 3 years). Patrols may take place after a series of auto recloses to try and identify the cause of the tripping's.

6.2.3.2 Inspections - Inspection, testing and condition monitoring practices

Inspections are used to take a more detailed look at assets and drive the longer-term preventative maintenance. Cables are maintained on a time based programme.

Time based inspection and maintenance programmes include:

- Three yearly cable and till box integrity inspection
- 15 yearly detailed cable termination and till box termination inspections as well as earth testing and insulation resistance testing.

6.2.4 Vegetation

6.2.4.1 Vegetation: Reliability and Compliance of Vegetation Control Programmes

The 2003 Reliability Report identified vegetation maintenance as an important component in improving network reliability. Analysis found that a large number of the faults had their root causes associated with vegetation. The Electricity (Hazards from Trees) Regulations 2003 were gazetted in December 2003 and focused on controlling hazards after the electrocution of a child in Auckland.

Analysis of tree data, collected since 2003, shows that complying with the regulations and thereby reducing hazards also increases costs. This cost increase is due to the administration/supervision needed to manage the processes as specified by the regulations and TLC's responsibilities when tree owners do not cut trees. The cut distances stipulated in these regulations focus on ensuring people cannot climb a tree and touch energised conductors. These distances will help reliability, but do not ensure that clearances are great enough to stop trees falling through lines, especially these associated with plantation trees.

Overall the implementation of vegetation and compliance strategies has meant that landowners have become more aware of their responsibilities. Generally most co-operate and allow trees to be cut.

Each year the program for reliability and complains is received and of this line there has been no sustainable or commercial justification for altering the loose approaches.

6.2.4.2 Vegetation: Inspection, Testing and Condition Monitoring Practices

6.2.4.2.1 Planned – Inspection, testing and condition monitoring practices

A review of TLC's tree strategy took place during late 2006. The strategy adopted as a result of the 2006 review was to focus more on maintaining the areas where cutting had taken place in the 4 years previous and moving out into uncut areas in response to outage and known problem areas. Since this time the three yearly patrols have covered the more remote uncut areas and most of these have now been addressed. At this point in time the clearances on the outlying lines are not as great as the clearances along more important lines; however, distances are increasing with each 3 yearly cycle. Vegetation patrols are included in the line patrols outlined in the preceding sections. Costs associated with vegetation control are included in the maintenance expenditure projections. The areas patrolled each year are identified by feeders and asset groups. The workflow includes the following key activities:

- Split the network into three 30% groupings.
- Fly one group in a particular year.
- GPS trees and other line problems observed.
- Complete a written report giving specifications and prepare instructions for each work site.
- Record work completed in the asset database.

6.2.4.2.2 Unplanned – Inspection, testing and condition monitoring practices

Emergent notifications of tree problems are received from customers, staff and other sources. Records are taken of these notifications and the issues are investigated by TLC's line inspectors. Customer liaison, work specifications and instructions are undertaken for each site.

6.2.4.3 Vegetation: Processes for ensuring defects identified by Inspection and Condition monitoring programmes are rectified

Once tree inspection personnel have identified, specified and detailed requirements, further processing is completed by administrators.

This processing includes:

- Laying out on maps the locations of vegetation infringements.
- Reconciling locations and instructions to previous cut data.
- Notifying and discussing issues via mail or directly with landowners. The approach taken is dependent on the issue, previous history and local knowledge.
- Engaging tree contractors to carry out work.
- Receiving cut data and invoices from tree contractors.
- Storing all cut data including costs, landowner agreement details etc. in the Basix database.
- Allocating, scheduling and co-ordinating personnel for auditing of completed work and any necessary landowner follow up.

6.2.4.4 Vegetation: Systemic Problems and Solutions

Table 6.3 summarises the systemic problems and solutions associated with vegetation and the steps taken to address these.

VEGETATION SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problems	**Steps to Address**
Landowners planting under lines.	» 3 yearly patrols following up on new plantings.
Trees that breach the fall distance.	» Charging landowners for problems caused by trees that breach the fall distance if the tree does fall through lines.
Landowners not complying with Tree Regulations.	» Strict follow up on notices. » Account follow up on any invoiced charges.
Legacy issues.	» Issues are addressed one at a time when problems occur. They are mostly associated with plantation owners and their desire to maximise forest production.
Forest fires started by trees falling through lines.	» The Rural Fire Act has been poorly written, leaving network companies liable for damage caused by trees, no matter how good their tree programmes are. Insurance is the only solution to potential liabilities.

TABLE 6.3 SYSTEMIC PROBLEM AND SOLUTIONS ASSOCIATED WITH VEGETATION

NOTE: TLC'S VEGETATION'S PROGRAMMES ARE REVIEWED ANNUALLY WHEN THIS PLAN IS PREPARED.

6.2.5 Zone Substations

6.2.5.1 Zone Substations: Inspection, Testing and Condition Monitoring Practices

Zone substations and voltage control equipment are maintained on both a time and a condition based programme.

Time-based inspection and maintenance programmes include:

- Inspections every two months to ensure site security and identify potential hazards. General operation is checked and minor maintenance issues addressed such as batteries, servicing and weed spraying.
- Annual substation earth tests.
- Two yearly oil and other testing as appropriate for the site: i.e. corona, partial discharge and thermo vision. Major equipment oil tests are conducted to ensure equipment, particularly transformers, are within operating specifications.

A fifteen year major maintenance cycle where equipment is extensively maintained and tested. The fifteen year major maintenance cycle was selected based on:

- The typical period a good paint job lasts, and an appropriate period for a repaint.
- The typical maximum period that technical equipment can be expected to operate reliably before extensive maintenance/renewal and testing. The scope of this work varies from site to site but typically includes protection testing, circuit breaker timing tests, SCADA calibration checks, busbar cleaning etc.
- Three yearly oil changes in active Oil Circuit Breakers.
- Five yearly tap changer oil changes.

The condition-based programmes include:

- Maintenance of equipment after faults.
- Maintenance of transformers after oil analysis.
- Renewal of faulty equipment.
- Maintenance or renewal after testing.

Table 6.4 summaries the inspection regime for substations.

SUBSTATION EQUIPMENT & MAINTENANCE SCHEDULES				
	Asset Inspection	**Routine Inspection Frequency Period**	**Scheduled Maintenance Frequency Period**	**Operations**
1	Substation buildings and grounds	2 Monthly	-	
2	Power transformers and voltage regulating transformers:-			
	- Oil sample and Dissolved Gas Analysis	-	2 Yearly	
	- Oil levels	2 Monthly	-	
	- Silica gel breather	2 Monthly	Annually	
	- Earth connections	-	Annually	
	- Tank	2 Monthly	15 Yearly	
	- Radiators	2 Monthly	15 Yearly	
	- Tap changer mechanism	2 Monthly	5 Yearly	
	- Tap changer oil & diverter switches		5 Yearly	
	- ABB & Cooper VR 32's	2 Monthly	15 Yearly	50,000
	- Buchholz	2 Monthly	5 Yearly	
	- Insulation resistance	-	5 Yearly	

SUBSTATION EQUIPMENT & MAINTENANCE SCHEDULES				
	Asset Inspection	**Routine Inspection Frequency Period**	**Scheduled Maintenance Frequency Period**	**Operations**
3	Outdoor Busbars, Airbreak switches & structure supports	2 Monthly	15 Yearly	
4	Outdoors VTs and CTs	2 Monthly	15 Yearly	
5	Lightning arrestors	2 Monthly	15 Yearly	
6	33kV OCBs - McGraw Edison - Vacuum Break - Oil break - Scarpa Magnino - Generator OCBs - Taharoa Substation - Others	 2 Monthly 2 Monthly 2 Monthly 2 Monthly 2 Monthly 2 Monthly	 15 Yearly 3 Yearly 3 Yearly 3 Yearly 3 Yearly 15 Yearly	
7	11kV Metal Clad OCBs - Generator OCBs (oil break) - Other oil break - Vacuum break	 2 Monthly 2 Monthly 2 Monthly	 3 Yearly or 3 Yearly or 15 yearly	Post fault 60
8	11kV Fuse Switches	2 Monthly	15 Yearly	
9	11kV Pole Mounted OCBs - Oil break - Vacuum break	 2 Monthly 2 Monthly	 3 Yearly or 15 Yearly	60
10	11kV Pad Mounted Transformers	2 Monthly	15 Yearly	
11	11kV Switchboard and Internal Busbars	2 Monthly	15 Yearly	
12	Substation Protection Relays	2 Monthly	15 Yearly	
13	Load Control Equipment	2 Monthly	Annually	
14	Battery Banks and Charges	2 Monthly	3 Yearly	
15	Substation phones and radios	2 Monthly	15 Yearly	
16	R.T.U's and Dehumidifiers	2 Monthly	15 Yearly	

TABLE 6.4 : ZONE SUBSUBSTATION EQUIPMENT AND MAINTENANCE REGIME

In addition to these practices, various components and architecture associated with zone substations are included in the long-term renewal and development programmes outlined in Section 5. This renewal and development work is implemented in addition to the above programmes.

Many of TLC's zone substation components are old and, when they fail, repairing existing equipment is not an option due to parts availability. In these situations components are renewed with modern equivalents.

6.2.5.2 Zone Substations: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

Zone substation renewal and maintenance workflows will follow several paths. In summary these include:

Two-Monthly Inspections: Data records are completed and returned after work has been done. These are reviewed by engineering staff and reports are entered into databases. Works are specified and orders are raised for non-conforming issues. Follow up audits are completed to ensure work is done to specifications.

Annual Substation Inspections and Tests: Results are checked and when tests are outside codes, regulations or good industry practices, designs are completed and works orders are issued. Follow up tests are completed and works are audited to ensure work is done to specifications.

2 and 3 yearly Inspection and Testing: Works orders are raised every two years for full Dissolved Gas Analysis testing of oil in main tanks of 33/11kV transformers. The results are reviewed by a consultant and updated information used for the oil maintenance programme and long term asset condition. Works orders are raised for corona, partial discharge and thermo vision testing relevant to a particular site to follow up any outstanding issues. Where tests indicate oil maintenance is needed, specifications are prepared and works orders are issued. Follow up tests are done as necessary after work as part of the auditing process. All results and actions are recorded against the asset.

5 and 15 year Maintenance: A task list is put together that is additional to planned renewal and minor maintenance. Work may include any catch-up needs and other items such as painting, wooden arm replacement, corroded steel work, protection tests, SCADA calibration checks etc. The 2 monthly inspection data and site condition information is the main input into the specifications associated with this work.

Schedules for each substation may differ but they generally follow the list in table 6.1 and 6.4

Maintenance of Equipment after Faults: The Engineering staff specifies and allocates the work to contractors. The Engineering staff review and evaluate the options. Usually the lowest cost option is selected, which often involves renewal of equipment components with modern equivalents. In all cases specifications are prepared and works orders are issued after quotes are obtained.

6.2.5.3 Zone Substations: Systemic problems and solutions

Table 6.5 summarises the systemic problems associated with zone substations and the steps taken to address these. .

ZONE SUBSTATION SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problem	**Solutions**
Voltage control and protection systems	» Repair or, if obsolete and parts not available, renew equipment.
Transformer failure after passage of fault current	» Limit fault current by design. » Dry and tighten transformer cores when oil test indicates high moisture content in insulation.
Lightning damage	» Design for lightning protection.
Switchgear failure	» Repair or, if obsolete and parts not available, renew.
Insecure fences	» Repair or renew.
Transformers ageing	» Regular oil tests. » Oil or transformer refurbishment. » Contingencies in case of failure.
Discharging switchgear and cables	» Clean, re-terminate or replace faulty components.

TABLE 6.5: SYSTEMIC PROBLEMS ASSOCIATED WITH ZONE SUBSTATIONS

6.2.6 Distribution Pole Mounted Transformers

6.2.6.1 Distribution Pole Mounted Transformers: Inspection, Testing and Condition Monitoring Practices

Pole mounted transformers are maintained when:

- The 15 yearly cycle line renewal/maintenance programme inspection and test process finds aged or poor condition transformers.
- After site visits, due to faults or other reasons, transformers are found to be in poor condition.
- Customers require increased or reduced transformer sizes.
- When hazard elimination/minimisation projects are completed at a site and the transformer is exchanged. Often a different transformer configuration is needed when a hazard elimination/minimisation project is completed.
- TLC receives reports or information indicating that the earthing system has been compromised.

6.2.6.2 Distribution Pole Mounted Transformers: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

Transformers, when returned from the field, are sorted into three categories.

These are:

- Return to field without any work.
- Refurbish.
- Write off.

The decision as to which category transformers go into is controlled by the Operations or Technical Support Engineer. The decision is made on a number of criteria:

- The cost of refurbishment versus repair.
- Bushing layout and hazard control issues likely at future sites the transformer may be located.

Work orders are raised for transformer refurbishment and the costs are placed against the transformer asset. Once completed and ready for service, they go back into the available stock. The Basix asset management system is the main tool used to track these costs and transformer movements.

Maintenance of pole hanging transformers typically involves painting, oil filtering and bushing replacement if damaged. Pole hanging transformers with internal winding faults are usually written off.

6.2.6.3 Distribution Pole Mounted Transformers: Systemic Problems and Solutions

Lightning damage, age and tank rust are the typical systemic problems with distribution transformers. The solution is either to refurbish or renew. Lightning arrestors and over-current protection fuses are fitted to all transformers. In recent times problems have been experienced with earthing systems being stolen for copper value. There are no solutions at present to eliminate this problem.

6.2.7 Ground Mounted Transformers

6.2.7.1 Ground Mounted Transformers: Inspection, Testing and Condition Monitoring Practices

Ground mounted transformers are inspected 5 yearly.

These checks include:

- Labelling and danger signs.
- Inspection of the physical integrity of the site including equipment, equipment numbering, hazard control labelling and earthing.
- Recording and resetting Maximum Demand Indicators.
- Locks, labels and any switchgear locks, fuses, operating equipment etc.
- Minor maintenance including painting over any superficial graffiti.
- Visual check of any switchgear attached to the site.
- General spot heat check of equipment.
- Data reconciled for site including photographs.

This annual inspection data feeds into a fifteen-year major maintenance programme. The major maintenance programme is also linked to other programmes such as line and switchgear renewals. Sites have been assessed and prioritised based on the annual data collected.

Major maintenance includes:

- Painting and site security (additional locks).
- Insulating exposed terminals.
- Internal cleaning and part replacement.
- Renewal is generally triggered by condition and the need to control hazards.

6.2.7.2 Ground Mounted Transformers: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

Defects found as part of the 5 yearly checking process have work specifications prepared and orders are issued. Completed works are monitored and reconciled to works orders.

The major renewal and major maintenance work coming out of 5 yearly inspections are prioritised and detailed in future plans by site. In the year preceding the planned work, the network engineers work through these lists and prepare detailed specifications. These are forwarded to contractors for pricing generally before the programmed year for the works.

During the planned year, works orders are issued to contractors. Once work is completed, auditing takes place before invoices are paid. At the completion of work, data and plans are updated.

6.2.7.3 Ground Mounted Transformers: Systemic Problems and Solutions

6.2.7.3.1 Hazard Control – Special Maintenance

All ground mount transformer sites have been inspected and assessed for hazards. Whilst some will be replaced in the renewal work programme, others will have maintenance completed to allow the renewal programme to be cycled. Systemic problems and solutions are summarised in Table 6.6.

GROUND MOUNTED TRANSFORMER SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problem	**Solution**
Graffiti	» Repaint
Rust and decay	» Treat and repaint » Renew if severe
Labels missing or faded	» Relabelled
Locks broken or seized up	» Replace or repair
Exposed bushings	» Tape or, if not practical, renew
Oil leaks	» Minor - on site repairs » Major – exchange/renew
Overheated connections	» Renew connections and associated equipment (circuit breakers, fuses etc.)
Damaged earthing	» Replace or repair earthing
Exposed LV	» Cover or renew

TABLE 6.6 : GROUND MOUNTED TRANSFORMERS: SYSTEMIC PROBLEMS AND SOLUTIONS

6.2.8 Service Boxes

6.2.8.1 Service Boxes: Inspection, Testing and Condition Monitoring Practices

Service boxes are being inspected on a five-yearly rotation.

This inspection includes:

- Security check.
- Location details (GPS, and placement on GIS maps).
- Number check including renumbering if the number has come off.
- Damage check.
- Integrity check.
- Reconciling type and approximate age to asset records.
- Minor repairs such as replacing screws or locks.
- Identifying access, fences and vegetation issues.
- Fitting/refitting of hazard and identification labels.

Service boxes are often found in a poor state due to vehicle damage. If the inspection reveals the need for further work then these requirements are factored into future renewal programmes.

The maintenance data collected is reviewed and a renewal programme is formulated based on this. The renewal programme is detailed further in the constraints and renewal section of the AMP. In summary, this focuses on renewing damaged (and fibreglass type) boxes that have become brittle due to age. The maintenance programme focuses on more minor repairs including making sure boxes are numbered, hazard labelled and secured. There are a number of boxes with un-earthed metal fronts/lids. These are being replaced with plastic fronts/lids as part of this programme.

6.2.8.2 Service Boxes: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

Defects found as part of the five-yearly inspection process have work specifications prepared and orders are issued. Completed jobs are monitored and reconciled to works orders. Emergent defects are reported to the asset management administrators, work specifications are prepared and orders are issued. Completed jobs are monitored and reconciled to works orders.

All service boxes are numbered and have details recorded in the asset database. The location details are added to the mapping database.

6.2.8.3 Service Boxes: Systemic Problems and Solutions

Systemic problems and solutions are summarised in Table 6.7.

SERVICE BOX SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problem	**Solution**
Vehicle damage.	» Straighten and re-secure or replace
Decay due to age (especially fibreglass units).	» Renew
Unearthed metal covers.	» Replace covers with plastic or renew whole unit
Cover screws stripped or missing.	» Replace screws, install new inserts or renew box as necessary to secure the unit.

TABLE 6.7: SERVICE BOXES: SYSTEMIC PROBLEMS AND SOLUTIONS

6.2.9 SCADA

6.2.9.1 SCADA: Inspection, Testing and Condition Monitoring Practices

SCADA equipment is maintained to ensure it is always in good working condition. This maintenance is completed on a combination of time and condition-based approaches.

Annual work includes installing the latest software, checking calibration, battery testing, replacement and other tuning. The condition-based work largely involves carrying out repairs after equipment has failed or the renewal of aged, obsolete equipment.

6.2.9.2 SCADA: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

Control room staff monitor SCADA operations and when problems are found they ensure specifications and work orders for repairs are issued. Repair invoices are reconciled to work orders and specifications. All works are recorded and reconciled against assets and annual plans.

Checks of field equipment are completed as part of zone substation, recloser and regulator inspections. Batteries and the like are checked and, if outside specifications, are renewed at these times.

6.2.9.3 SCADA: Systemic Problems and Solutions

Over the last few years, the most common systemic problems with SCADA have been lightning and fault current generated surges affecting electronic equipment. The solutions to these problems include a combination of bonding and earthing.

From time to time there are other minor problems associated with complex electronic equipment. The renewal programme discussed in other sections focuses on keeping equipment up to date and in good condition.

6.2.10 Radio Repeater Sites

6.2.10.1 Radio Repeater Sites: Inspection, Testing and Condition Monitoring Practices

Radio voice and data communication equipment is critical to the safe operation of the network. Time-based work includes annual visits to repeater sites and checking of equipment at these sites. These checks include:

- Aerial and feeder cable inspections.
- Connector inspections.
- Building checks and minor maintenance.
- Battery and charger checks and servicing.
- Alignment and level checks including bandwidth and carrier frequencies.
- Other general minor works and adjustments.
- "Gain" and other radio tests.

Condition-based work includes repairs after failure or renewal of aged, obsolete equipment.

6.2.10.2 Radio Repeater Sites: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

Control room staff monitor radio operation and when problems are found they ensure specifications and work orders for repairs are issued. Repair invoices are reconciled to work orders and specifications. All works are recorded and reconciled against assets and annual plans.

The renewal programme discussed in other sections focuses on keeping equipment up to date and in good condition.

6.2.10.3 Radio Repeater Sites: Systemic Problems and Solutions

Systemic problems and solutions are summarised in Table 6.8.

RADIO REPEATER SITE SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problem	**Solution**
Lightning damage.	» Replace damaged equipment. » Ensure adequate protection devices installed.
Flat batteries.	» Ensure annual servicing and battery replacements are completed.
Radio equipment out of specification.	» Retune equipment. » Retain a strategy of renewing equipment to keep up to date.

TABLE 6.8: RADIO REPEATER SITES: SYSTEMIC PROBLEMS AND SOLUTIONS

6.2.11 Load Control

6.2.11.1 Load Control: Inspection, Testing and Condition Monitoring Practices

6.2.11.1.1 Rotating plant

Rotating plants are visited every 3 months and the following checks are completed:

- Operation.
- Building clean.
- Generator brush gear.
- Contactors.
- Visual checks of other components.

Other general servicing and minor adjustments are completed in addition to the above. Every 2 years vibration checks of motor generators are carried out to ensure bearings have not worn excessively and equipment is balanced.

6.2.11.1.2 Static Plants

An annual inspection and operational check is made of static plants. During this visit inductor and capacitor enclosures are also weed sprayed and cleaned as necessary. The plants are retuned, and inductance and capacitance values checked when injection power levels are out of specification.

6.2.11.2 Load Control: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

Control room staff monitor load control operation and when problems are found they ensure specifications and work orders for repairs are issued. Repair invoices are reconciled to work orders and specifications. All works are recorded and reconciled against assets and annual plans.

6.2.11.3 Load Control: Systemic Problems and Solutions

Systemic problems and solutions are summarised in Table 6.9.

LOAD CONTROL SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problem	**Solution**
No signal getting to plant.	» Repair communication or SCADA system.
Plant power electronics or controller failure.	» Repair using specialist technicians.
Electro Mechanical Plant generators not operating.	» Vibration and regular checking of brushes etc.
Electro Mechanical Plant contactors failing.	» Inspection and repairs of contacts.

TABLE 6.9: LOAD CONTROL: SYSTEMIC PROBLEMS AND SOLUTIONS

6.2.12 Three Phase Reclosers and Automated Switches

6.2.12.1 Three Phase Reclosers and Automated Switches: Inspection, Testing and Condition Monitoring Practices

An annual inspection of 3-phase line reclosers and automated switches is carried out.

The inspection involves:

- Checking site and equipment integrity.
- Checking numbering and labelling. This includes renewing labels if they are incorrect or not readable.
- Replacing gel cell batteries - typically on every third visit.
- Checking charging systems.
- Checking/testing earthing.
- Checking SCADA and radio systems.
- For electronic units, downloading all memory buffers and settings.
- Reconciling settings to records including load flow and fault study models.
- For manual units, recording operations counters.
- Where recloser bypass switches are fitted, operate these to allow the switch remote and local operating functions to be tested.

6.2.12.2 Three Phase Reclosers and Automated Switches: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

The control room and engineering staff monitor line recloser and automated switch operation. When problems are found they ensure specifications and work orders for repairs are issued. Repair invoices are reconciled to work orders and specifications. All works are recorded and reconciled against assets and annual plans.

6.2.12.3 Three Phase Reclosers and Automated Switches: Systemic Problems and Solutions

The systemic problems with this equipment and the solutions are summarised in Table 6.10.

THREE PHASE RECLOSERS AND AUTOMATED SWITCHES SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problems	**Steps to Address**
Faulty or flat batteries.	» Replace after 3 years.
Software and programming errors affecting settings.	» Download and reconcile annually » Re-adjust and monitor.
Hardware, connections and earthing.	» Visually check annually. » Carry out repairs as necessary.
Operating outside settings.	» Service, retest and tune as necessary. » Run network analysis to find a solution when necessary.

TABLE 6.10: SYSTEMIC PROBLEMS AND SOLUTIONS FOR THREE PHASE RECLOSERS AND AUTOMATED SWITCHES

6.2.13 Voltage Regulators

6.2.13.1 Voltage Regulators: Inspection, Testing and Condition Monitoring Practices

Voltage regulators are inspected annually. The inspection includes:

- Checking site and equipment integrity.
- Checking numbering and labelling.
- Replacing any control equipment batteries (typically every third visit).
- Checking charging systems (remote control and SCADA).
- Downloading all memory buffers and settings.
- Checking numbers of operations and range.
- Reconciling settings and operations to records and network analysis software.
- Check/testing earthing.
- Checking operation.

6.2.13.2 Voltage Regulators: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

The control room and engineering staff monitor voltage regulator operation and when problems are found, ensure specifications and work orders for repairs are issued. Repairs and invoices are reconciled to work orders and specifications. All works are recorded and reconciled against assets and annual plans.

6.2.13.3 Voltage Regulators: Systemic Problems and Solutions

The systemic problems with this equipment and the solutions are summarised in Table 6.11.

VOLTAGE REGULATORS: SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problems	**Steps to Address**
Faulty or flat batteries in Control equipment.	» Replace at manufacturer's recommended intervals.
Software and programming errors affecting settings.	» Download and reconcile annually. » Readjust and monitor.
Hardware connections and earthing.	» Visually check annually. » Carry out repairs as necessary.
Operating outside settings.	» Service, retest and tune as necessary. » Run network analysis to find a solution when necessary.

