The Lines Company Limited

ASSET MANAGEMENT PLAN

2013

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 Arthur Patrick MULDOON, 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.

27 MARCH 2013
Date

Angus Malcolm DON
Chairman

27 MARCH 2013
Date

Arthur Patrick MULDOON
Director

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
DoL..... Department of Labour
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
MED ..... Ministry of Economic Development
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:

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

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

The principal objective of the Asset Management Plan (AMP) is to meet the requirements of stakeholders as reflected in the Statement of Corporate Intent, the agreement between The Lines Company (TLC) and its owners. This agreement obliges TLC to continue to invest in its network, to undertake a sustainable renewal programme, to minimise/eliminate hazards and meet reliability targets in a way that makes charges as affordable as possible to customers.

The network covers the area shown in the illustration below.

FIGURE 1.1: AREA OF NORTH ISLAND OF NZ WHERE TLC ASSETS ARE LOCATED

The TLC network has many contrasts and includes:

- 60 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 who provide approximately 12% of the revenue.

The assets have a regulatory value of $184 million. (Valued using March 2011 Commerce Commission 53ZD Notice methodology.)

TLC's assets are old by industry standards with the highest proportion of any line company (39%) within 10 years of total life[1]. The average remaining life of fixed assets is 21 years, the second highest when compared to other network companies.

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.

The forward expenditure predictions in the previous AMP and this AMP reconcile approximately to the age based Commerce Commission Farrier Swier consulting report as part of the work leading up to the 2010 regulatory reset. The differences were associated with hazard elimination/minimisation and localised issues.

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. That price, at times, is at the limit of what the customer is willing to pay. Thus, there is a limited ability to cover extra rural investment from existing customers. Renewals will increase the values of these assets and thus revenue requirements.

  As a consequence they 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 rural customers so that they can better understand the cost of supply and more adequately decide on the trade-off among cost, service and hazard control. This approach and improved data will be vital for putting options to customers and making decisions given the government's decision to continue with the obligation to supply beyond 2013 and the need for this to be funded from existing customers.

  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.

  Many aspects of hazard control are non-negotiable in terms of legislation and from a practical sense preventing lines from falling down are also part of the quality consideration. Balancing these issues and the obligation to maintain supply to remote rural areas whilst maintaining reliability, renewing assets and providing acceptable dividends to stakeholders are part of the challenge facing TLC.

  During the 2011/12 and 2012/13 AMP review, work was prioritised to minimise this impact; however, it does mean that work on minimising hazards was spread further into the future. The 2013/14 review will continue with this approach.

[1] PWC Electricity Line Business 2011information Disclosure Compendium

TLC is focused on completing renewal work in a way that minimises the value increase aspect. Initiatives include minimising live line and increased investment in engineering to better ensure that only assets that require renewal are replaced.

» Secondly, 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. These homeowners on the whole are willing to pay a reasonable line charge, but do expect a service level that is close to what they receive in their permanent residences in return. 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.

» Thirdly, urban areas normally have much fewer outages, as the income from such areas justifies investment in back feeds and other supply enhancing assets. If most network customers are located in an urban area then the low urban number producing a low average will mask the high rural outages. The lack of this masking effect means that TLC's outage figures will always be close to the industry extreme.

The Electricity Industry uses two core standard assessments of service level; System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). In 2003 TLC carried out a customer survey that provided sufficient data to allow the establishment of target performance levels for these two assessments. In 2009 the Commerce Commission released Decision 685 which set independent normalised reliability limits for both SAIDI and SAIFI. In 2010 the Board of TLC determined that the SAIFI performance level target should be increased to give more "headroom" for an increased level of renewal whilst minimising revenue increase requirements.

Figure 1.2 shows the Customer and Compliance reliability targets

CUSTOMER AND COMPLIANCE RELIABILITY TARGETS		
Target	**SAIDI**	**SAIFI**
TLC Customer Target	300.00	4.86
Normalised Compliance Target	307.69	4.15

FIGURE 1.2: RELIABILITY TARGETS

The Commerce Commission reliability limits are comparable with TLC's SAIDI and SAIFI target performance levels. AMP forecasting expects to revise these target performance levels as part of the on-going customer consultation as part of a Customised Price Path application (CPP). The renewal programmes outlined in this document aim to maintain the company's SAIDI and SAIFI performance targets at levels that meet stakeholder expectations.

The Asset database (BASIX) provides the raw data for both the compliance reliability limits and the actual/target performance levels of SAIDI and SAIFI.

The actual performance data for SAIDI and SAIFI have different influences. Measures to reduce SAIDI may act to increase SAIFI. An example of this is the increased use of automatic network switches that reduce the duration of an unplanned outage, such as bird strike, but may increase the frequency of unplanned outages. Unfortunately unplanned weather and other natural events may cause extraordinary network outages. This would significantly affect the actual data provided for SAIDI and SAIFI and depending on the severity may cause TLC to miss both performance targets and compliance limits.

TLC is preparing an application for a CPP. This option has been provided by the Commerce Commission and recognises the unique profile of different networks. As noted TLC has a large aged rural network. Planned network renewals may mean the current compliance limits and performance targets can easily be breached through increased outages to do renewal work at the lowest possible cost. Customer consultation is being

used to find an acceptable level of performance targets that result from a compromise between price and service quality.

Figure 1.3A and 1.3B show the historical data for both SAIDI and SAIFI along with TLCs performance target. Transpower related outages are not included in these illustrations.

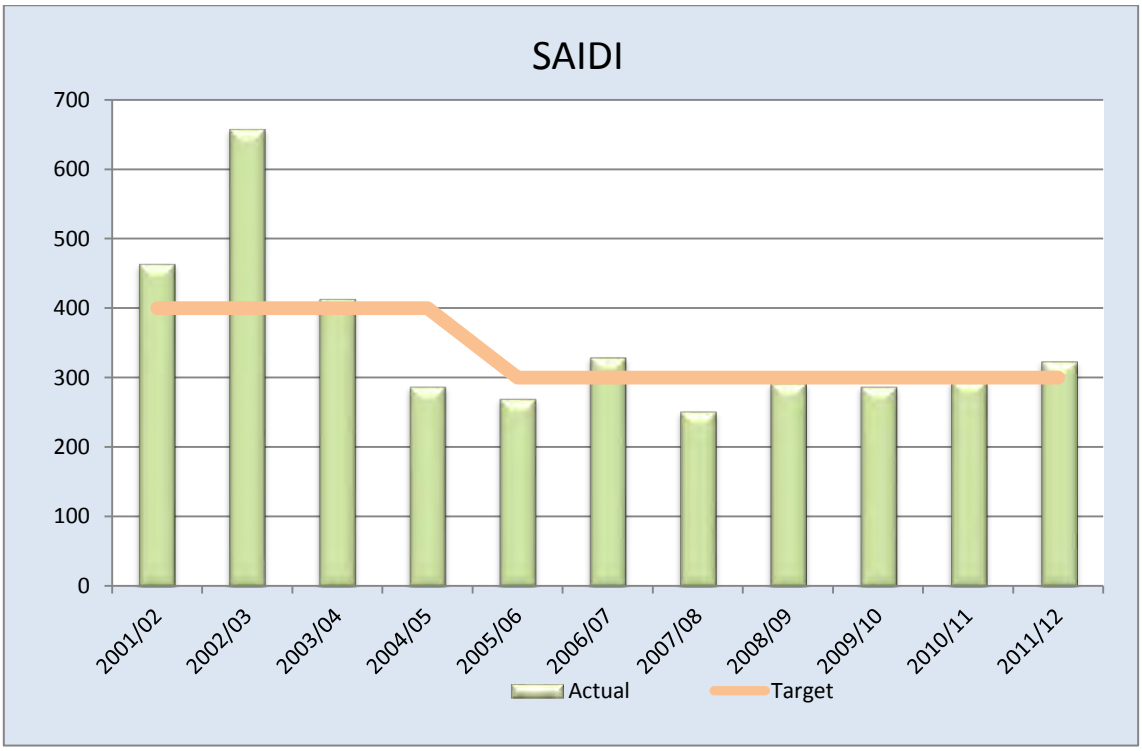


FIGURE 1.3A: 2002-2012 TOTAL SAIDI (EXCLUDING TRANSPOWER)

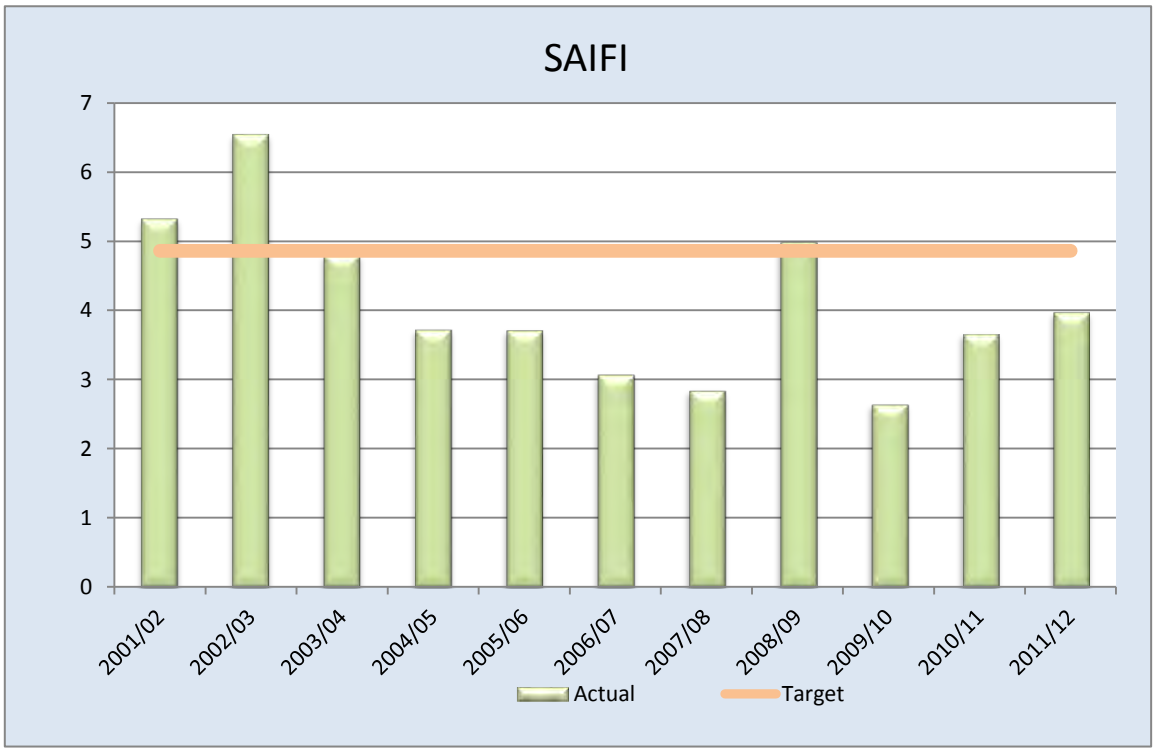


FIGURE 1.3B: 2002-2012 TOTAL SAIFI (EXCLUDING TRANSPOWER)

The improvement is evidence to show that TLC's asset management programmes are working. The reality is that it takes time to cement in many of these strategies across a large infrastructure asset such as an electricity network.

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. As the Plan notes, 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.

Most of the generation is renewable with little or no storage. The river hydro schemes produce the highest outputs after wet periods, which predominantly occur in the winter months. TLC's industrial load peaks tend to occur in the summer months when demands for meat, limestone, and forest processing are at their highest. This means that the distributed generation does not often reduce network expenditures. Network assets have to be put in place to handle load off take without generation and maximum generation injection during light load times. The charging regime to generators has to reflect the fair value of asset installation, renewal, and maintenance costs based on the asset utilisation by this activity. This tends to be determined on a generator-by-generator basis. Distributed generation adds technical complexity to operating, maintaining and developing the network. For example, it substantially reduces grid exit power factors. Generation can have benefits such as voltage support, TLC is encouraging investors to operate plants in a way that both they, and TLC, can maximise these.

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. Some analysis work has been done to compare the saving in capex programs that come about with increasing engineering analysis and design as compared to the extensive use of standard designs or uncalculated designs. The results of this work showed an experienced design

engineer overseeing the line renewal work was able to reduce the line renewal capex spend by about 10% with little likely effect on network sustainability.

In 2012 the commerce commission released an Electricity Distribution Information Disclosure Determination, Decision No. NZCC 22. The 2013 AMP has been drafted to comply with the requirements. Part of the new requirement is that EDB's must submit an Asset Management Maturity Assessment Tool (AMMAT) which has been developed to assess the maturity of the EDB asset management system. This has highlighted key areas in the asset management system that TLC will need to improve on, this means that engineering resources will be consumed when updating the asset management system.

The engineering resource problem is also being further amplified by the increasing requests for information and compliance from various government and other agencies. These requirements now consume a significant amount of engineering time that would otherwise give greater benefit to customers if it was focused on developing innovative solutions. In an effort to minimise the impacts of these requests, TLC continues to invest in new data systems that are automating much of this reporting in an effort to control compliance costs. Recent initiatives have included automating much of the Safety Management System (SMS) and forward renewal job system.

In order to gain the full benefit from our engineering resources we ensure that they are focused on engineering matters and that non-engineering staff are used for other duties wherever possible. The projected direct maintenance expenditure for the planning period is predicted to track as illustrated in Figure 1.4. An inflation rate of 2.5% has generally been used.

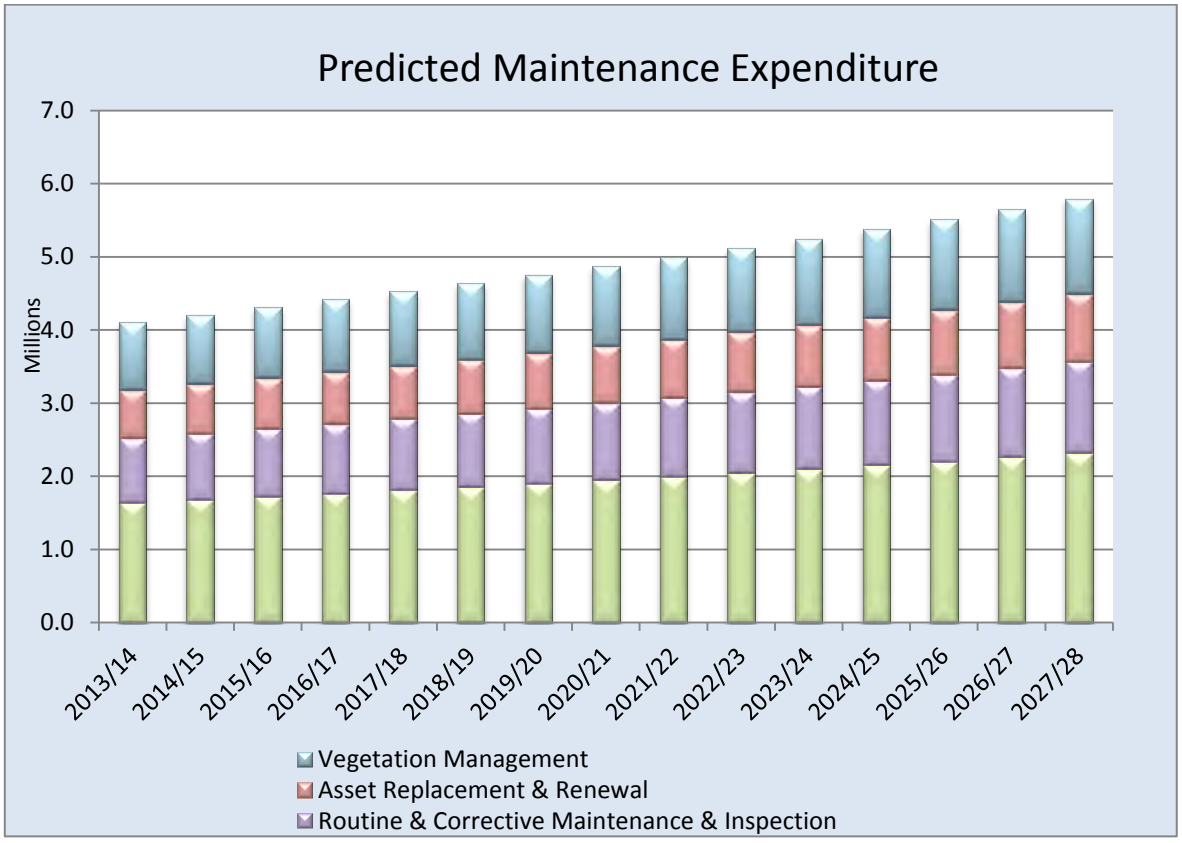


FIGURE 1.4: PREDICTED DIRECT MAINTENANCE EXPENDITURE
(AS DEFINED BY 2012 COMMERCE COMMISSION DISCLOSURE REQUIREMENTS).

The major direct cost included in maintenance expenditure is vegetation control. Since 2007/08, initial cutwork has been slowed and focus has been placed on maintaining the gains that have been made since the poor reliability years around 2002/03. This has involved the issue 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.

Figure 1.5 illustrates the predicted forward capital expenditure for the planning period in 2013/14 dollars plus forward inflation of 2.5%.