TABLE 6.11: SYSTEMIC PROBLEMS AND SOLUTIONS FOR VOLTAGE REGULATORS

6.2.14 Single Wire Earth Return Isolating Transformer Structures

6.2.14.1 Single Wire Earth Return (SWER) System Isolating Structures: Inspection, Testing and Condition Monitoring Practices

TLC operates just over 60 SWER systems. A vital component of the SWER system is the isolation transformer and associated earthing system. Isolation transformer sites are inspected two yearly and the following inspections/tests are completed:

- The earthing system is visually inspected and electrically tested.
- Operation counter readings are recorded at recloser and system sectionaliser sites. These are reconciled to previous readings.
- Maximum Demand Indicators (if fitted) are read and reset.
- Labelling is checked and where necessary labels are renewed.
- System configuration is checked, i.e. by-pass switches, links etc. and reconciled with control room records.
- Site security and integrity is checked.

The distribution transformer earths downstream of the isolation transformer are inspected and tested on a 15 year cycle.

6.2.14.2 Single Wire Earth Return System Isolating Structures: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

The Lines Inspectors complete testing and forward results to asset management staff. These results are analysed and specifications are prepared for improvements to sites with earth mats that have resistance values that are above the TLC's standard or/and outside regulatory values. Network analysis design software is used to assist with improving the earth mat design. Improvement work packages are issued to contractors. Repairs and invoices are reconciled to work orders and specifications. All works are recorded and reconciled against sites and annual plans.

6.2.14.3 Single Wire Earth Return System Isolating Structures: Systemic Problems and Solutions

The systemic problems with this equipment, and the solutions, are summarised in Table 6.12.

SINGLE WIRE EARTH RETURN SYSTEM ISOLATING STRUCTURES SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problems	**Steps to Address**
Earth potential rises around earth mat.	» Test and maintain
Structures have hazards that need elimination/minimising (working clearances, ground clearances etc.)	» Include in a Renewal Programme

TABLE 6.12: SYSTEMIC PROBLEMS AND SOLUTIONS FOR ISOLATING TRANSFORMER STRUCTURES ON SWER SYSTEMS

6.2.15 SWER (Single Wire Earth Return) Distribution Transformers Structures

6.2.15.1 SWER Distribution Structures: Inspection, Testing and Condition Monitoring Practices

For SWER distribution systems to work effectively, low resistance earth systems must be installed and maintained. The earthing systems on distribution SWER systems were all reference tested during the 2006/07 and 2007/08 years. A number of improvements were completed. A 15 year cyclic testing programme has been introduced.

The objective of the programme is to ensure the hazards associated with SWER systems are minimised and, specifically, that the earth potential rises around earth mats are within acceptable limits. The maintenance earth inspections also focus on identifying sites where there is bonding between HV and LV earthing systems.

6.2.15.2 SWER Distribution Structures: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

The Lines Inspectors complete testing and forward results to asset management administration staff. The results are analysed and specifications are prepared for improvements to sites with earth mats that have high values. The network analysis software is used to assist with site improvement design.

Improvement work packages are issued to contractors. Repairs and invoices are reconciled to work orders and specifications. All works are recorded and reconciled against sites and annual plans.

6.2.15.3 SWER Distribution Structures: Systemic Problems and Solutions

The systemic problems with this equipment and the solutions are summarised in Table 6.13.

SINGLE WIRE EARTH RETURN SYSTEM DISTRIBUTION STRUCTURES: SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problem	**Steps to Address**
Broken HV earth wire when bonding is in place to LV MEN earthing system. This results in 11kV being available at installation switchboards if the main earthing conductor is open circuited.	» Locate installations by inspection and testing. » Install separate earthing systems.
High impedance earth connections.	» Earth potential rises around occupied dwellings especially under fault conditions overcome by improving earthing systems. » Design and specify new systems using tools such as the network analysis programme.
Bonded HV and LV MEN earths (MEN then becomes an 11 kV current path).	» Install separate earthing systems.

TABLE 6.13: SYSTEMIC PROBLEMS AND SOLUTIONS FOR DISTRIBUTION TRANSFORMERS ON SWER SYSTEMS

6.2.16 Other System Inspections

6.2.16.1 Other System Inspections: Inspection, Testing and Condition Monitoring Practices

All asset and engineering staff visually check assets on their travels to ensure equipment integrity. Specific items of importance include:

- Equipment labelling and integrity.
- Locking of equipment.
- Obvious defects.
- Close excavations, cranes etc.

6.2.16.2 Other System Inspections: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programmes are Rectified

It is the responsibility of engineering and asset management staff to follow through and ensure the defects observed are rectified. They have to select the correct process. Hazard issues such as cranes and excavators that are being operated close to network assets are followed up by the Controller and Inspection and Vegetation Controller.

6.2.16.3 Other System Inspections: Systemic Problems and Solutions

Customers and contractors are often reluctant to ensure machinery operating close to lines complies with regulations. A discussion pointing out the hazards is normally sufficient to overcome the issue.

6.2.17 Power Quality

6.2.17.1 Power Quality: Inspection, testing and condition monitoring

Voltage readings are taken from time to time - either initiated by customer complaints or engineering analysis. Harmonic levels and loadings are checked at the same time if they are suspected to be an issue. Spot checks are completed annually at key locations throughout the network to monitor total harmonic distortion. These checks are made at the same locations each year.

Voltage, current and other data are logged at remotely controlled equipment and substations. In a number of cases distributed generation has been found to have adverse effects on local voltage. In these cases TLC has requested modifications to generator controllers. The logged data are used for various activities including:

- System planning and analysis.
- Fault finding.
- On-going power quality monitoring.
- Reconciling to network analysis programme and performance targets.
- Reconciling loads to billable demand based charges from the various parts of the network.

6.2.17.2 Power Quality Monitoring: Processes for Ensuring Defects Identified by Inspection and Condition Monitoring Programme are Rectified

Voltage issues are followed up by either short term adjustment of transformer taps, regulators or tap changers. Where the problem is found to be in a customer installation or works, this information is passed on to the customer. Network modelling is used to identify the issues associated with longer term problems. Solutions are developed and included in the AMP.

The network harmonic levels are being carefully monitored to understand the effect of the increasing number of appliances and other equipment that include power electronics. Harmonic measurements are showing high levels of total harmonic distortion on parts of the TLC network, particularly SWER systems, lightly loaded long lines and around industrial installations.

TLC is rectifying this problem by being particularly sensitive to power electronics associated with new connections including distributed generation and the specifications in the connection codes and standards. In the longer term it may be necessary to add filters to some SWER systems.

6.2.17.3 Power Quality Monitoring: Systemic Problems and Solution

The systemic problems with quality monitoring and the solutions are summarised in Table 6.14.

POWER QUALITY MONITORING: SYSTEMIC PROBLEMS AND SOLUTION	
Systemic Problem	**Steps to Address**
Incorrect readings due to instrument calibration.	» Ensure good quality instruments are used that have calibrations checked regularly. » Ensure substation and equipment maintenance programmes routinely check transducer calibrations and recording equipment are accurate.
Issues that can be rectified by short term network adjustment and tuning.	» Specify instructions and issue work orders to field staff. » Where appropriate follow up and audit.
Issues that cannot be rectified by short term network adjustment and tuning.	» Include in longer term planning, development and renewal programmes (e.g. filters and blocking chokes).

TABLE 6.14: SYSTEMIC PROBLEMS AND SOLUTIONS IN POWER QUALITY MONITORING

6.2.18 Asset Efficiency

6.2.18.1 Asset Efficiency: Inspection, Testing and Condition Monitoring Practices

6.2.18.1.1 Power factor and network losses: Inspection, testing and condition monitoring practices

Spot checks are completed annually at key locations throughout the network to monitor power factor in the distribution and sub-transmission system. Particular attention is paid to 33kV feeders, industrial areas and distributed generation sites.

The national data set is obtained annually from the Electricity Commission and the grid exit power factors are monitored. Data are also downloaded from other equipment that is capable of monitoring power factors. All power factor data are reconciled to current system network analysis data so that modelling is as close as possible to actual network active and reactive power flows. Network loss calculations are completed annually to benchmark technical losses. Billed energy data are obtained from the Reconciliation manager and reconciled to calculated technical losses and the amount of energy coming into the network. (Data from the Reconciliation Manager also include distributed generation injection.) Network loss calculations are completed annually to benchmark technical losses.

6.2.18.1.2 Network constraints: Inspections, testing and condition monitoring practices

Network models are run annually as part of the AMP process to determine network constraints. Peak loading models of each grid exit are run based on the recorded previous period peak loading conditions. The constraint areas - normally areas with voltages likely to be outside of statutory limits - are identified. The models are then run to determine constraint thresholds. These then become drivers for network load control settings and input into the network development programmes when solutions are required.

6.2.18.2 Asset Efficiency Monitoring: Process for Ensuring Defects Identified By Inspection, Tests and Condition Monitoring Programmes Are Rectified

6.2.18.2.1 Power factor and network losses process for ensuring defects identified by inspection, testing and condition monitoring programmes

As detailed in other sections, poor power factor is caused in the TLC network mostly as a consequence of distributed generation and to a lesser extent by industrial load. The higher the injection power factor of distributed generation, the lower the capacity that generally can be injected into the network as the voltage at light load times quickly becomes too high.

TLC has a draft agreement with Transpower for an exemption from grid exit power factor requirements at Hangatiki. When technical resources are available exemptions will be applied for at other grid exits. TLC's demand based billing has been introduced across the board to try and encourage customers to improve power factor. TLC is also concerned that the encouragement of the use of low cost compact fluorescent lamps and heat pumps, which generally have poor power factors, will have a long term detrimental effect on network efficiency.

TLC believes the best place for power factor correction is demand side management but recognises that long term it may be forced to invest in power factor correction within the distribution system. (The preferred option is demand side.) As a consequence one of the criteria used in selecting voltage regulators and tap changers is to ensure controllers are capable of controlling potential future capacitor banks.

Losses are related to power factor and network development solutions. Losses are a consideration for network planning and demand billing is focused on trying to minimise demand growth and the exponential impact on losses.

6.2.18.2.2 Network constraints: Inspection, testing and condition monitoring practices

Network modelling is used to identify network constraints. Measurements are used from time to time to verify these. The constraint levels are used to set the master load controller with appropriate network settings. These settings are independent of Transpower Regional Co-Incidental Peak Demand (RCPD)

6.2.18.3 Asset Efficiency Monitoring: Systemic Problems and Solutions

The systemic problems with asset efficiency monitoring and the solutions are summarised in Table 6.15.

ASSET EFFICIENCY MONITORING SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problem	**Steps to Address**
Incorrect readings due to instrument calibration.	» Ensure good quality instruments are used that have calibration checked regularly. » Ensure substation and equipment maintenance programmes check and ensure transducer calibration and recording equipment is accurate.
Incorrect retailer energy data.	» Source data (at a cost) from the reconciliation manager.
Reducing network power factor.	» Encourage demand side correction. » Allow for future network correction when equipment is being selected.
The level of network constraint is below a realistic load control set point.	» Develop the network in a way that removes constraints. » Manage set points so that the level of non-compliance risk is acceptable.

TABLE 6.15: SYSTEMIC PROBLEMS AND SOLUTIONS IN ASSET EFFICIENCY MONITORING

6.2.19 Forward Maintenance Expenditure Projections

6.2.19.1 Summary Maintenance Activities

Table 6.16 lists forward budgets for summary of maintenance activities by asset category.

Summary Maintenance Activities Cost Estimates										
Classification	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**
Cable Maintenance	90,000	91,359	92,976	94,938	96,979	99,113	101,293	103,522	105,799	108,127
Distribution Transformer Maintenance	153,500	155,818	158,576	161,922	165,403	169,042	172,761	176,562	180,446	184,416
Faults and Standby	1,262,000	1,281,056	1,303,731	1,331,240	1,359,862	1,389,779	1,420,355	1,451,603	1,483,538	1,516,176
Line Maintenance	295,000	299,455	304,755	311,185	317,876	324,869	332,016	339,321	346,786	354,415
Network Equipment Maintenance	205,800	208,908	212,605	217,091	221,759	226,637	231,624	236,719	241,927	247,250
Vegetation Control	692,417	702,873	715,313	730,406	746,110	762,525	779,301	796,446	813,967	831,875
Zone Substation Maintenance	376,500	382,185	388,950	397,157	405,696	414,621	423,743	433,065	442,593	452,330
Total	**$3,075,217**	**$3,121,653**	**$3,176,905**	**$3,243,939**	**$3,313,685**	**$3,386,586**	**$3,461,092**	**$3,537,238**	**$3,615,056**	**$3,694,587**

TABLE 6.16 FORWARD BUDGET SUMMARY FOR MAINTENANCE ACTIVITIES

Vegetation control and the costs caused by trees falling through lines will remain to be one of TLC's greatest direct to maintenance costs.

Long-term maintenance expenditure is expected to increase at about the rate of inflation. It is generally accepted that capital expenditure will reduce maintenance costs in the long term. Due to the amount of renewal needed, this will be beyond the planning period included in this Plan. Analysis work completed to date of TLC cost structures would suggest this is true, but the amount of costs that capital expenditure will affect is relatively small. For example, most of the time-based work will still be required. There will be a drop off in faults and emergent work costs. Numbers included to date would suggest this saving would be only in the order of 5 to 10% of direct maintenance and associated overhead costs.

Emergent work is generally reducing, but perturbations occur when repairs are necessary after storms and other abnormal events.

The following sections give budget predictions for maintenance activities broken down by asset category for the planning period. Unless stated otherwise, the figures are in current dollars.

6.2.19.2 Cable Maintenance

Table 6.17 lists the cable maintenance predictions by asset category for the planning period.

Cable Maintenance Predictions										
Classification	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**
Cable 33/11 kV	20,000	20,302	20,661	21,097	21,551	22,025	22,510	23,005	23,511	24,028
Cable LV	10,000	10,151	10,331	10,549	10,775	11,013	11,255	11,502	11,755	12,014
Pillar Box Maintenance	20,000	20,302	20,661	21,097	21,551	22,025	22,510	23,005	23,511	24,028
Cable Ski Fields	40,000	40,604	41,323	42,195	43,102	44,050	45,019	46,010	47,022	48,056
Total	**$ 90,000**	**$ 91,359**	**$ 92,976**	**$ 94,938**	**$ 96,979**	**$ 99,113**	**$ 101,293**	**$ 103,522**	**$ 105,799**	**$ 108,127**

TABLE 6.17 CABLE MAINTENANCE PREDICTIONS FOR THE PLANNING PERIOD

6.2.19.3 Distribution Transformer and Site Maintenance

Table 6.18 lists the Distribution transformer and site maintenance predictions broken down by activity for the planning period.

Distribution Transformer and Site Maintenance Predictions										
Classification	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**
Network Earthing	35,000	35,529	36,157	36,920	37,714	38,544	39,392	40,258	41,144	42,049
Transformer Audits	7,000	7,106	7,231	7,384	7,543	7,709	7,878	8,052	8,229	8,410
Transformer Grounds/Painting	14,500	14,719	14,979	15,296	15,624	15,968	16,319	16,678	17,045	17,420
Inspections	35,000	35,529	36,157	36,920	37,714	38,544	39,392	40,258	41,144	42,049
Transformer Workshop Refurbishment	62,000	62,936	64,050	65,402	66,808	68,278	69,780	71,315	72,884	74,487
Total	**$ 153,500**	**$ 155,818**	**$ 158,576**	**$ 161,922**	**$ 165,403**	**$ 169,042**	**$ 172,761**	**$ 176,562**	**$ 180,446**	**$ 184,416**

TABLE 6.18 DISTRIBUTION TRANSFORMER AND SITE MAINTENANCE PREDICTIONS FOR THE PLANNING PERIOD

6.2.19.4 Faults

Table 6.19 lists the Faults cost estimates for the planning period.

Faults Predictions										
Classification	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**
LV Lines	285,000	289,304	294,424	300,637	307,100	313,857	320,762	327,818	335,030	342,401
11kV Lines	525,000	532,928	542,360	553,804	565,711	578,157	590,876	603,876	617,161	630,739
33kV Line	50,000	50,755	51,653	52,743	53,877	55,063	56,274	57,512	58,777	60,070
LV Cable and Pillar Boxes	35,000	35,529	36,157	36,920	37,714	38,544	39,392	40,258	41,144	42,049
33/11kV Cables	30,000	30,453	30,992	31,646	32,326	33,038	33,764	34,507	35,266	36,042
Disconnections for Safety	30,000	30,453	30,992	31,646	32,326	33,038	33,764	34,507	35,266	36,042
Regulators, Motorised Switches and Load Plant	30,000	30,453	30,992	31,646	32,326	33,038	33,764	34,507	35,266	36,042
SCADA and Radio	17,000	17,257	17,562	17,933	18,318	18,721	19,133	19,554	19,984	20,424
Substations	35,000	35,529	36,157	36,920	37,714	38,544	39,392	40,258	41,144	42,049
Transformers	20,000	20,302	20,661	21,097	21,551	22,025	22,510	23,005	23,511	24,028
Voltage Faults	5,000	5,076	5,165	5,274	5,388	5,506	5,627	5,751	5,878	6,007
Standby Costs	200,000	203,020	206,613	210,973	215,509	220,250	225,096	230,048	235,109	240,281
Total	**$1,262,000**	**$1,281,056**	**$1,303,731**	**$1,331,240**	**$1,359,862**	**$1,389,779**	**$1,420,355**	**$1,451,603**	**$1,483,538**	**$1,516,176**

TABLE 6.19 FAULTS AND STANDBY PREDICTIONS FOR THE PLANNING PERIOD

6.2.19.5 Lines Maintenance

Table 6.20 lists the lines maintenance predictions by asset category for the planning period.

Line Maintenance Predictions										
Classification	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**
11 kV Lines	140,000	142,114	144,629	147,681	150,856	154,175	157,567	161,034	164,576	168,197
33 kV Lines	85,000	86,284	87,811	89,664	91,591	93,606	95,666	97,770	99,921	102,120
Permanent Disconnections	30,000	30,453	30,992	31,646	32,326	33,038	33,764	34,507	35,266	36,042
LV Lines	40,000	40,604	41,323	42,195	43,102	44,050	45,019	46,010	47,022	48,056
Total	**$ 295,000**	**$ 299,455**	**$ 304,755**	**$ 311,185**	**$ 317,876**	**$ 324,869**	**$ 332,016**	**$ 339,321**	**$ 346,786**	**$ 354,415**

TABLE 6.20 LINES MAINTENANCE PREDICTIONS FOR THE PLANNING PERIOD

6.2.19.6 Network Equipment Maintenance

Table 6.21 lists other network equipment maintenance predictions broken down by asset activity for the planning period.

Network Equipment Maintenance Predictions										
Classification	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**
Line Motorised Switches Inspections	20,000	20,302	20,661	21,097	21,551	22,025	22,510	23,005	23,511	24,028
Line Motorised Switches Renewal	12,000	12,181	12,397	12,658	12,931	13,215	13,506	13,803	14,107	14,417
Line Regulator Inspections	45,000	45,680	46,488	47,469	48,490	49,556	50,647	51,761	52,900	54,063
Northern Load Plant Renewal	5,000	5,076	5,165	5,274	5,388	5,506	5,627	5,751	5,878	6,007
Northern Load Plant Testing	13,000	13,196	13,430	13,713	14,008	14,316	14,631	14,953	15,282	15,618
Other Network Equipment/Spares Renewal	5,000	5,076	5,165	5,274	5,388	5,506	5,627	5,751	5,878	6,007
Other Network Equipment/Spares Testing	10,000	10,151	10,331	10,549	10,775	11,013	11,255	11,502	11,755	12,014
Other Network Material Acquisition	10,000	10,151	10,331	10,549	10,775	11,013	11,255	11,502	11,755	12,014
Radio/Repeater Site Grounds and Access	5,000	5,076	5,165	5,274	5,388	5,506	5,627	5,751	5,878	6,007
Radio/Repeater Site Rentals and Licences	23,800	24,159	24,587	25,106	25,646	26,210	26,786	27,376	27,978	28,593
Radio/Repeater Upgrades Renewal	5,000	5,076	5,165	5,274	5,388	5,506	5,627	5,751	5,878	6,007
SCADA Testing & Investigation	10,000	10,151	10,331	10,549	10,775	11,013	11,255	11,502	11,755	12,014
SCADA Upgrades Renewal	10,000	10,151	10,331	10,549	10,775	11,013	11,255	11,502	11,755	12,014
Southern Load Plant Renewal	15,000	15,227	15,496	15,823	16,163	16,519	16,882	17,254	17,633	18,021
Southern Load Plant Testing	10,000	10,151	10,331	10,549	10,775	11,013	11,255	11,502	11,755	12,014
Voltage Investigations	7,000	7,106	7,231	7,384	7,543	7,709	7,878	8,052	8,229	8,410
Total	**$ 205,800**	**$ 208,908**	**$ 212,605**	**$ 217,091**	**$ 221,759**	**$ 226,637**	**$ 231,624**	**$ 236,719**	**$ 241,927**	**$ 247,250**

TABLE 6.21 OTHER NETWORK EQUIPMENT MAINTENANCE PREDICTIONS FOR THE PLANNING

6.2.19.7 Vegetation Control Maintenance

Table 6.22 lists the vegetation control maintenance predictions for the planning period.

Vegetation Control Maintenance Predictions										
Classification	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**
Initial Work	204,000	207,080	210,746	215,192	219,819	224,655	229,598	234,649	239,811	245,087
Maintenance Existing	476,417	483,611	492,171	502,556	513,361	524,655	536,197	547,994	560,050	572,371
Patrols/Surveys	12,000	12,181	12,397	12,658	12,931	13,215	13,506	13,803	14,107	14,417
Total	**$ 692,417**	**$ 702,873**	**$ 715,313**	**$ 730,406**	**$ 746,110**	**$ 762,525**	**$ 779,301**	**$ 796,446**	**$ 813,967**	**$ 831,875**

TABLE 6.22 VEGETATION CONTROL MAINTENANCE PREDICTIONS FOR THE PLANNING PERIOD

6.2.19.8 Zone Substation Maintenance

Table 6.23 lists the Zone substation maintenance predictions broken down by activity for the planning period.

Zone Substation Maintenance Predictions										
Classification	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**
Battery Charger Replacement	35,000	35,529	36,157	36,920	37,714	38,544	39,392	40,258	41,144	42,049
Protection and Control	16,000	16,242	16,529	16,878	17,241	17,620	18,008	18,404	18,809	19,223
Transformers	70,000	71,057	72,315	73,841	75,428	77,088	78,784	80,517	82,288	84,098
Building and Site Works	47,500	48,217	49,071	50,106	51,183	52,309	53,460	54,636	55,838	57,067
Inspections	130,000	131,963	134,299	137,132	140,081	143,163	146,312	149,531	152,821	156,183
Rates and General Maintenance	78,000	79,178	80,579	82,279	84,049	85,898	87,787	89,719	91,693	93,710
Total	**$ 376,500**	**$ 382,185**	**$ 388,950**	**$ 397,157**	**$ 405,696**	**$ 414,621**	**$ 423,743**	**$ 433,065**	**$ 442,593**	**$ 452,330**

TABLE 6.23 ZONE SUBSTATION MAINTENANCE PREDICTIONS FOR PLANNING PERIOD

6.3 Description of Asset Renewal and Refurbishment Policies

TLC's refurbishment policy is based on renewing equipment that cannot be maintained and/or is no longer fit for purpose. As stated in other sections, the TLC network has not experienced growth like other areas in New Zealand and, therefore, there has been no need to upgrade components. This, coupled with the original construction being completed at the lowest possible cost, resulted in network performance not meeting customers' expectations in 2002. Successful programmes have since been put in place to improve reliability. There are, however, still some pockets of the network that these programmes have not reached and customers are experiencing a lower reliability level than they require.

The concept of short term risk identifying patrols and a 15 year inspection and renewal cycle that looked at overall security was initiated in the 2003/04 year. Since this time the concept has been regularly reviewed and developed. The most important spokes in the overall network wheel were addressed first. The importance of how each section of line contributes to revenue and the need to not over-invest has always been a key consideration (Over investment will drive up RAB values and result in prices customers cannot afford to pay).

Analysis work has shown that lines inspectors are recommending about 10% to 20% of poles and lines they inspect be renewed due to aged or poor condition. Further analysis of selected areas has shown that, if line renewals are based on the ideal strengths and conditions from design codes, about 30% of poles should be replaced. TLC customers cannot afford to fund this and, as a consequence, a level of compromise based on acceptable risks is applied, particularly in the more rural areas. Reducing renewals below levels in this plan will mean hazards are not being addressed to stakeholder expectations.

One of the other issues facing TLC is that much of the legacy equipment such as substation enclosures, switchgear, ground-mounted transformers and other equipment does not meet present day hazard expectations. A large proportion of the renewal work in the planning period will involve removing and minimising the hazards this equipment presents. Almost all renewals have an effect on hazard reduction.

6.3.1 Overhead Line Renewal Policies and Procedures

The TLC network consists of approximately 5,000 km of overhead lines. Just under 10% of this distance consists of 33 kV lines, 10% is LV lines and the remaining 80% is 11 kV lines in various configurations.

The pole population is mixed with about one third wood, one third iron rail and one third concrete. The lines are generally old and many components are from the original construction. Few of the lines are on the roadside with most in remote rugged hill country. The iron rails typically spent the first 50 years of their life carrying trains. In the 1950s these were removed from the railway lines and the sections of track have carried power lines for the last 60 or so years. In addition to these recycled steel members much of the hardware was also recycled from earlier use in transmission lines (typically suspension insulators).

Customers are deemed to own lines from the point of connection at all voltages. The point of connection is normally where the line to their particular property taps off the main line.

As described in earlier sections, line assets have been broken into asset groups. These asset groups form the basis for renewal planning and performance measurement. The asset groups aggregate up to the service level standards described in earlier sections. The renewal programme consists of a matrix of these asset groups prioritised and arranged into a consistent 15 year cyclic programme. The cost estimates from this matrix produce the annual and long term estimates.

6.3.1.1 Planned Overhead Renewals Policies and Procedures

Once the data are gathered by lines inspectors as described in earlier sections, a detailed review of the asset group takes place. The long term asset programme consists of these asset groups laid out and estimates have been allowed that drive into the long term plan, assuming about a 10% to 15% pole replacement level.

Overall considerations include:

- Hazard elimination/minimisation.
- Faults data.
- Equipment and transformer earth test and earthing systems inspection data.
- Service level performance.
- Importance of the line to the network, including long term significance and income generation. (Models have been put together based on accepted disclosure criteria to calculate sections of feeders that are uneconomic. These models will continue to be developed and more data on assets revenue generation ability will become available during the planning period.)
- Other customer and landowner driven issues.
- Estimate of project costs in the long term plan.

The engineering analysis includes:

- Consideration of any hazards.
- Checking of line strengths required on renewal.
- Evaluation of alternative designs.
- Selection of renewal design options.
- Specification and preparation of plans including earthing improvements and labelling.
- The potential for non-asset solutions including alternative supplies.

The administration functions include:

- Entering and reconciling inspection data with previous records.
- Filing and linking photographs.
- Preparing packages for engineering consideration.
- Taking engineering results and putting together work packages.
- Issuing work packages and updating asset records.
- Detailing material requirements.
- Monitoring spends against estimate.
- Issuing audit packages.
- Receiving audit packages back from auditors.
- Issuing non-compliance notes.
- Follow-ups.
- Related records updated.

The renewal trigger criteria for components of overhead lines does vary depending on importance, geographical location and other practical “real world” issues.

In summary the trigger criteria are:

Poles

- Failure of pole test.
- Bad splitting etc. that will probably deteriorate excessively in the next 15 years.
- Iron rails that have extensive corrosion.
- Concrete poles that are cracked or have large amounts of reinforcing showing.
- Poles that, when a line review is done, are well under strength for the situation they are in, to the point that they will fail at wind strengths in the 100 to 120km/hr. range.
- Conductor height above ground.
- Other rot or corrosion that means a structure cannot perform to expectations.

It should be noted that the programme does not replace iron rail poles as a matter of course. Iron rail poles are only replaced if they are corroded or obviously under strength. The cost of wholesale replacement of iron rail poles would add significant additional funding difficulties to the renewal programme.

Cross arms

- Decay that will not allow them to last another 15 years.
- Too short for the span lengths.

Note: Care is taken not to change cross arms too early. Most are rotten, to the extent that daylight can be seen through them, before they are recommended for changing.

Insulators

1950s 830 type insulators, and 3320 type insulators that are susceptible to fertiliser build up and discharges, are replaced when poles or cross arms are changed.

Conductor

Conductor is renewed when it shows signs of corrosion that will lead to failure in next 15 years. (Conductor is not usually renewed unless broken strands are obvious, if there are large numbers of joints, or there has been a recent history of failures, sometimes due to corrosion, in the section of line being renewed.)

Environmental

Slips, forest, reserves, rivers, access, and other environmental factors.

Landowner and Land Use

Various landowner and land use issues may influence the trigger criteria. Once field data have been measured against these criteria, engineering analysis is completed and asset performance data are considered, asset group work packages are put together. They are issued to the service provider.

Once the service provider has the job pack, a pre job briefing takes place between the sites works controller and the asset management group. The objective of the briefing, which may include an on-site visit, is to:

- Identify and develop on site control measures for any hazards associated with the project.
- Outline the renewal decisions made and the reasons for these.
- Discuss landowner and site access.
- Develop outage plans.
- Discuss other local and individual project issues.

At the completion of works, an audit against specifications takes place. Poles, and a selection of cross arms that have been removed, are inspected and analysed from at least one renewal project annually to ensure the renewal decision was correct. The results of this analysis are discussed at a post job briefing. (All poles removed are also photographed and filed in the asset database and these form a basis for much of the analysis and discussions around the renewal decisions made and the justification for these. This process leads to continuous improvement and review practices.

6.3.1.2 Unplanned Overhead Line Renewal Polices and Procedures

The unplanned renewals and high risk repairs focus on maintaining supply and minimising/eliminating the hazards in the immediate area. High risk repairs that are more complex and need attention before the next planned renewal cycle in that area are inspected and specifications are produced for contractors. The focus of these is to repair the problem to present day design criteria outlined in the previous section, but confine this to the immediate problem area. Examples of this type of work include under height conductors and red tagged poles that have to be changed within three months for compliance.

These emergent repairs, however, should be to a standard that do not require total rework when the next 15 year cycle is completed. Emergency repairs after faults are often temporary and will maintain supply until inspected by lines inspectors or a line designer. The workflows as described in earlier are then followed to ensure the best option is taken for the permanent, emergent repairs., the planned line inspection and renewal process is based on a 15 year cycle in addition to patrols, which take care of short term hazards and reliability issues.

The principal reasons for this cycle are:

Compliance

The Electricity Regulations require the owners of works to have an inspection programme in place that ensures asset hazards are minimised or eliminated and the safety management system is complied with.

Level of Funding

TLC's customers have limited ability to pay. This means that, unless funds come from some other source, TLC is limited in the size of the renewal programme that can be undertaken. (It should be noted that there are customers in the TLC network area who do not have the means to pay for a network connection and have chosen to disconnect their installations from the network.)

Cost of Inspection and Design Review

TLC has about 50,000 poles. On average, it takes 2.5 hours inclusive of overheads to assess the condition of a pole. A 15 year cycle equates to approximately three to four labour units and a cost of about $180,000 to $210,000 per annum. (Unplanned work and supervision etc. is in addition to these costs.) Funding of this cost fits into the present matrix of the organisation's charging policies and cost structures.

Consistent decision making

Determining the condition of overhead lines is not black and white. In general, the longer the period between judgement calls, the more consistent the call. Hence, the judgement call on whether an item of hardware will last 15 years as opposed to say 5 is easier to make and experience has shown that more consistent calls are made. Experience has also shown that assets are not renewed too early when removed items are analysed. (Comment made based on the post project briefing process and examination of removed pole photographs.)

Experience with pole testing

Pole testing results from other organisations show that once a segment of line has been pole tested and then retested 10 years later, the failure rate for decay in the ten year period is low. This means there is not a lot of gain to be had by retesting at ten years, but the subjective decision was that 15 years would be the maximum acceptable period between tests.

Resources available to TLC

The output of a detailed asset condition assessment generally produces a gap between present condition and target condition. Work planning and design therefore has to be done to bring assets up to a suitable standard. It is important that the organisation has the people to do this work in a timely manner. In TLC's case it was estimated that the organisation could cope with the work levels that a fifteen-year cycle would generate. It could not cope with a five year cycle unless the asset age was globally improved first.

Landowner concerns

Landowners are becoming increasingly concerned about work on overhead power lines through their land. The 15 year cycle minimises the need to repeatedly enter land.

Establishment/Disestablishment Costs

The 15 year programme minimises contractors' familiarisation and establishment/disestablishment costs. Short-term small scattered projects add cost when compared to a more planned approach.

Other points associated with this programme that need to be understood include:

Patrols for High Risk Defects

The 3 yearly 11 kV and shorter cycle patrols of urban areas and 33 kV lines (as described in earlier sections) coupled with fault patrols take place and are designed to identify any "short term" or urgent issues.

Project Management: Project reviews

TLC places a significant amount of importance on continuous improvement and the need for staff and stakeholders at all levels to be able to understand renewal programmes and contribute to the continuous improvement process. Pre and post project briefings reviews take time. Shorter cycles would reduce our ability to complete this process comprehensively and, as a consequence, the learning process would not develop as quickly. The continuous improvement process is leading to cost savings and focuses heavily on hazard control. In saying this, the 15 year programme is also reviewed and reconsidered to ensure that it is still an appropriate strategy.

Overall Analysis and Data

The 15 year cycle produces data and information that allows detailed analysis and long term solutions to be found, including the consideration of non-asset solutions. This often involves complex landowner discussions. Considerably more resource and cost would be needed to handle data analysis, resolution of landowner issues and other planning and design issues if a shorter cycle were adopted.

The repairs, after high risk defects are found during patrols, focus on ensuring that the structure or structures are serviceable until the planned works programme completes renewal of the asset group within which the assets are located. The 15 year cycle is wider than just the lines. Other renewals in an area are completed at the same time while resources are in the region.

For example, as mentioned earlier, the condition of distribution transformers is assessed and units in poor condition are changed. Landowners are also notified of private lines in poor condition and fuses are installed at the tap-off points. Transformer earthing is tested and checked. The programme is focused on asset groups (typically 10km lengths of line) and the areas receiving attention, in any year, are spread throughout the network. A long term plan is being followed, cycling through asset groups.

It should also be noted that local knowledge and a detailed knowledge of each line asset including such things as how exposed lines are on hill tops, landowners, and a multitude of other issues are also in the back of one's mind when line renewal work is being planned. There are also a number of short term issues like slips, storms, landowners' needs, etc. that create a level of unplanned work needs.

6.3.2 Other Equipment Renewal Policies and Procedures

6.3.2.1 Policies and Procedures: Zone Substation, Voltage Control, Distribution Substations, Cables, Switchgear and Other Distribution Asset Renewal (excluding Line Renewal)

This section covers the capital expenditure primarily associated with replacement and refurbishment of existing assets. This work is to maintain the network and equipment to meet target levels of service.

The policy is to renew when the existing equipment will cost more to refurbish than renew or it is not possible to refurbish up to a level that will meet present day hazard control, operational or customer service targets. This means for example that if a relatively major component fails in an item of switchgear, and it is not possible to get suitable parts that will ensure the switch will operate reliably, then it would be replaced with a present day equivalent.

The general principle of economic evaluation is to use regulatory cost for the particular piece of equipment that has failed. If the cost of refurbishment is greater than the regulatory cost, then it would generally be renewed. The ages used in depreciation calculations are those in the Commerce Commission regulatory documents.

The factors that may modify this approach are:

- Parts availability.
- Availability of equivalent replacements.
- Importance in network, i.e. how long and what are the risks of equipment being out of service for either refurbishment or renewal periods.
- Any other justified technology gains or other advances by renewal.
- On-going guaranteed reliability of renewal vs. refurbishment.
- TLC's pricing models for the area or local area that show the regulatory valuation and level of return being generated.

The renewal or refurbishment is triggered by:

- An emergent failure where equipment either has to be renewed or refurbished to keep the network operational.
- A 15 year detailed inspection and review of the assets.
- Test results that indicate the need for renewal or refurbishment. An example of this is oil test results and other transformer tests that signal the need for refurbishment.
- Hazard elimination/minimisation issues.
- Customer requests for capacity changes.
- Environmental issues.
- Equipment identified to be at the end of its life.

If equipment is old but in good operational condition and meets service expectations, then it would not be considered for refurbishment or renewal.

Generally, when good quality parts are available and repairs can be done to a standard that will ensure reliability and the cost is below regulatory cost and the equipment will last to periods expected, then refurbishment takes place as opposed to renewal. The expected lives used in assessments are those listed in the information disclosure handbook for valuations of lines companies. (TLC's experience is that these life lengths are a reasonable expectation.) Examples of equipment that would be renewed because they would not meet the refurbishment criteria in each of the asset sub categories are:

Zone Substations

- Electro mechanical relays that stops operating or are not meeting test criteria.
- Batteries that are outside manufacturer's age criteria or are not testing correctly.
- Hardware that is corroded.
- Insulators that are cracking or have failed.
- Other equipment that has failed and if repaired cannot be trusted to give reliable service.
- Low, inadequate fencing.
- Underrated switchgear.
- Conductor with low clearance into structures.
- Equipment that is exposed to fault current greater than ratings.

Voltage Control

- Old regulators are replaced when they have failed and parts are no longer available.
- Electro mechanical voltage relays are replaced on failure or when it becomes difficult to adjust them to the operating requirements of the network.

Distribution Substation

- Ground mounted substations are replaced when they are found to be in poor condition and maintaining them on site is not an option.
- On failure of integral LV or HV switchgear.
- When there is a lack of, or underrated, HV and LV switchgear and this equipment is part of the structure.
- When the operation of HV or LV equipment places the operator at risk of contact with live conductors or an arc flash.
- When a site has a high risk of vehicle impact.
- When structures or enclosures can be accessed easily by the public.
- When inspections or tests show that earthing systems are inadequate.
- When ground mounted enclosures with dropper wires coming down are found to be hazardous.

Cables

- Cables are replaced when test results indicate that joining pieces together will no longer give reliable operation.
- When live terminals on termination structures have less ground clearance than specified in the codes of practice.

Switchgear

- When it fails and parts are no longer available.
- Underrated or has a possibility of putting the operator or public at risk.

Distribution Transformers

- On failure or when they are in poor condition and the cost of repair is greater than the regulatory value. (If repair costs are greater than this then the unit would be written off.)
- If bushing arrangements, tapping ranges and other fixtures do not allow unit to be used in structure layouts and the cost of altering a unit is greater than the regulatory value.

6.3.2.2 Policies and Procedures: SCADA, Communication Equipment and Other Related Equipment Renewal

The policy of renewing and refurbishing this equipment is to do it in a way that keeps the systems current, serviceable and avoids, as far as practical, the need to replace large amounts of equipment at one time due to it becoming obsolete.

The reasons for this policy include:

- The importance of the equipment in operating the network to meet expected levels of service.
- The speed with which technology is advancing.
- The cost and technical resource needed for a one off upgrade.

Typically this policy results in equipment that is greater than 15 years old being progressively renewed.

SCADA

SCADA equipment is renewed on failure and on an on-going basis typically after 15 years' service or when it is no longer supported. TLC works closely with an independent specialist SCADA Engineer/Technician to review the equipment annually and select equipment that is not performing or obsolete and in need of renewal. Priority is placed on key equipment that has a significant impact on the overall system operation.

This strategy has resulted in relatively few failures of equipment and, when they do occur, repairs can be quickly completed because parts and support are available.

Communication Equipment

TLC works closely with an independent specialist communications Engineer/Technician to review the equipment annually and select equipment that is not performing or is obsolete and in need of renewal. Priority is placed on key equipment that has a significant effect on the overall system operation.

Examples of equipment that would be renewed as not meeting the refurbishment criteria for communication equipment are:

- Batteries that are old or are not testing correctly.
- Aged radio sets that have failed and that are no longer supported by the manufacturer.
- Radio aerials and hardware that have failed or when a frequency adjustment is needed as required by the spectrum allocations regulator.

(Note: TLC is slowly converting the legacy analogue system to a digital system. The main driver for this is the band width requirements of the spectrum regulator. It should be noted that the system being implemented does not have a high data rate transfer; cost makes high data transfer rate difficult to justify).

6.4 Description and Identification of Renewal or Refurbishment Programmes, including Associated Expenditure Projections

6.4.1 Detailed Description of the Line Renewals Planned in 2015/16 year

The line renewal capital expenditure is primarily associated with replacement and refurbishment of existing lines. This work is to maintain the network and equipment to meet target levels of service. Table 6.24 summarises planned renewal expenditure.

ASSET RENEWAL AND REPLACEMENT LINE RENEWAL CAPITAL EXPENDITURE PREDICTION 2015/16	
Project	**Estimate ($)**
11 kV Line Renewals (includes emergent)	4,321,065
33 kV Line Renewal (includes emergent)	498,225
LV Line Renewals (includes emergent)	748,125
TOTAL	**$ 5,567,415**

TABLE 6.24 SUMMARY OF LINE RENEWAL CAPITAL EXPENDITURE PREDICTIONS

6.4.1.1 11kV Line Renewals 2015/16

Point of Supply	Description	Estimate ($)
Whole Network	Emergent Work	714,000
Hangatiki GXP	Aria 114-04	169,050
Hangatiki GXP	Aria 114-05	288,750
Hangatiki GXP	Caves 101-11	55,650
Hangatiki GXP	Coast 125-05	506,100
Hangatiki GXP	Coast 125-06	191,625
Hangatiki GXP	Mokau 128-01	152,250
Hangatiki GXP	Mokau 128-08	107,100
Hangatiki GXP	Mokauiti 115-06	121,800
Hangatiki GXP	Rural 126-03	13,650
National Park GXP	Raurimu 410-02	248,325
Ohakune GXP	Ohakune Town 414-01	161,700
Ohakune GXP	Turoa 415-01	299,250
Ongarue GXP	Nihoniho 412-02	224,700
Ongarue GXP	Ohura 413-04	306,600
Ongarue GXP	Ohura 413-09	72,450
Ongarue GXP	Ongarue 421-03	221,025
Tokaanu GXP	Oruatua 417-01	239,925
Whakamaru GXP	Huirimu 121-04	67,200
Whakamaru GXP	Whakamaru 120-03	159,915

TABLE 6.25 11KV LINE RENEWALS 2015/16

6.4.1.2 33kV Line Renewals 2015/16

Point of Supply	Estimate ($)	Estimate ($)
Whole Network	Emergent Work	221,025
Tokaanu	Kuratau Top Yard 610-01	54075
Ongarue	Taumarunui / Kuratau 608-01	223,125

TABLE 6.26 33KV LINE RENEWAL 2015/16

6.4.1.3 LV Line Renewals 2015/16

Point of Supply	Description	Estimate ($)
Whole Network	Emergent Work	113,925
Hangatiki GXP	Coast 125-05	65,100
Ohakune GXP	Ohakune Town 414-01	212,100
Ohakune GXP	Turoa 415-01	15,750
Ongarue GXP	Ongarue 421-03	28,350
Tokaanu GXP	Oruatua 417-01	198,975
Whakamaru GXP	Whakamaru 120-03	113,925

TABLE 6.27 LV LINE RENEWALS 2015/16

6.4.2 Detailed Description of Other Asset Replacement & Renewal (Excluding Line Renewals) Projects for the 2015/16 year

6.4.2.1.1 Ground Mount Transformer Renewal - $128,100

Three transformers that are reaching end of life are planned to be changed out with modern ground mounted transformers.

The three transformers are:

- 10S44
- T603
- T688

6.4.2.1.2 Transformer Switch Renewal - $94,500

Scope

Two transformers are being replaced with transformers that include RTE switches. This will allow cable sections and the transformers to be isolated. The three transformers are:

- 09R16
- 20L59

Justification

At present the transformers cannot be individually isolated. This means that extensive outages are necessary to do relatively minor works. Experience has shown that staff, when faced with this situation, often take risks. A by-product of this project will be improved reliability given that the transformers will be able to be more easily isolated.

Alternative Options

The sites could be left as is.

6.4.2.1.3 Mahoenui Zone Substation- Refurbish - $102,900

Scope

The project involves removal of the transformer to perform a half-life service and replace the rusted fins. The ex-National Park transformer will replace the current transformer that will be serviced. The transformer replacement will coincide with work to install a new circuit breaker.

Justification

Cheaper than letting the transformer rundown and need replacing.

Alternative Options

Replace transformer.

6.4.2.1.4 Equipment Renewals - $1,168,125

Equipment renewals covers general non-specific individual equipment renewal contingencies.

6.4.2.1.4.1 Tap-offs with new connections - $35,700

This is a contingency amount set aside each year for the installation of fuses on private line tap-offs or new connections. This protects the network from private line faults. It is a renewals bought forward allowance – i.e. if a tap-off pole needs to be replaced to facilitate a new connection, then TLC may contribute to this via this allowance if the pole was likely to be replaced as part of the next renewal cycle. It is considered unfair to expect a customer to fund the total renewal of a pole if it is in poor condition and likely to be renewed as part of the next cycle of the renewal programme.

6.4.2.1.4.2 Radio Specific - $630,000

TLC is upgrading is radio communication sites. This equipment upgrade is being completed to comply with the regulations of changing from 25 kHz bandwidth to 12.5 kHz bandwidth. The equipment that is used to achieve the upgrade is capable of switched between analogue and digital. An upgrade programme has been prepared by a communications consultant.

6.4.2.1.4.3 Radio Contingency - $12,075

This is a sum set aside per annum to cover any unforeseen capital work on the radio system. TLC owns and operates 20 repeater sites for data and voice communications throughout the network. Each of these sites contains various numbers of radios, batteries, chargers, aerials and other electronic equipment that need to be replaced on an on-going basis as the equipment ages. The data radio system is the backbone of network automation and in recent times there have been a lot of additional remote circuit breakers, substations and other controlled equipment added.

If the radio network fails, communication with remote equipment is lost. When this occurs, load control inputs and signals cannot be sent and automated equipment cannot be communicated with. Potential cost increases come from loss of load control during peaks. When failures occur, various options are considered. The refurbish/renew decision is based on the policies and issues outlined in the preceding sections.

6.4.2.1.4.4 SCADA Contingency - $18,375

This is a sum set aside per annum to cover any unforeseen capital work on the SCADA system. TLC now has automation in some form at approximately 30 zone substations, a distributed generation site, 11 load control plants and about 80 field devices. In addition to operation of field devices the equipment provides the central summation function of system load, generation and dispatch of load control signals.

6.4.2.1.4.5 SCADA Specific – $44,100

This is work to ensure the SCADA system is using the latest software and computers. The organisation has two options with SCADA equipment: either maintain and renew it on an on-going basis or let it run its course and complete a total replacement at the end of the equipment life.

The equipment is at the heart of the operating of the network and the rundown option would have many negative flow-on effects as reliability decreases. Increasing SAIDI would be one of these effects plus increased costs from having to send staff to various sites. The option of maintaining the equipment in a reliable state is currently being followed.

6.4.2.1.4.6 Transformer Renewals $357,000

This is a contingency amount set aside for distribution transformer failure through lightning strikes or either damaged or old units that are uneconomic to refurbish. This allowance also covers refurbishment of recycled transformers.

6.4.2.1.4.7 Protection & Voltage Relays - $12,075

A contingency amount set aside per annum to cover any protection equipment failure. This contingency is to mostly renew but sometimes refurbish in service equipment on failure. The TLC network has about 150 relays plus a similar number of other tripping and alarming relays in service. Over the past few years a number have failed or been found to be working incorrectly.

6.4.2.1.4.8 Distribution Equipment – $58,800

A contingency amount set aside per annum to cover any protection equipment failure. TLC owns, and still has in service, some very old switchgear, regulators and other distribution equipment. From time to time units fail and parts to repair this equipment are no longer available. When these events occur, the purpose of the equipment is reviewed and if it is still needed it is replaced with a modern equivalent.

6.4.2.1.5 Load Control Relays - $320,828

One of the weaknesses identified in the constraints section and in earlier AMPs was the implications of old high frequency ripple injection into the Hangatiki and Whakamaru supply points. A full report was put to Directors in July 2008 and they approved the plant renewal in the 2009/10 programme.

The report included a full discussion of operational and financial evaluation. In summary the conclusions were:

- That reliable load control and demand based charges would not be possible without renewal.
- All smart metering solutions deployed to date in New Zealand have continued to use load control systems.
- The long term financial benefit of replacing the plants outweighed the option of not renewing.
- The best technology option was to replace the existing system with a lower frequency ripple system.

The new load control plants are in place and the programme now moves onto relay replacement. It is envisioned that the programme will continue for the next 4 years.

The load control replacement programme was originally planned to start in the 2010/11 year; however, this was delayed due to the intent to combine it with TLC's advanced meter programme rollout. The cost of advanced meters which now include load control relays are such that the installation of a combined unit is similar to that of a legacy relay.

Advanced meter firmware has now been developed to the point that it will read both retailer and TLC demand based charging data and includes the capabilities for future communications and in-home displays.

The allowance included in this Plan is based on the amount it would cost to replace the relays. It is based on a model of a typical relay replacement programme and will form a contribution to the meter rollout; the numbers and costs are not fully funding the meter rollout.

<u>Justification and Scope</u>

TLC requires meters that will operate with the load control signal of the new ripple plants 317Hz decabit signal, which will improve TLC's ability to use demand side management load control.

The network must fund the renewal of relays and the associated administration systems to control these assets. The metering on the network is also substantially owned by a subsidiary company. These meters largely need recertification and renewal under the Electricity Authority's rules. There are about 5500 relays in the northern area that are affected by the load plant change out.

Note: This allocation is a notional amount given that the meters are now inclusive of relays. The notional amount is for the like for like replacement of relays.

For the purpose of planning, the relay exchange cost of $210 per relay inclusive of administration has been included in estimates.