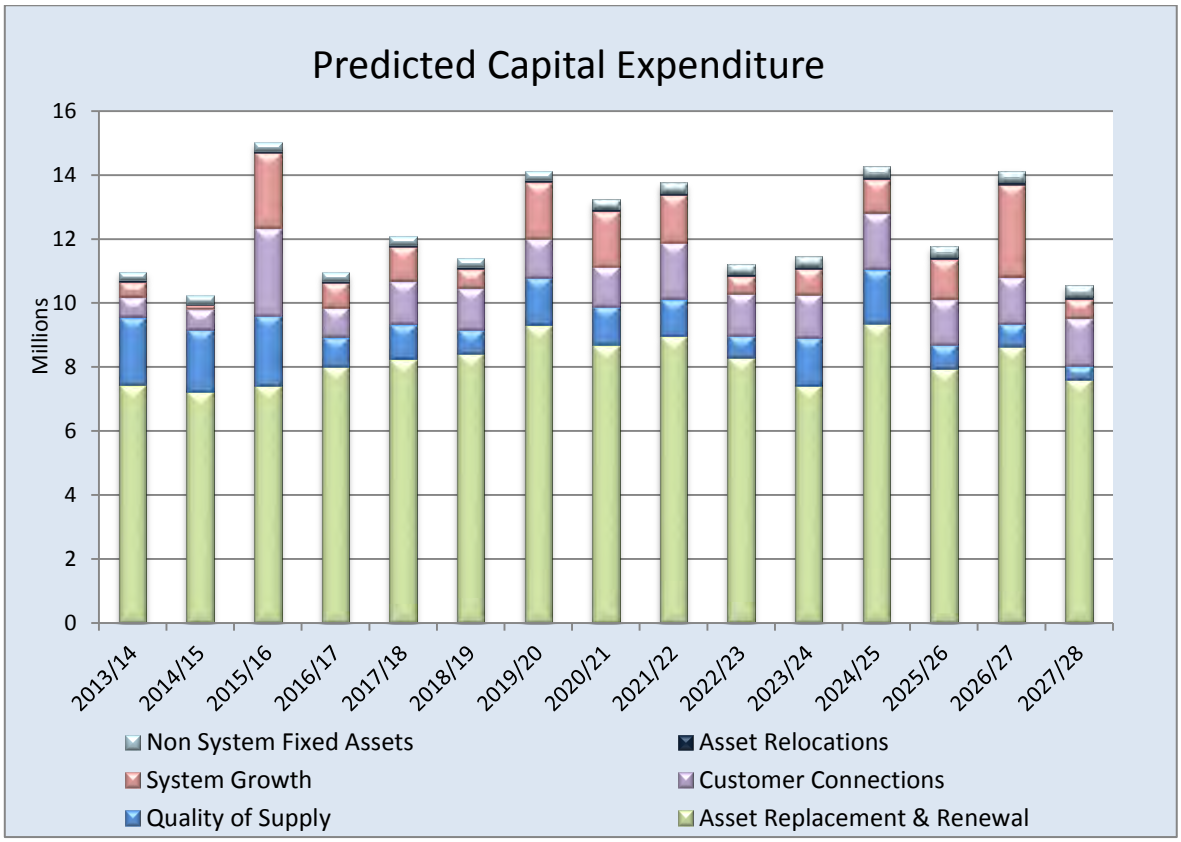


FIGURE 1.5: PREDICTED CAPITAL EXPENDITURE
(AS DEFINED BY 2012 COMMERCE COMMISSION DISCLOSURE REQUIREMENTS).

The CAPEX predictions are the output of a complete review of network needs. These 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. (These estimates are pre the CPP application as until the application is approved the figures cannot be modified). The predictions are also conservative in that they do not include many of the intellectual savings that will develop; but at this time are difficult to measure.

This level of capital expenditure will drive up prices and given the work is necessary due to the age and condition of assets the challenge for TLC is to do this work at costs below estimates. Any such savings will reduce the level of potential revenue increase needs.

The risks of price shocks to customers will also come from increases in Transpower charges, an escalation of data and compliance requirements by government agencies, earlier decisions to minimise renewals, the imposition on TLC's customers to fund, unaided, the costs of renewing TLC's uneconomic lines that were originally constructed using RERC funds and requests by customers to improve reliability to less than the targets listed in table 1.2.

In November 2012 the Commerce Commission issued a decision to reset regulatory controls for the electricity distribution businesses from 2012 to 2015 in which TLC is included. The most notable feature

was the new starting prices based on the current and projected profitability of electricity distribution businesses.

Table X20 of the paper[2] shows that the present value of revenue that TLC would be projected to earn relative to the amount required to earn a normal return over the full five years of the regulatory period is negative $14.5 million. Table X1 of the paper (i) shows that indicative adjustment to maximum allowable net revenue in 2013/14 is CPI+ 10% and the annual percentage rate of change 2014/15 is CPI+ 10%. At the time of writing, price adjustments will be a subject of debate with the stakeholders. Lines charge increases will fund capital, operational expenditure and the revenue to cover stakeholder returns and dividend returns. To minimise the level of lines charge increases TLC has looked into new and innovate ways to save costs on capital works (less live line, more design overview etc.). It is any likely increase will be aligned to CPI plus a small amount. The small amount will in simple terms be "renewal catch-up".

In 2005 TLC introduced direct billing and, in response to customers' requests for flat annual charges, introduced demand based charging for all customers. Customer bills are now made up of capacity, demand and dedicated asset charges. These are also area specific to allow customers to make choices on what they want. These charges encourage demand reductions including the control of peaks, alternative generation during peaks, maximising dedicated asset utilisation, minimising installation capacity requirements and, for larger installations, responses to reactive power signals. The objective of doing this is to buy time for TLC's existing assets so that the revenue from existing customers can be used for renewals. Given there is a significant need for renewal any need to upgrade because existing customers are driving peak demands up would have to be funded by increased prices to these groups.

In an effort to minimise costs for renewals, TLC is looking to new innovative solutions. The foundations, which include demand based billing, improved network, customer and financial data and detailed network analysis/automation tools, are in place. Intellectual learning is underway, and many ways by which the network can be tuned to improve efficiency for minimal cost have been identified, and are being systematically applied. For example, better ways of tuning distributed generation to run in conjunction with TLC voltage control equipment have been identified and TLC is recommending improvements to the generator whenever they modify their plant. TLC demand billing and pricing systems are also undergoing continual development to increase the incentives for customers to manage demand for both active and reactive power. These initiatives are integrated and form the basis for a "smarter" network.

TLC has developed advanced meter software including an in home display that aligns to its pricing. This software and the in home display has been trialled and will be developed as soon as this work is completed.

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 under utilised. 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.

2 Commerce Commission, *2010-15 Default Price Quality Path for Electricity Distributors*, November 2012

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.

The costs, particularly of solar cells, have reduced over the last year or so; 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.

TLC recognises that the government will not fund rural lines and, as a consequence, it must use some other approach to ensure customers can afford to pay for their electricity delivery.

A major element of a different approach is demand side management through demand billing. TLC has evidence of two effects from recent data of its demand side management initiatives.

- Firstly, retailers have not increased energy charges in the same proportion as the rest of New Zealand. De-coupling appears to have placed greater pressure on retailers to avoid price increases and “hidden” repackaging margins.
- Secondly, demand growth data is indicating that customers are responding and shifting load. Initial analysis is showing that the impact this could have on delaying development expenditure is such that it will allow TLC to complete its renewal programmes.

The effect of stable energy rates and strong incentives in line charges to reduce demand gives customers options to ensure total electricity accounts are competitive with other places in New Zealand, (even densely populated urban areas). TLC’s challenge is to deliver these innovative approaches in such a way that customers recognise their choices and options.

Now that the reliability has been stabilised, the next challenge is to complete the renewal programmes at lower costs than estimated. The achievement of this will be of pricing benefit to customers.

Section 2

2. Background and Objectives

2.1 The Purpose of the Plan

The primary purpose of this document is to communicate the asset management policies, processes and outcomes adopted by TLC to all interested stakeholders. The Asset and Engineering Department prepare the plan annually after reviewing previous years' Plans and discussing the information that stakeholders wish to have included. The Plan therefore incorporates information that is prepared for other planning purposes, or is the result of the asset management process adopted by the company.

The Plan is drafted to comply with the Electricity Information Disclosure Requirements 2012, Decision No. NZCC 22. The Plan is aligned to and is part of TLC's asset management policy and forms a significant part of the asset management strategy. It is also aligned to and forms part of TLC's Safety Management System (SMS).

If the electricity information disclosure requirements did not exist it is likely that the asset management planning process would be part of TLC's annual plan and the Plan would become more aligned to the international PAS 55 standard, but likely have more of a customer and stakeholder focus.

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, and feedback is welcomed. The Plan has a purpose to inform stakeholders of the implications of growth, renewal, hazard elimination, maintenance, vegetation, and other expenditure streams on service levels and risks, such as levels of hazards, for both the short term and longer term. The document also gives customers an understanding of the links between asset costs and pricing structures, including the need for future adjustments to fund asset renewals. Figure 2.1 illustrates the documents and papers that have a relationship with the writing of the AMP; from an AMP perspective.

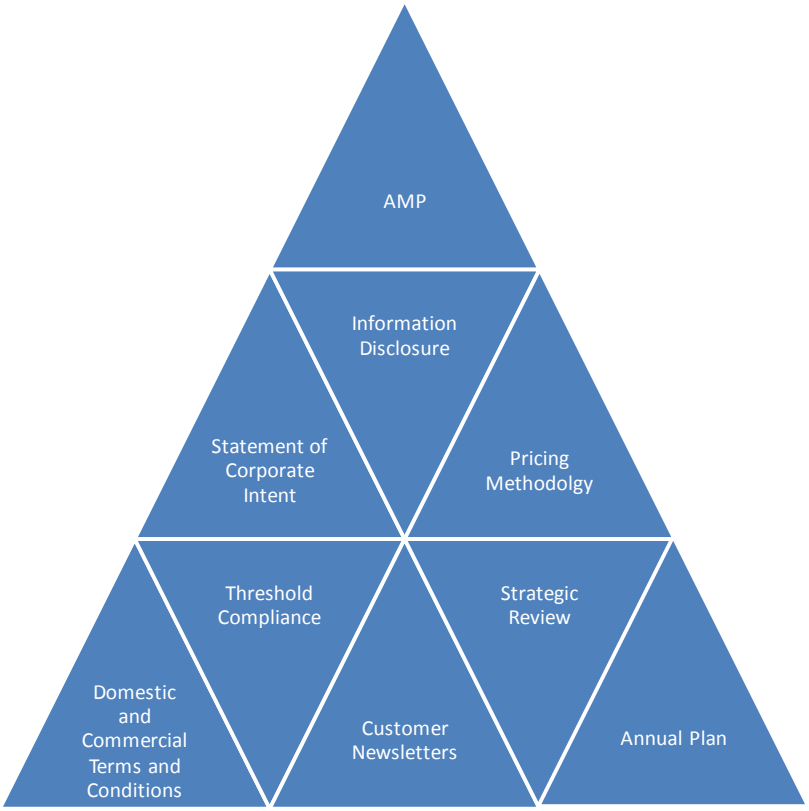


FIGURE 2.1: RELATIONSHIP PYRAMID OF AMP

The area supplied by the TLC network includes large areas of Maori owned and other long term tenure land. TLC assets are located on this land and a purpose of this Plan is to document its intentions for these assets for the short, medium and longer terms.

In addition to disclosing network information, the Plan has the objective of forming the documented base for all engineering/asset planning implementation processes and activities. The Plan discloses the asset information and processes used to manage the assets to all stakeholders.

The Plan also has a purpose to provide the framework that enables asset management strategy objectives and detailed plans to be produced and implemented. These include the principles to be applied, such as the organisation's approach to hazard control and sustainable development. The Plan is consistent with TLC's vision/mission statements.

2.2 Description of the Interaction between these Objectives and Other Corporate Goals

2.2.1 High Level Corporate Mission or Vision

The high-level corporate mission or vision for the network business is to be recognised as the best supplier of electrical capacity to remote rural customers. This includes both load and generation customers.

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.

The company recognises that one of its main missions is to deliver a strong sustainable network to the greater King Country area, as covered by its two trust shareholders. In order to do this, it 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.

TLC has identified that in order to meet this requirement it must excel in:

- Asset management including:
  - » Asset management strategies consistent with other organisational polices and strategies and the needs of stakeholders.
  - » Asset management strategies that take into account the lifecycle of assets, asset types and systems over which the organisation has control.
  - » A documented asset management plan across the lifecycle of its assets.
  - » Communicated plans to all of the relevant parties to a level of detail appropriate to the roles of the reviewers.
  - » Designated responsibilities for delivery of asset management actions.
  - » Appropriate arrangements are made available for the efficient and cost effective implementation of the plans.
  - » Plans and procedures for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities.
  - » A management team responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy objectives and plans.
  - » Provision of sufficient resources for asset management.
  - » Communication of the importance of meeting asset management requirements.
  - » Where activities are outsourced, ensuring that appropriate controls are in place to produce compliant delivery of its organisational strategies/plans, including asset management.
  - » Developing plans to secure the human resources required to undertake asset management activities.
  - » Identifying competency requirements and then plan, provide and record the training necessary to achieve the competencies.
  - » Ensuring that persons under the organisation's direct control undertaking asset management have an appropriate level of competence in terms of education, training or experience.
  - » Ensuring pertinent asset management information is effectively communicated to and from employees, or other stakeholders including contracted service providers.
  - » Documentation to describe the main elements of the asset management system and the interaction between them.
  - » Determining what the asset management information systems should contain in order to support its asset management system.
  - » Maintain asset management information systems to ensure that the data held is of requisite quality and accuracy, and is consistent.
  - » Ensuring its asset management information system is relevant to its needs.

  - Documented processes and/or procedures for the identification and assessment of asset and asset management related risk throughout the asset life cycle.
  - Ensure that the results of risk assessments provide input into the identification of adequate resources and training/competency needs.
  - Ensure the organisation has identified and provided access to its legal, regulatory, statutory and other asset management requirements and incorporated these into the asset management system.
  - Establish, implement and maintain processes for the implementation of its asset management plan and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities.
  - Ensure that processes and/or procedures for the implementation of the asset management plan and control 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.
  - Have in place indices to measure the performance and condition of assets.
  - Ensure the organisation has delegated responsibility and the authority for the handling, investigation and mitigation of asset related failures, incidents and emergency situations and non-conformance is clear, unambiguous and communicated.
  - Established procedures for the audit of its asset management systems.
  - Instigate appropriate corrective and/or preventative actions to eliminate or prevent the causes of identified poor performance and non-conformance.
  - Ensure continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole lifecycle.
  - Seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation.

- 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.

2.2.2 The 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
  This document 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
  This document is prepared in parallel with the strategic review and contains more detail.
  This document is approved by Directors.
- Asset Management Plan (AMP)
  Key document covering the major investment owned by TLC.
  This document is approved by Directors.
- Annual Plan/Budget
  Operating document detailing activity budgets approved by Directors.
  This is prepared in parallel with the Asset Management Plan.
- Monthly Board Reports
  Reports to Directors updating them on progress against the plan and detailing other issues that they need to know and/or approve.
- Annual pricing reviews.
  Approved by the Directors and relates closely to the above documents.

2.2.3 How the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management

TLC's planning process commences at the ownership level with the strategic review of the businesses that TLC is in, the purpose of these businesses, and whether each business can return, on a sustainable basis, a margin above our cost of capital.

The Strategic Review includes a financial analysis on the position of the network business based on the expenditure requirements derived from the Asset Management Plan. This analysis sets the high-level revenue requirement. Another major contributor to the outcomes of this analysis and subsequent decisions is the Commerce Commission Default Price Path. The 'rules' as set by the pricing regulator have a bearing on TLC's strategic direction. The Strategic Review also summarises the high level corporate strategy and includes an update on the criteria for new business activities.

The Statement of Corporate Intent is prepared in parallel with the Strategic Review and contains more detail. It includes key performance objectives of the network business, which are based around the contents of the current Asset Management Plan. There are close ties between the three documents.

The asset management policies and strategies that flow into this plan are identified from the Strategic Review and Statement of Corporate Intent and the strategies put in place to achieve these through the management of the physical assets.

The principal driver for revenue is the condition of the assets and the need to have a sustainable network that meets customers' expectations, including acceptable hazard related risk levels whilst producing a 'WACC' (Weighted Average Cost of Capital) within the regulatory bounds.

The ability of customers to pay is recognised in all documents and is an important consideration in the annual pricing review. This process ensures that the asset management strategy is consistent with other organisational policies and needs, and aligns with the needs of other stakeholders. The Annual Plan/Budget is a more detailed, activity level document that also fits under the Strategic Review, Statement of Corporate Intent and AMP.

Much of the detail in the Annual Plan replicates the present to one year out sections of the AMP. Specific detail is included on individual projects such as design outlines and financial evaluations.

Once approved, monthly reports to Directors document the progress against planned work for financial and other performance indicators. Monthly reports also include six monthly and annual updates against the AMP and Annual/Budget plans.

Feedback into future documents comes via Directors' resolutions and minutes from monthly and other meetings. The next cycle of documents includes this feedback. Any variations to the plan are approved by Directors at monthly meetings during the year. The documents include feedback and consideration coming from stakeholders and the associated regulatory/government requirements.

All stages of this process recognise the 'doing' aspects of asset management including asset lifecycles, performance and costs to users.

2.3 The Period Covered by the Plan and the Date the Plan was Approved by the Board of Directors

This Plan covers the period 1st April 2013 through to 31st March 2028. The Board of Directors approved it on the 28th March 2013. The Plan is reviewed annually.

Due to the age of the network and historic practices, many of the assets within the TLC network fall short of present day hazard and risk expectations. The Directors have requested priority on hazard related asset renewals in order to eliminate or minimise known risks of harm to the public or employees.

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 biggest changes likely in the planning forecasts will come from distributed generation, industrial, holiday homes and farming development.

The time scale needed for projects to be completed is also increasing due to a whole host 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 2028 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 2028 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 5. The estimates and performance expectations align with the asset management strategy that takes into account the lifecycle of assets, asset types and asset systems. The above assumptions are based on present project approaches. One of TLC's objectives for the coming period is to complete this work at a lower cost by trying to do things like reducing the amount of live line and generator by-pass work.

2.4 Stakeholder Interests

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

2.4.1 Shareholders

The interests of our shareholders are identified through the Corporate Review process and other consultation. Although our shareholders hold different percentages of ownership, they have some common interests and some that are of greater priority for the major shareholder.