<u>Alternative Option</u>

The alternative options include:

- Not replacing relays and allow the effectiveness of the load control plant to reduce.
- Replacing the mains signal load control system with some other system. Analysis of options has shown that the lowest cost and most effective option is to replace the system with lower frequency load control equipment.

<u>Non Asset Solution</u>

The objective of load control and network constraint signalling is to create the opportunities for non-asset solutions. A non-asset solution may have been to go to some other form of signalling but, at the time the decisions were made, there were no alternative technologies that could provide reliable and effective load control for the TLC network.

6.4.3 Summary Description of the Line Renewals Planned for 2016/17 to 2019/20

6.4.3.1 Asset Replacement & Renewal – Line Renewal Capital Expenditure Predictions

. A summary of the proposed expenditure for the next four years is shown in Table 6.28.

ASSET RENEWAL AND REPLACEMENT – LINE RENEWAL EXPENDITURE PREDICTIONS 2016/17 to 2019/20				
Projects	**2016/17**	**2017/18**	**2018/19**	**2019/20**
11 kV Line Renewals (includes emergent)	4,022,025	5,434,590	4,974,165	4,968,915
33 kV Line Renewal (includes emergent)	701,925	1,050,000	1,236,900	2,102,100
LV Line Renewals (includes emergent)	631,575	597,450	783,825	301,350
TOTAL	**$5,355,525**	**$7,082,040**	**$6,994,890**	**$7,372,365**

TABLE 6.28 LINE RENEWAL CAPITAL EXPENDITURE FORECAST FOR 2016/17 TO 2018/19

6.4.3.1.1 2016/17 Line Renewals

6.4.3.1.1.1 11kV Line Renewals 2016/17

Point of Supply	Description	Estimate ($)
Whole Network	Emergent Work	714,000
Hangatiki GXP	Caves 101-12	271,425
Hangatiki GXP	Caves 101-13	134,925
Hangatiki GXP	Gravel Scoop 109-10	47,250
Hangatiki GXP	Gravel Scoop 109-11	55,650
Hangatiki GXP	Gravel Scoop 109-12	5,775
Hangatiki GXP	Mahoenui 113-07	114,975
Hangatiki GXP	Maihiihi 111-10	315,000
Hangatiki GXP	Maihiihi 111-11	156,450
Hangatiki GXP	Maihiihi 111-14	84,000
Hangatiki GXP	McDonalds 110-03	90,300
Hangatiki GXP	McDonalds 110-04	41,475
Hangatiki GXP	Mokau 128-02	399,000
Hangatiki GXP	Te Mapara 117-06	236,775
Ohakune GXP	Ohakune Town 414-01	161,700
Ohakune GXP	Turoa 415-01	300,825
Ongarue GXP	Ongarue 421-01	210,000
Ongarue GXP	Southern 409-08	245,700
Ongarue GXP	Western 403-03	150,675
Tokaanu GXP	Motuoapa 425-01	108,675
Tokaanu GXP	Waiotaka 427-01	177,450

TABLE 6.29 11KV LINE RENEWALS 2016/17

6.4.3.1.1.2 33kV Line Renewals 2016/17

Point of Supply	Description	Estimate ($)
Whole Network	Emergent Work	221,025
National Park	National Park / Kuratau 609-04	287,175
Hangatiki	Te Waireka Road 303-01	193,725

TABLE 6.30 33KV LINE RENEWALS 2016/17

6.4.3.1.1.3 LV Line Renewals 2016/17

Point of Supply	Description	Estimate ($)
Whole Network	Emergent Work	113,925
Hangatiki GXP	Gravel Scoop 109-10	68,250
Ohakune GXP	Ohakune Town 414-01	136,500
Ohakune GXP	Turoa 415-01	142,275
Tokaanu GXP	Motuoapa 425-01	170,625

TABLE 6.31 LV LINE RENEWALS 2016/17

6.4.3.1.2 2017/18 Line Renewals

6.4.3.1.2.1 11kV Line Renewals 2017/18

Point of Supply	Description	Estimate ($)
Whole Network	Emergent Work	714,000
Hangatiki GXP	Aria 114-06	151,725
Hangatiki GXP	Benneydale 103-09	399,000
Hangatiki GXP	Gravel Scoop 109-07	335,475
Hangatiki GXP	Gravel Scoop 109-13	66,150
Hangatiki GXP	Maihiihi 111-06	224,175
Hangatiki GXP	Mokau 128-05	619,500
Hangatiki GXP	Otorohanga 112-01	345,450
National Park GXP	Raurimu 410-03	327,600
National Park GXP	Raurimu 410-04	120,015
Ongarue GXP	Ohura 413-07	139,650
Ongarue GXP	Tuhua 422-03	134,400
Ongarue GXP	Western 403-04	102,900
Tokaanu GXP	Kuratau 406-03	256,725
Whakamaru	Mangakino 118-01	390,600
Whakamaru	Whakamaru 120-01	361,200
Whakamaru	Wharepapa 122-01	251,475
Whakamaru	Wharepapa 122-02	494,550

TABLE 6.32 11KV LINE RENEWALS 2017/18

6.4.3.1.2.2 33kV Line Renewals 2017/18

Point of Supply	Description	Estimate ($)
Whole Network	Emergent Work	221,025
Hangatiki GXP	Gadsby / Wairere 307-03	294,525
Hangatiki GXP	Te Kawa Street 304-01	210,525
Ongarue GXP	Nihoniho 603-02	323,925

TABLE 6.33 33KV LINE RENEWALS 2017/18

6.4.3.1.2.3 LV Line Renewals 2017/18

Point of Supply	Description	Estimate ($)
Whole Network	Emergent Work	113,925
Hangatiki GXP	Otorohanga 112-01	227,325
Tokaanu GXP	Kuratau 406-03	113,925
Whakamaru	Mangakino 118-01	142,275

TABLE 6.34 LV LINE RENEWALS 2017/18

6.4.3.1.3 2018/19 Line Renewals

6.4.3.1.3.1 11kV Line Renewals 2018/19

Point of Supply	Description	Estimate ($)
Whole Network	Emergent Work	714,000
Hangatiki GXP	Aria 114-01	249,375
Hangatiki GXP	Benneydale 103-09	399,000
Hangatiki GXP	Mahoenui 113-08	232,575
Hangatiki GXP	Rangitoto 106-01	171,675
Hangatiki GXP	Rangitoto 106-02	32,550
Hangatiki GXP	Rangitoto 106-07	295,575
Hangatiki GXP	Te Kuiti South 104-02	374,325
National Park GXP	Chateau 419-01	153,825
National Park GXP	National Park 411-01	158,025
National Park GXP	Raurimu 410-04	120,015
Ongarue GXP	Manunui 407-01	134,925
Ongarue GXP	Manunui 408-01	324,450
Ongarue GXP	Southern 409-01	361,200
Ongarue GXP	Tuhua 422-03	134,400
Tokaanu GXP	Tokaanu 420-01	30,975
Whakamaru	Whakamaru 120-02	236,775
Whakamaru	Wharepapa 122-03	271,425
Whakamaru	Wharepapa 122-04	265,650
Whakamaru	Wharepapa 122-06	313,425

TABLE 6.35 11KV LINE RENEWALS 2018/19

6.4.3.1.3.2 33kV Line Renewals 2018/19

Point of Supply	Description	Estimate ($)
Whole Network	Emergent Work	221,025
Hangatiki GXP	Gadsby / Wairere 307-01	129,675
Hangatiki GXP	Taharoa B 302-01	593,775
Ongarue GXP	Nihoniho 603-01	292,425

TABLE 6.36 33KV LINE RENEWALS 2018/19

6.4.3.1.3.3 LV Line Renewals 2018/19

Point of Supply	Description	Estimate ($)
Whole Network	Emergent Work	113,925
Hangatiki GXP	Aria 114-01	22,575
Hangatiki GXP	Rangitoto 106-01	136,500
Hangatiki GXP	Rangitoto 106-07	16,800
National Park GXP	National Park 411-01	204,750
Ongarue GXP	Manunui 408-01	119,175
Tokaanu GXP	Tokaanu 420-01	56,700
Whakamaru Supply Point	Whakamaru 120-02	113,400

TABLE 6.37 LV LINE RENEWALS 2018/19

6.4.3.1.4 2019/20 Line Renewals

6.4.3.1.4.1 11kV Line Renewals 2019/20

Point of Supply	Description	Estimate ($)
Whole Network	Emergent Work	714,000
Hangatiki GXP	Coast 125-01	288,750
Hangatiki GXP	Mahoenui 113-01	227,850
Hangatiki GXP	Mahoenui 113-06	292,950
Hangatiki GXP	Mokauiti 115-01	137,550
Hangatiki GXP	Otorohanga 112-02	157,500
Hangatiki GXP	Otorohanga 112-05	3,675
Hangatiki GXP	Otorohanga 112-06	110,775
Hangatiki GXP	Piopio 116-01	435,225
Hangatiki GXP	Piopio 116-02	198,450
National Park GXP	Chateau 419-01	153,825
National Park GXP	Raurimu 410-04	120,015
Ohakune GXP	Turoa 415-04	107,625
Ongarue GXP	Manunui 408-02	422,100
Ongarue GXP	Ongarue 421-04	398,475
Ongarue GXP	Southern 409-01	362,775
Ongarue GXP	Southern 409-09	192,150
Ongarue GXP	Tuhua 422-03	134,400
Whakamaru	Huirimu 121-01	262,500
Whakamaru	Tihoi 124-00	10,500
Whakamaru	Tihoi 124-01	177,975
Whakamaru	Whakamaru 120-05	59,850

TABLE 6.38 11KV LINE RENEWALS 2019/20

6.4.3.1.4.2 33kV Line Renewals 2019/20

Point of Supply	Description	Estimate ($)
Whole Network	Emergent Work	221,025
Hangatiki GXP	Gadsby / Wairere 307-03	294,525
Hangatiki GXP	Taharoa A 301-01	593,775
Hangatiki GXP	Waitete 306-01	249,375
National Park GXP	National Park / Kuratau 609-03	616,875
Whakamaru Supply Point	Whakamaru-33 310-01	126,525

TABLE 6.39 33KV LINE RENEWALS 2019/20

6.4.3.1.4.3 LV Line Renewals 2019/20

Point of Supply	Description	Estimate ($)
Whole Network	Emergent Work	113,925
Hangatiki GXP	Coast 125-01	5,775
Hangatiki GXP	Piopio 116-02	142,275
Ongarue GXP	Manunui 408-02	28,350
Ongarue GXP	Northern 402-01	227,325

TABLE 6.40 LV LINE RENEWALS 2019/20

6.4.4 Summary Description of the Projects Planned for 2016/17 to 2019/20

6.4.4.1.1 Ground Mount Transformer Renewal

Transformers that are reaching end of life are planned to be changed out with modern transformers.

6.4.4.1.1.1 Ground Mount Renewals 2016/17

- 08R15 – Waihaha Feeder
- 08R16 – Waihaha Feeder
- T1001 – McDonalds Feeder

6.4.4.1.1.2 Ground Mount Renewals 2017/18

- T1927A – Otorohanga Feeder
- T1927B – Otorohanga Feeder
- T1463 – Mokauiti Feeder

6.4.4.1.1.3 Ground Mount Renewals 2018/19

- T404 – Otorohanga Feeder
- T4030 – Whakamaru Feeder
- T1470 – Tangiwai Feeder
- T1436 – Oparure Feeder

6.4.4.1.1.4 Ground Mount Renewals 2019/20

- 01A30 – Hakiaha Feeder
- 08I54 – Northern Feeder
- 08J38 – Manunui Feeder

6.4.4.1.2 Transformer Related Switch Renewal

The scope of works and justification for the following transformer related switch renewals is in line with what is discussed earlier in this section.

Installation of ring main units in association with transformer replacements:

- 16N09 – Chateau Feeder – 2016/17
- 16N01 – Chateau Feeder – 2017/18

Installation of ring main units:

- 20L18 – Ohakune Town Feeder 2016/17

Installation of new transformers with RTE switches:

- 20L43 – Tangiwai Feeder – 2016/17
- 10S41 – Turangi Feeder – 2018/19
- 20L45 – Tangiwai Feeder – 2018/19
- 16N29 – Chateau Feeder – 2019/20

Other works include reticulation renewal work planned for the Whakamaru old hydro village in 2016/17. The reticulation is old and hazardous. The houses are directly connected to the low voltage reticulation with no isolation equipment at the point of supply. The proposal is to address this issue and also install a 300 kVA transformer at site T2523 and remove units T2524 and T2521. Through-joint at T2523 and 2525 and replace LV cable around village with 4c Cable and pillar boxes.

6.4.4.1.3 Substation Renewals

6.4.4.1.3.1 Waitete – $69,615 in 2018/19

Replace bulk oil circuit breakers due to age, reliability and condition. Spare parts are no longer able to be obtained to maintain these circuit breakers.

6.4.4.1.3.2 Wairere – $94,500 in 2018/19

Refurbish transformer T1 to increase its expected life cycle and to ensure continued reliability. This is more cost effective than replacing the transformer.

6.4.4.1.4 Equipment Renewals

General non-specific individual equipment renewal contingencies for the next four years are summarised in Table 6.41.

EQUIPMENT RENEWAL CAPITAL EXPENDITURE PREDICTIONS 2016/17 to 2019/20				
Category	**2016/17**	**2017/18**	**2018/19**	**2019/20**
Radio Specific	$462,000	$44,100	$44,100	$44,100
Radio Contingency	$12,075	$12,075	$12,075	$12,075
SCADA Specific	$44,100	$44,100	$44,100	$44,100
SCADA Contingency	$18,375	$18,375	$18,375	$18,375
Tap-offs with new connections	$35,700	$35,700	$35,700	$35,700
Load Control				$120,750
Transformer Renewals	$357,000	$357,000	$357,000	$357,000
Protection	$12,075	$12,075	$12,075	$12,075
Distribution Equipment	$58,800	$58,800	$58,800	$58,800
TOTAL	**$1,000,125**	**$582,225**	**$582,225**	**$582,225**

TABLE 6.41 EQUIPMENT RENEWAL EXPENDITURE FORECAST FOR 2016/17 TO 2019/20

6.4.4.1.4.1 Radio Specific

On-going upgrade of the radio system to comply with new spectrum requirements. This will involve upgrading TLC communications to a digital network.

6.4.4.1.4.2 Radio Contingency – $18,375 p.a.

This is a contingency amount per annum for replacing radio equipment on failure. From time to time water gets into aerials and lightning destroys repeaters.

6.4.4.1.4.3 SCADA Specific – $44,100 p.a.

Annual allowance based on recommendations from SCADA experts to keep equipment up to date.

6.4.4.1.4.4 SCADA Contingency – $18,375 p.a.

This is a contingency amount per annum for replacing failed SCADA equipment.

6.4.4.1.4.5 Tap-offs with New Connections – $35,700 p.a.

This is a contingency amount per annum to cover brought forward renewals associated with replacing poles when new customer connections are taking place.

6.4.4.1.4.6 Load Control – $120,750 in 2019/20

This is an amount for renewals and upgrades to the load control plants.

6.4.4.1.4.7 Distribution Transformer Renewals – $357,000 p.a.

This is a contingency amount per annum for renewal of transformers that are uneconomic to repair. Typically units are renewed when repair cost is greater than regulatory value: see earlier sections for criteria details.

6.4.4.1.4.8 Protection – $12,075 p.a.

This is a contingency amount per annum for replacing relays and voltage control equipment on failure.

6.4.4.1.4.9 Distribution Equipment Contingency – $58,800 p.a.

This is a contingency amount per annum for failed equipment. (Typically circuit breakers and regulators.)

6.4.4.1.5 Load Control Relays

Expenditure is for the continuation with the upgrade of relays to the advanced meter type within TLC's network as described in the preceding section.

6.4.4.1.6 Supply Points – $714,000 in 2016/17

Expenditure is for the rationalisation of the number of outgoing feeder breakers in 2016/17. This reduces the number of circuit breaker from 3 to 2 by putting breakers on Taumarunui and Tuhua and removing Nihoniho. This allows splitting of feeders and isolation of Transpower Supply. The alternative to this is to maintain the current network configuration.

6.4.5 High Level Description of Asset Replacement and Renewal Projects Being Considered for 2020/21 to 2024/25

The final years of asset replacement and renewal planning are summarised below. Major projects for the final years of the planning period are outlined in the following sub sections. These are either financially significant projects (>$400,000) or projects that significantly affect network configuration or operation.

6.4.5.1 Equipment Renewals

Major projects programmed for these years include:

- Refurbishment of Wairere zone substation transformers.
- Renewal of circuit breakers at Atiamuri POS
- Renewal of aging indoor oil circuit breakers at various zone substations.

6.4.5.2 General Equipment Renewals

Equipment renewal expenditure includes contingency amounts per annum to cover equipment failure and refurbishment, these categories are:

- SCADA
- Radio & Data communications
- Distribution Transformers renewals
- Tap-offs with new connections
- Protection, relays and equipment
- Distribution Equipment

There are specific amounts set aside for load control, Radios and SCADA for planned upgrades.

6.4.5.3 Line Renewals

Programmes based on 15 year cycle for 33 kV, 11 kV and LV lines.
The full details of the line renewal and replacement programme are discussed in the lifecycle asset management planning – section 3 of this document.

Section 7

7. Risk Management

7.1 Overview

TLC has started a review of the entire risk management process to better align it with New Zealand standard. Going forward this will form the basis for risk management across the business.

Currently TLC uses formal and informal studies based on industry experience and information to identify any risks. Risk management is a continual improvement process that encompasses many things including assets, health and safety, the community, operations, public hazard control, natural events and other infrastructure flaws.

Most of TLC's business processes and activities have an element of risk management. A key driver for this business approach is the company's corporate objective of delivering a strong sustainable network to the greater King Country. A high risk approach to business activities may not achieve this. The AMP, Annual Plans and SMS are documents that manage risk. These plans and other inputs are used to manage the network in such a way that continually focuses on the identification of hazards and their control (elimination, isolation or minimisation).

Documenting and having strategies in place to manage risks is a key aspect of this Plan. A focus of the Plan is to manage and reduce risk. The cost of not completing renewal and other activities to satisfactorily manage risk has a high potential liability cost.

7.2 Risk Policies

7.2.1 Risk Framework

TLC has a structure of policies and standards that are used to manage corporate risk. A subset of these is distribution-related policies and standards as is the SMS. These policies and standards include direct risk lowering policies and others that are closely related. The SMS focuses on all network assets with a view to controlling hazards to the public and property such that the risks of serious harm or significant damage are deduced to a tolerable level.

Policies and standards are reviewed regularly and there is a formal process in place to ensure this. The process involves new policies and standards being considered, approved, and reviewed by an executive committee. The SMS has its own review and audit policies and procedures. The structure of this process is illustrated in Figure 7.1.**Error! Reference source not found.**

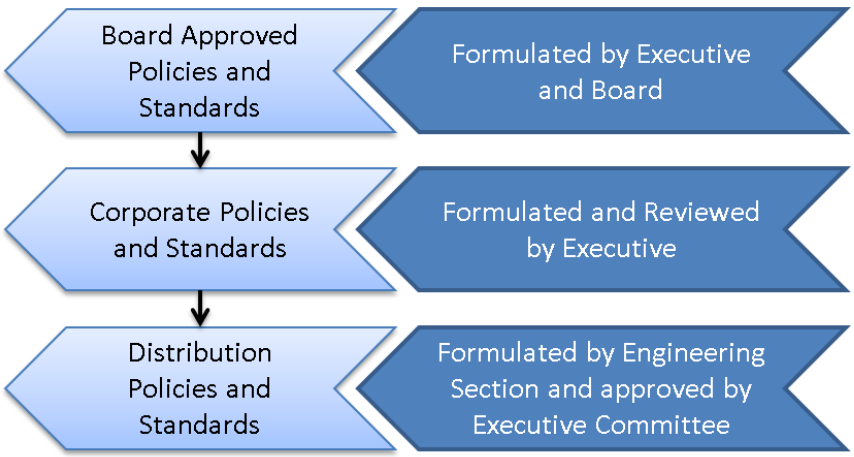


FIGURE 7.1 STRUCTURE OF CORPORATE POLICIES AND STANDARDS

The methods used to assess risk issues include:

- Previous events.
- Legislation and Regulation.
- Financial security.
- Strategic requirements.
- Network performance analysis.
- The cost and implications of not controlling risks.
- Public hazards are mitigated via the SMS.

The details that the risk policies cover include hazard control, compliance, financial, strategic, human resources, and events.

Risk analysis and its considerations are fundamental to business and corporate strategy to provide customers with a network that produces a reliable, adequate quality and hazard controlled service at an affordable price.

7.2.2 Distribution Asset Risk Policies

The asset risk policies are mostly placed within the Distribution Policies and Standards as illustrated in figure 10.1. The details of asset risk policies are included in distribution standard codes, policies and other documents, which include:

- Emergency management procedures.
- Civil defence policies.
- Hazard control policies and procedures.
- Design standards.
- Construction and material standards.
- Operating standards and procedures.
- Specific instructions.
- Distribution code.
- The Asset Management Plan.
- The Safety Management System.
- Individual project specifications and standards.
- Insurance for equipment other than overhead lines related hardware.

These policies consider the probability of an event and its consequences. These include:

- Physical failure risks.
- Operational risks.
- Natural environmental events.
- Factors outside of the organisation's control.
- Stakeholder risks.
- Risk associated with the different life cycle phases of assets.
- Public related hazard control.

TLC policies recognise that risk is defined as the product of probability and consequences. For example, as described in Section 5, planning criteria and assumptions are based on this recognition.

The policies include various techniques for identifying, quantifying and managing asset related risks with varying levels of complexity. TLC is constantly reviewing its individual requirements in terms of risk identification, including the availability of information and implementation practicalities of reduction strategies.

TLC uses the understandings gained from risk assessments and the performance of risk control strategies to provide input into:

- Asset management strategy and objectives.
- Long and short term asset management and business plans.

- Identification of adequate resources.
- Training and competency needs.
- Controls for asset life cycle activities and the implementation of this plan and annual plan subsets.

A key strategic tool for the implementation of the asset management process is the Basix information system. This allows performance to be measured, and forms the foundation for on-going risk assessment and prioritising projects for risk.

7.3 Network Risk and Methods to Mitigate Risk Events

7.3.1 Corporate Risk

Table 7.1 summarises the corporate risk assessment and mitigation.

CORPORATE RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
HAZARD CONTROL	
Events that may cause harm to staff, public, and property.	Methods: Identify potential and existing hazards associated with network operation, staff, public and other stakeholders. Place importance on hazard free designs. A safety management system in compliance with the Electricity (Safety) Regulations 2010 has been in operation from 1st September 2011. This document is referenced to the AMP and it will become an increasingly integrated document to identify hazards to the public, assess them for risk and apply controls to significant hazards. Various workplace hazard control mechanisms are in place to ensure compliance with HSE legislation. Methods for control include various policies, procedures and on-going programmes. High level corporate risk is managed by having a strategic plan that addresses various environmental risks and develops a high level plan to control the risk. Details: Corporate strategy documents that are designed to provide direction and thus reduce the risk of doing business include, by controlling hazards: • Strategic Review. • Statement of Corporate Intent. • Annual Strategic and Business Plans for each section of the company. • HSE policies procedures and plans. • Safety Management System development and compliance. • A SWOT analysis is often used when these plans are being formulated. • Insurance. Various criteria are used when this analysis is carried out at a high level. These include factors such as: • Previous work and plans. • The environment. • Customer service. • Asset needs. • Other factors. From an asset needs perspective, risk consideration includes: • Physical failure risk. • Natural environmental risks. • Factors outside the organisation's control. • Stakeholder risks. • Risks associated with different life cycle phases of assets. Conclusion: The objective is to be aware of hazard related risks and have plans in place to control hazards to a level that is acceptable to all stakeholders. The risk of not having these in place will have detrimental effects on people, equipment, customer service and organisational profitability/sustainability. (Businesses that cannot control hazards to adequate levels become unsustainable.)

CORPORATE RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
Human Error.	Methods: Policies, training and, as a backstop, insurance. Details: On-going training, assessment and monitoring to ensure staff are competent to complete the tasks in front of them. On-going review of policies and follow up after reported incidents. Conclusions: It is a corporate objective to have a well-trained and competent work force. As a backstop to reduce stakeholder risk, insurance is in place.
COMPLIANCE	
Threat of prosecution and extensive investigation.	Methods: Include objectives and strategies at all levels of operations (various plans including AMP, disclosures, policies) to comply. Details: Various policies, work activities plans and documents to comply with legislation and regulations, including HSE, Finance, Commerce Commission, Tax, Technical, Pricing, Industry, Human Resources, Electricity Act/regulations and Others. Conclusion: Business objectives that comply with acts and regulations that avoid costly investigations and prosecutions by enforcing authorities.
FINANCIAL	
Events that restrict the organisation's ability to generate income to finance operations and capital investment.	Methods: Carefully analyse revenue risks and implement strategies to minimise these. Details: Dry year energy savings and future environmental concerns driving new technologies put energy based revenue streams at risk. TLC decided to move away from energy based billing income streams to create a more environmentally focused asset capacity and demand based method of charging. Conclusion: Asset capacity and demand based billing introduced in 2006/07.
Remote rural lines that were built with government subsidy need renewing. The government is not providing any subsidy for renewal.	Methods: The impact was calculated and politicians and officials were lobbied. Strategies put in place to manage rural lines such as ensuring capacity requirements do not increase and require upgrades as well as renewals. Details: Results in cross subsidy from urban areas to rural areas. TLC has informed stakeholders of these consequences. Conclusion: Politicians and officials have no solution to this problem. TLC will implement renewal strategies to keep these costs minimised, extend programmes as far as possible and to maximise renewal efficiency and to reduce cross subsidisation.
Customers' ability to pay.	Methods: Close monitoring and extensive discussions with customers. This includes comparing rates with other network companies. Details: Use of focus groups, customer clinics, consultation and stakeholder feedback to monitor the issue. On-going meetings and discussions on reliability, renewal and hazard control issues. Models have been set up to compare rates with other network companies. These models also give TLC an understanding of the levels of cross subsidisation that results with volumetric based charges. Conclusion: The TLC area is low income as indicated via various national studies. TLC has to be very mindful of customers' ability to pay and the charges relative to other network companies.