Both are interested in:

- The business being sustainable in the long term and the asset management strategies to achieve this.
- A reasonable standard of service being given to customers.
- The price to customers being equivalent to that charged in other rural areas.
- Customer satisfaction and fair treatment.
- A network that meets acceptable industry hazard related risk standards.
- A network that meets 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.
- The asset management strategies and plans communicated to them.

The major shareholder is also interested in:

- An acceptable return being earned from the assets.
- An acceptable cash return from the network, as the only way customers who are the beneficiaries of the trust can receive benefit from their ownership is by way of a regular cash return. (Customers leaving the area cannot receive cash for any capital growth they have funded while with TLC.)
- Customers and community acceptance of The Lines Company activities including the asset management strategies and plans communicated to them.

It is considered inequitable that current customers be asked to fund upgrades from which they will receive no benefit. It is also considered inequitable if current customers do not contribute to renewal network expenditure from which they do receive a benefit.

The above interests are not achievable if revenues are limited to below an acceptable return.

The above interests are accommodated in the Plan by:

- 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 (SAIDI 300 minutes, SAIFI 4.86 frequency).
- 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.
- Communication of the key parts of the asset management plan and related strategies.

The organisation can limit investment in new customer driven work if acceptable returns cannot be earned. Investment in existing assets is however a sunk cost.

Balancing the customers' ability to pay against the need to reduce hazards and risk is not straightforward and is driven by priorities. The mechanisms for determining and managing these priorities are outlined throughout the Plan.

2.4.2 Customers

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. Customers are interested in:

- 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. i.e. appropriate communication on the key issues, impacts and strategies in this plan that are likely to effect them.
- Having choice to reduce charges by reducing demand/energy use and improving power factor.
- Having clear claim and compensation systems when TLC assets do not perform.
- Having several pricing options available.

The above interests are accommodated in the Plan by:

- The reliability targets that have been developed to be 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 effect them.
- Direct customer billing, including demand based charges for all customers. This signals demand, leading to fairer charging of customers and better asset utilisation.
- 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.
- 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.

Conflicting interests occur when customers expect good service at a fair price, as well as a continued distribution by shareholder trusts. Customers tend to judge the efficiency of the company from the size of the distribution and charges. Some have had trouble understanding demand based charges, and separate lines and energy bills. The demand based charging system, however, does pass on cost signals and will facilitate lower long term charges than line charges based on volumetric energy.

A large number of systems are used to manage these EGCC conflicts, both internally and externally. These include:

- The Commerce Commission rules and regulations.
- Electricity Authority rules and regulations.
- Other legislation and regulations.
- Complaints resolution organisations.
- TLC's Trusts.
- TLC's Directors.
- TLC management.
- Customer advisors.
- Presentations to customer groups explaining TLC's pricing methodology.
- Customer clinics and focus groups.
- Development of a customer communications section within the organisation.
- Various independent reports on the charging structure that include recommendations on how these should be modified going forward.
- Development of pricing options following this meeting.
- Acceptance of an asset strategy to roll out advanced meters to all customers across the network.
- Information coming from independent bodies such as the Commerce Commission and MED (Ministry of Economic Development) that compare TLC's operation with other networks.
- Independent load projection data that shows TLC's predictions reconcile with independent assessments (particularly Transpower).
- A strategy going forward is to develop an advanced network aligned to a rural environment.

2.4.3 Employees

The interests of our employees are identified through direct discussion with them and their representatives. Our employees are interested in:

- 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.
- A safe working environment.
- Having a clear purpose for coming to work and "making a difference" for the benefit of customers and their personal development.

The above interests are accommodated in the Plan by:

- 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 that creates a high level of self-worth.
- 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.

Conflicting interests occur when individuals or groups of employees have a different vision to that of the company or disruptive personal behaviour.

These conflicts can be managed by:

- Communication and discussion including the asset management strategies and actions included in this plan.
- Management techniques and systems.
- Unions.
- In extreme cases, disciplinary procedures.

2.4.4 Transpower

Transpower's interests are identified through communication and direct discussion. Currently Transpower is interested in:

- 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.

The above 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.

Conflicting interests occur when Transpower's systems and policies do not fit with TLC's or its customers' needs. These conflicts are managed by researching Transpower's polices and negotiating a solution that best fits TLC's needs aligned with this AMP. A continuous asset management initiative is to better align TLC's and Transpower's asset management strategies and plans to create better outcomes aligned to both organisations strategies and ultimately reducing customers costs. An essential part of this will involve the communication of asset management strategies. It should be noted that the Electricity Governance regulations often make Transpower's position more difficult in terms of negotiating a win-win solution for things such as transformer renewals and reactive power flows at the grid interface.

2.4.5 Contractors/Suppliers

Contractors' interests are identified through direct discussion. Currently they are interested in having:

- 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, not researching what the outcome will be.

The above interests are accommodated in the plan by:

- 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.

Conflicts occur with suppliers and contractors over price and quality of services provided. These conflicts are normally managed by informing the suppliers of the issues. If they do not respond, an alternative supplier is used or payment can be withheld.

2.4.6 Landowners

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.

Currently they are interested in:

- 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.

These interests are, in parts of the Plan, recognised directly; however, it is more likely that they are not specifically identified but are part of the background ethos. Landowners, where supply is provided, are ultimately responsible for TLC charges. Conflicts occur mostly over charges, land entry, vegetation and lines on private property.

Cost conflicts are managed by using cost reflective charge rates and polices. It is important that TLC takes a consistent, but fair approach. The line charge rates are regulated by the Commerce Commission. The terms and conditions of supply that effectively apply these rates have been developed in consultation with customers and other stakeholders.

Land entry rules are covered under the Electricity Act and Regulations. TLC manages land entry in compliance with these.

Vegetation is managed in accordance with the Tree Regulations, the law of nuisance and rural fire regulations. Communication of the asset management strategies and intended actions minimises conflicts and is an important element of this plan.

Lines on private property are managed in accordance with the Electricity Act and Regulations. TLC often involves the regulator (Energy Safety) in these conflicts because it is not TLC's responsibility to enforce the legislation.

Conflicts outside of these most common issues are managed by negotiation and communication.

2.4.7 District Councils

The TLC network is located in 6 Districts. Listed below are the District Councils:

- New Plymouth District Council
- Otorohanga District Council
- Ruapehu District Council
- Taupo District Council
- Waipa District Council
- Waitomo District Council

District Council interests are identified through direct discussion. Currently they are interested in having sufficient infrastructure development available so that:

- 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.

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 as is the need to manage assets to give acceptable levels of service.

Conflicting interests occur when District Council systems and policies do not fit with TLC's or its customers' needs. These conflicting interests are managed by researching council policies and negotiating a solution that best fits TLC's and each Council's needs/policies.

2.4.8 Regional Councils

The TLC network is located in 3 Regional areas. Listed below are the Regional Councils:

- Manawatu – Wanganui Regional Council
- Taranaki Regional Council
- Waikato Regional Council

Regional Council interests are identified mostly by correspondence and written information. 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.

The contact with regional councils is not extensive; however this Plan is used to communicate TLC's asset strategies and policies.

Conflicting interests occur when Regional Council systems and policies do not fit with TLC's or its customers' needs. These conflicting interests are managed by researching council's policies and negotiating a solution that best fits both TLC's and each Council's needs. These solutions are either presently included in the AMP or are included during the next review.

2.4.9 Central Government

Central government's interests are identified mostly by internet correspondence, written information, meeting with officials, and legislation.

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.

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. These conflicting interests are managed by researching the government's position and negotiating or complying in a way that best fits TLC's needs.

Feedback from these interactions is included in this Plan and the on-going development of asset management plans and strategies.

2.4.10 Retailers

Retailers' interests are identified through industry papers, communication and direct discussion. 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.

The above interests are accommodated in the Plan by TLC's direct billing programme. TLC's interaction with retailers has reduced since the introduction of direct demand based billing.

Retailers are aware of this Plan, but generally they have little interaction. They are communicated to about the asset management strategies associated with legacy relays (currently in the regulated asset base), and advanced meters (currently outside of the regulated asset base).

Historically, conflict occurred with retailers over payments associated with this group collecting TLC's charges but repackaging them so that TLC's cost signals were not passed on to customers. There were also conflicts over the volumetric energy quantities transported and thus how much a particular retailer should pay TLC.

Continuing to work through retailers would not pass onto customers the demand side management signals TLC requires. Meter reading data and customer details were also very inaccurate. TLC has managed this conflict by decoupling from retailers and introducing direct billing and demand based charges.

TLC continues to work with retailers, including communicating the relevant contents of this Plan. 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.

One of the frustrating areas of conflict coming out of retail operations is data accuracy associated with energy transported. There seems to be a level of volatility when the amounts of energy sold to customers is compared on a year by year basis. Most of this appears to be associated with non-technical losses. The most likely source of this error is the accuracy and timing of meter readings. Long term, the rollout of advanced meters in line with this plan should eliminate this.

2.4.11 Maori

Maori interests (such as protecting cultural values especially with long tenure Maori land) are identified through discussions with various groups. To date there has been little thought given to the impact of electricity distribution on cultural values. Maori are interested in having supply available in their homes and Marae, which are sometimes located in very remote areas. Often they have access to few resources to fund these services. Maori groups also hold significant tracts of land in the King Country. Development of these is a key to generating future funds for the owners.

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.

The Plan accommodates the development plans of Maori landowners who wish to create income for their families. Relevant parts of this plan and associated policies/strategies are communicated to Maori so that their needs can be aligned. Feedback and inputs are used during the review periods and some significant project alignment strategies have been achieved. Examples are Mokai Energy Park, Wairarapa Moana farm development and modification of renewal works plans in the Turangi area.

2.4.12 Distributed Generation

Distributed generation investor interests are identified by way of new connection applications and the issues associated with the continuing operations of existing plant.

Distributed generation investors are interested in:

- 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.

The above interests are accommodated in the plan by:

- Detailed information on existing larger connections and the implications of these.
- Technical detail on the general implications of distributed generation connections in Section 7.
- A list of the conditions that must be fulfilled before connecting distributed generation equipment.
- Not acting as engineering consultants for generators by setting guidelines only. Generation investors are invited to employ consultants to find innovative solutions to meet the guidelines.

Conflicting interests occur when the drive of distributed generation to minimise investment results in costs that must be borne by load taking customers.

TLC's asset management strategies and pricing strategies resolve this conflict by being cost reflective. This strategy ensures generation investors receive maximum returns when plant is sized and built in an effective and efficient way.

2.5 Conflicting Interests that are Common and Affect All Stakeholder Groups

2.5.1 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.

2.5.2 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 systems 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.

2.5.3 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.

2.5.4 Asset Renewal

Our shareholders require that their investment returns TLC's cost of capital. Customer beneficiaries were not willing to lower cash returns received in order to fund network upgrades. Customers were unwilling to meet high price increases. Both groups want a sustainable network and improvements in reliability.

This conflict is met through a targeted renewal programme, which ensures that the network does invest in assets, and a programme to ensure that reliability is improved with minimal network investment.

Innovative practices also play a major part in aligning these interests. Time is spent communicating and justifying the need for renewal expenditure with stakeholders. This includes customer, media and community leader presentations, and site visits. On these visits, the hazards and risks are discussed along with the costs associated with eliminating/minimising these.

The TLC network, because of its age, requires considerable investment.

Stakeholders have, in recent times, accepted lower levels of return mostly due to an increased awareness that assets need to be renewed.

Looking forward however, there is a difference between the Plan's predicted asset renewal spend and revenue per Commerce Commission models. This difference is largely the returns to shareholders (dividends). Some stakeholders, particularly the minority shareholder, is having difficulty accepting this given the customer pressure they endure.

This is one of the issues that on-going discussions and consultation between Directors and stakeholders are addressing. This is a high level communication on the realities of shareholder return associated with investment in assets and the management of these assets in a sustainable way.

2.5.5 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 their 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.

2.5.6 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 not shared by other customers. The advantages of this charging structure are numerous and discussed in various sections of the Plan.

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.

The consultation between TLC and stakeholders at corporate and stakeholder level is focused on this conflict. An objective of this is to communicate asset management policies, strategies and plans to stakeholders. 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.

2.5.7 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. 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.

2.5.8 Conflict between the Requirements of Legislation and Customers' Wants

Legislation and regulations passed, particularly over the last 10 years or so, have often failed to achieve key objectives and have sometimes produced counter-productive outcomes. TLC has found that many pieces of legislation are difficult to interpret, and require frequent and costly legal advice. This makes it difficult for the parties to which the legislation applies and for others, especially customers, to understand and thus tends to suppress innovation.

The requirements of this legislation usually increase cost with little benefit to customers. For example, legislative regimes designed to promote improvements in areas such as environmental protection appear to do little, or nothing, positive but impose significant additional costs that flow through to customers. There are over 25 pieces of legislation that apply to electricity distributors.

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.

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 however, 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.

2.6 Accountabilities and Responsibilities for Asset Management

2.6.1 Governance

TLC is owned by two trusts: Waitomo Energy Services Customer Trust (90%) and King Country Electric Power Trust (10%). 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 (annual spend plans, the 2003 Reliability Plan, vegetation control strategies, charging policies etc.) 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.

In addition to strategic approvals, Directors approve:

1. Development expenditure priorities and the business cases for development projects.
2. Overall annual renewal expenditure projects with detail available on a project-by-project basis.
3. Capital development projects.
4. All unbudgeted emergent work over a $50,000 threshold.

Expenditure against budget and explanations for variations on a category or project basis is reported to Directors monthly. Key system performance indicators are reported on a monthly basis. These elements form important parts of feedback on asset management plan performance.

2.6.2 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 Engineering Manager. The Directors are kept informed and updated on significant issues. They also approve variations, caused by unpredicted work and customer demand, upwards of $50,000. The Engineering Manager is involved in the technical aspects of most commercial decisions and modelling of network income associated with the management of TLC assets.

2.6.3 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, is 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.

The AMG group consists of the following staff:

- One qualified CPEng – REA, and Registered Electrical Inspector.
- One Senior Engineer – REA qualified.
- One Design Engineer – Degree qualified.
- One Network Performance Engineer – Registered electrician, Diploma of Engineering
- One Design and Analysis Officer – Degree qualified.
- One Network Performance Cadet – Degree qualified.
- One Technical Engineer
- One Network Lines Controller.
- One Vegetation Co-ordinator.
- One Tree Administrator.
- Three Line Designers/Inspectors/Auditors.
- One Network Data Controller
- One GIS Administrator.
- One Control Room Operator.
- One Backup Controller/New Connection Controller.
- One Line Renewal Co-Ordinator.
- One Emergent/Fault Work Co-Ordinator.
- One Administration Officer/SMS Co-ordinator.

The current structure for this group is illustrated in Figure 2.2. It is likely to be amended in the near future due to a number of resignations, increasing compliance requirements and the need to do capital works at the lowest possible cost.

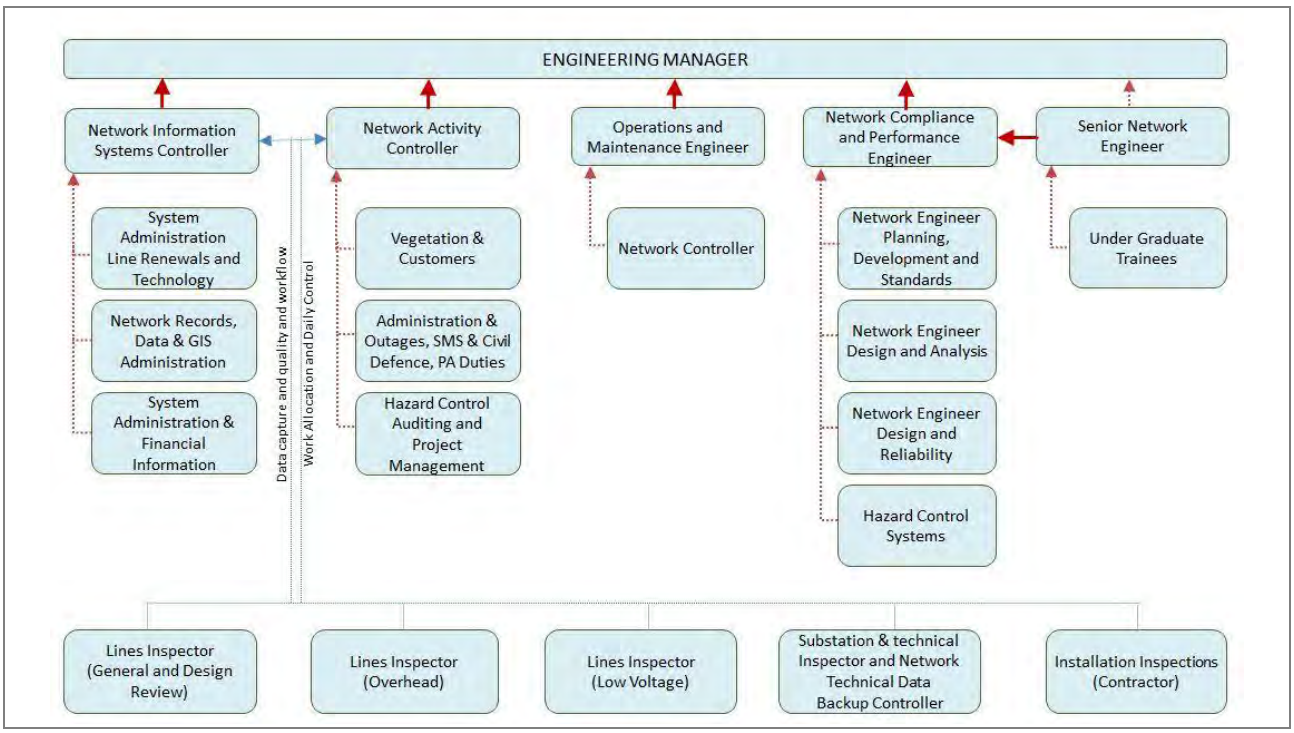


FIGURE 2.2: GROUP STRUCTURE

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.

The difficulty in recruiting experienced technical staff is recognised and TLC is currently sponsoring one graduate and will likely sponsor others in the future.

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.

2.6.4 Field Operation Level

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

The Contracting Operations Controller is responsible for the contracting operations. He reports to a management committee made up of the CEO, CFO and the Engineering Manager. Regular meetings take place between senior contracting staff and the senior asset and engineering staff 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 about 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 line capital 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.

Due to the rugged nature of the local terrain, and the fact that many lines are off-road, niche techniques have had to be developed to reduce outages due to planned work. In-house staff are used for work where these skills are required; external staff tend to be used for the more common work (e.g. straight forward planned renewals).

It should be noted that Commerce Commission Decisions 685 and NZCC 22 will require the development of further niche techniques to meet quality threshold criteria.

As discussed in other sections of this Plan, the terrain and architecture of the TLC network make live line work difficult. The niche techniques being developed include the use of generators to bypass work sites and mobile reactive power capacitor banks to support the network alternative supplies.

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. A project has been initiated to add a calculator to the asset database that breaks down the latest industry unit rates into component amounts so that works controllers can see and compare the benchmark rates for various activities. Quotations and invoices for work from internal and external providers are currently reconciled to these benchmarks.

2.6.5 Staffing

TLC has difficulty attracting specialist staff to the King Country as the area is distant from major population centres. The 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. TLC is aware that intellectual understanding should be rewarded with competitive remuneration in order to retain skills. Most employees who settle into the local area, and become part of the community, are retained. Moving forward TLC's strategy to overcome the skills shortage will be to train an increasing number of local people. TLC has also undertaken a programme to attract local graduates to the organisation.

Due to the relatively small size of the network, staff have to be flexible and this leads to challenging work across more diverse activities than larger organisations might offer. Similarly the relatively low staff numbers mean all staff have a greater sense of worth than they would have working for larger organisations. The effects of individual efforts are more transparent.

The financial and administration section is responsible for billing the network services, administration and providing accurate and timely financial information.

TLC has been an industry leader with its separate billing for lines charges. This has led to some confusion and increasing communication with our stakeholders. A Communications Manager has been appointed and she holds regular meetings with stakeholders and customers to ensure good lines of communication are developed and retained.

2.6.6 Outcomes Reported to the Board

In addition to monthly financial reports to Directors, reports covering the key performance criteria (as included in Section 5 of this Plan) are submitted regularly to Directors. Additional reports are provided as required.

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

2.7.1 Systems Overview

Since 2008, TLC has been rebuilding and refining its IT and database structure. The rebuild has resulted in three systems: 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.

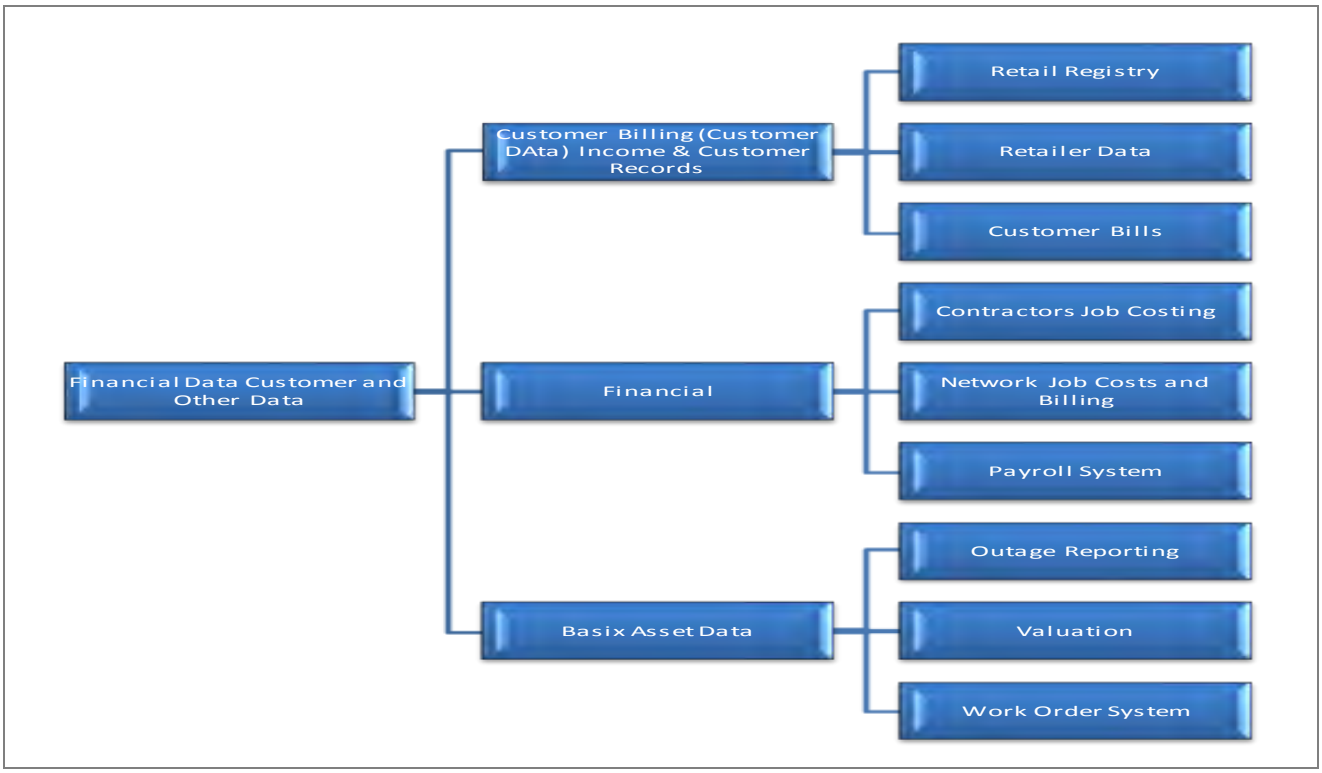


FIGURE 2.3: OVERALL SYSTEM LAYOUT AND INTERACTION

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. Included in the plan is the upgrade of the billing system in 2014, as there have been on-going performance issues. An Ideal replacement system is currently being scoped.

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 has been developed over the last 4 years; it now contains asset data and is used to calculate reliability statistics and valuations. It also produces reports that align with the network performance criteria in Section 5 and Section 6 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 thing's such as improved outage notification systems and the changed NZCC22 disclosure requirements.

The work undertaken over the last 12 months includes:

- Valuation calculations rewritten to reflect the changes that Commerce Commission Decision NZCC 22 has required.
- Valuation reporting modified to enable values to be dissected for different requirements.
- Other minor developments to make system use easier and the information available more reliable.
- Integration between Gentrack and BASIX.
- Commencement of a project to get LV connectivity down to ICP level.
- Annual Planning spread sheets being transferred into BASIX – tuned further.
- Tools for entering all incoming network customer 'no power calls' and linking of these to asset fields.
- Initial development of a customer focused outage notification system.
- SMS system reporting.

The work planned includes:

- Further breakdown of network complaints and reporting.
- Other customer service related developments.
- Other reports and data required by the Commerce Commission as part of a quality CPP submission. This will involve a more detailed analysis of outages and allocation of outages to the capital works programme.
- Other system development to gain more efficiency.
- On-going development of a Safety Management System data and information for compliance with the Electricity (Safety) Regulations, 2010.
- Development of the job control system to allow forward spends estimates to be put into the package and link projects. The objective of this is to empty further data silos sitting in spread sheets. This development will be relatively complex in terms of reporting requirements, in particular those required to provide links with the accounting system and Commerce Commission reporting.
- Investigating and preparation of specifications for putting a mapping system over the top of asset data using a low cost modular package.
- Setting up a linked section to receive and store meter and relay data as part of the development towards an advanced network.
- Capture of low voltage data.
- Modification for changes to Commerce Commission disclosure requirements.

Assets are broken down into components (for example, lines are broken down into poles, cross arms and spans) and photographs are attached to these records. The asset type, capacity and condition are recorded along with a considerable number of other data fields.

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.

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. Integrating however will lead to some (relatively minor) labour savings.

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.

2.7.2 Financial Forecasts

An array of spread sheets were originally set up to generate the long-term work plans. The data used in putting together the long-term forecasts comes from the asset databases, photographs, and network knowledge. For example, the hazard elimination/minimisation section of the forward forecasts was put together and prioritised by looking at over 600 photographs of equipment and using a network overview of the alternative arrangements to determine priority. Equipment age, condition, environmental factors, location, and other factors were considered.

A complex series of linking and allocation masks were used over the top of the detailed spread sheets to group work into equipment categories and Commerce Commission disclosure formats. It was recognised that a more stable IT platform was required and the transfer of these long-term estimates to the BASIX system has now been completed. Looking forward, this will significantly improve TLC's asset management estimates and reporting processes.

2.7.3 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. A project to improve the quality of LV data has been instigated and work continues to break assets into smaller items to improve detail.

The starting point for the transfer to the BASIX system was the 2004 ODV data.The errors found at the time of transfer include:

- Records of poles and related span lengths not being correct.
- Asset age estimates of remote rural lines not being correct.
- Lumping of substation assets into groupings and when these are broken down the value of the individual totals sums to a greater amount, with a different average age.
- Items that had previously not been included, such as short lengths of cable between poles and ground mounted transformers.
- Private responsibility lines were included in the data.
- Poles and equipment that had been replaced having incorrect age information.
- Missed equipment, such as reclosers and automated switches.

These errors continued to be corrected and the effects flow into the annual regulatory valuation calculations made up until the 2009/2010 calculation.

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.

Base data and models are now generally accurate in the following areas:

- Overhead Lines and associated equipment
- Zone Substation Buildings
- Zone Substations up to 66kV
- Zone Substation Transformers
- 33kV Zone Substation Switchgear
- 11kV Zone Substation Switchgear
- Distribution Lines
- Distribution Cables
- Distribution Transformers
- LV Reticulation
- SCADA and Communication
- Load Control
- Capacitors

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 50% of the network. For the remainder, the accuracy is limited and based on the area and pole type.

Data is not accurate for:

- Low voltage overhead Conductor.
- Overhead and underground Consumer Service Connections.
- LV Underground Cable.
- LV Street Lighting.
- Some SCADA and communication equipment.

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 case remains, complex. The best reference to get a better understanding of the issues is a paper on this subject produced by the Electricity Authority. The paper is available from the website.

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 improving and it took a major step forward with the transfer from old data systems to the BASIX system. Correcting and maintaining data is an on-going task.

The BASIX system includes a connectivity model that is used for outage reporting. As further discussed in subsequent sections, 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. However, due to the high level set up of the BASIX outage calculator inaccuracies in outage data may develop when the calculator is configure to comply with the new NZCC 22 disclosure rules.

The feeling of independent auditors of regulatory data confirm TLC's opinion that data inaccuracies have caused assets to be undervalued, not overvalued. The biggest risk to overvaluing comes from the costs of internal contractors doing renewal and capital expenditure work using live line and generator by pass approaches. The recently proposed Commerce Commission disclosure changes will also mitigate this risk if they are implemented. The development of a calculator within BASIX with data coming from national industry survey data is seen as a key strategy to minimise this risk.

2.7.4 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.

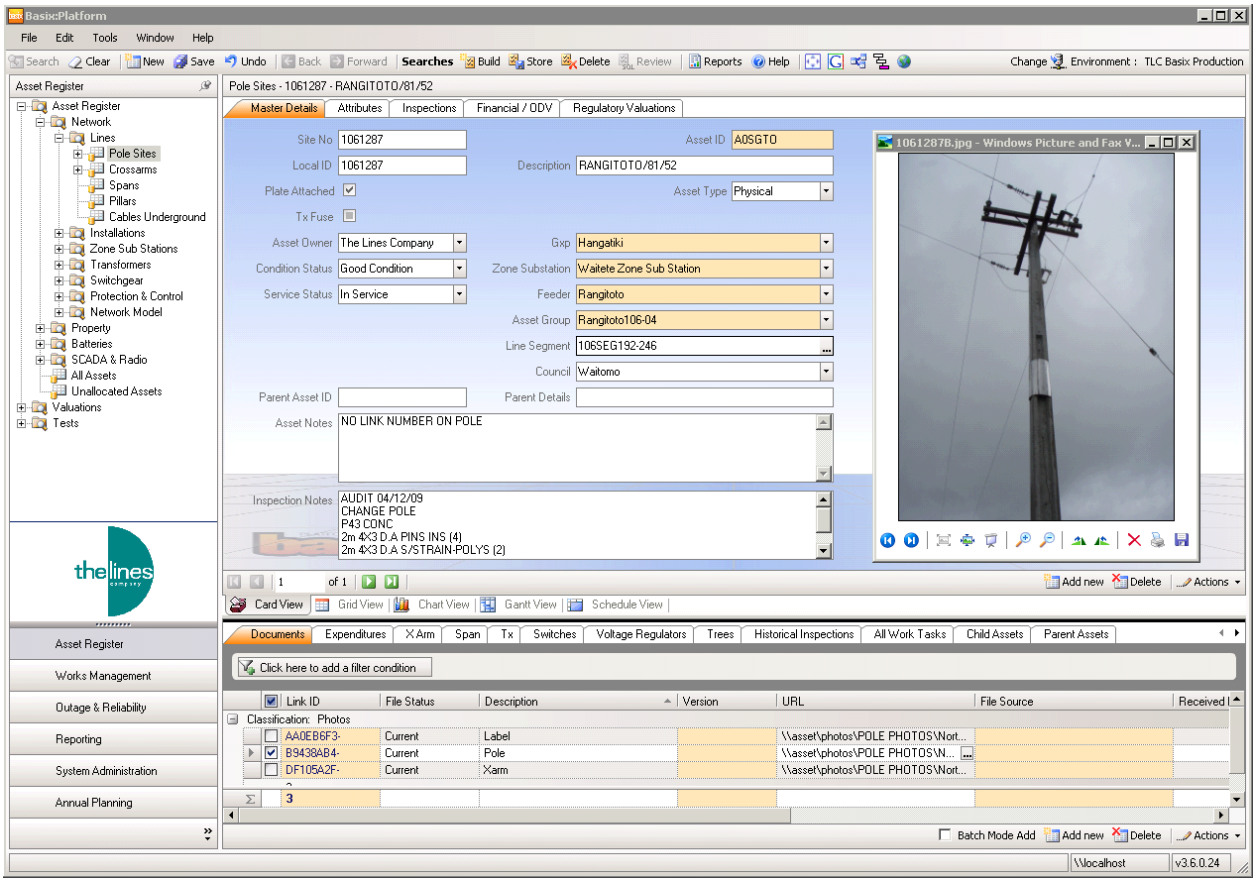


FIGURE 2.4: EXAMPLE OF BASIX POLE DATA SHOWING LINK TO ATTACHED PHOTO

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.

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. The reliability calculator includes the facility to produce Commerce Commission Decision 685 information.

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. (Note: The linked program may not be ESRI.)

TLC is now undertaking all customer telephone answering services in-house, 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.

An improved customer service has been delivered by an in-house call centre. Local knowledge in reconciling faults to customers, manually at present, has seen many network problems being addressed further and more efficiently.

2.7.5 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 (SWER, Ground mount, Pole mount).
- Zone substations (Planned, Unplanned, Buildings, Oil etc.).
- Faults (33kV, 11kV, LV, Zone subs).
- Vegetation (Planned and Unplanned).
- Other technical equipment (SCADA, Communications, Reclosers, Protection, Regulators, etc.).

Both the renewal and maintenance plans extend to 2027/28 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.

Because of the old network, TLC needed to get a good understanding of expenditure needs into the future. TLC is also facing issues such as the need to fund continuance of supply to remote rural customers beyond 2013 and the implications of being an organisation that is regulated under Commerce Commission legislation.

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 and control 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.

More detail is given on the specific processes for each asset class in subsequent sections.

2.7.6 Overhead Lines: Routine Asset Inspections and Network Maintenance

2.7.6.1 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. Further discussion on the justification for this programme is included in Section 6, Lifecycle Asset Management.

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. Load 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 load 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.

2.7.6.2 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 and Engineering 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 and Engineering 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.

2.7.7 Ground Mounted Transformers: Routine Asset Inspections and Network Maintenance

2.7.7.1 Planned Work and Information: Ground Mounted Transformers

Ground mounted transformers are inspected on a five yearly cycle and major maintenance is scheduled every 15 years. 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 five and 15 year inspection and maintenance cycles are currently being managed by the BASIX system.

The BASIX system includes all data associated with outage calculations and the asset values associated with ground mounted transformers.

2.7.7.2 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.

2.7.8 Zone Substations

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

These systems include the following.

2.7.8.1 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.

The BASIX system currently includes data for calculating outages and asset values associated with zone substation transformers.

2.7.8.2 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.

2.7.8.3 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.

2.7.8.4 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.

As stated in each of the component sections, the BASIX system contains the valuation and outage calculation data. The data are arranged in hierarchical segment sections.

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

2.7.9 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 (as explained in previous sections) and as a special project. The special project involves using more skilled labour to trace out the circuits and correctly record assets.

This data are 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 are 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 service 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.

2.7.10 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. Historically distribution voltage tapping and phasing data have not been stored. Moving forward, systems are to be developed to include this functionality.

2.7.11 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.

2.7.12 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.

2.7.13 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 are 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.

2.7.14 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. As a consequence, the boxes were initially inspected in 2003/04 and urgent repairs completed. Pillar boxes are now being 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.

2.7.15 Processes for Planning and Implementation of Network Development Projects

As outlined previously, TLC has formulated a network development plan out until 2028. 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 are 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.

2.7.16 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.

2.7.17 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. Further discussion on these issues is included in later sections. At presently hardcopy and electronic filing systems are used to manage distributed generation applications in compliance with the regulations.