CORPORATE RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
Fraud	Methods: Checking of payment systems. Use of insurance as backstop. Details: All payments are checked by executives from different sections. Various policies and levels of authorisation of accounts for payment are in place. Auditing to ensure items exist and that they have been purchased for realistic prices takes place. Quotes and estimates have to align to annual plan. Reconciliation of annual plan to payments. Insurance in place as a "backstop". Conclusion: Auditing and checks are in place.
STRATEGIC	
The organisation continuing to develop activities that ensure customers' expectations are satisfied.	Methods: Asset management systems tailored for the network. Structure to maximise renewal efficiency. Reliability and quality of supply that customers want. The organisation will develop advanced network technologies. Details: AMP produced that contains comprehensive details. Plan reviewed annually and updated based on feedback from customers and changes to the operating environment. Conclusion: One of the purposes of the AMP document is to mitigate the risk of having a network that does not perform to expectations. Initiatives for an advanced network are included in the AMP.
ENVIRONMENTAL	
Environmental issues will influence many of the future national and international governance requirements. The organisation needs to recognise this and minimise the risk looking forward into the future.	Methods: Strategic and operational decisions need to consider the long term environmental issues. Details: Corporate strategies and policies that consider the environmental impact. For example minimising SF6 gas, demand billing to promote demand side management of active and reactive power, billing structures to promote distributed generation, end of life disposal considerations with all assets, and investment in distributed generation. Reviews of compliance with resource management legislation. Conclusion: TLC is looking to the future and considering all aspects of its operation. This will include the development of advanced network technology.
HUMAN RESOURCES	
Loss of skills with intellectual knowledge leaving the organisation. (Network and local)	Methods: Creating a good working environment with competitive remuneration. Details: Focus on developing local people and providing them with the skills to meet company's and customers' needs. Conclusion: TLC recognises the importance of retention of staff members who have the intellectual knowledge to maintain and operate the network in a sustainable fashion.

CORPORATE RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
CUSTOMER RELATIONS	
Poor customer relations over direct and demand based billing	Methods: Various customer campaigns and other customer service plans/programmes/initiatives. Pricing has also been reviewed by an independent body. Establishment of a communications section. Details: Initiatives include: • Call centre staffed by local people. • Training programmes for call centre staff. • Focus group meetings. • Customer Clinics. • Other public relations programmes. • Independent review of pricing and the way demand levels are charged. Conclusion: Managing the risk of adverse public relations is important to the organisation.
DISTRIBUTED GENERATION	
Distributed Generation Applications	Methods: Demand billing to reduce the risk of volume changes. Researched lists of engineering issues that need considering when completing distributed generation analysis. Details: Volume charges reduce the incentives for lines companies to connect generation. Demand billing overcomes this. TLC has a list of about 25 conditions that need consideration before intermediate and large distributed generation plant can be connected. Generators are made aware of these and asked to have consultants work through each of these and submit solutions with the final applications. Distributed generators often choose not to do this and want TLC to take on the risks of connection. TLC resists this as it is well aware of the damage unstable distributed generation can cause on the network. Distributed generators' investors can then complain to the Electricity Authority and these complaints can add considerable legal costs to the organisation's operation. Conclusion: The connection of distributed generators to a network that was originally designed to carry energy from a central point out to customers can add considerable costs and complexities. The Electricity (Distributed Generation) Regulations add to this complexity (now the participation code).

TABLE 7.1 CORPORATE RISK ASSESSMENT AND ANALYSIS

TLC has insurance to mitigate corporate risk should incidents occur.

7.3.2 Overhead Lines

Table 7.2 summarises the overhead line risk assessment and mitigation:

OVERHEAD LINE RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
PHYSICAL FAILURE RISKS	
Vegetation	Methods: About 50% of faults in rural areas originate from some form of tree issue. As a consequence of this TLC has established, and will continue, a comprehensive vegetation control programme. Details: The programme consists of planned patrols and follow ups and emergent activities as detailed in this Plan. Conclusion: Vegetation is one of the key spokes in the wheel of mitigating risks with overhead lines. Related issues include hazard control, reliability, public hazard control and quality. For example, trees falling through lines often cause voltage spikes, which then destroy appliances.
Aged Equipment	Methods: Renewal programmes, patrols, follow ups after faults and auto recloses, customer and staff reports, inspections, observations, outage data, performance monitoring, and the intellectual property of experienced staff are all methods used to mitigate risk with aged overhead lines. Details: The various policies, strategies, processes and plans detailed in this Plan. Conclusion: Mitigating old overhead lines risk forms a large part of this Plan.
Line clashing	Methods: Fault investigation to identify possible causes. Line design review when problem areas are identified. Details: When line clashing is suspected, all upstream fault current recording devices are downloaded and reconciled to runs of TLC's network analysis programs to try and identify the location. Once the expected location is identified a site patrol is carried out to pin point the exact location. Once the problem area is identified, designs are completed to remove the problem. Conclusion: Line clashing is caused by birds, fault currents, wind and flying tree branches can cause conductor burn down and consequential risk issues such as forest fires. Line clashing also reduces the effectiveness of protection schemes and is an important risk to mitigate.
Lines around boat ramps	Methods: Line inspections include recording of overhead line heights above ground to ensure they comply with Regulations. Signs are also put in place. Details: Boat masts coming into contact with overhead lines is a problem around the shores of Lake Taupo. Line heights have been found to comply, but this is still a problem when boat operators forget to lower their masts. Warning signage is in place and is being monitored to ensure it is maintained. Monitoring of this signage is part of line patrols and inspections. Conclusion: Line clashing caused by boat is difficult to guard against. More signage is planned to help mitigate the risk.
Theft of copper	Methods: Theft of copper earthing and overhead conductor can result in hazards to the public and animals. This risk is reduced by substations inspections, other switchgear/equipment inspections, line patrols, line inspections and other observations made by staff, the public and police. Details: Substation inspections, other switchgear/equipment inspections, line patrols, line inspections and other observations all place priority on the integrity and testing of earthing systems. Data on earthing systems is stored in the Basix system. The police are informed of all thefts and assisted with information to try and apprehend the offenders. Conclusion: Earthing systems are critical for hazard control. The theft of components of these systems leads to risks.

OVERHEAD LINE RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
OPERATIONAL RISKS	
Capacity	Methods: Asset and engineering staff monitor field equipment loadings and annually work through the entire network examining data and reconciling these to network models. Some equipment also has alarms set at certain load points. Protection systems are in place. Details: Models are reconciled to field data and run. All equipment ratings and their operation are considered. (This is an annual exercise, in addition to the daily use of models to check specific needs such as customer requests for load and motor starting etc.) This repeated modelling gives regular on-going monitoring of network loads. Conclusion: Accurate, up-to-date and regularly used network models by all levels of technical staff are the principal tools for mitigating the risk of overloading network equipment. Priority is placed on ensuring protection systems are operational.
Hazard Control	Methods: The renewal programmes, patrols, follow-ups after faults, auto recloses, customer and staff reports, inspections, priority setting, observations, outage data, performance monitoring, and the intellectual property of experienced staff are all methods used to mitigate hazards with aged overhead lines. Protection systems are set up in compliance with legislation and industry practice. SMS and accreditation of this to a standard. Details: The various policies, strategies, processes and plans described in this Plan. A major focus of daily activities is to control hazards including both work and public related. Protection systems that are effective, simple and reliable are implemented. The protection systems are tested, monitored and renewed as detailed in this Plan. The network analysis model has a protection sequencing model and this is used to ensure protection is operating in the correct fashion to minimise the impacts of faults on overhead lines. Conclusion: Mitigating the hazards associated with old overhead lines risk forms a large part of this Plan.
Fault Currents	Methods: The effects of fault currents on overhead lines are considered by modelling fault current levels and checking these throughout the network. Details: Levels are looked at regularly and reconciled to line strength and spacing. (Experience has shown that fault levels above 100MVA on standard 11 kV light construction will cause problems.) Control of fault current levels is one of the reasons why the modular substation concept was developed, i.e. smaller modular zone substations designed to limit fault currents. Conclusion: Mitigating the hazards caused by fault currents has been included in this plan.
Private Lines Connected to TLC Lines	Methods: Inform line owners of hazards observed on their lines when patrols and inspections are taking place. Details: Line owners are written to when hazards are observed. Fuses are placed at the point of connection to minimise the risk of these lines affecting other customers. Conclusion: Privately owned lines are now better covered by the Electricity (Safety) Regulations, but to date there has been no indication as to how Energy Safety intends to police the obligations.

OVERHEAD LINE RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
NATURAL ENVIRONMENTAL EVENTS	
Slips	Methods: Potential slips are identified during patrols, 15 yearly inspections or other reports. Details: Plans completed and lines/poles moved as required. Conclusion: Slips regularly occur in the rugged King Country and inspection/patrol staff have to be vigilant to observe ground cracks and potential slip sites.
Wind	Methods: 15 year renewal programme, patrols and other reports. Details: Line design programme used to ensure line strengths are adequate when renewal and patrol data analysed. Conclusion: Many of TLC's older lines are under strength (see section 3) and the renewal programme is gradually increasing line strengths. (Depends on importance of each line and its location as to how much strength is increased during each pass.)
Flooding	Methods: Poles and other equipment likely to be washed out or affected by floods identified as part of 15 year programme. Details: Major issues resolved as part of 15 year programme. Conclusion: Pole washouts and difficulties accessing key equipment are the greatest flood risks.
Seismic	Methods: Construction standards used to ensure the impact of seismic events on pole loadings are considered. Details: Line design calculations include seismic considerations. Conclusion: Many of the older sections of the network have inadequate seismic strength.
Lahar	Methods: Lahar paths are identified by 15 year inspections, patrols and other special events. Details: Lines are kept out of Lahar paths or, where this is not practical, protection is put in place. Conclusion: TLC had protected poles prior to the 2007 Mt. Ruapehu event. Lahars are a consideration when lines are being designed.
Geothermal	Methods: Geothermal areas are normally unstable and overhead lines are kept away from these areas as far as practical. They are often associated with sensitive Maori land. Details: Geothermal areas are identified by steam coming out of the ground. Often overhead lines have to be used through these areas as an alternative to cabling. Conclusion: TLC has to be aware of geothermal activity.
Volcanic	Methods: TLC has several active volcanoes in the network area. The potential of ash contamination has to be considered when selecting insulators and positioning equipment. Details: The size of insulators used in the network generally has been increased to improve performance when subject to ash and fertiliser. Conclusion: A number of lines have the potential to be affected by ash and volcanic activity.

OVERHEAD LINE RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
Snow, ice and other storm hazards	Methods: Renewal programmes that take into account likely snow and ice loadings when line designs are reviewed. Details: Existing and proposed designs are checked with a line design computer programme before work is issued. Conclusion: Many of TLC's existing lines are under present code strength requirements. Renewal programmes are addressing these in a staged way. The strength of existing assets means that it is not possible to do this in the first 15 yearly cycle unless more funding is available. The more important lines have more work completed on the first cycle. The more remote lines with fewer customers will have the most likely points of failure, or most significant consequence sections strengthened. For example, attention is given to long river crossing spans, etc.
Natural Hazards with greater intensity than can normally be expected	Methods: Natural events with intensity greater than design standards do occur. The local environment is considered when lines are being designed or inspected prior to renewal. Details: Lines inspectors and designers are involved with fault analysis after natural events and outage records. Engineering staff have also built up knowledge on natural events and consider the specific environments when completing designs. Conclusion: Care is taken to minimise the risk of natural events. It is not possible to eliminate all possible events as costs would be prohibitive.
STAKEHOLDER RISK	
Extensive destruction of overhead lines	Methods: Renewal programmes included in this AMP need to be completed to manage risk. Overhead lines are not insured. Details: Patrol and inspection programmes as detailed in the AMP. Conclusion: The steps for controlling hazards detailed in this plan are designed to manage shareholder risk.
Fire started by overhead lines	Methods: Renewal and maintenance programmes included in the AMP. Protection systems set up in accordance with industry practice. Details: Renewal to reduce the likelihood of failure is included in the AMP. (Failure can lead to fires being started). Vegetation control programme helps reduce the risk of fire. TLC works with forest owners where practical to advise them of this risk. TLC uses corona camera inspections as detailed in Section 8 to reduce the risk of fire due to tracking insulators. Protection systems in place that are effective and isolate faulty lines. Public Liability insurance is in place as a backstop. Conclusion: Forest and grassland fire is a major risk to stakeholders as is the cost of putting the fires out. (This cost is passed onto TLC by the rural fire authority).
Age of TLC overhead lines assets	Methods: Age of assets recognised in the plan and strategies put in place to control these. Details: Patrol and renewal inspections and the corrective actions that come out of these plans is the base for renewals. Conclusion: Have a long term plan to change out overhead assets before they reach the end of their lifecycle and fail.
Supply quality components into the network as part of the renewal programme	Methods: Have clear quality standards for components and checking of items to ensure they meet these standards. Details: Constantly reviewing, updating, standards, monitoring and auditing performance of components to ensure they will meet lifecycle expectations. Conclusion: Component quality is vital to minimise the risks associated with different lifecycle phases of assets. Early failure will cause costs and customer disruption.

TABLE 7.2 IDENTIFIED RISKS AND MITIGATION OF RISKS TO OVERHEAD LINES

7.3.3 Zone Substations and Voltage Regulation Equipment

Table 7.3 summarises the zone substation and voltage regulation risk assessment and mitigation.

ZONE SUBSTATION AND VOLTAGE REGULATION RISK ASSESSMENT AND MITIGATION	
Risks	**Mitigation**
PHYSICAL FAILURE RISKS	
Aged Equipment	Methods: Inspection, maintenance and renewal programmes are in place. Details: TLC is keeping a close watch on its aged transformers and switchgear. Regular oil tests are completed. Emergency alternatives are being put in place for aged switchgear, both for maintenance work and in case they fail. The Plan includes a programme for refurbishing aged zone substation transformers that have high winding water content. Conclusion: The risk of aged equipment failing in zone substations is being mitigated by this Plan.
Electronic Equipment and Software	Methods: Today's substation equipment, including voltage regulators, is driven by software. It is important that systems are in place to both manage equipment settings and the software itself. TLC's maintenance plan requires annual downloading of equipment settings and the reconciling of these to master files. Details: In addition to regular downloads and reconciliation, TLC, as far as practical, sources equipment that has similar software for both protection and voltage regulators. In addition, the master file settings are also reconciled with the network analysis program. Conclusion: TLC's technical staff are very mindful of the need to carefully manage various control and protection packages, and to have these backed up for disaster recovery.
Security	Methods: Security is enhanced by improving fences, gates and increasing the number of locking devices. Security is also an important design consideration. Details: This Plan includes a number of security improvements at zone substations. Security has been improved in future designs by using low cost methods such as locating equipment in shipping containers, and similar enclosures with relatively high security. Designs are also increasingly focused on ensuring that security risks are reduced. Conclusion: TLC has recognised that a number of its legacy sites lack the level of security expected with infrastructure in today's environment, and improvements are being made.
Theft of earthing systems copper	Methods: Theft of copper earthing and overhead conductor can result in hazards to the public and their property, i.e. livestock. This risk is reduced with a programme of substations inspections, other switchgear/equipment inspections, line patrols, line inspections and other observations made by staff, the public and police. Details: Substation inspections, other switchgear/equipment inspections, line patrols, line inspections and other observations all place priority on the integrity and testing of earthing systems. Data on earthing systems is stored in the Basix system. The police are informed of all thefts and assisted with information to try and apprehend the offenders. Conclusion: Earthing systems are critical for hazard control. The theft of parts of these systems may lead to risks for staff and the public.

ZONE SUBSTATION AND VOLTAGE REGULATION RISK ASSESSMENT AND MITIGATION	
Risks	**Mitigation**
OPERATIONAL RISK	
Hazard Control	Methods: TLC has recognised that many of its legacy substations have hazard control needs and much of the expenditure in this plan is associated with addressing these. Hazard control is a priority consideration for new designs. Details: Much of the expenditure is focused on making it more difficult for staff, and the public, to get into hazardous situations while working on, or being in close proximity to, substations. TLC is looking beyond this and is using its network analysis program to calculate arc flash and fault current levels. These quantities are carefully considered in new designs and operating criteria. Conclusion: Hazard control and minimising/eliminating risks of incident/accident and harm, is one of the main focuses of this Plan.
Capacity	Methods: The load on zone substation equipment is being monitored. These loads are reconciled to data models, which are regularly run (daily) for many reasons. The existing network is modelled, as is any future load predictions, when alternative supplies are configured. An annual detailed review takes place. Details: Loading data are used to check capacity constraints. The models are set up to assist with identifying equipment that is operating beyond capacity limits. Conclusion: TLC's on-going network analysis and data collection is focused on utilising asset capacity without exceeding ratings. This work mitigates the risk of TLC operating equipment beyond ratings.
Substations supplying areas with no alternative. Supplies via single bus bars with no emergency or alternative supply option	Methods: Various methods are included in this plan to put in place some form of alternative light load supply. Details: Alternatives are being developed with the deployment of modular substations and adding additional modular switchgear. Conclusion: There are risks of extended outages in a number of areas that would be unacceptable to customers.
Environmental risks associated with operational issues	Methods: A number of TLC's legacy substations do have environmental risks mostly associated with lack of automatic oil separation control. These are being addressed in this plan. Present and future designs consider environmental issues. Design and equipment selection also considers end of life disposal. Details: This Plan and the engineering approaches taken by TLC with zone substations and voltage regulators focus on protecting the environment. For example, TLC's modular substation does not include tanked tap changers that often have oil leaks after covers are removed for maintenance. Modular substations and equipment shelters include integral oil containment and site environmental control systems. Conclusion: TLC is addressing legacy environmental issues and is finding innovative ways to address future environmental issues at the lowest possible cost.

ZONE SUBSTATION AND VOLTAGE REGULATION RISK ASSESSMENT AND MITIGATION	
Risks	**Mitigation**
NATURAL RISK ENVIRONMENTAL EVENTS	
Wind, Snow, Ice and other storm hazards	Methods: Zone substations and regulator sites are designed and positioned to withstand expected winds, snow, ice, etc. Vegetation around zone substations is controlled. Details: Zone substations and regulator sites have been assessed for their ability to withstand storms etc. Conclusion: Where shortfalls have been identified these have been included in this Plan, e.g. protection and switchgear improvements.
Flooding	Methods: Zone substations and regulator sites in flood prone areas have been identified. Details: The Plan includes proposals for alternative supplies for substations that are in flood prone areas. Conclusion: Flooding is a low probability, high impact risk that has been considered and mitigated against in this Plan, e.g. Taumarunui north.
Lahar, Geothermal	Methods: Locations of zone substations have been evaluated for potential Lahar and geothermal risk. Details and Conclusion: Zone substations are not located in Lahar paths or geothermal areas.
Volcanic	Methods: Locations of Zone substations have been evaluated for risk due to volcanic activity. Details: Three substations are likely to be affected by volcanic activity on the central plateau. Two of these substations are capable of backing one another up. It is not economic to be able to back up the third. The plan does include additional automation to be able to transfer the 33 kV supply to this third site by alternative lines. The Plan includes improvements to several sites that will increase resistance to volcanic eruptions. Conclusion: Volcanic effect on zone substations is a low probability, high consequence event that has been considered and mitigated in putting together the programmes in the AMP.
Seismic	Methods: Zone substation transformers and the effects of seismic activity have been assessed. Buildings have not at this time. Details: Most sites have seismic security. Security for the remaining sites has been included in the plan. Where buildings pose a risk, an alternative switchgear installation has been included in the Plan. These installations are often housed in containers. Conclusion: Earthquake effects on zone substations are a relatively certain, but infrequent event, and have been considered and mitigated against in putting together the programmes in the AMP. Note: At the time of writing, we have reviewed the Plan after giving consideration to the effects of the Canterbury earthquakes and intend to continue the strategies included in earlier AMPs. Based on the information that has come available to date, we believe TLC's Plan will address the needs adequately.

ZONE SUBSTATION AND VOLTAGE REGULATION RISK ASSESSMENT AND MITIGATION	
Risks	**Mitigation**
FACTORS OUTSIDE OF THE ORGANISATION CONTROL	
Network events that are more severe than Standards and Codes	Methods: When it is obvious that a risk exists that exceeds the design requirements listed in codes, additional engineering is applied. Details: Designers are aware of local issues and these are included in the design process. Conclusion: TLC designs have to consider local issues. At the end of the day, however, it is difficult to include every issue that may or may not happen and build economic outcomes to cover off potential eventualities. The calls are made based on professional intellectual learning with partial insurance as a risk backstop.
STAKEHOLDER RISKS	
TLC's demand billing system failing	Methods: The demand billing system is important in controlling the demand growth and the loadings on zone substations and voltage regulators. If growth is higher than predicted, network strengthening will be required at a level greater than that included in this plan. Details: TLC is developing and reviewing the demand billing processes constantly to ensure its success. This includes: Reviewing/developing the integration with the AMP. Reviewing customer feedback. Reviewing the success of its ability to control demand growth. Altering load control strategies. Modifying and tuning all of the above. Conclusion: TLC is committed to developing its demand based billing and integrating it into its overall asset management strategy.
Major failure of sub-transmission or zone substation resulting in an extended outage.	Methods: TLC is increasing diversification as detailed in this Plan to minimise this risk. Details: The existing sites are being developed to ensure reliance is not placed on any one piece of equipment. Additional modular units are being used to reduce the dependence on any one piece of equipment. Conclusion: Risk is being reduced through diversification at the lowest possible cost.
RISK ASSOCIATED WITH DIFFERENT LIFECYCLE PHASES OF ASSETS	
Equipment failing early in lifecycle	Methods: Quality standards and contingencies are in place to cover early failure. Details: Quality specifications are prepared and work is audited against these specifications. Contingencies include planning for initial problems in the early part of equipment lifecycle "bathtub reliability curve". Conclusion: Quality standards are important, along with recognising the reality is that failures may occur in the initial part of an equipment lifecycle.
Equipment failing when it is run beyond lifecycle	Methods: Renewal programmes are in place and there are contingencies for equipment that is run beyond its lifecycle. Details: Renewal programmes are targeting equipment that is no longer fit for purpose. If equipment is fit for purpose, contingencies need to be in place in case the equipment fails. The Plan has been prepared on this basis. Conclusion: Some items within the TLC network are old. Failures from time to time are an expectation and a risk that has to be lived with given that resources, both financial and staff, are not available to renew much of this old equipment in a short time.

TABLE 7.3 IDENTIFIED RISKS AND MITIGATION OF RISK TO ZONE SUBSTATIONS AND VOLTAGE CONTROL EQUIPMENT

Note: Equipment insurance policies with excesses in the $20k to $30k range are in place for substation equipment.

7.3.4 Distribution Substations, Switchgear and Underground Systems

Table 7.4 summarises distribution substations, switchgear and underground systems risk assessment and mitigation.

DISTRIBUTION SUBSTATIONS, SWITCHGEAR AND UNDERGROUND SYSTEMS RISK ASSESSMENT AND MITIGATION	
Risks	**Mitigation**
PHYSICAL FAILURE RISKS	
Earthing Systems, particularly SWER systems causing earth potential rise	Methods: Design and test earthing systems including considering the effects of fault currents. Details: Bi-annual testing of isolating SWER transformers, and a 15 year programme for other transformers. Use of TLC's earth design module network analysis to correctly design the initial work and any improvements. Conclusion: The risk associated with earthing systems is recognised and being mitigated as part of this Plan.
Loss of Circuit Breaker Electronic Setting Data	Methods: The importance of equipment data settings and firmware is recognised. Details: An annual dump of data occurs as part of maintenance programmes. These are reconciled to originals and copies are kept off site. Conclusion: The loss of recloser, and other distributed software and equipment settings, is recognised and the risks are mitigated.
Security of equipment not being up to standard with potential for unauthorised public access.	Methods: Initially, and on an on-going basis, check and upgrade security. SMS reporting. Details: All service boxes are inspected to ensure security is up to current TLC standards, and maintained or renewed if found insecure. All ground mounted equipment has been inspected and is progressively being maintained with an increased number of locking devices. All new equipment must have all terminals insulated at ground level. All existing equipment has been surveyed and renewals included in programmes. Conclusion: Unauthorised entry to equipment is a credible, but low probability/high impact risk. Note: Securing against unauthorised access is a key focus of the Safety Management System that is being implemented as part of the requirements of the Electricity (Safety) Regulations 2010.
Legacy underground systems that have been constructed using low cost methods and often using unskilled labour	Methods: Renewal programmes are in place to identify and implement hazard controls. Details: A renewal design review process is used to develop prioritised solutions. Conclusion: TLC is identifying and managing this risk. It will take a number of years to remove the risk of, for example, civil contractors making contact with a shallow, buried, unmarked, and unprotected cable.
Other equipment failures such as distribution transformers and related equipment	Methods: Renewal programmes in place that considers known equipment failure modes. Contingencies in place in case of failures. Details: The history of previous failures and the types of events that will likely occur are included in renewal programmes. Emergency spares such as distribution transformers are kept in stock. Engineering is done in such a way to minimise the risk of failure. For example, lightning arrestors are placed on each transformer; attention to detail is given to the quality of materials and workmanship, (cable jointing, types of insulators, fuses, switchgear, etc.). Conclusion: Contingencies for equipment failures is part of TLC's planning processes.

DISTRIBUTION SUBSTATIONS, SWITCHGEAR AND UNDERGROUND SYSTEMS RISK ASSESSMENT AND MITIGATION	
Risks	**Mitigation**
OPERATIONAL RISK	
Capacity	Methods: Equipment loadings monitored. Network analysis package used. Details: MDIs fitted to ground mounted equipment and read annually. Data from various recording devices analysed to ensure equipment has capacity. Load flow and fault current packages regularly used to make sure equipment is operating within ratings. Conclusion: The risk of equipment being required to operate beyond its ratings is closely monitored.
Protection systems operating incorrectly	Methods: The set up and performance of protection systems associated with distribution switchgear is closely monitored. Details: Protection systems set up with care using computer programmes. Performance of equipment monitored for operation after each event. Priority placed on changing batteries and servicing/renewing other equipment that causes protection equipment to operate incorrectly. Attention given to fault currents and clashing effects in addition to other co-ordination difficulties. Conclusion: Protection systems operating incorrectly add to risk of harm and damage. Incorrect protection operation is a low probability high impact risk. The risk is minimised by monitoring and regular modelling.
Contractors digging up underground cables	Methods: Detailed as built drawings and auditing processes in place to ensure records are correct. Competitive cable location service. Details: TLC audits cable installs to ensure they are completed to specification and drawings. Care is taken to ensure all variations are correctly recorded. Several contractors are available to do cable locations, which results in excavation contractors being able to get competitive quotes. Conclusion As built and audits are checked and filed. Cable locations and good records minimise the risk of underground cables being damaged.
Loss of skill to set up and maintain Electronic Protection and Circuit Breakers	Methods: On-going training of staff, either in-house or external courses. Details: Systems in place to identify needs and schedule training. The importance of ensuring staff with the intellectual knowledge are retained is recognised. Conclusion: Protection systems built into distribution equipment switchgear have become more complex in recent years. Systems have to be in place to manage this complexity.
NATURAL RISK – ENVIRONMENTAL EVENTS	
Seismic	Methods: Designs to include seismic requirements. Details: Care is taken to mount transformers and switchgear on poles of suitable strength. TLC uses a design package that includes a seismic calculator when reviewing existing designs as part of the renewal programmes and also for future designs. A preferred option for laying cables is to place them in ducts. Conclusion: TLC considers seismic risk as part of its renewal and new construction design practices. It mitigates this risk.
Flooding	Methods: Underground equipment is, where possible, located away from flooding areas. Details: Where equipment is located in areas that may flood waterproof and sealed equipment is used as far as practical. Conclusion: Flooding risk is considered and mitigated as far as practical.

DISTRIBUTION SUBSTATIONS, SWITCHGEAR AND UNDERGROUND SYSTEMS RISK ASSESSMENT AND MITIGATION	
Risks	**Mitigation**
Wind, Snow, Ice and other System Hazards	Methods: Distribution substations, switchgear, and underground systems are designed to withstand storms in compliance with the various industry Codes of Practice and the needs of the King Country environment. Details and Conclusion: Local knowledge and TLC's design package, which contributes to codes, are used to mitigate this risk.
Lahar, Geothermal and Volcanic	Methods: Lahar, geothermal and volcanic areas have been identified. Details: Distribution substations, switchgear and underground systems are not located in Lahar paths or geothermal areas. Conclusion: Where possible, risks are mitigated. Given that a number of New Zealand's active volcanoes are in the middle of the network area it is not possible to totally mitigate volcanic effects.
FACTORS OUTSIDE OF THE ORGANISATION'S CONTROL	
Natural events that are more severe than expected	Methods: Have emergency procedures in place to help minimise the effects. Use available intellectual knowledge to include designs to minimise the effects. Details: TLC has emergency event handling procedures in place. Local knowledge is used to vary designs to minimise the effects of severe events. Conclusion: Unexpected events will happen. It is not possible, practical and economic to eliminate this risk.
Traffic accidents and other damage	Methods: Have emergency procedures in place to help minimise the effects. Have emergency stocks of materials. Designs that reduce the risks. Details: TLC has emergency event handling procedures and holds minimum stock levels. Conclusion: Unexpected events happen. The severity has to be controlled by emergency procedures.
Public access to Pillar boxes in areas where power is underground	Methods: Have a planned inspection programme to inspect and record pillar box conditions. Details: TLC replaces approximately 50 service boxes per year. The new boxes are labelled and securely fastened with padlocks and security screws. Conclusion: Unauthorised access is minimised by the use of security locking and pillar box design.
Theft of earthing systems copper	Methods: Theft of copper earthing and overhead conductor can result in hazards to the public and animals. This risk is reduced by substations inspections, other switchgear/equipment inspections, line patrols, line inspections and other observations made by staff, the public and police. Details: Substation inspections, other switchgear /equipment inspections, line patrols, line inspections and other observations all place priority in the integrity and testing of earthing systems. Data on earthing systems are stored in the Basix system. The police are informed of all thefts and assisted with information to try and apprehend the offenders. Conclusion: Earthing systems are critical for hazard control. The theft of parts of these systems leads to risks.

DISTRIBUTION SUBSTATIONS, SWITCHGEAR AND UNDERGROUND SYSTEMS RISK ASSESSMENT AND MITIGATION	
Risks	**Mitigation**
STAKEHOLDER RISKS	
Damage caused by third parties who do not wish to pay	Methods: Resources are assigned to making sure that third party damage repair costs are recorded. Details: Incidents are followed-up and accounts are sent. Bad debts are chased until the issues are resolved. Conclusion: Stakeholders understand that debts will be followed up.
RISK ASSOCIATED WITH DIFFERENT LIFE CYCLE PHASES OF ASSETS	
Early life and end of life failures	Methods: Recognises that early and end of life failures occur and have contingencies in place to control these. Details: Contingencies include back feeds set up or things such as emergency spares. Conclusion: The reality is that the probability of early, and end, of life failure rates are higher with most components.

TABLE 7.4 IDENTIFIED RISKS AND MITIGATION OF RISKS TO DISTRIBUTION SUBSTATIONS, SWITCHGEAR AND UNDERGROUND SYSTEMS

Distribution substations, switchgear and underground systems are generally not insured.

7.3.5 Other Equipment

Table 7.5 summarises other secondary distribution assets risk assessment and mitigation.

OTHER SECONDARY DISTRIBUTION ASSETS RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
DISTRIBUTED GENERATION	
Distributed Generation Applications	Methods: Demand billing to reduce the risk of volume changes. Researched lists of engineering issues that need considering when completing distributed generation analysis. Details: Volume charges reduce the incentives for lines companies to connect generation. Demand billing overcomes this. TLC has a list of about 25 conditions that need consideration before intermediate and large distributed generation plant can be connected. Generators are made aware of these and asked to have consultants work through each of these and submit solutions with the final applications. Distributed generators often choose not to do this and want TLC to take on the risks of connection. TLC resists this as it is well aware of the damage unstable distributed generation can cause on the network. Distributed generators' investors can then complain to the Electricity Authority and these complaints can add considerable legal costs to the organisation's operation. Conclusion: The connection of distributed generators to a network that was originally designed to carry energy from a central point out to customers can add considerable costs and complexities. The Electricity (Distributed Generation) Regulations add to this complexity (now the participation code).

OTHER SECONDARY DISTRIBUTION ASSETS RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
PHYSICAL FAILURE RISKS	
Electronic Software	Methods: Current copies taken and kept off site. Details: Backup copies of SCADA and other software are kept on and off site. Conclusion: A software problem with key equipment is a low probability high impact risk.
Repeater failure	Methods: Maintain the existing systems to a reliable standard. Establish a level of redundancy on key links during the planning period. Details: Continue with renewal strategy to keep links maintained and renewed so that they have current supported equipment. Long term development plans are included to reduce dependency on one or two key links. Conclusion: TLC's automation is very important for the network operation. Repeater links are the backbone of the system.
SCADA Failure	Methods: Renewal plans are in place to keep equipment up to date so that it is reliable and modern equivalent replacement components can be used when failures occur. Details: An independent SCADA expert with knowledge of TLC's and other systems throughout the country advises and helps TLC engineers keep the system up to date, current and reliable. The renewal programme includes an on-going updating strategy to keep the technology current. Conclusion: A failure of the SCADA system especially during periods of network stress will lead to a low probability high impact risk.
Load control plant failure	Methods: TLC has a forward strategy to keep its load control plants renewed and of an age that is supported by suppliers. Legacy high frequency plants now have a low frequency alternative; however it will be a number of years before all relays downstream of legacy plants are reprogrammed or replaced and as a consequence this risk will exist for a number of years. A level of backup between the new plants will be possible through the 33 kV network in addition to the strategy to keep plants up to date and supported. Details: All the 317 Hz static plants are being kept up to date and under maintenance warranties from the suppliers. The legacy 725 Hz plants are being replaced with 317 Hz relay installations. It will take at least five years for relays in customers' meter boxes to be renewed, exchanged or replaced with combination relays and meters. In the meantime the old plants have to be kept running. A spare plant is planned to be set up in a container to cover off a failure of one of legacy plants. A risk to load control going forward is the effects of distributed generation on signal levels. Units are being well sized to cover this risk. Conclusion: TLC's risk of a load control plant failure will reduce due to the renewal programmes included in the Plan. The loss of load control plants will increasingly become a low probability high impact risk, as opposed to the present low to medium probability (old 725 Hz plants), high risk impact.

OTHER SECONDARY DISTRIBUTION ASSETS RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
Flat batteries or failed battery chargers resulting in incorrect operation	Methods: Maintenance and renewal programmes. Critical supplies have generation backup. Details: Batteries and chargers are subject to testing as part of the maintenance programmes and time based renewal. Critical supplies have generator backup. Conclusion: Batteries are critical for the operation of many items of modern equipment.
OPERATIONAL RISKS	
Failure of technical equipment through incorrect or inappropriate use	Methods: Design of equipment, training and on-going monitoring of the activities it is used for. Details: Equipment is designed to be simple to use and specified/rated for its intended use. Training and on-going monitoring of staff and what equipment continually takes place. Conclusion: Care is taken to ensure equipment is used for intended purpose.
Theft of earthing systems copper	Methods: Theft of copper earthing and overhead conductor can result in hazards to the public and animals. This risk is reduced by substations inspections, other switchgear /equipment inspections, line patrols, line inspections and other observations made by staff, the public and police. The SMS also reports on these activities. Details: Substation inspections, other switchgear/equipment inspections, line patrols, line inspections and other observations all place priority in the integrity and testing of earthing systems. Data on earthing systems is stored in the Basix system. The police are informed of all thefts and assisted with information to try and apprehend the offenders. Conclusion: Earthing systems are critical for hazard control. The theft of parts of these systems leads to risks.
NATURAL ENVIRONMENTAL EVENTS	
Seismic	Methods: The need for seismic constraining of all secondary distribution assets is recognised. This equipment is checked and where necessary renewals and or adding seismic constraints are included in forward programmes. Details: Load control equipment set up with protection. Equipment in radio repeater sites secured. Control room and associated support rooms have equipment secured. Conclusion: The need for seismic constraints is a certain but infrequent requirement and it is often overlooked.
Flooding	Methods: Contingencies are in place for events such as loss of access to the control room. Details: The control room is located close to a river that may flood and stop access (last event 1958). Two full copies of all key control room drawings are kept at alternative sites. Contingencies are in place to get SCADA, telephone and radio systems going at these alternative sites. Conclusion: Loss of access to the control room is a low probability high impact event.

OTHER SECONDARY DISTRIBUTION ASSETS RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
Earthquake damage to Control Centre	Methods: Contingencies are in place for loss of access to the control centre. A structural check of the strength of the control centre is currently being undertaken. Details: Initial results indicate there is an earthquake risk with the control room. Once the results of this work are available, options for strengthening or relocation will be developed. Conclusion: There is a risk associated with the present building that is currently being quantified.
Wind, snow, ice and other storm hazards	Methods: Renewal and development programmes consider these effects. Details: Radio repeater sites are constructed to withstand wind, snow, and ice. Load control plants are designed to be capable of withstanding storm conditions. Conclusion: Storms affecting secondary assets do occur from time to time. The effects of a key radio repeater site not operating during a storm can be high impact.
FAILURES OUTSIDE OF THE ORGANISATION'S CONTROL	
Harmonics	Methods: TLC is monitoring network harmonic levels. Harmonics have the potential to cause complex customer equipment interference. Details: Harmonics data are being gathered by spot checks and from distribution equipment that is capable of detecting harmonics. These are reconciled with network analysis models. From this on-going research, controls are being put on new customer connections. SWER lines in particular are susceptible to harmonics. Electronic appliances are potentially increasing harmonic levels on these. Harmonics on SWER systems in addition to customer interference have the potential to produce high strength electromagnetic fields. This may be considered in the future to have adverse health effects. Harmonic levels have to be researched and if necessary filtering put in place to remove these effects. At this time no such filtering has been included in this Plan. Conclusion: Harmonics are a credible low probability high impact risk. TLC recognises they need to be monitored and researched.
Voltage Flicker	Methods: TLC uses standard AS/NZS 61000.3.7-2001 with recommended limits. Details: The network analysis program is used to calculate voltage flicker levels. The standard is used to apply these to customer requests. Conclusion: There is a low probability high impact risk if a particular connection generates excessive voltage flicker. Excessive voltage flicker will cause complaints from customers and affect industrial operations. TLC is mitigating this risk by analysing connections that may lead to problems.

OTHER SECONDARY DISTRIBUTION ASSETS RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
Voltage Surges	Methods: Experience has shown that voltage surges in the network cause customers' appliances to be destroyed. Details: TLC deploys arrestors at key points in the network of a rating that restrict surge values. Specifically network standards require arrestors at impedance change points such as transformers (all) and cables. In addition to this TLC has purchased and is giving away to customers 15,000 plug-in protectors via various educational promotions. It also promotes the importance of surge protection being included in the installation of switchboards via newsletters, customer clinics, focus groups and newspaper articles. Conclusion: Surge suppression from a customer perspective is a low probability high consequence event.
STAKEHOLDER RISK	
Extensive amounts of equipment being destroyed by an abnormal event	Methods: In addition to the risk control strategies described in earlier sections, the majority of this type of equipment has backstop insurance. Details: Equipment has back stop insurance in place. Conclusion: Large scale loss of equipment is an on-going risk for TLC.
Risk associated with different life cycle phases of assets	Methods: Recognise that risk of failure is a greater risk at the beginning and end of lifecycle. Details: Have contingencies in place to be able to continue to maintain energy supply to customers if an individual piece of new or old equipment fails. Conclusion: Contingencies are put in place to minimise risk.

TABLE 7.5 RISKS AND MITIGATION OF RISKS ASSOCIATED WITH OTHER SECONDARY DISTRIBUTION EQUIPMENT

Secondary equipment is generally insured under TLC's equipment policies. TLC does not have cover for damage to customers' equipment unless assets are substantial and the public liability policy is triggered.

7.4 Risk evaluation

7.4.1 Potential Liability Analysis

Table 7.6 summarises an analysis of the potential liability estimate associated with low/medium probability, high impact events. This table gives an indication of our current best estimates of the potential costs of not controlling these risks.

ESTIMATE OF THE POTENTIAL COST OF NOT CONTROLLING RISKS		
Item/Type of Issue	**Events**	**Potential Cost Implications**
ZONE SUBSTATIONS AND VOLTAGE REGULATORS		
Aged equipment that is expensive to maintain, unreliable, the intellectual knowledge to maintain it is no longer available in the industry, it is getting pushed operationally harder than any other time in its life and does not meet today's hazard control expectations in a simple way. (e.g. oil filled switchgear operating in a high fault current, high arc flash energy environment).	Equipment failure, leading to explosion, fire, environmental damage, injury to staff or the public.	Extended outages that cause SAIDI and SAIFI thresholds to be breached. The costs, in addition to repairs, will include fine liabilities for breaching thresholds and potential customer claims. Possible costs if an event of this scale were to occur could be up to $1,000,000. Repairs – The cost of repairs, that could take some time, could quickly escalate from $500,000 to $1,000,000 per event. Environmental damage – Fire on resulting burning oil spills and explosions could quickly escalate from $500,000 to $1,000,000 in costs. Hazard Control – Injury to staff or the public again could quickly escalate to fines and legal costs in the $500,000 to $1,000,000 range.
Electronic equipment and software problems	Equipment not operating or operating incorrectly. (Including protection).	As with aged equipment above.
Security	Insecure sites allowing people to enter them.	Prosecution under the Electricity (Safety) Regulations and HSE Act– potential fines and legal costs of at least $500,000.
Capacity	Capacity of equipment is exceeded and damage results.	As with aged equipment above.
Environmental	Oil spills and transformer falling over during earthquakes.	Repairing of damage after transformers fail. The cost per transformer in zone substations would typically be $200,000 to $500,000 to complete repairs.
Demand growth constraint	Demand growth constraint assumptions are critical in this plan.	If demand growth is faster than the assumptions made and demand billing is not successful in restraining the growth, then the additional cost to the organisation will likely be about $1,000,000 annually.

ESTIMATE OF THE POTENTIAL COST OF NOT CONTROLLING RISKS		
Item/Type of Issue	**Events**	**Potential Cost Implications**
OVERHEAD LINES		
Rundown lines in poor condition	Vegetation not controlled to present levels	Reliability indices are exceeding Commerce Commission thresholds; fines to the company are possible. More resourcing required that is focused on repairing faults. Could realistically be expected to add $500,000 to $1m p.a. to operating costs. The costs of putting out rural fires can be substantial. A cost of $50,000 to $100,000 would be typical.
	Lines that are not inspected, patrolled and renewed that are left to rundown with legacy hazard control issues such as under-height conductor	Increase fault costs in the range of $500,000 to $2m p.a. Risk of prosecution and fines by DoL and Energy Safety. The typical OSH fine would be in the order of $100,000 plus legal costs. Electrical safety related fines and legal costs could quickly sum to $500,000 p.a. if lines were left to run down.
	Lines that are in poor condition and cause fault current flows. The fault currents then cause damage to transformers, line connections and from time to time circuit breakers.	Additional fault current damage would increase costs in the order of $200,000 p.a.
	Private Lines affecting TLC's Network	Private lines can cause faults that affect the TLC network. Costs arise with identifying and isolating these faults, particularly if TLC's renewal programme is not being completed and isolating links are not installed at the point of connection. Labour and inconvenience associated with private line issues could quickly add $100,000 p.a. to TLC's operating costs.
Environmental events	Wind, slips, flooding, seismic, lahar, geothermal, volcanic, snow, ice and other storm hazards	These events typically cost $50,000 per day to fix the damage. The less damage that occurs, the lower the cost. These costs quickly get back to the extent and success of the renewal and maintenance programmes. If the current renewal programmes were not as effective as they currently are, estimates place the additional operating costs at $500,000 to $1m p.a.
Quality of components coming into the network as part of the renewal programmes	Components failing before lifecycle expectations, quickly adds to costs	It is estimated that low quality materials that result in assets failing before lifecycle expectations would add $100,000 to $500,000 to operating costs p.a.

ESTIMATE OF THE POTENTIAL COST OF NOT CONTROLLING RISKS		
Item/Type of Issue	**Events**	**Potential Cost Implications**
Harmonics	SWER systems	TLC is monitoring the harmonic levels on SWER systems and is concerned about increasing harmonic levels due to the increasing use of power electronics. Filtering can be used to remove harmonics at an estimated cost of $50,000 per SWER system. (TLC has over 60 SWER systems).
	Remainder of network	As with SWER systems, TLC is monitoring harmonic levels and connection standards require compliance with the Codes. The tools for overcoming harmonic issues can involve numerous filters and changed transformer vector groups and the like. The cost of overcoming a major harmonic problem such as those found in the irrigation areas of the South Island can quickly escalate to $1m to $2m. The potential damage to customers' equipment and loss of production at major industrial sites would result in similar costs to TLC, insurance companies and customers.
Voltage Surges	Destruction of appliances and poor customer relations	Voltage surges are typically causing $50,000 worth of damage to customers' equipment annually. In an extreme event this figure could reach $1m to $2m worth of damage.
DISTRIBUTION SUBSTATIONS, ASSOCIATED SWITCHGEAR AND UNDERGROUND SYSTEMS		
Earthing systems not being tested, maintained and renewed.	Earth potential rises around failed earthing systems.	Hazard control – earth potential rises that result in human or animal shock and electrocution. Liabilities associated with fines and legal costs in the $100,000 to $500,000 range per event. If systems are not in place to ensure this work is taking place, there is the potential for numerous events.
Loss of Circuit Breaker Electronic Setting Data	Equipment not operating correctly or failing to operate.	Hazard control – Electronic setting data of protection equipment must be correct if equipment is going to operate correctly. Protection equipment not operating correctly results in increased human and animal shock and electrocution risk. Not ensuring equipment is fit for purpose and operating correctly could be expected to attract fines and legal costs of typically $100,000 to $500,000 per event. Equipment Damage – Protection equipment not operating correctly will result in increased equipment damage. Increased damage of about $10,000 to $500,000 per event could quickly result. (The higher amount would come about with an event such as a zone substation transformer failure due to the passage of fault current).
Security	Insecure sites allowing people to enter them.	Prosecution under the Electricity (Safety) Regulations – potential fines and legal costs of $500,000.

ESTIMATE OF THE POTENTIAL COST OF NOT CONTROLLING RISKS		
Item/Type of Issue	**Events**	**Potential Cost Implications**
Legacy underground systems	Old systems that have been constructed using low cost methods and often using unskilled labour. (The renewal and other operational criteria are monitoring and renewing these cables as required).	Hazard control – many of these old systems (especially in Ohakune, Turangi and part of Taumarunui) consist of PVC insulated, unprotected single core aluminium cables. Excavation contractors often damage these. Neutrals also fail from time to time resulting in customers' installations being exposed to high voltages. The potential cost of not renewing these would be that the occasional event where fines and legal costs of typically $50,000 per event may result.
Other equipment failures such as distribution transformers and related equipment	Lightning and switching surges	Lightning and switching surges can destroy both TLC transformers and also customers' equipment. As discussed in other sections of this plan, TLC installs lightning arrestors throughout the network to minimise the risk of its own, and customers', equipment damage. Lightning and switching surges destroy about $100,000 worth of TLC and customers' equipment annually. Without proper protection this figure is estimated to be a factor of 10 higher.
Component failures	Quality of components and workmanship	Poor quality components and workmanship can quickly add to costs. The level and number of events is variable. TLC has experienced high numbers of component failures in the past due to quality of materials and workmanship. The cumulative cost of poor workmanship or quality of components could quickly add $500,000 to $1m to operating costs.
Capacity failures	Capacity	Ensuring that selected equipment has the correct capacity is part of sound engineering, i.e. equipment must be adequate. As a counter to this, it should not be overrated and thus not generating the correct level of income. A moderate level of capacity failures could quickly add $500,000 to annual operating costs. TLC is also reliant on customers not adding substantially more load or reducing load and overloading, and under loading, equipment. TLC has a load application process in place to minimise this effect; however, from time to time customers do not correctly advise of changes and the cost of operating increases.
Protection systems operating incorrectly	Members of the public or staff receiving a more severe electric shock due to protection system failures. Forest fires and other events that may not have occurred if protection system operated correctly.	Fines and legal costs of up to $300,000 per event. Various claims from customers and insurance companies for damage. These would vary from a few thousand dollars to potentially millions of dollars. Equipment repairs to distribution and possibly, zone substation transformers, i.e. $10,000 to $200,000 typically
Contractors damaging cables	Diggers hitting cables.	Contractors would normally be charged for these events; however, they normally involve a claim against an insurance company, which results in a negotiation. Often it is difficult to get a full payment and admin/engineering time is involved in preparing detailed accounts etc. The cost of these events is typically $5000 per event.