A number of the applications TLC currently has underway have triggered complex legal processes controlled by the Electricity Authority.

2.7.18 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.

2.7.19 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.

The detailed justification for each network project is submitted to Directors for approval in the Annual Plan. Variations are also submitted. Once approved, detailed designs, specifications and landowner arrangements are completed as part of the project costs. Once finalised, these plans are forwarded to contractors 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.

More detail 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.

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.

2.7.20 Processes for Measuring Network Performance for Disclosure Purposes

Preparing disclosure reports for performance measuring and evaluation has often been a stressful process. To minimise this staff pressure, and maximise organisational efficiency, TLC has been developing processes to increase the automation of reporting. This also has other advantages including minimisation of errors, provides consistent information, is backed up by documented specifications and reduces the risk of a single staff member leaving with key intellectual knowledge that is difficult to replace.

Good progress has been made with this, especially with the BASIX system over recent years and continuous development/improvement is taking place.

2.7.20.1 Financial Performance

The policy is to review financial performance of all levels of network operations, including income and costs on a monthly basis. 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.

Annual financial disclosure information comes from the financial system. The financial system includes the normal inputs of debtors, creditors, payroll etc. The system is progressively being developed to produce outputs aligned to disclosure regulatory requirements with minimal spread sheet manipulation.

The schedules as per the Electricity Distribution (Information Disclosure) Requirements 2012 that the financial system provides information for include:

- Schedule 1: Analytical Ratios
- Schedule 2: Report on Return on Investment
- Schedule 3: Report on Regulatory Profit
- Schedule 4: Report on Annual Regulatory Valuation Roll-Forward
- Schedule 5: Report on Regulatory Tax Allowance
  Report on Related Party Transactions
  Report on Term Credit Spread Differential Allowance
  Report on Cost Allocations
  Report on Asset Allocations
  Report on Supporting Cost Allocations
  Report on Transitional Financial Information
  Report on Initial RAB Adjustment
- Schedule 6: Report on Capital Expenditure for the Disclosed Year
  Report on Operational Expenditure for the Disclosed Year
- Schedule 7: Comparison of Forecasts to Actual Expenditure
- Schedule 8: Report Billed Quantities and Lines Charge Revenues
- Schedule 11: Report on forecast Capital Expenditure

2.7.20.2 Customer Information

The billing system Gentrack is used to produce customer information for disclosure performance information. The schedules as per the Electricity Distribution (Information Disclosure) Requirements 2012 that the billing system produces information for is:

- Schedule 9e: Report on Network Demand

2.7.20.3 Valuation

A valuation calculator has been set up in the BASIX system to produce valuation information in line with disclosure requirements. In addition, this system uses the asset data to produce accounting valuations. The valuation calculation is complex and uses data from multiple fields to produce the various valuations.

The schedules as per the Electricity Distribution (Information Disclosure) Requirements 2012 that the BASIX valuation produces data for include:

- Schedule 3: Report on Regulatory Profit
- Schedule 4: Report on Annual Regulatory Valuation Roll-Forward
- Schedule 5: Report on Regulatory Tax Allowance
  Report on Initial RAB Adjustment
- Schedule 6: Report on Capital Expenditure for the Disclosed Year
  Report on Operational Expenditure for the Disclosed Year
- Schedule 7: Comparison of Forecasts to Actual Expenditure
- Schedule 11: Report on forecast Capital Expenditure

2.7.20.4 Network Information

The BASIX system, SCADA logs, Billing System, Network Analysis and Transpower Accounts are used to complete the network data section of the Electricity Distribution (Information Disclosure) Requirements 2012 network information schedules.

These include:

- Schedule 10: Report on Network Reliability

Specifically:

- Circuit length by Operating Line Voltage (at year end): BASIX
- Overhead Circuit Length by Terrain: BASIX
- Transformer Capacity: BASIX
- Systems Fixed Assets age: BASIX

Electricity Demand and Volumes:

- *System Demands:* SCADA Logs, embedded generation data and Transpower demand data.
- *Large Customers:* Metering Data.
- *Electricity Carried:* Transpower and Metering Data.
- *Network Losses:* Network Analysis Software and Reconciliation Manager Reports/Data
- *Numbers of Connection Points:* Basix
- *Intensity of Services:* Self filling

2.7.20.5 Expenditure Forecasts and Reconciliation

The expenditure forecasts are developed in BASIX and broken down into individual jobs and items. This planned and forecast expenditure is allocated to disclosure categories. Actual expenditure data is manually entered from the financial system.

The schedules as per the Electricity Distribution (Information Disclosure) Requirements 2012 that the job planning system produces information for includes:

- Schedule 7: Comparison of Forecasts to Actual Expenditure

2.7.20.6 Reliability Reporting System

Reliability reporting is 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 logs. The data are entered, run and checked every few days. The results are reconciled to control room data. Monthly performance reports are generated and reviewed at both management and Director level. Customer numbers are updated regularly from the billing database.

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 system to produce the regulatory and internal performance data, including Commerce Commission Decision 685 reports.

The schedules as per the Electricity Distribution (Information Disclosure) Requirements 2012 that the reliability reports (BASIX) system provides information for include:

- Schedule 10: Report on Network Reliability

2.7.21 Processes for Measuring Other Performances

2.7.21.1 Contractor Performance

Contractor work practices and quality are monitored for both network and private line connections. Contractors are not paid until they have completed works to specifications.

If construction audits reveal work standards are not meeting industry hazard control expectations, contractors' network access is cancelled. The contractor then has to submit details of how systems are going to be put in place to overcome these deficiencies before they are reinstated. Rework levels are monitored, as is SMS compliance.

2.7.21.2 Customer Service Levels

The BASIX system is used to report on the customer service levels as described in Section 5 and reported in Section 6. These include time to restore supply and maximum number of shutdowns.

Software calculators and reports have been set up to produce monthly and annual reporting on these performance indicators. Considerable effort is put into ensuring that the input data are accurate and timely so that these reports are correct.

The telephone system provides reports on the number of calls and unanswered calls.

2.7.21.3 Customer Consultation

Customer Service Representatives record the number of customer clinics and focus group meetings that they are involved in annually. The number of customers attending and the number of presentations made by the Customer Services Manager explaining TLC's pricing methodology and advice on reducing kW load for individual customers are recorded.

2.7.21.4 Asset Performance Targets

The BASIX system is used to measure voltage complaints and system component failures. The network analysis and Annual Plan is used to determine and measure the number of legacy network voltage issues addressed.

Harmonic levels are measured using a high voltage clip-on sensor link meter. Results are currently recorded by the Design Engineer.

2.7.21.5 Asset Efficiency Targets

Network technical losses are calculated using models that include the effects of generation. The data supplied by retailers on non-technical losses has been shown over the years to have very limited accuracy. To get around this problem TLC pays a Reconciliation Manager to produce data that show the energy sold by balancing areas (as defined in Electricity Governance Rules) and grid exits. TLC takes these data and subtracts them from the technical losses to determine non-technical losses.

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

2.7.21.6 Asset Effectiveness Target

Network incidents/accidents are measured from the incident reports submitted to the HR section. The number of hazards removed from the network each year is measured when actual works are reconciled with forecasts.

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.

2.7.21.7 Lines Business Activity Efficiency Targets

Most of the other asset reports are based on disclosure information. The sources of disclosure information are discussed previously.

Most of the disclosure data comes from the BASIX and financial systems. An objective of our system development is to produce these outputs directly from system reports without any additional spread sheet calculation, maximising accuracy by minimising the risk of errors. We are close to achieving this.

In summary, the financial based targets are reported from the Navision (financial) system, customer numbers from the billing (Talgentra) system and asset information, including reliability, from the EMS BASIX system.

2.8 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 l be further refined. For example large customers are currently charged on kVA demand, smaller customers kW demand. When single phase and small three phase meters are available to give kVA demand at smaller sizes, TLC will move to charging on kVA. (This encourages customers to improve power factor.) Similarly, 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.

2.9 All Significant Assumptions

2.9.1 Growth Funding

2.9.1.1 All Significant Assumptions, Clearly Identified in a Manner that makes their Significance Understandable to Electricity Consumers and Quantified where possible

It has been assumed the cost of developing the network for growth and customer connections, other than a few "catch up projects," will be financed by the additional income from the increased customer demand.

2.9.1.2 The Basis on which Significant Assumptions have been Prepared, including Principal Sources of Information from which they have been derived

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 investment needs to produce returns that are bankable.

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.

2.9.1.3 The Assumptions Made in Relation to these Sources of Uncertainty and the Potential Effects of the Uncertainty on the Prospective Information

If growth as assumed does not go ahead, then other than a few catch-up projects, 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.

Load growth estimates, and actuals, over recent years are detailed in the Asset Management Plan. Overall, a conservative approach has been taken to growth. The most likely variation will be greater growth in some parts of the network driven by specific commercial activity, e.g. milk processing.

2.9.2 Continuance of supply

2.9.2.1 All Significant Assumptions, Clearly Identified in a Manner that makes their Significance Understandable to Electricity Consumers and Quantified where possible

The 2010 Electricity Act has been amended in a way that requires TLC to continue to operate uneconomic lines.

2.9.2.2 The Basis on which Significant Assumptions have been Prepared, including Principal Sources of Information from which they have been derived

The principal source of information for developing this assumption is the contents of the Act.

2.9.2.3 The Assumptions Made in Relation to these Sources of Uncertainty and the Potential Effects of the Uncertainty on the Prospective Information

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.

The present pricing structures means there is an element of cross-subsidisation between urban and rural customers, (approximately 30%); if this were to be removed remote customers would see an increase of about 100% in there charges.

2.9.3 Distributed Generation

2.9.3.1 All Significant Assumptions, Clearly Identified in a Manner that makes their Significance Understandable to Electricity Consumers and Quantified where possible

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 assumed that industry rules will be formatted in such a way that grid connected and distribution connected generation face a similar matrix of costs. (This is currently not the case.) It is also assumed that existing load taking customers will not be penalised in a way that cross subsidises the connection of generation.

2.9.3.2 The Basis on which Significant Assumptions have been Prepared, including Principal Sources of Information from which they have been derived

This assumption is based on government policy statements and the lack of rules to cover some of the complex technical issues associated with connecting distributed generation.

It has also been assumed that the regulators will want to make the connection of generations equitable between transmission and distribution networks.

The principal sources of information for developing these assumptions are:

- Government policy statements.
- Electricity Governance Rules
- Transmission connection charges.
- Various papers produced by officials.
- Network studies showing the effects of distributed generation.

2.9.3.3 The Assumptions Made in Relation to these Sources of Uncertainty and the Potential Effects of the Uncertainty on the Prospective Information

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.

If regulators accept that grid exit power factors with generation connected will be lower, but the same amount of reactive power would have to be supplied into that point with or without the active power injection, then there would be no additional revenue requirements (status quo).

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.

2.9.4 Demand side management and peak control

2.9.4.1 All Significant Assumptions, Clearly Identified in a Manner that makes their Significance Understandable to Electricity Consumers and Quantified where possible

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.

2.9.4.2 The Basis on which Significant Assumptions have been Prepared, including Principal Sources of Information from which they have been derived

This assumption is based on the fact that power systems have to be designed for peak capacity.

Increased power system efficiency and minimisation of investment comes largely by minimising demand. Power factor is also directly related to power system efficiency and is part of demand side management. Losses and investment are minimised if power factors are close to unity and demands are controlled.

This assumption is based on the information that suggests investors will want to minimise costs for network development, i.e. customer connection and growth development costs.

All stakeholders want costs controlled and environmental lobbies want losses minimised. Power factor and changing demand behaviour affects losses.

The initial results of data analysis are indicating that TLC's demand side management signalling through financial signalling is effective. The forecasts in the Asset Management Plan assume this effect continues. Section 5 of the Plan includes some initial forecasting work on the effects if TLC did not adapt this strategy. This work suggests that without demand side management many more network components would be beyond their capacity limits by the end of the planning period. Indications are that the benefits of demand side management have the potential to be significant.

2.9.4.3 The Assumptions Made in Relation to these Sources of Uncertainty and the Potential Effects of the Uncertainty on the Prospective Information

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.

This assumption is based on the initial data available. 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. Initial analysis work completed at the time of writing indicates that a growth greater than forecast will cause significant system strengthening expenditure to be triggered. (See Section 5 of AMP for further details on this work.)

Customers' reaction to demand side management signals to date has been encouraging. Retailers have yet to introduce energy rates that provide reasonable incentives for customers to manage their demands further.

Because demand billing is unique and new to many customers (even though it was extensively used down to relatively small commercial customers up until the Bradford reforms in the early 1990s, the concept has generally been ignored industry wide since this time), most have trouble understanding the concept and TLC has incurred criticism from some.

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.

2.9.5 Economic activity

2.9.5.1 All Significant Assumptions, Clearly Identified in a Manner that makes their Significance Understandable to Electricity Consumers and Quantified where possible

It has been assumed that economic activity based on primary production and processing will continue to develop. The Asset Management Plan assumes land use development in a gradual, slow way. That is, the forward assumptions include allowances for existing dairying land being converted back to dry stock farming and vice versa. 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 electrical equipment involved can also introduce harmonics and cause power factor attenuation). The forward land use assumption does not include large scale development of irrigation.

2.9.5.2 The Basis on which Significant Assumptions have been Prepared, including Principal Sources of Information from which they have been derived

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 and recognising the demand the various processing within the plant creates.

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.

2.9.5.3 The Assumptions Made in Relation to these Sources of Uncertainty and the Potential Effects of the Uncertainty on the Prospective Information

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. Reducing renewals will involve stakeholders accepting that they will be operating and accepting liabilities associated with a network that contains hazards that should be eliminated or minimised.

2.9.6 Reliability and quality

2.9.6.1 All Significant Assumptions, Clearly Identified in a Manner that makes their Significance Understandable to Electricity Consumers and Quantified where possible

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. (These will be subject to customer consultation in compliance with Commerce Commission Customised Price Path requirements).

2.9.6.2 The Basis on which Significant Assumptions have been Prepared, including Principal Sources of Information from which they have been derived

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.

2.9.6.3 The Assumptions Made in Relation to these Sources of Uncertainty and the Potential Effects of the Uncertainty on the Prospective Information

The forward plans include projects totalling about $200,000 to $500,000 p.a. for reliability development (mostly automated switches). If stakeholders do not want a gradual improvement in reliability, then this expenditure could be eliminated.

2.9.7 Hazards

2.9.7.1 All Significant Assumptions, Clearly Identified in a Manner that makes their Significance Understandable to Electricity Consumers and Quantified where possible

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. Plans are in place to reduce network hazards over the planning period. It is assumed that there will be no stepped inputs to significantly alter this plan. The Asset Management Plan includes specific sites and conceptual design detail.

2.9.7.2 The Basis on which Significant Assumptions have been Prepared, including Principal Sources of Information from which they have been derived

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.

2.9.7.3 The Assumptions Made in Relation to these Sources of Uncertainty and the Potential Effects of the Uncertainty on the Prospective Information

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.

2.9.8 Pricing

2.9.8.1 All Significant Assumptions, Clearly Identified in a Manner that makes their Significance Understandable to Electricity Consumers and Quantified where possible

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.

2.9.8.2 The Basis on which Significant Assumptions have been Prepared, including Principal Sources of Information from which they have been derived

The assumption is based on the regulators and stakeholders continuing to encourage efficient network development and for revenue to reflect cost drivers.

2.9.8.3 The Assumptions Made in Relation to these Sources of Uncertainty and the Potential Effects of the Uncertainty on the Prospective Information

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. The present pricing structures also encourage demand side responses such as power factor correction.

A change in the structure would increase the risks to revenue in the future during energy shortages or greater uptake of solar panels etc.

2.9.9 Inflation

2.9.9.1 All Significant Assumptions, Clearly Identified in a Manner that makes their Significance Understandable to Electricity Consumers and Quantified where possible

It has been assumed that inflation will continue through the planning period.

2.9.9.2 The Basis on which Significant Assumptions have been Prepared, including Principal Sources of Information from which they have been derived

The rate of inflation for cost increases has been based on recent CPI figures. The assumption is based on published CPI data.

2.9.9.3 The Assumptions Made in Relation to these Sources of Uncertainty and the Potential Effects of the Uncertainty on the Prospective Information

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.)

2.9.10 Performance Measures

2.9.10.1 All Significant Assumptions, Clearly Identified in a Manner that makes their Significance Understandable to Electricity Consumers and Quantified where possible

It has been assumed that stakeholders want development of performance measures that align with customer expectations.

2.9.10.2 The Basis on which Significant Assumptions have been Prepared, including Principal Sources of Information from which they have been derived

It is considered important that performance measures are in place to quantify performance in a way that aligns with stakeholders' expectations.

The principal sources of information from which they are derived include:

- Terms and Conditions of Supply.
- 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.

2.9.10.3 The Assumptions Made in Relation to these Sources of Uncertainty and the Potential Effects of the Uncertainty on the Prospective Information

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.

2.9.11 Customers Ability to Pay

2.9.11.1 All Significant Assumptions, Clearly Identified in a Manner that makes their Significance Understandable to Electricity Consumers and Quantified where possible

It has been assumed that customers in the King Country are not affluent and have limited ability to pay increasing line and energy charges.

2.9.11.2 The Basis on which Significant Assumptions have been Prepared, including Principal Sources of Information from which they have been derived

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.

2.9.11.3 The Assumptions Made in Relation to these Sources of Uncertainty and the Potential Effects of the Uncertainty on the Prospective Information

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. This means that forward expenditure predictions may be greater than the actual cost of completing work.

2.9.12 Other Significant Assumptions

2.9.12.1 Considerations associated with adverse events

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.

2.9.12.2 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.

2.9.13 The price inflator assumptions used to prepare the financial information disclosed

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.
- The average of the last 3 year CPI factors (2.01%, 4.50%, and 1.57%) is 2.69%.
- Given the above, it was decided 2.5% would be appropriate.