ESTIMATE OF THE POTENTIAL COST OF NOT CONTROLLING RISKS		
Item/Type of Issue	**Events**	**Potential Cost Implications**
Loss of skill associated with protection	Incorrect setup	Fines and legal costs of up to $300,000 per event. Various claims from customers and insurance companies for damage. These would vary from a few thousand dollars to potentially millions of dollars. Equipment repairs to distribution and possibly, zone substation transformers, i.e. $10,000 to $200,000 typically.
Environmental events	Wind, slips, flooding, seismic, lahar, geothermal, volcanic, snow, ice and other storm hazards.	These events typically cost $50,000 per day to fix the damage. The less damage that occurs, the lower the cost. These costs quickly get back to the extent and success off the renewal and maintenance programmes. If the current renewal programmes were not as effective as they currently are, estimates place the additional operating costs at $500,000 to $1m p.a. Unlike overhead lines, some technical items have insurance backup. These insured events, however, are subject to excesses, which are typically $20,000.
Early life and end of life failures	Back up contingencies including the ability to connect generators.	Backup contingencies include many things such as alternative suppliers. The contingencies vary greatly and it is difficult to put a cost on them. The "back to the wall" solutions are to use generators as an alternative supply. TLC typically spends $200,000 p.a. on its own and hire generators. (Most of these costs go against the individual projects).
Traffic accidents, third party and other damage	Traffic accidents	The vehicle driver picks up much of the costs associated with traffic accidents via insurance companies. Insurance companies are often reluctant to pay out and costs are incurred in arguing with insurance companies/court claims and other administration. Traffic accidents could add about $50,000 p.a. to operating costs associated with insurance companies not paying out full amounts, legal claims and uninsured vehicle owners who cannot afford to pay.
OTHER EQUIPMENT		
Distributed Generation	Investor generators permitted to connect equipment that causes the network to become unstable.	Unstable distributed generation can quickly cause significant damage to TLC, customers and generator equipment. The cost of any such event is related to the size of the plant. TLC has had experience with one event that led to a claim of about $2m.
Electronic software and hardware	SCADA and radio equipment software and electronic equipment failing and not being backup up.	TLC operations are now reliant on electronic SCADA and radio software and hardware. This software and hardware is backed up and has been kept up to date so that, in addition to the backup, it is fully supported by local agents, manufacturers and suppliers. In the low probability, high consequence event that a major problem ensured, the costs of an extensive repair and replacement of this equipment could quickly approach $1m to $2m. Through the repair period, network operating costs would increase due to the need to manually operate equipment and reliability would reduce due to the time involved in getting staff to site. (Individual repeater failure would have similar consequences but would be more localised).

ESTIMATE OF THE POTENTIAL COST OF NOT CONTROLLING RISKS		
Item/Type of Issue	**Events**	**Potential Cost Implications**
Load plant failure	Failure of audio frequency generator or tuning equipment	TLC has a strategy of keeping this equipment modern (317 Hz system) and it is fully supported by the suppliers. An operational load control system is an important part of TLC's demand billing strategy. The importance of load control plants has increased since the deployment of this charging scheme. Failure of a plant could lead to Transpower Regional Co-Incidental Peak Demand (RCPD) charges not being avoided, parts of the network being overloaded, streetlight signals not being sent and timed mostly retail based energy charge period tariff signals not being sent. In the worst case, a house fire could result from a missed night store signal for timed signals. The likely costs of this would be: Missed RCPD reduction opportunities - $500,000 to $1,000,000 Network damage due to overloading typically - $200,000 to $500,000 Streetlights – poor public relations and service to road controlling authorities. The cost is difficult to quantify, but would perhaps be - $10,000 Missed time signals assuming a house fire and fines and legal costs associated with this occurring - $500,000
Backup power supply failures	Flat batteries or failed battery chargers resulting in incorrect operations.	TLC has battery and battery charging renewal programmes in place. Battery failure can lead to many problems, the worst of which would be hazards and equipment damage resulting from a protection system failure. The fines, legal costs and damage repairs resulting from an event of this nature could quickly exceed $500,000 to $1m.
Failure of technical equipment through incorrect or inappropriate use	Equipment destroyed and requiring replacement after an event	TLC puts a lot of effort into making sure equipment is designed to be simple to use and is specified/rated for its intended use. TLC has experienced events when equipment has been destroyed and these typically cost $50,000 to $100,000 per event.
Natural environmental events	Seismic, flooding, wind, ice and other storm hazards.	These events typically cost $50,000 per day to fix the damage. The less damage that occurs, the lower the cost. These costs quickly get back to the extent and success off the renewal and maintenance programmes. If the current renewal programmes were not as effective as they currently are, estimates place the additional operating costs at $500,000 to $1m p.a.

TABLE 7.6 CURRENT BEST ESTIMATES OF THE POTENTIAL COSTS OF NOT CONTROLLING RISKS

7.4.2 Areas where Analysis highlights the need for Specific Development Projects or Maintenance Projects

The analysis in Table 10.6 highlighted the need for the various maintenance, renewal and development programmes outlined in Sections 3 and 5 of this Plan. Most of the risks were offset by the various projects and activities.

Table 10.6 did highlight two areas where TLC is exposed and as such the Plan has been modified to cover these off. Specifically, these are the levels of contingency for risks associated for different lifecycle phases of assets, and the effects of a load control plant failure, given TLC's demand based billing strategy and the importance of load control looking forward into the future.

7.4.2.1 Contingency for Risk Associated with Different Lifecycle Phases of Assets

The normal "bath tub" curve of reliability of components illustrates that most failures occur early and late in most equipment lifecycles. TLC has a number of relatively new assets (as a consequence of the renewal programme), and old assets. There are a relatively high number of assets in the high likelihood of fail regions of the 'bath tub' curve.

The strategy to overcome this risk is to have some form of backup. A key part of this backup strategy is to have generators available for backup. TLC currently has one 165 kVA genset on a truck complete with a 400 to 11 kV transformer and related control/protection equipment. TLC hires in additional generators as needed. Unfortunately, there are no local hire companies and this plant has to come by truck from Auckland, Hamilton, Waihi or New Plymouth. The establishment time is normally about 12 hours from the fault to supply from the generator. A delay of this length is unacceptable to most customers.

The above analysis has highlighted an associated risk. Further analysis has shown that often back-up supplies can be maintained by connecting a reactive power source to the network, as opposed to expensive generators. As a consequence, TLC has development of mobile reactive power sources to help mitigate this risk.

7.4.2.2 Effects of a Load Control Plant Failure

TLC's demand billing strategy significantly increases the importance of having reliable load control signals. There is currently no redundancy in injection plants and there is a very limited ability to remove existing plant from service to be used in an emergency at another site.

The analysis in table 10.6 highlighted TLC's exposure to a plant failure and the need for some form of contingency. The development section of the plan includes an allowance for having a contingency plan in place.

7.5 Risks associated with economic downturn and the need for on-going hazard elimination/minimisation

As outlined in other sections, the TLC network assets are old and many were constructed using second hand materials. Many of these assets have hazard risks. This Plan is designed to address these in a prioritised way and by 2020 a significant improvement will be achieved. The revenue required to implement the Plan will require price rises and during times of economic downturn there will be pressure not to move prices. Failing to renew assets will result in unaddressed hazard issues and stakeholders need to be aware of this. (Table 10.6 estimates the potential liability risks).

For example, if TLC's largest asset class, overhead lines, are considered, this Plan includes allowances to replace about 10% of poles, as the 15 year line renewal programme cycles through the network. Strength calculations show typically 30% of poles need renewing to comply with codes. If renewal expenditure is constrained below levels in this Plan, then poor condition and under strength pole hazards will not be addressed.

It is hoped a forward strategic objective of driving the organisation to complete capital works at a lower cost will go a significant way in reducing the lower strength poles that are not renewed as part of TLC's programme.

Risk is being mitigated by the proportion of this comprehensive asset management plan and strategies to make stakeholders aware of the issues. Looking forward, the Plan is to further develop detailed asset data and system, to provide continually improved planning and asset knowledge.

There is a risk however that the political and governance pressure not to do this work nor to increase prices to fund it will stall the hazard renewal programme. It is expected that other pressures such as the Electricity (Safety) Regulations and on-going strengthening of HSE regulations/enforcement will go some way in mitigating this risk.

7.6 Details of Emergency Response and Contingency Plans

7.6.1 Civil Defence

TLC has in place an approved Civil Defence plan and has been involved with the Horizon and Waikato lifelines groups. Staff attends group meetings and contact lists are maintained. Communication channels are set up whenever an event occurs.

Contingency event procedures are invoked whenever supply is lost to 50 or more customers. As events become more serious, more and more layers of contingency action are applied. A staff member has been assigned the responsibility of maintaining, reviewing and updating the Civil Defence Plan.

7.6.2 Event Management

The event management process is initiated when it is likely that 1000 customers will be affected for 10 minutes or 50 customers for 4 hours. As the event worsens, the additional staff layers include Duty Engineer, Engineering Manager, Communication Managers, Staff Welfare Management and Civil Defence functions.

This response and layers of contingency depending on the event seriousness is used to manage events when they occur. TLC has in place a 24/7 service using local people. When an event occurs this is scaled up and additional resources are called in.

The event management procedure is a formal approved procedure and is reviewed/updated annually. Additional rooms around the control room are transformed into communication and co-ordination centres when an event occurs. These rooms have radio plugs, additional telephones, maps, computer connections, emergency lighting and the like, wired in ready for these events. Various staff have nominated responsibilities for staff communications, staff welfare, dispatch, stores etc. when an event occurs.

7.6.3 Seismic

It is anticipated that a seismic event will cause damage to poles and transformers. Depending on the size of the event, the procedure described in the above section will be implemented.

The contingency process would involve despatch of line repair and technical staff. If the control room were destroyed this function would have to be set up at any of the alternative three sites where system drawings are kept and access to internal and external communication systems are available.

Recent analysis of the control centre has indicated that strengthening is required. Options for this will be developed through the coming year.

7.6.4 Lahar

Lahars present a risk on Mount Ruapehu; hence, cables and other equipment are installed away from known Lahar paths where possible. Recent development work on the Whakapapa ski field has seen a number of transformers moved from the known Lahar path. However, some risk of damage has to be accepted in this environment.

TLC has 11 kV lines in the Tangiwai Lahar path, which could affect customers on the Tangiwai feeder if the Lahar level were to be substantially higher than the 2007 event.

A plan was produced in December 2001, dealing with the steps that should be taken and this is reviewed after each Lahar planning meeting. When the 2007 event occurred, no damage resulted because of the planning that had previously taken place.

7.6.5 Emergency Event in Control Room

If an abnormal serious event occurs in the control room or on the network, and the Controller becomes under stress, overworked or unsure of what is needed, he contacts the Duty Engineer who provides additional support.

7.6.6 Damage to Control Centre

In the event of damage to the control centre TLC will relocate to a recovery centre. Two full copies of all key control room drawings are kept at alternative sites. Contingencies are in place to get SCADA, telephone and radio systems going at these alternative sites.

7.6.7 Emergency Generators

TLC network owns a number of both small and large generators that are used in emergencies. There are several small, compact, electronic inverter units that are made available to customers who have emergency needs. A recent example of their deployment was to two families with essential medical equipment on the end of a remote SWER line. In this case an absentee landowner's trees kept destroying the line and it took a number of weeks before they co-operated and brought in heavy equipment to remove the trees.

7.7 Capability to Deliver

As mentioned in Section 2, the network and financial performance are taken into consideration when preparing the AMP. Part of the review process of the AMP is that TLC continues to add more detail to its long-term renewal and maintenance plans.

7.7.1 Asset and Network Maintenance

The renewal and development expenditure plan lists expected renewals under lines (33 kV, 11 kV and LV), substations, distribution transformers, SCADA, communications, protection and switchgear renewal by individual jobs, items, and asset groups. Estimates are derived from the type of projects, previous expenditure on similar projects, cost of equipment in today's dollar and the cost of labour. Estimates are reported in equipment categories and Commerce Commission disclosure format.

The long-term renewal and maintenance plan is on a year-by-year and activity-by-activity basis extended out to year 2027/28. The activities for each coming year are then extracted and reviewed. These form the basis of the annual plan for the coming year. The plan is adjusted when justified due to previously unknown environmental, customer, equipment and other issues, which mostly feed into the 1 to 5 year forecast period.

Over the planning period, all predictions and control are transferred into the BASIX system. The long-term plan flows down and controls the various asset inspections, network maintenance (renewals), planning and network development projects.

7.7.2 Network Performance

A review of the financial performance at all levels of network operations, including income and costs on a monthly basis is undertaken. The monthly reports are reconciled against the Annual Plan. Variations over 10% have to be individually reported to Directors along with explanations for these variations.

Consumer oriented performance targets are reviewed as part of the preparation of this plan and as part of the DDP compliance. Area's that are underperforming are analysed further, rectification for these areas are then included in the plan.

7.8 Asset *Management Organisation Structure*

As mentioned in Section 2 of this Plan, the organisation has established and maintained an organisational structure of roles, responsibilities and authorities, consistent with the achievement of its AMP. The AMP, policies and strategies are used as reference and form the basis of asset management decisions. Decisions can be referenced back to this document.

TLC ensures that any person under its direct control undertaking asset management related activities has an appropriate level of competence in terms of education, training or experience. The staffing, the structure and the skills are aligned to the Plan to ensure effective and efficient implementation. The individuals within this team have various delegated authorities to implement the Plan. The supply chain logistics are handled by field service providers; however, specification of the actual items is completed by the Engineering and Asset group. This information is included in distribution standards and individual project details.

The delegated authority to asset and engineering staff includes a responsibility to communicate the Plan to employees, other stakeholders and contracted service providers.

The current structure for this group is illustrated in Section 2, Figure 2.2. Recent changes at executive and staff levels have depleted experience in asset management and technical skill areas. These will take time to rebuild given the challenges of recruitment in rural areas and the time required to develop skills and expertise.

Currently most asset management tasks, including asset inspection, are undertaken in-house. In this way, TLC can control the work on the assets so that the desired outcomes are achieved. Planned work is allocated to the in-house service provider. The finished work is inspected by Asset Management Group (AMG) staff to ensure that it meets acceptable hazard and quality standards.

Specialist work such as SCADA (Supervisory Control and Data Acquisition) and communications is controlled directly by the AMG group. Specialist SCADA and communication contractors complete the work. Vegetation work is controlled and issued by the AMG group to tree contractors who have the necessary quality and hazard control systems in place. These contractors include a local helicopter operator who provides a large proportion of the overhead line fault finding service.

The AMG group inspects and prepares detailed designs including regulatory approvals before forwarding line, mechanical workshop and faults activities to the service provider group. External drafting and engineering consultants are used when workloads are high. Specialist data, valuation and safety consultants are also engaged to assist as required.

In summary the stakeholders require a sustainable network and as such the AMP forms the key document to achieve this. If the requirements listed are not achieved then the network will likely not be sustainable. The document is used to drive the structure and strategic direction of the organisation.

Section 8

8. Further Disclosed Schedules

8.1 Further Disclosed Schedules

- 11a Report on Forecast Capital Expenditure
- 11b Report on Forecast Operational Expenditure
- 12a Report on Asset Condition
- 12b Report on Forecast Capacity
- 12c Report on Forecast Demand
- 12d Report on Forecast Interruptions and Duration
- 13 Report on Asset Management Maturity

EDB Information Disclosure Requirements

Information Templates

for

Schedules 11–13

Company Name	The Lines Company
Disclosure Date	31 March 2015
AMP Planning Period Start Date (first day)	1 April 2015

Templates for Schedules 11a–13 (Asset Management Plan)
Template Version 2.0. Prepared 15 November 2012

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
7												
8	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	633	3,255	3,312	1,093	673	687	702	1,190	734	750	766
11	System growth	225	368	1,133	1,887	1,877	1,007	1,607	1,270	1,035	1,502	1,419
12	Asset replacement and renewal	7,273	7,532	8,052	8,145	8,453	8,893	8,657	9,031	9,594	7,894	8,440
13	Asset relocations	11	11	11	11	11	12	12	12	12	13	13
14	Reliability, safety and environment:											
15	Quality of supply	832	326	187	201	177	432	260	248	217	253	208
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	1,454	918	528	580	413	497	1,118	1,008	502	1,013	718
18	**Total reliability, safety and environment**	2,286	1,243	714	781	590	929	1,378	1,256	720	1,266	926
19	**Expenditure on network assets**	10,427	12,408	13,222	11,917	11,605	11,527	12,356	12,760	12,094	11,425	11,564
20	Non-network assets	3,105	4,497	4,565	1,753	208	212	217	221	226	231	236
21	**Expenditure on assets**	13,532	16,905	17,787	13,670	11,813	11,739	12,573	12,982	12,321	11,656	11,800
22												
23	*plus* Cost of financing	223	236	251	226	220	219	235	242	230	217	220
24	*less* Value of capital contributions	165	30	35	38	40	45	50	52	55	59	63
25	*plus* Value of vested assets											
26												
27	**Capital expenditure forecast**	13,590	17,111	18,003	13,859	11,993	11,913	12,758	13,172	12,495	11,814	11,957
28												
29	Value of commissioned assets	10,427	12,408	13,222	11,917	11,605	11,527	12,356	12,760	12,094	11,425	11,564

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
30	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
32		**$000 (in constant prices)**										
33	Consumer connection	618	3,255	3,263	1,058	638	638	638	1,058	638	638	638
34	System growth	220	368	1,116	1,827	1,780	935	1,460	1,129	900	1,278	1,181
35	Asset replacement and renewal	7,102	7,532	7,932	7,884	8,014	8,253	7,861	8,024	8,340	6,715	7,025
36	Asset relocations	11	11	11	11	11	11	11	11	11	11	11
37	Reliability, safety and environment:											
38	Quality of supply	812	326	184	194	210	401	236	221	189	215	173
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	1,420	918	520	562	392	461	1,015	896	437	862	597
41	**Total reliability, safety and environment**	2,232	1,243	704	756	602	862	1,252	1,116	626	1,077	771
42	**Expenditure on network assets**	10,182	12,408	13,025	11,536	11,044	10,698	11,220	11,337	10,515	9,719	9,625
43	Non-network assets	3,032	4,497	4,539	1,746	197	197	197	197	197	197	197
44	**Expenditure on assets**	13,215	16,905	17,564	13,282	11,240	10,895	11,417	11,534	10,711	9,916	9,822
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses											
48	Overhead to underground conversion											
49	Research and development											

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
58	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
59	**Difference between nominal and constant price forecasts**	**$000**										
60	Consumer connection	15	-	49	35	35	49	65	133	96	112	128
61	System growth	5	-	17	60	98	72	148	142	135	224	238
62	Asset replacement and renewal	171	-	120	261	440	640	796	1,007	1,253	1,179	1,415
63	Asset relocations	0	-	0	0	1	1	1	1	2	2	2
64	Reliability, safety and environment:											
65	Quality of supply	20	-	3	6	(33)	31	24	28	28	38	35
66	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
67	Other reliability, safety and environment	34	-	8	19	21	36	103	112	66	151	120
68	**Total reliability, safety and environment**	54	-	11	25	(11)	67	127	140	94	189	155
69	**Expenditure on network assets**	244	-	197	381	562	830	1,136	1,423	1,580	1,706	1,939
70	Non-network assets	73	-	26	7	11	15	20	25	30	35	40
71	**Expenditure on assets**	317	-	222	388	572	845	1,156	1,447	1,609	1,741	1,978

11a(ii): Consumer Connection

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
75	*Consumer types defined by EDB**	**$000 (in constant prices)**					
76	Urban A	168	138	172	592	172	172
77	Rural B	69	57	71	71	71	71
78	Rural C	125	103	129	129	129	129
79	Rural D	209	2,919	2,841	216	216	216
	Remote Rural E	24	20	25	25	25	25
80	Remote Rural F	24	19	24	24	24	24
81	**include additional rows if needed*						
82	**Consumer connection expenditure**	618	3,255	3,263	1,058	638	638
83	*less* Capital contributions funding consumer connection						
84	**Consumer connection less capital contributions**	618	3,255	3,263	1,058	638	638

11a(iii): System Growth

86	Subtransmission		-	299		-	
87	Zone substations	-	-	-	1,575	903	725
88	Distribution and LV lines	-	-	-	-	-	-
89	Distribution and LV cables	-	-	-	-	-	-
90	Distribution substations and transformers	-	263	712	147	772	105
91	Distribution switchgear	220	-	-	-	-	-
92	Other network assets	-	105	105	105	105	105
93	**System growth expenditure**	220	368	1,116	1,827	1,780	935
94	*less* Capital contributions funding system growth						
95	**System growth less capital contributions**	220	368	1,116	1,827	1,780	935

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
104		for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
105	**11a(iv): Asset Replacement and Renewal**		**$000 (in constant prices)**					
106		Subtransmission	602	498	702	1,050	1,237	2,102
107		Zone substations	147	253	714	-	164	-
108		Distribution and LV lines	5,277	5,069	4,654	6,032	5,758	5,270
109		Distribution and LV cables	-	-	-	-	-	-
110		Distribution substations and transformers	355	128	124	130	162	130
111		Distribution switchgear	95	95	670	53	95	47
112		Other network assets	626	1,489	1,069	620	599	703
113		**Asset replacement and renewal expenditure**	7,102	7,532	7,932	7,884	8,014	8,253
114	*less*	Capital contributions funding asset replacement and renewal						
115		**Asset replacement and renewal less capital contributions**	7,102	7,532	7,932	7,884	8,014	8,253
116	**11a(v):Asset Relocations**							
117		*Project or programme**						
118		Miscellaneous	11	11	11	11	11	11
119								
120								
121								
122								
123		**include additional rows if needed*						
124		All other asset relocations projects or programmes						
125		**Asset relocations expenditure**	11	11	11	11	11	11
126	*less*	Capital contributions funding asset relocations						
127		**Asset relocations less capital contributions**	11	11	11	11	11	11
128								
129	**11a(vi):Quality of Supply**							
130		*Project or programme**						
131		11kV Fdr Dev - Switch Automation	234	273	184	194	210	184
132		Sub & 33 Dev - Substations	-	53	-	-	-	217
133		Sub & 33 Dev - Supply Points	579	-	-	-	-	-
134								
135								
136		**include additional rows if needed*						
137		All other quality of supply projects or programmes						
138		**Quality of supply expenditure**	812	326	184	194	210	401
139	*less*	Capital contributions funding quality of supply						
140		**Quality of supply less capital contributions**	812	326	184	194	210	401
141								
142	**11a(vii): Legislative and Regulatory**							
143		*Project or programme**						
144								
145								
146								
147								
148								
149		**include additional rows if needed*						
150		All other legislative and regulatory projects or programmes						
151		**Legislative and regulatory expenditure**	-	-	-	-	-	-
152	*less*	Capital contributions funding legislative and regulatory						
153		**Legislative and regulatory less capital contributions**	-	-	-	-	-	-

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
161								
162		for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
163	**11a(viii): Other Reliability, Safety and Environment**							
164	*Project or programme**		**$000 (in constant prices)**					
165	11kV Fdr Dev - Switchgear for Safety		412	53	53	147	53	53
166	Sub & 33 Dev - 33kV Lines		-	-	-	-	-	-
167	Sub & 33 Dev - Substations		380	445	49	47	18	-
	Tx & Service Boxes - 2 Pole Structures		363	212	253	222	216	264
168	Tx & Service Boxes - Capital Pillar Boxes		111	66	-	-	-	-
169	Tx & Service Boxes - GMT		153	142	165	146	105	145
170	**include additional rows if needed*							
171	All other reliability, safety and environment projects or programmes							
172	**Other reliability, safety and environment expenditure**		1,420	918	520	562	392	461
173	*less* Capital contributions funding other reliability, safety and environment							
174	**Other reliability, safety and environment less capital contributions**		1,420	918	520	562	392	461
175								
176								
177								
178	**11a(ix): Non-Network Assets**							
179	**Routine expenditure**							
180	*Project or programme**							
181	Eng & Asset Capital - Data Systems		95	96	96	96	96	96
182	Eng & Asset Capital - Metering		11	2,800	2,842	1,550	-	-
183	Eng & Asset Capital - Misc Equip		21	11	11	11	11	11
184	Eng & Asset Capital - Office Area		71	21	21	21	21	21
185	Eng & Asset Capital - Vehicle Replacements		2,310	68	68	68	68	68
186	**include additional rows if needed*							
187	All other routine expenditure projects or programmes							
188	**Routine expenditure**		2,507	2,997	3,039	1,746	197	197
189	**Atypical expenditure**							
190	*Project or programme**							
191	Eng & Asset Capital - Building Re-structure		525	1,500	1,500	-	-	-
192								
193								
194								
195								
196	**include additional rows if needed*							
197	All other atypical projects or programmes							
198	**Atypical expenditure**		525	1,500	1,500	-	-	-
199								
200	**Non-network assets expenditure**		3,032	4,497	4,539	1,746	197	197

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref												
7		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,354	1,262	1,281	1,304	1,331	1,360	1,390	1,420	1,452	1,484	1,516
11	Vegetation management	756	851	864	879	898	917	937	958	979	1,001	1,023
12	Routine and corrective maintenance and inspection	1,105	1,062	1,078	1,097	1,120	1,144	1,169	1,195	1,222	1,248	1,276
13	Asset replacement and renewal	119	302	307	312	319	325	333	340	347	355	363
14	**Network Opex**	3,334	3,477	3,530	3,592	3,668	3,747	3,829	3,914	4,000	4,088	4,178
15	System operations and network support	2,936	3,114	3,189	3,265	3,344	3,424	3,506	3,590	3,676	3,765	3,855
16	Business support	4,122	3,787	3,878	3,971	4,066	4,164	4,264	4,366	4,471	4,578	4,688
17	**Non-network opex**	7,058	6,901	7,067	7,236	7,410	7,588	7,770	7,956	8,147	8,343	8,543
18	**Operational expenditure**	10,392	10,378	10,596	10,828	11,078	11,335	11,599	11,870	12,147	12,430	12,721

19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,290	1,262	1,262	1,262	1,262	1,262	1,262	1,262	1,262	1,262	1,262
23	Vegetation management	720	851	851	851	851	851	851	851	851	851	851
24	Routine and corrective maintenance and inspection	1,053	1,062	1,062	1,062	1,062	1,062	1,062	1,062	1,062	1,062	1,062
25	Asset replacement and renewal	113	302	302	302	302	302	302	302	302	302	302
26	**Network Opex**	3,176	3,477	3,477	3,477	3,477	3,477	3,477	3,477	3,477	3,477	3,477
27	System operations and network support	2,797	3,114	3,114	3,114	3,114	3,114	3,114	3,114	3,114	3,114	3,114
28	Business support	3,927	3,787	3,787	3,787	3,787	3,787	3,787	3,787	3,787	3,787	3,787
29	**Non-network opex**	6,724	6,901	6,901	6,901	6,901	6,901	6,901	6,901	6,901	6,901	6,901
30	**Operational expenditure**	9,900	10,378	10,378	10,378	10,378	10,378	10,378	10,378	10,378	10,378	10,378
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of energy losses	346	346	346	346	346	346	346	346	346	346	346
33	Direct billing*	1,188	1,187	1,161	1,134	1,133	1,161	1,190	1,219	1,249	1,280	1,262
34	Research and Development											
35	Insurance	190	212	212	212	212	212	212	212	212	212	212

37 ** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

38

39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	64	-	19	42	69	98	128	158	190	222	254
43	Vegetation management	36	-	13	28	47	66	86	107	128	149	171
44	Routine and corrective maintenance and inspection	52	-	16	35	58	82	108	133	160	186	214
45	Asset replacement and renewal	6	-	5	10	17	23	31	38	45	53	61
46	**Network Opex**	158	-	53	115	191	270	352	436	522	610	700
47	System operations and network support	139	-	75	151	230	310	392	476	562	651	741
48	Business support	195	-	91	184	279	377	477	579	684	791	901
49	**Non-network opex**	334	-	166	335	509	687	869	1,055	1,246	1,442	1,642
50	**Operational expenditure**	492	-	218	450	700	956	1,221	1,492	1,769	2,052	2,342

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

					Asset condition at start of planning period (percentage of units by grade)						
7											
8	**Voltage**	**Asset category**	**Asset class**	**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
9											
10	All	Overhead Line	Concrete poles / steel structure	No.	0.62%	0.90%	62.00%	10.66%	25.82%	2	6.35%
11	All	Overhead Line	Wood poles	No.	2.26%	2.80%	35.77%	5.06%	54.11%	2	6.35%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	N/A	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	12.80%	65.98%	0.41%	20.81%	2	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	41.18%	22.67%	36.15%	2	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	-	N/A	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	N/A	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	-	N/A	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	N/A	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	N/A	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	N/A	-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	N/A	-
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	N/A	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	88.89%	11.11%	-	3	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	N/A	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	10.71%	35.71%	48.21%	5.37%	3	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	7.73%	77.32%	12.89%	2.06%	3	-
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	N/A	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	N/A	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	-	N/A	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	13.89%	63.89%	22.22%	-	3	-
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	11.54%	71.79%	16.67%	-	3	-

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

					Asset condition at start of planning period (percentage of units by grade)						
	Voltage	**Asset category**	**Asset class**	**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
45	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	5.26%	76.32%	18.42%	-	3	-
46	HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	15.81%	62.57%	0.25%	21.37%	2	1.41%
47	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	N/A	-
48	HV	Distribution Line	SWER conductor	km	-	21.69%	39.29%	0.38%	38.64%	2	-
49	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	6.45%	4.30%	89.25%	2	-
50	HV	Distribution Cable	Distribution UG PILC	km	-	-	-	-	-	N/A	-
51	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	-	N/A	-
52	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	6.09%	42.13%	24.37%	27.41%	2	7.11%
53	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	100.00%	-	3	-
54	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	0.03%	0.69%	77.76%	15.79%	5.73%	2	0.07%
55	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	50.00%	50.00%	-	2	-
56	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	62.03%	37.97%	-	2	5.06%
57	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.06%	0.11%	63.80%	16.03%	20.00%	2	0.36%
58	HV	Distribution Transformer	Ground Mounted Transformer	No.	1.63%	2.65%	67.21%	28.51%	-	3	6.52%
59	HV	Distribution Transformer	Voltage regulators	No.	-	3.06%	64.29%	32.65%	-	3	-
60	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	50.00%	50.00%	-	2	-
61	LV	LV Line	LV OH Conductor	km	-	4.81%	53.07%	0.71%	41.41%	2	-
62	LV	LV Cable	LV UG Cable	km	-	-	3.67%	1.94%	94.39%	2	-
63	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	2.81%	43.11%	0.19%	53.89%	2	-
64	LV	Connections	OH/UG consumer service connections	No.	-	-	62.82%	27.40%	9.78%	2	-
65	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	-	99.26%	0.74%	-	3	-
66	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	9.26%	7.41%	74.07%	9.26%	-	3	-
67	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	100.00%	-	4	-
68	All	Load Control	Centralised plant	Lot	-	7.14%	50.00%	42.86%	-	3	-
69	All	Load Control	Relays	No.	-	-	82.54%	17.46%	-	3	-
70	All	Civils	Cable Tunnels	km	-	-	-	-	-	N/A	-

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

8

Existing Zone Substations	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
Arohena	2.1	0.0	N	0.7	-	0	-	No constraint within +5 years	
Atiamuri	10.0	0.0	N	0.0	-	0	-	No constraint within +5 years	New point of supply will alleviate transformer constraint.
Awamate Road	1.2	0.0	N	1.3	-	0	-	No constraint within +5 years	
Borough	7.9	5.0	N - 1	2.5	157%	5	165%	No constraint within +5 years	
Gadsby Rd	3.4	0.0	N	5.7	-	0	-	No constraint within +5 years	
Hangatiki	3.6	0.0	N	1.3	-	0	-	No constraint within +5 years	
Kaahu Tee	1.6	0.0	N	1.0	-	0	-	No constraint within +5 years	
Kiko Rd	1.4	0.0	N	0.1	-	0	-	No constraint within +5 years	
Kuratau	2.5	1.5	N-1	0.1	165%	2	169%	No constraint within +5 years	
Mahoenui	0.9	0.0	N	0.5	-	0	-	No constraint within +5 years	
Manunui	2.2	0.0	N	1.2	-	0	-	No constraint within +5 years	
Maraetai	4.4	0.0	N	0.5	-	0	-	No constraint within +5 years	
Marotiri	2.5	0.0	N	1.3	-	0	-	No constraint within +5 years	
Mokai	3.8	0.0	N	1.0	-	0	-	No constraint within +5 years	
National Park	1.8	0.0	N	1.2	-	0	-	No constraint within +5 years	
Nihoniho	0.6	0.0	N	0.7	-	0	-	No constraint within +5 years	
Oparure	1.5	0.0	N	1.1	-	0	-	No constraint within +5 years	
Otukou	0.3	0.0	N	0.0	-	0	-	No constraint within +5 years	
Taharoa	11.4	10.0	N - 1	0.0	114%	15	153%	Transformer	Upgrade of transformers is planned for 2016 to provide additional capacity.
Tawhai	4.0	0.0	N	0.7	-	0	-	No constraint within +5 years	
Te Anga	2.2	0.0	N	0.0	-	0	-	No constraint within +5 years	
Te Waireka Rd	11.3	10.0	N - 1	2.1	113%	10	120%	No constraint within +5 years	
Tokaanu	0.2	0.0	N	0.0	-	0	-	No constraint within +5 years	
Tuhua	0.8	0.0	N	0.7	-	0	-	No constraint within +5 years	
Turangi	4.6	5.0	N - 1	1.9	92%	5	83%	No constraint within +5 years	
Waiotaka	0.5	0.0	N	0.5	-	0	-	No constraint within +5 years	
Wairere	3.1	2.5	N - 1	1.1	122%	3	129%	No constraint within +5 years	
Waitete	9.3	10.0	N - 1	3.8	93%	10	78%	No constraint within +5 years	

29 *[1] Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

30 **12b(ii): Transformer Capacity**

	(MVA)
Distribution transformer capacity (EDB owned)	240
Distribution transformer capacity (Non-EDB owned)	10
Total distribution transformer capacity	249
Zone substation transformer capacity	153

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

12c(i): Consumer Connections

Number of ICPs connected in year by consumer type

		Number of connections					
		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
	*Consumer types defined by EDB**						
	Urban A	29	32	32	32	32	32
	Rural B	4	5	5	5	5	5
	Rural C	13	20	20	20	20	20
	Rural D	52	55	55	55	55	55
	Remote Rural E	4	6	6	6	6	6
	Remote Rural F	-	4	4	4	4	4
	Connections total	102	122	122	122	122	122

**include additional rows if needed*

Distributed generation

Number of connections	4	4	4	4	4	4
Installed connection capacity of distributed generation (MVA)	0.0202	0.0203	0.0204	0.0205	0.0206	0.0207

12c(ii) System Demand

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
Maximum coincident system demand (MW) for year ended		**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
	GXP demand	57	58	58	59	60	61
plus	Distributed generation output at HV and above	8	8	8	8	9	9
	Maximum coincident system demand	65	66	67	68	69	70
less	Net transfers to (from) other EDBs at HV and above	0	0	0	0	0	0
	Demand on system for supply to consumers' connection points	65	66	67	68	69	70
Electricity volumes carried (GWh)							
	Electricity supplied from GXPs	287	291	295	299	303	308
less	Electricity exports to GXPs	4	4	4	4	4	4
plus	Electricity supplied from distributed generation	58	59	59	60	61	62
less	Net electricity supplied to (from) other EDBs	0	0	0	0	0	0
	Electricity entering system for supply to ICPs	341	345	350	355	360	365
less	Total energy delivered to ICPs	311	315	320	324	329	333
	Losses	30	30	30	31	31	32
	Load factor	60%	60%	60%	60%	60%	60%
	Loss ratio	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**
Network / Sub-network Name	**The Lines Company**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	90.7	58.9	58.9	58.9	58.9	58.9
12	Class C (unplanned interruptions on the network)	217.0	149.9	149.9	149.9	149.9	149.9
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.70	0.45	0.45	0.45	0.45	0.45
15	Class C (unplanned interruptions on the network)	3.45	2.62	2.62	2.62	2.62	2.62

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question		Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?		1	The Lines Company's (TLC) Asset Management Policy is derived from, and is consistent with TLC's Statement of Corporate Intent. The Asset Management Policy is consistent with other organisational policies and the risk management framework. The Asset Management Policy is reviewed and updated every 12-18 months by the TLC Board of Directors. The Asset Management Policy and Strategy flow into the Asset Management Plan (AMP) and one of the objectives of the AMP is to communicate the Asset Management Policy and Asset Management Strategy to stakeholder, regulatory bodies, customers, TLC employees and general public. An electronic copy of the AMP is available on the TLC website and bound paper copies are available be by request.	TLC Statement of Corporate Intent, AMP, Asset Management Policy.	Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?		2	The Asset Management Strategies are identified from the Strategic review and the Statement of Corporate Intent; the agreement between TLC and its owners. TLC ensures that the Asset Management Strategy is consistent with other organisational policies and strategies and aligns with the needs of other stakeholders. The AMP is aligned to and is part of TLC's Asset Management Policy and forms a significant part of the asset management strategy. One of the objectives of AMP is to communicate the Asset Management Policy and Asset Management Strategy to stakeholder, regulatory bodies, customers, TLC employees and general public.	TLC Statement of Corporate Intent, AMP	In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?		2	When establishing the a long term asset management strategy TLC has considered the asset related risk, the physical condition of the assets, age profile, flexibility and suitability of the assets and their intended use. Other items that have been considered are asset type, condition, and historical asset related information such as reliability, maintenance records and operational performance.	AMP	Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question		Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?		2	The Asset and Engineering Team prepare the AMP annually. Part of the process is reviewing the previous years AMPand discussing information that stakeholders wish to have included. When establishing the Asset Management Plan TLC has taken into consideration: • Asset Management Policy • Risk management Policy • TLC's existing asset management objectives and performance and condition targets • Financial and resource capabilities or constraints • Life cycle costs • Legal, regulatory, statutory and other asset management requirements • Historic and predicted asset condition, deterioration and failure mechanism and performance profiles.	AMP	The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question		Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?		1	At the start of each financial year completed copies of the AMP are distributed to TLC's Trust shareholders, Board of Directors, Finance Team, Communications Team, Asset and Engineering Team, Contracting Team and various regulatory bodies. Electronic copies of the AMP are available for all employees on TLC's Network database. An electronic copy of the AMPs available on the TLC website for customers and members of the public, bound paper copies are available by request. TLC keeps an up to date record of all distributed AMPs.	AMP Distribution Register	Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?		1	Designated responsibilities for delivery of the AMP are documented and set out in the asset and engineering team structure. The asset and engineering team consists of four groups, knowledge, implementation, operation and decisions, which are all governed by the Network Asset and Engineering Manager. The Network Asset and Engineering Manager has overall responsibility of network management, including the preparation, drafting, and implementation of the AMP.	Copy of the structure can be found in section 2 of the AMP	The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)		1	TLC endeavours to align the staff numbers, structure and skills to ensure an efficient and cost effective implementation of the asset management plan. TLC has resources in place for the implementation of the asset management plan; however these resources are not yet adequately sufficient. Due to the difficulty of attracting staff to the King Country, staff resignations and the increasing regulatory requirements it is not always possible to have the required staff numbers.	AMP	It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?		1	TLC's Contingency budgets are set in section 5 (Reliability, Safety and environmental Development Program) of the AMP, the Risk Policies are outlined in Section 10 (Risk Management) of the AMP. Contingency budgets are set aside each year to cover any unforeseen capital works such as tap-off fuses for new connection, SCADA, distribution transformers, protection relays and radio systems including repeater sites. TLC recognise that risk is defined as the product of probability and consequences therefore the planning criteria and assumptions are based on this recognition. TLC has in place a Civil Defence Plan and an Event Management Plan.	AMP Section 5 (Reliability, Safety and environmental Development Program) of the AMP, the Risk Policies are outlined in Section 7 (Risk Management) Civil Defence Plan and a Event Managment Plan	Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question		Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?		2	The Asset and Engineering Team consists of four groups, knowledge, implementation, operation and decisions, which are all governed by the Network Asset and Engineering Manager. Each team is responsible for carrying out the various activities that are specified in the AMP and individuals within the groups have various delegated authorities to implement the Asset Management Plan. Designated responsibilities for delivery of the Asset Management Plan are documented and set out in the Asset and Engineering Team structure. The structure differs from that of the AMP, this is due to a number of resignations, increasing compliance requirement and the need to do capital works at the lowest possible cost.	Copy of the structure can be found in section 2 of the AMP	In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?		1	TLC understands the need for sufficient resources; a budget has been allocated for resources such as staff, material, equipment and services from third parties. Due to the difficulty in attracting staff to the King Country (as the area is distant from major population centres), a number of resignations, and the increasing compliance requirements it is not continuously possible to have the required staffing numbers. TLC endeavours to align the staffing, the structure and skills with the AMP to ensure effective and efficient implementation.	Section 2 of AMP	Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?		1	The Asset and Engineering Team conduct fortnightly meetings to review and report the progress of activities set out in the Asset Management Plan. The asset management requirements, organisational policies and strategies are reiterated, common goals, targets and planned work are identified and coordinated at the meeting.	Minutes of Fortnightly Meetings	Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question		Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?		1	Most asset management tasks, including asset inspection, are undertaken in-house by the Asset and Engineering Team . The Engineers in the team inspect and prepare detailed designs and specifications, including legal and regulatory approvals for all capital and maintenance works, these are then issued to TLC's in-house service provider or external specialist contractors. The internal service provider is mainly staffed for fault response, however they carry out about 70% of the capital and maintenance works. The balance of the work is then subcontracted out to external contractors. Independent Contractor Agreements are put in place with external providers; the contract agreement provide detailed designs and specifications of the work to be done, the legal and regulatory requirement associated with the job and the rules and procedures that the contractor shall abide by when working on TLC's network. Specialist work such as SCADA , communications and vegetation is controlled directly by the AMG group but is completed by contractors.	Section 2 of AMP, Service Agreements with contractors	Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question		Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?		1	TLC uses the understandings gained from risk assessments and the asset management policies and strategies to help identify the resources requirements and then plan, provide and record the training necessary to achieve the competencies. The current strategy has been to employ a number of industry experienced and qualified personnel, and then use them to impart their knowledge in training local people.	Section 2 of the AMP	There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?		1	TLC uses the understandings gained from risk assessments and the performance of risk control strategies to identify the competency requirements and then plan, provide and record the training necessary to achieve the competency level. TLC supports personal development and training of all employees.		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?		1	Moving forward TLC's strategy to overcome the skills shortage will be to train an increasing number of local people, as well as encouraging personal development and training of current employees. TLC has also undertaken a programme to attract local graduates to the organisation.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

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Question No.	Function	Question		Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?		2	Two way communication exists between TLC and its shareholders, TLC provides its shareholders with regular newsletters, which include information on non-financial performance. Annual and Half yearly reports comprising of a report from the board of directors covering the operations for the reporting period and consolidation financial statements for the reporting period are delivered to the shareholders. TLC also supplies its shareholders with auditors' report on the financial statement and the performance targets (together with other measures by which the performance of the company has been judged in relation to the Company's objectives). Furthermore TLC provides its stakeholders with the annual capital expenditure budget adopted by the board, including identification of all programmed projects with a capital expenditure in excess of $200,000.	Statement Of Corporate Intent	Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?		2	TLC has uses three systems; a Financial System (Navision), Billing System (Gentrack), and an Asset Data System (Basix). All have an SQL server databases and data is being exchanged between systems. The financial system is based on a Navision software package over an SQL server database. In addition to processing and providing financial information for the various companies associated with TLC, it includes detailed job costing packages. The financial system is stable, but further development is needed to give the low level detailed reports required. The billing software is based on a heavily modified Talgentra system over an SQL server database. The "off the shelf" volumetric traditional billing system had to be modified to an extent far greater than originally envisioned to cope with demand based billing. The asset management system is based on BASIX software over an SQL server database. The BASIX system contains asset data and is used to calculate reliability statistics and valuations. It also produces reports that align with the network performance criteria in the Asset Management Plan.	Section 2 of the AMP	Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.

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Question No.	Function	Question		Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?		2	TLC has determined what its asset management information system should contain by reviewing historically recorded data, the increasing requirements from various regulatory bodies, the safety management system requirements, internal information required for pricing and billing, as well as the intellectual knowledge of staff. The asset management information system is regularly reviewed and improved when necessary.	Section 2 of the AMP	Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?		2	The data in Basix is stored in various SQL server tables that are viewed and written to by the various Basix user interface forms. Reports are run in SQL to pick up variances between actual data and the system held data. Control of the database is maintained by assigning individuals different levels of authority. Mandatory field are set up in the Basix database, this means that when new assets are entered into the database these fields must be populated before the program allows you to save the asset. All asset changes are tracked through an audit tracer that is built into the database.	Section 2 of the AMP	The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question		Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?		2	TLC's asset management information system is reviewed and algined current asset management requirements, it also aligns with the increasing regulatory and safety management requirement. TLC has included in the annual plan a budget for information system upgrades and maintenance, the asset management information system is regularly reviewed and improved when necessary.	Section 2 of the AMP	Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?		1	TLC uses formal and informal studies based on industry experience and information to identify risks. The process and procedures for the identification and assessment of asset and asset management related risks throughout the asset lifecycle is documented in the Distribution Policies and Standard. The details of asset risk policies are included in the distribution standard codes, policies and other documents. The policies also include various techniques for identifying, quantifying and managing asset related risk with varying levels of complexity. TLC constantly review its individual requirements in terms of risk identification, including the availability of information and implementation practicalities of reduction strategy.	Section 7 of the AMP	Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?		1	TLC reviews and analyses the results of the risk assessment, once an understanding is gained the results are then used to help identify the resources, training and competency requirements to achieve the asset management strategy. TLC believes on-going training, assessment and monitoring is important to ensure staff are competent to complete assigned tasks.	Section 7 of the AMP	Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?		1	The Asset Management Policy identifies TLC's legal, regulatory and statutory requirements. It also identifies the regulatory compliance documentation that must be prepared and published by the asset and engineering team. Electronic copies of TLC's regulatory documents are available on the TLC website and bound paper copies are available be by request.	Stated in the AMP	In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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Question No.	Function	Question		Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?		2	TLC's overarching asset management strategy is to have policies, systems and procedures in intellectual understanding to create, operate and maintain a sustainable network. TLC has established an asset management procedure to assist with the implementation of the Asset Management Plan; the procedure outlines the responsibilities of the asset management group, this includes the responsibilities of maintenance and project works. The design, modification, construction and commissioning activities are set out in TLC's distribution standards and the operations of assets are covered by the operating procedures. The Basix database allows TLC to monitor the life cycle activities of all network assets. The Basix database is used to record the creation, acquisition, procurement and enhancement of network assets as well as recording asset information, condition and expenditure.	AMP,Distribution Standard, Operating Procedures, Basix Database	Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?		2	TLC's process and procedures are reviewed regularly; the asset management procedure, distribution standard and operating procedure are reviewed every 12-18 months. Due to the increasing regulatory requirement the Basix database is constantly reviewed and updated to ensure it is effective and efficient as well as ensuring it aligns with the asset management policy, strategy and objectives and the asset management plan.	AMP,Distribution Standard, Operating Procedures, Basix Database	Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.

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Question No.	Function	Question		Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?		2	Reliability monitoring is done via the Basix system. Fault information is entered from daily reporting sheets, which in turn are completed from a variety of sources including SCADA, sentries, the telephone database and control room data. Monthly performance reports are generated and reviewed at management level and reported at board level. Equipment failures in the various sections of the network and the SAIDI/SAIFI effects of these are monitored closely. Reports are set up in the Basix system to produce the regulatory and internal performance data, including Commerce Commission Decision reports. The BASIX system is used to report asset performance and effectiveness such as voltage complaints and system component failures. The ratio of billed kVA to the sum of the kVA of distribution transformers is determined from BASIX and the billing data boxes by running sequel server reports. Network technical losses are calculated using models that include the effects of generation. The BASIX system is also used to report on the customer service levels. These include time to restore supply and maximum number of shutdowns.	AMP, Basix Database	Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?		1	The responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non-conformances are documented and outlined in TLC's Accidents/Incident Management Procedure and the Network Access and Operating Competency Procedure. The Accidents/Incident Management Procedure is communicated to employees during the company induction. The Network Access and Operating Competency Procedure is communicated during the network induction Process.	Accidents/Incident Management Procedure.Network Access and Operating Competency	Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

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Question No.	Function	Question		Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?		1	TLC recognises and understands the need for systematic checks, especially of the effectiveness of its asset management process. Currently the asset management procedures and processes are reviewed every 12-18 months; changes to the procedures and processes are made to reflect the outcomes of the review.	Review Log for Processes and Procedure	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?		1	Investigation and mitigation of asset-related failures, incidents and emergency situations and non-conformances are documented in TLC's Accidents/Incident Management Procedure and the Network Access and Operating Competency Procedure. As part of the accident/incident investigation a Root Cause Analysis (RCA) is conducted is to identify the factors that resulted in the nature, the magnitude, the location, and the timing of the harmful outcomes (consequences) of one or more past events in order to identify what behaviours, actions, inactions, or conditions need to be changed to prevent recurrence of similar harmful outcomes and to identify the lessons to be learned to promote the achievement of better consequences.	3 Nonconformities and incidents are outline in operating procedure 12 - appendix D. Root Cause Analysis is carred out on asset related failure.	Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?		2	TLC is continually assessing and improving the performance, condition, related risk, and cost of assets across their whole lifecycle. TLC has performance measures in place to meet regulatory requirement, to ensure each customer is receiving the promised standard of service and to measure the performance of the assets both physically and financially. Where gaps, poor performance and non-conformance exist TLC instigate appropriate corrective and/or preventative action to eliminate or prevent the causes. Where performance targets are achieved TLC finds new and innovative ways to maintain or improve asset performance both financially and physically.	Performance Target, Basix database improvements	Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question		Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?		1	TLC acquires knowledge about new asset management related technology and practices by researching international papers and standard to identify benchmarks for asset management practices, as well as sending engineering staff on conferences and forums to gain knowledge of new and innovative asset management techniques and practices. TLC also actively engage in industry discussions with other networking companies, professional bodies and regulatory bodies about what are the best asset management system, technology and practices.	R&D documents.	One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.