2.10 Asset Management Maturity Assessment Tool

Information Disclosure Determination Decision No. NZCC 22 states EDB's must complete an Asset Management Maturity Assessment Tool (AMMAT) which has been developed to assess the maturity of EBD's asset management system. The Asset Management Maturity Assessment Tool (AMMAT) has been developed to assess the maturity of EBD asset management systems. The tool consists of a self-assessment questionnaire which is derived from PAS55:2008. This has highlighted key area in the asset management system that TLC will need to improve in, this means that engineering resources will be consumed when updating the asset management system.

The questionnaire covers the following topics:

- Asset Management Policy
- Asset Management Strategy
- Asset Management Plan
- Contingency Planning
- Structure, Authority and Responsibilities
- Outsourcing of Asset Management Activities
- Training, Awareness and Competence
- Communication, Participation and Consultation
- Asset Management System documentation
- Information management
- Risk Management Processes
- Use and Maintenance of Asset Risk Information
- Legal and other requirements
- Life Cycle Activities
- Performance and Condition Monitoring
- Investigation of Asset Related Failures, Incidents and Nonconformities
- Audit
- Continual Improvement

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

Figure 2.5 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)

FIGURE 2.5: AMMAT MATURITY RATING SCALE

Figure 2.6 shows TLC current self-assessed score for the 2013/14 AMMAT and forecast score for 2014/15.

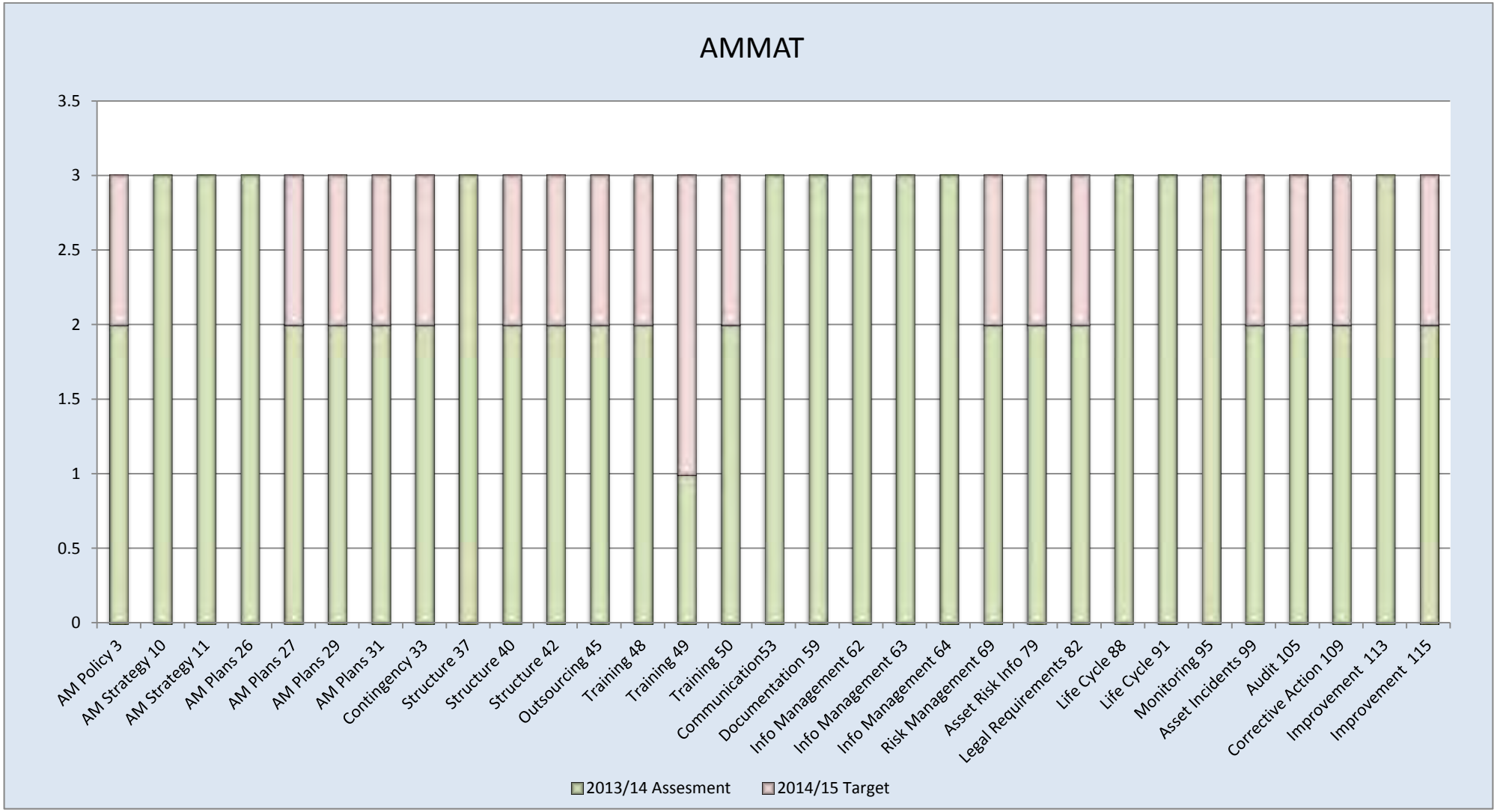


FIGURE 2.6: CURRENT SELF-ASSESSED SCORE FOR THE 2013/14 AMMAT AND FORECAST SCORE FOR 2014/15.

2.10.1 Overview of Asset Management Strategy and Delivery

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. TLC's AMP makes up part of the Asset Management Policy and it is derived from, and is consistent with TLC's Statement of Corporate Intent. The Policy is consistent with other organisational policies and the risk management framework. The Policy is reviewed and updated every 12-18 months by the TLC Board of Directors.

When establishing the 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.

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 reviews individual requirements in terms of risk identification, including the availability of information and implementation practicalities of reduction strategy.

Both the 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. 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. An electronic copy of the AMP is also available for customers and members of the public to download from the TLC website and bound paper copies are available by request. TLC keep a record of all Asset Management Plans it sends out.

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 Engineering Manager is responsible for overall network management, including the preparation, drafting, and all aspects of implementation of the AMP.

TLC endeavours to align the staff numbers, structure and skills to ensure an efficient and cost effective implementation of the asset management plan; however due to the changing environment these are under continuous review. TLC has resources in place for the implementation of the asset management plan. Due to the difficulty of attracting staff to the King Country, industry skill shortage and the increasing regulatory requirements it is not always possible to have the required staff numbers.

2.10.2 Overview of Systems and Information Management Data

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.

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.

2.10.3 Overview of Asset Management Documentation, controls and review processes

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. TLC recognises and understands the need for a systematic check, especially of the effectiveness of its asset management process. The asset management procedure, distribution standard and operating procedure are reviewed every 12-18 months. Changes to the procedures and processes are made to reflect the outcomes of the review.

Most asset management tasks, including asset inspection, are undertaken in-house by the AMG staff. AMG engineers 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.

2.10.4 Overview of Communication and Participation processes

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 consolidated financial statements for the reporting period are delivered to the shareholders. TLC also supplies its shareholders with auditors' report on the financial statements 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.

2.10.5 Asset Management Improvements

Going forward TLC's focus is on improving the asset performances as well as improving the asset management, planning and information systems that support the assets. This includes planning and documenting the asset management systems in more detail. The conclusion is that to meet or surpass the standard (PAS 55:2008) in the most effective way the following items need to be achieved:

- Make it clear who is responsible for which element of the assessment tool;
- Develop and document processes for assessing staff competency levels and provide employees with the necessary training and skill set to competently do their work. (At present a young team that need a lot of "experience" training.)
- Develop and document audit procedures for appropriate asset related activities, including having mechanisms in place to systematically investigate, prevent and correct non conformities, incidents identified by investigations, compliance evaluations or audits (ISO-type approach).

Section 3

3. ASSETS COVERED

3.1 A High Level Description of the Distribution Area

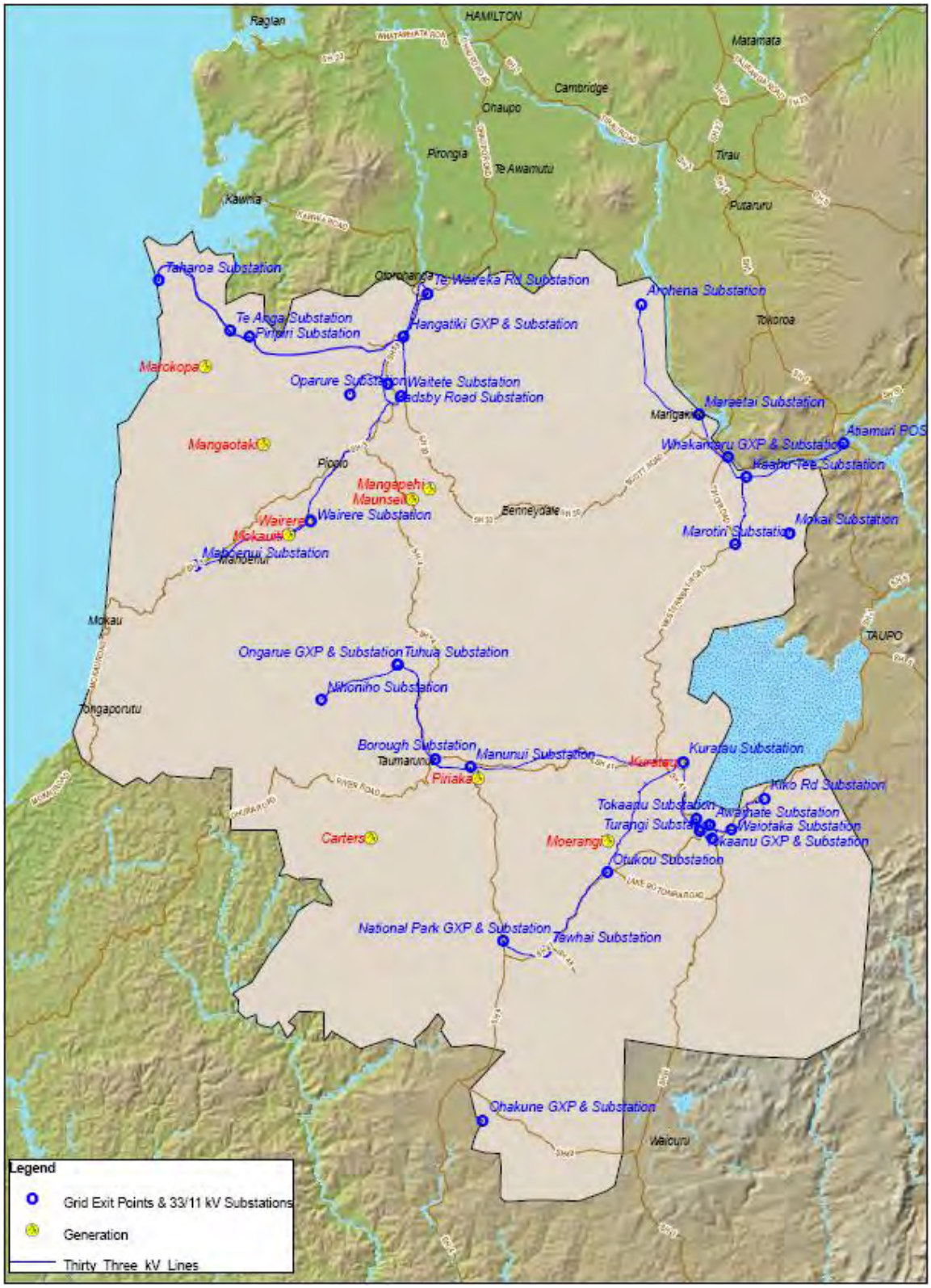


FIGURE 3.1: DISTRIBUTION AREA COVERED BY TLC NETWORK

3.1.1 Distribution Areas Covered

Figure 3.1 illustrates the distribution area covered by The Lines Company network. Also illustrated are 33 kV sub-transmission lines, Transpower grid exit connections, and major generator supply points and embedded generators. The distributed generators are indicated by the arrows in a yellow circle symbol.

The north-western part of the area starts on the south side of the Kawhia harbour and extends to the south-western corner is Mt Messenger. From this point the network area to the east 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. The area then 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.

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. (Note: The 'Point of Connection' can be different to the 'Point of Supply' as defined in various sections of legislation). The point of demarcation between customers and network assets can be complex and difficult to define in legislation. Much of this difficulty is because the various amendments to Acts and Regulations over the last 40 years have not been consistent 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.

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 number of Single Wire Earth Return (SWER) systems (60 plus).
- Significant area is supplied directly from major Waikato generation plants bypassing Transpower grid exit points (GXPs). (Note: A new 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 number 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 special 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 and close conductor spacing with 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.

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 20% or approximately 800km.

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.

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.

3.1.3 Large Customers that have a significant impact on network operations and management priorities

The large customers that have a significant impact on network operations and management priorities fall into two groups, customers that draw load from the network and those that generate into the network.

3.1.3.1 Large load taking customers who have a significant impact on network operations

a.	**Business:**	**Iron sands extraction** Iron sands processing and ship loading.
	Location:	Taharoa
	Dedicated Assets:	Approximately 100km of heavy 33 kV line, one zone substation and two Transpower grid exit circuit breakers.
	Impact on TLC Network:	The plant has a steady mining load of about 3 MW that increases to 8MW at interval of 5 to 6 weeks during ship loadings over a four day period. It is during these periods that the Hangatiki grid exit system peak loads occur. The zone substation at Taharoa has been constructed on a west coast iron sand beach. The maintenance and renewal requirements for the site are high. The amount of dedicated asset, the income received from this, the size of peaks and the amount of maintenance required ensuring assets are reliable to have significant impact on network operations. 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 to three years. The mining load will increase to 7.5MW by end of 2013; therefore the projected site load will be approximately 15MW.
b.	**Business:**	**Ski Fields** Operators of Whakapapa and Turoa Ski field chairlifts, ski field facilities and snow making
	Location:	Mt Ruapehu
	Dedicated Assets:	One Zone Substation. Approximately 25km of on-mountain cables, 40 ground-mounted transformers, 11 kV on-mountain switchgear, 4 regulators, and 5km of 11 kV lines.
	Impact on TLC Network:	An additional 6 MVA (approx.) of winter peak load is added to 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.

c.	**Business:**	**Corrections Department**
	Location:	Hautu and Rangipo Prisons.
	Dedicated Assets:	Approximately 15km of 11 kV overhead lines. 33/11 kV modular zone substation.
	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.
d.	**Business:**	**Limestone extraction and processing**
	Location:	Six plants at several locations surrounding Te Kuiti
	Dedicated Assets:	One 3 MVA 33/11 kV substation, 7km of 33 kV lines, approximately 15km of heavier 11 kV line, onsite distribution transformers and switchgear.
	Impact on TLC Network:	Have a combined load of about 8 MVA. Operating loads tend to be seasonal and dependent on orders. Connected plant consists of mainly large motors that tend to reduce network power factor. These loads add to autumn loads.
e.	**Business:**	**Meat Processors**
	Location:	Two plants on Te Kuiti urban boundary and a third plant at the end of two 40km long 11 kV feeders.
	Dedicated Assets:	Four regulators, distribution transformers and associated 11 kV switchgear. Approximately 5km of heavier overhead line.
	Impact on TLC Network:	Combined load of about 7 MVA. Plants on town boundaries are connected to 11 kV feeders. Reclosers are located on these feeders just beyond the plant Point of Connection. The object of these reclosers is to isolate the sections of rural line when faults occur beyond the plants. The plants are, however, sensitive to switching surges and discussions are underway to provide the plants with dedicated 33/11 kV zone substations to reduce voltage sag. The 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.
f.	**Business:**	**Timber Processors**
	Location:	Two plants on Te Kuiti urban boundary. One plant at Tangiwai. Several smaller plants at Taumarunui and Otorohanga.
	Dedicated Assets:	Local distribution transformers and switchgear. Approximately 5km of dedicated 11 kV line at Tangiwai.
	Impact on TLC Network:	Two Te Kuiti plants have a combined load of about 5 MVA. The plants are connected to the 11 kV network and are sensitive to feeder faults, auto recloses, and surges beyond the connection points.

g.	**Business**	**Energy Park: Milk Plant: Glasshouses: Reinjection Pumps**
	Location:	Mokai
	Dedicated Assets:	Local distribution transformers; fault reducing transformer; 3 11 kV metering units; approx. 3 km of heavy cable; 11 kV switchgear and ring mains; approx. 7 km of 11 kV overhead lines; reclosers; automated 11 kV switches and related RTU's.
	Impact on TLC Network	The 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.

3.1.4 Generation Customers that have an impact on network operations

The connection of generation to networks quickly adds complexity.

Examples of the issues include:

- Islanding.
- Voltage fluctuations.
- Alters network voltage profiles.
- Frequency fluctuations.
- Auto-reclosing difficulty.
- Self-excitation.
- Protection.
- Current Flows: Positive, negative, zero sequence and fault currents.
- Resonance.
- Increased fault capacity.
- Losses.
- Commercial terms of connection.
- Power factor (Distribution network and grid exit).
- Energy reconciliation.
- Network stability.
- Other unusual effects.

Further details on these issues are discussed in later sections of this Plan.

The owners of distributed generation plants usually have little power system engineering expertise and have difficulty understanding the often complex technical issues. Frustration between the network and the generation investors can occur.

The following is a summary of the impact of the various generators' plants on the network operations and asset management priorities. More specific capacity details are included in later sections of this Plan.

a.	**Business:**	**Energy Retailer**
	Location:	Kuratau Piriaka Wairere Falls Mokauiti
	Dedicated Assets:	33 kV lines, two zone substations, 33 kV switching equipment, 11 kV lines, 11 kV switchgear.
	Impact on TLC Network:	This plant was originally owned by local power companies and split out at the time of the Bradford reforms. The plant and network are integrated and designed to be operated as one. Separation did create a reduction in operating and energy delivery efficiency. (Many of the plant controllers and much of TLC's voltage control equipment has been updated over recent years. This has meant that it is now possible to restore some of this efficiency by tuning the new equipment settings in conjunction with the use of TLC's network analysis programme.) These distributed generators have a significant effect in reducing grid power factor. The presences of the plants affect asset management and operational decisions. Each plant has the following summary implications:

Kuratau

Output is normally back through the network to the Ongarue grid exit point. This plant causes the grid exit to run backwards for long periods. The Kuratau generation connection arrangement and controller restricts auto-reclosing on some 33 kV lines. This has caused longer outage times.

This 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 present generator controllers at Kuratau cause some unhealthy surges in combination with the investor owned Moerangi generation on rundown after a line tripping.

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.

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 plant reduces the Ongarue grid exit power factor.

Piriaka

The Piriaka site was the original supply point for Taumarunui. The output is used to maintain network voltages during shutdowns of the Ongarue, National Park, and Tokaanu grid exits.

Over the last year 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.

Wairere Falls

This historic plant was originally built to supply the Piopio area. 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.

Mokauiti

The connection is integrated into that of the Wairere Falls complex. The site has two induction machines that tend to not 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.

b.	**Business:**	**Subsidiary of TLC owned**
	Location:	Mangapehi
	Dedicated Assets:	Regulators, 11 kV lines, complex circuit breaker and regulator settings.
	Impact on TLC Network:	The 2 MW Mangapehi generation has caused a number of technical difficulties that have had to be solved since its initial connection to the network in 2002. 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. Other technical difficulties with this plant have included zero sequence current flow and resonance problems. 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. The plant also causes a reduction in the Hangatiki grid exit power factor.
c.	**Business:**	**Investor owned**
	Location:	Marokopa
	Dedicated Assets:	11 kV line and 11 kV 200 kVA transformer.
	Impact on TLC Network:	The 2 induction machines totalling 200 kVA at the Marokopa site has the following impact on network operations and asset management: » Reduced network and Hangatiki grid exit power factor. » Makes the use of generator by-pass during planned work shutdowns more complex. » Has the potential for self-excitation on rundown.
d.	**Business:**	**Investor owned**
	Location:	Moerangi Station
	Dedicated Assets:	33 kV line, 33 kV/400 V 200 kVA transformer. Lightning arrestors and drop out fuses.
	Impact on TLC Network:	The 2-3 induction machines totalling about 150 kVA at the Moerangi site has the following impact on network operations and grid exit power factor: » Reduced network and Ongarue grid exit power factor. » Has caused network self-excitation and over voltages. » Interacts with the Kuratau KCE plant and some oscillations have occurred that have destroyed electronic equipment in the area.

e.	**Business:**	**Investor owned**
	Location:	Mangaotaki Valley
	Dedicated Assets:	Dropout fuses
	Impact on TLC Network:	Two 75 kW induction machines. The Mangaotaki site has the following impact on network operations and grid exit power factor: » Reduced Hangatiki grid exit power factor. » Makes use of generator by-pass during planned work shutdowns more complex. » Has the potential for self-excitation on rundown. » Uses up all available generation capacity on existing lines in the Mangaotaki Valley area.

f.	**Business:**	**Subsidiary of TLC and Investor Owned**
	Location:	Speedies Road, Te Anga
	Dedicated Assets:	11 kV Lines
	Impact on TLC Network:	The single 2.2MW synchronous machine gas the following impact on network operations and asset management: » Reduced Hangatiki grid exit power factor. » The plant increases network voltages that have to be managed. » The plant causes a reduction in the Hangatiki grid exit power factor. »

3.1.5 Impact of Large Customers on Asset Management Priorities

All large customers have some impact on asset management needs. In TLC's case, there is on-going communication with each of these customers and the long-term asset plans the network has consider the expectations communicated by customers.

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 customers are advised of any hazards observed with equipment around their plants. In most cases, the owners of the plants are responsible for the funding to eliminate or minimise these hazards. The asset management and network operational impacts caused by the presence of these large customers include:

3.1.5.1 Ski Field operators

The ski field operators co-ordinated a process to fund the cost difference between renewing the existing overhead line to the Whakapapa area and undergrounding the 7km of overhead line. This project was completed in 2008. Further development has taken place on the Turoa Ski Field with the installation of ski lifts, snowmaking, and network inter-connected generation.

Both ski fields had, and still have, some higher hazard related risk sites on the ski field. Over the last few years, about 18 have been addressed including the installation of significant amounts of appropriately rated switchgear. This Plan includes estimates for addressing most of the remaining hazards on both sites. The ski field operators are aware of the higher risk sites and the need for the hazard minimisation/elimination program. Reliability to the Ski Fields has improved as a by-product of removing hazardous equipment.

TLC is also working with ski field owners to minimise peak-based charges by operating on-field generation into the network. Alterations to the network over the last six years have been completed in a way that this can be accommodated. The ski field and related accommodation use affect National Park and Ohakune grid exit peak loads. These loads are included in asset management planning. Meat and Limestone Processors, Te Kuiti

Owners of a number of these plants have concerns about voltage sags and reliability. These concerns are leading 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. A number have proposals to eliminate/minimise these hazards. It appears that the current economic downturn is delaying improvements. The ways these changes will affect the network have been included in long-term forecasts and development plans.

The peak meat and lime processor loadings occur 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.

3.1.5.2 Iron sand extraction

The current iron sand extraction process at Taharoa 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. The site is in poor condition and an amount has been allowed for to eliminate/minimise hazards associated with the site. The need to eliminate/minimise hazards and other impacts of the Iron Sand's operation has been considered when developing Asset Management Plans. The plant has recently indicated that it is willing to fund reinvestment as a consequence of forward customer supply contracts.

3.1.5.3 Mokai Energy Park

The Tuaropaki Trust has created an industrial Energy Park on land they own adjacent to the 120 MW Tuaropaki geothermal plant. TLC has constructed a network that interconnects with other assets and supplies energy park customers. The TLC assets include a fault reducing transformer, metering, SCADA, cabling, overhead lines and switchgear. This equipment is used to supply a milk plant and glasshouse in the industrial complex. These loads cannot be back fed totally from the surrounding legacy network. 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.

3.1.5.4 Distributed generation

Most sites connected to the TLC network have some issues and needs that require network engineering attention. However, currently, these issues have 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. This has become possible in recent times as outlined in the earlier part of this section, mostly due to improved network models becoming available.

Specifically, current examples of this are:

Mangapehi: The work to be completed includes the tuning of regulator, protection settings and adjustment of about 20 to 30 local transformer tap settings. A few days of engineering time is required using the analysis package to determine the most effective and efficient settings.

Kuratau: The work to be completed includes adjustment of controllers to stop voltage surges on rundown; 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.

A week of engineering time is required to determine the best way to improve the integration of this plant into the TLC network given the changes that have occurred with controllers in recent times. There have also been some recent tripping events at the site which require further analysis.

Piriaka: The work to be completed includes researching the new 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: As for Kuratau and Piriaka.

Speedies Road: The work to be completed is to 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 period.

Note: All sites have a significant effect on grid exit power factor. (A full explanation of why and how is included in Section 7 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.

The tuning of generator plant will become a higher asset management priority as TLC's analysis models are developed, the generation investors fit modern controllers, TLC renews its regulator controllers, TLC updates its protection and reactive power flows are better managed.

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 region (north western region)

Regional Activities that Affect Load Characteristics

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

Resulting Load Characteristics

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

Limestone and meat processing peaks are seasonal. Both these activities operate for varying periods during 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 a down time between May and August, and two daily peaks when milking is underway.

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 or Waikato River area)

Regional Activities that Affect Load Characteristics

- 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 region occurs early in the dairy season during the overlap of milking and domestic cooking load.

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 that Affect Load Connections

- Holiday homes around Lake Taupo.
- Whakapapa Ski Field.
- Kuratau Distributed Generation.
- Domestic load, Taumarunui.
- Corrections Department load in 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 or 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 load of Taumarunui 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 what the generation is doing during this period. 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 that Affect Load Conditions

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

Resulting Load Characteristics

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

3.1.7 The Peak Demand and Total Electricity Delivered in previous year

The figures on peak demand and energy delivered are based on information from:

- Transpower grid exit metering pulses that go into the SCADA system.
- Whakamaru and Atiamuri large generator connection metering pulses going into the SCADA system.
- Half-hourly metering pulses travelling into the SCADA system from larger distributed generation.
- Estimates for smaller distributed generation and the energy transported between the Winstone Pulp Mill site and the Tangiwai Sawmill.

Table 3.1 lists the total energy transported for non-contiguous, (but abutting) network areas, including estimates for distributed generators and the Winstones arrangement. The 'Average Change (%) p.a.' figures in the table are taken over the last 6 years.

UNITS TRANSPORTED (GWHrs)									
Electrically Non Contiguous Network Note: Network is non-contiguous, but abuts.	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**Average Change (%) p.a.**	**2010/11 - 2011/12 % Change**
Northern	185.64	187.69	191.69	194.60	201.58	204.07	203.74	1.57%	-0.16%
Central	98.80	102.75	103.38	103.47	105.00	104.15	102.54	0.64%	-1.55%
Ohakune	30.75	31.89	32.79	32.92	34.18	33.31	19.28	-5.65%	-42.12%
Total TLC Network	315.19	322.33	327.85	330.99	340.76	341.53	325.56	0.57%	-4.68%

TABLE 3.1: TOTAL ENERGY TRANSPORTED DURING THE 2005/06 TO 2010/11 YEAR

Notes:

1. The Northern and Central areas includes GWHrs from all Distributed Generation including the exported GWHrs.
2. The Ohakune are includes GWHrs for Winstones Mill.

Due to implementation of demand side management, the total energy consumption for the Northern and Southern network appear to decrease. Historically the estimated GWHrs has always been recorded as 13 GWHrs whereas in actual for current year was 3.59 GWHrs.

PEAK DEMAND (MW)									
Non Contiguous Network Note: Network is non-contiguous, but abuts.	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**Average Change (%) p.a.**	**2010/11 - 2011/12 % Change**
Northern	36.42	39.23	39.32	38.30	39.16	39.02	35.38	-0.35%	-9.34%
Central	25.37	28.02	27.86	24.74	27.40	28.92	25.13	0.31%	-13.10%
Ohakune	5.32	5.94	7.66	6.42	8.22	8.26	7.39	7.06%	-10.56%
Co-Incident Demand	57.90	58.44	64.78	61.30	63.50	62.98	53.17	-1.07%	-15.58%

TABLE 3.2: SYSTEM PEAKS FOR EACH OF THE SUPPLY AREAS

The table 3.2 shows the system peaks at GXP's including distributed generations for non-contiguous network areas. The demand in 2011/12 decreased in all three regions.

The impact of demand billing appears to help in slowdown in increase in demand. More data is required for further analysis before conclusive comment can be made on impact of demand billing. Distributed generation connections also complicate the measurement of these values; particularly when there is no half hourly metering data.

It should be noted that the demand figures in Table 3.2 are anytime and may include the effects of times when TLC is not signalling demand constraints to customers.

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.)

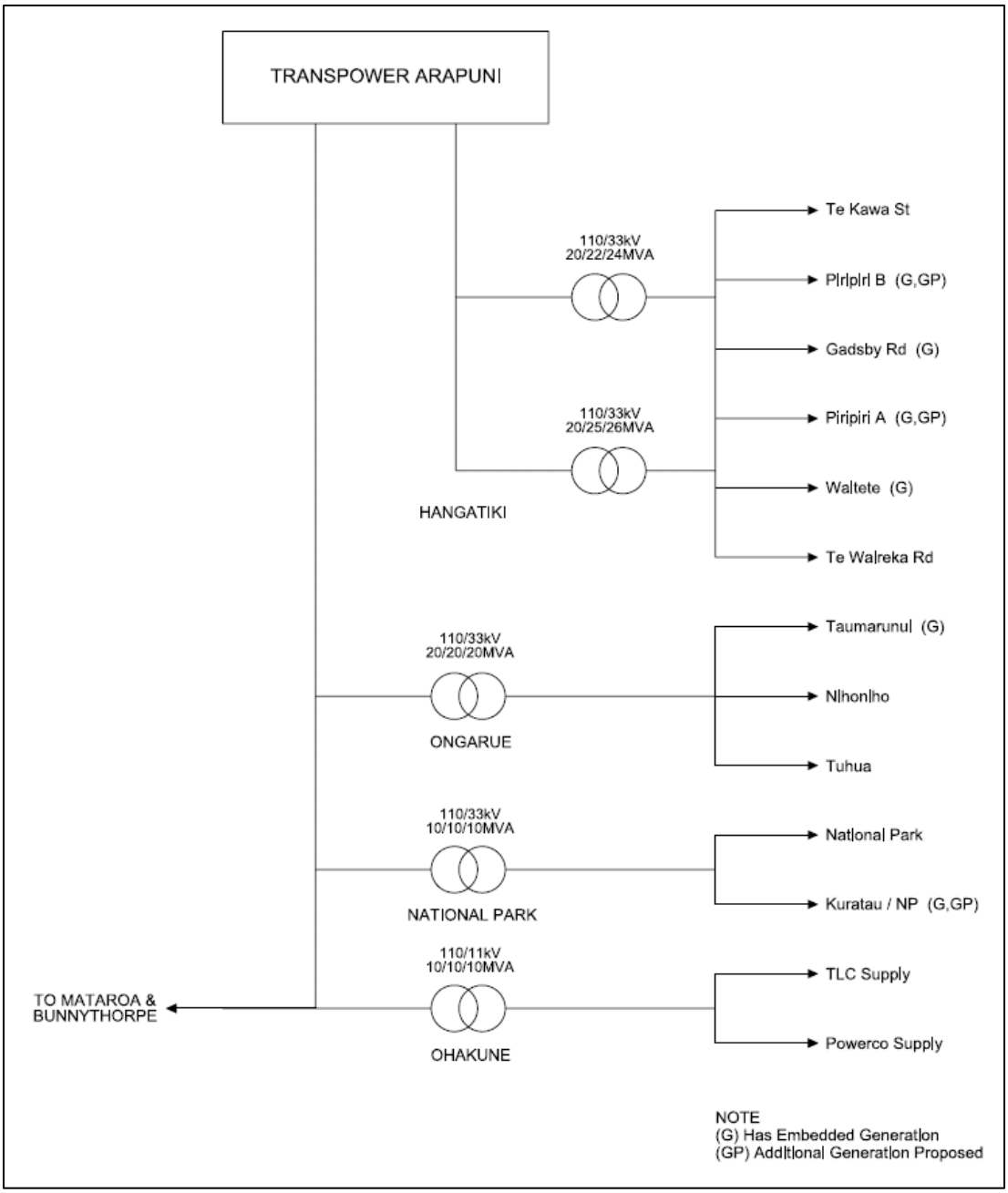


FIGURE 3:2: SIMPLIFIED SINGLE-LINE DIAGRAM OF THE HANGATIKI, ONGARUE, NATIONAL PARK, AND OHAKUNE GRID EXIT POINTS

Note: Transformer Ratings: Maximum Continuous/Summer/Winter. 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.

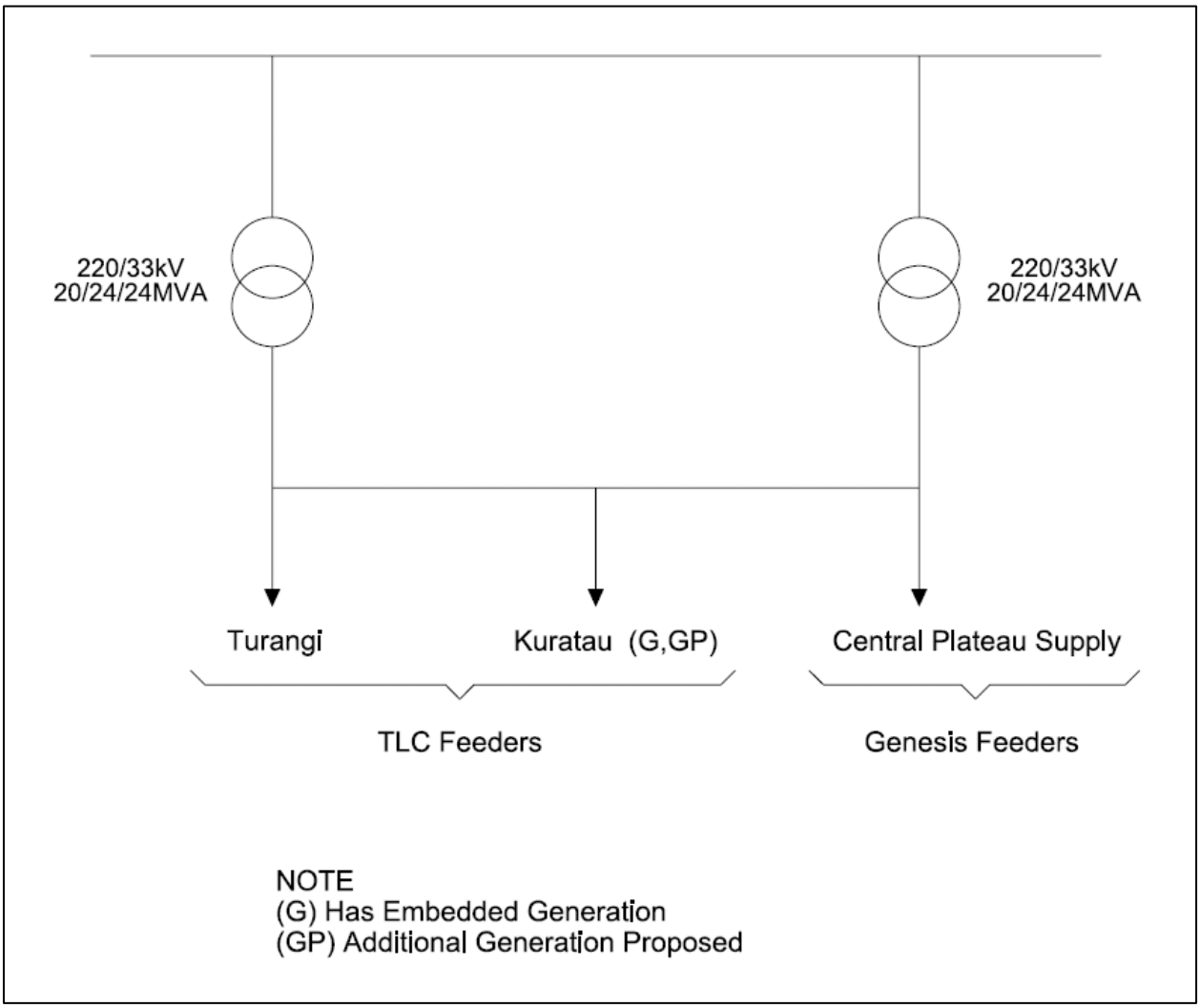


FIGURE 3.3: TOKAANU CONNECTION DETAIL

Note: Transformer Ratings: Maximum Continuous/Summer/Winter.

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.

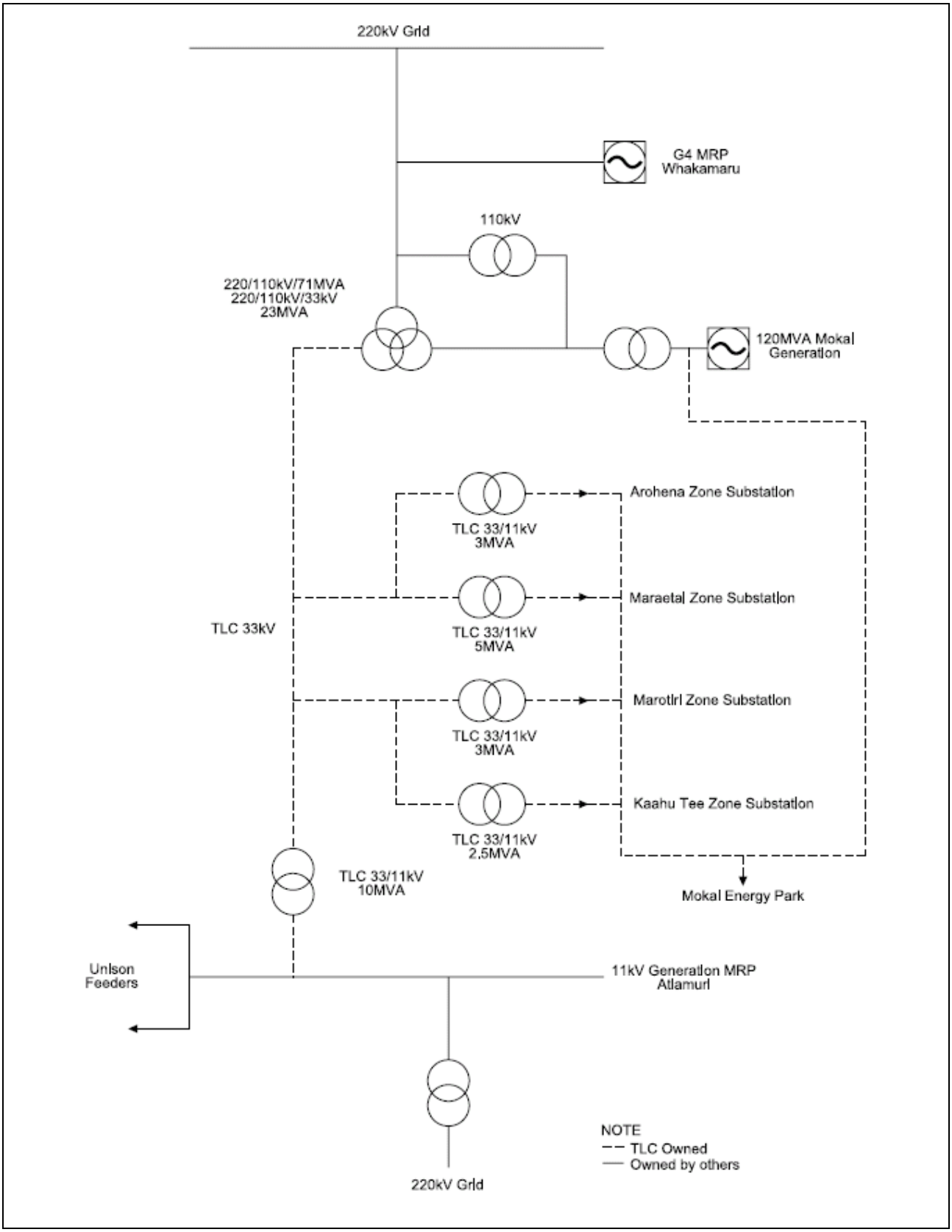


FIGURE 3.4: WHAKAMARU AND ATIAMURI CONNECTION DETAIL

Note: Transformer Ratings: Maximum Continuous/Summer/Winter

The TLC network is connected to a three-winding transformer that transforms the 110 kV output from Mokai to the 220 kV G4 generation bus. The third winding on this transformer supplies the TLC network. This network also has another connection and alternative supply via a TLC 33 kV line from the MRP Atiamuri site. This bus also connects to another power company network and the grid via 11/220 kV transformation. Mokai and/or G4 are run to supply TLC, and 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 between TLC and the Mokai generation is used to principally supply the Mokai Energy Park.

The arrangement at Whakamaru and Atiamuri is unique and one that 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 increase the cost of supply into the area significantly 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, convert the sub-transmission to 33 kV, and connect the substations to Mokai and Whakamaru G4 outputs. The development of the Mokai Energy Park resulted in the need for 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 Winstone's 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.

The supply 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.

Allowances are included in the Plan to make this supply permanent as running the supply from the Winstones Pulp Mill is complex from the operational, energy market and Transpower interconnection/connection perspective. It will be used to buy headroom at Ohakune until the Transpower transformers have been upgraded. There are also hazard control issues associated with the supply capacity.

3.2.2 Embedded Generators Connected to bulk electricity supply points greater than 1 MW

Table 3.3 details the embedded generation and which grid exit points it can be connected to.

EMBEDDED GENERATION			
Distributed Generation	**Size (MW)**	**Grid Exit Point (Normally Connected)**	**Other Switchable Options**
Kuratau	6	Ongarue	National Park, Tokaanu
Piriaka	1.5	Ongarue	National Park, Tokaanu
Wairere	5	Hangatiki	Whakamaru (Limited)
Mokauiti 1	1.5	Hangatiki	Whakamaru (Limited)
Mangapehi	2.5	Hangatiki	Whakamaru

TABLE 3.3: EMBEDDED GENERATION CONNECTED TO GRID EXIT POINTS GREATER THAN 1 MW CAPACITY

3.2.3 Existing Firm Supply Capacity and Current Peak Load of each supply point

Table 3.4 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 (2010/11 Year) (MW)**	**(MVA)**	**Power Factor**
Hangatiki	1 x 20/22/24 1 x 20/25/26	28.262	31.828	0.888
Ongarue	1 x 20/20/20	10.090	10.185	0.991
National Park	1 x 10/10/10	6.730	6.886	0.977
Ohakune	1 x 10/10/10	8.028	8.170	0.983
Tokaanu	2 x 20/24/24	8.572	8.624	0.994

TABLE 3.4: 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 thus 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.

Note: The Ongarue peak is when generation was not available and, as such, the power factor reduction effect is not occurring at this time.

3.2.4 Description of the Sub-transmission System fed from the bulk supply points, including identification and capacity of zone substations

3.2.4.1 Sub transmission 33 kV lines

Figure 3.5 shows geographically the layout of the sub-transmission system.

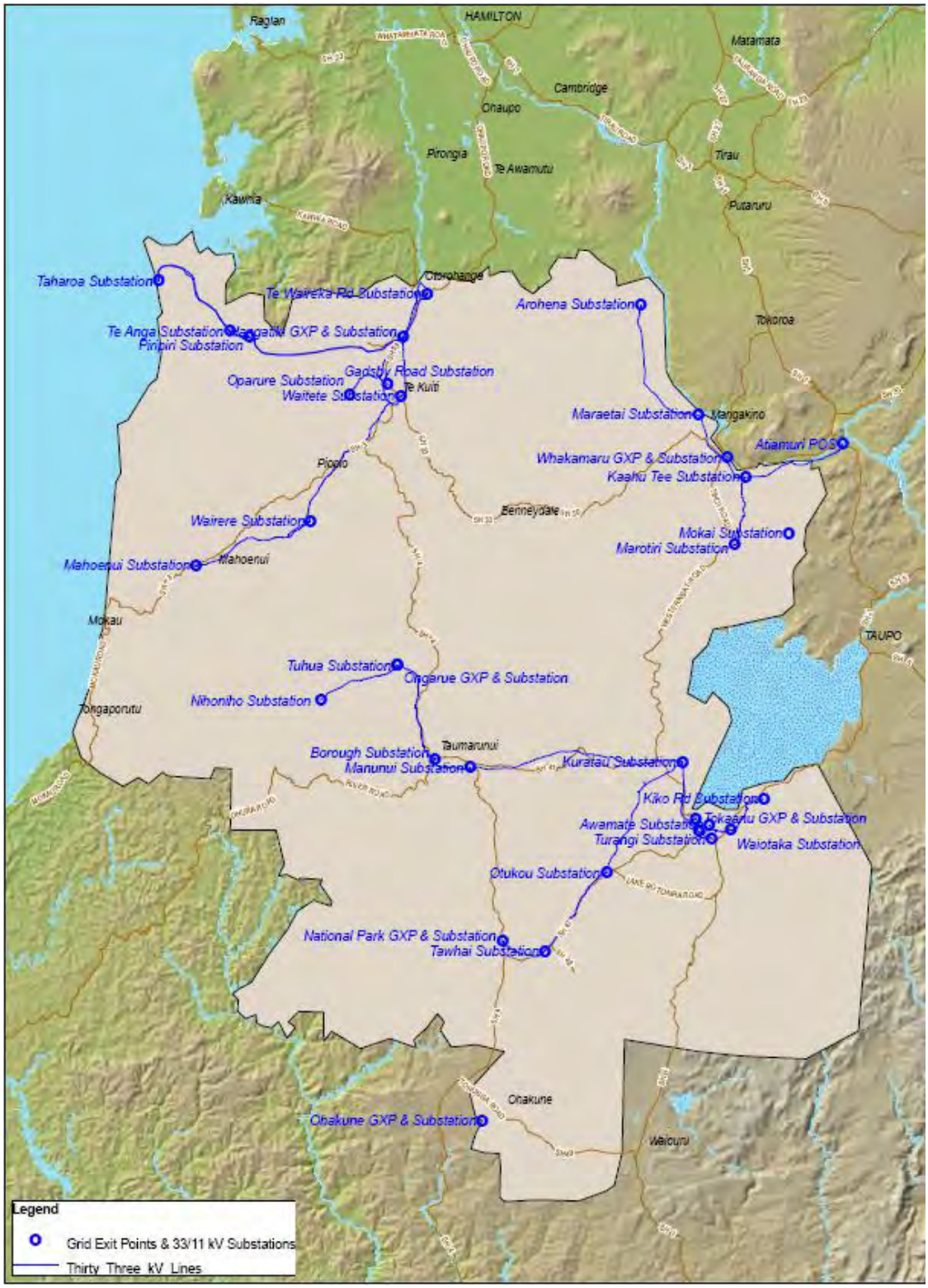


FIGURE 3.5: LAYOUT OF SUB-TRANSMISSION NETWORK

The specific configuration description of each of the sub-transmission line assets is included in Table 3.5.

SUB-TRANSMISSION ASSET CONFIGURATION		
Description	**Configuration Description**	**Backup Security**
HANGATIKI SUPPLY POINT		
Gadsby / Wairere 33 Overhead: 32.77km Underground: 0.00km	Part of ringed network linking Te Kuiti.	About 5% of the time it can be backed up by Wairere generation provided 11kV links made and generator very carefully controlled.
Gadsby Rd 33 Overhead: 17.4km Underground: 0.00km	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.	Waitete 33kV. Backed up to about 75% of present full load. (Back up has difficulty when load is high and river flows are low).
Mahoenui 33 Overhead: 22.57km Underground: 0.00km	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.
Taharoa A 33 Overhead: 53.51km Underground: 0.00km	Iron Sand Taharoa and future DG sites. Some local rural supply also.	Backed up to full load by Taharoa B line.
Taharoa B 33 Overhead: 45.87km Underground: 0.00km	Supply to Iron sand Taharoa and future DG sites. Some local rural supply also. Line is not on roadside. Travels through hill country. Operated in closed ring.	Taharoa A line. Backed up to present full load.
Te Kawa St 33 Overhead: 12.05km Underground: 0.00km	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.
Te Waireka Rd 33 Overhead: 8.22km Underground: 0.00km	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.
Waitete 33 Overhead: 10.79km Underground: 0.00km	Part of ringed network linking Te Kuiti.	Gadsby Road. Backed up to about 75% of present max loading.
NATIONAL PARK SUPPLY POINT		
National Park / Kuratau 33 Overhead: 57.25km Underground: 0.00km	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.
National Park 33 Overhead: 0.04km Underground: 0.00km	Few metres of spur line connecting National Park GXP to zone substations.	50 % load backup from 11kV network.

SUB-TRANSMISSION ASSET CONFIGURATION		
Description	**Configuration Description**	**Backup Security**
ONGARUE SUPPLY POINT		
Nihoniho 33 Overhead: 14.59km Underground: 0.00km	Spur line connecting Ongarue GXP to Nihoniho 33 Zone Substation. Line runs through very hilly remote country with poor access.	50% load backup on 11kV from Tuhua. (Voltage drop is main issue).
Ongarue / Taumarunui 33 Overhead: 18.21km Underground: 0.36km	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.
Taumarunui / Kuratau 33 Overhead: 38.02km Underground: 0.00km	Line travels across difficult access country.	Backup from National park GXP and Tokaanu (n-1) depending on generation and ski season.
Tuhua 33 Overhead: 0.08km Underground: 0.00km	Few metres of spur line connecting Ongarue GXP to Tuhua zone Substation.	50% load backup from Nihoniho on 11kV network.
TOKAANU SUPPLY POINT		
Lake Taupo 33 Overhead: 31.78km Underground: 0.91km	Spur line connecting Tokaanu GXP to the Kiko Road zone substation. Crosses many plots of extremely sensitive Maori land.	No backup, Generators have to be used to back this line up.
Tokaanu / Kuratau 33 Overhead: 15.53km Underground: 0.44km	Line travels across difficult access country and extremely sensitive Maori land.	Backup from National Park GXP and Ongarue via Taumarunui. (n-1) depending on generation and ski season.
Turangi 33 Overhead: 2.94km Underground: 0.00km	Spur line connecting Tokaanu GXP to the Turangi Zone Substation. Crosses sensitive Maori land.	Light to medium load backup
WHAKAMARU SUPPLY POINT		
Whakamaru 33 Overhead: 112.38km Underground: 0.00km	Connects Atiamuri and Whakamaru supply points to Arohena, Maraetai and Marotiri zone substations. Travels through hill country.	Very limited backup capacity (about 10%) through the 11kV network.

TABLE 3.5: SUB-TRANSMISSION ASSETS CONFIGURATION DESCRIPTION

3.2.4.2 Sub-transmission zone substations

A general summary description of zone substations is included in Table 3.6:

ZONE SUBSTATION ASSET SUMMARY	
Assets	**Number**
Site Development and buildings	36
Power Transformers	37
33 KV breakers excluding Fault Thrower Switches (135 total 11+33)	42
11 KV breakers	93
Switch Gear related equipment	117
Protection and controls	Various
Other equipment including Remote Terminal Units (RTUs), communications, load control injection, Direct Current (DC) supplies, and batteries	Various

TABLE 3.6: ZONE SUBSTATION ASSET SUMMARY

3.2.4.3 Specific details of the extent zone substations have (n-x) security

Table 3.7 details each of the zone substations and information on security.

ZONE SUBSTATION SECURITY INFORMATION		
Site	**Transformers**	**Security Information**
Arohena Zone Substation	1 @ 3000 kVA	Light load backup from 11kV network. This backup will not support the milking load in the area. In practical terms this means (N).
Atiamuri Point Of Supply	1 @ 10000 kVA	Site is backed up from 33kV network and MRP Atiamuri generation. Back up Whakamaru and is part of the innovative arrangement to take supply directly from generators and by pass transmission charges. In practical terms this means (N).
Awamate Zone Substation	1 @ 2000 kVA	Part of backup network for Turangi. Backup from Turangi. In practical terms this means (N) transformers.
Borough Zone Substation	2 @ 5000 kVA	Site is not fully backed up. 1x5MVA will not support all load at peak times. The site has a single 11kV bus with no bus coupling capability. Limited light load backup is available from 11kV network. In practical terms this means (N-1) transformers.
Gadsby Road Zone Substation	1 @ 5000 kVA	Medium load backup available from 11kV network. In practical terms this means (N).
Hangatiki Zone Substation	1 @ 5000 kVA	Medium load backup available from 11kV network. In practical terms this means (N).
Kaahu Tee Zone Substation	1 @ 2400 kVA	Embedded in Marotiri / Maraetai network. Backup from Marotiri/Maraetai. Cannot be taken out of service during heavy load times. In practical terms this means (N).
Kiko Road Zone Substation	1 @ 3000 kVA	No backup available other than bypassing sub and injecting 11kV from Turangi into 33kV line. This is light load backup only. In practical terms this means (N).

ZONE SUBSTATION SECURITY INFORMATION		
Site	**Transformers**	**Security Information**
Kuratau Zone Substation	1 @ 3000 kVA 1 @ 1500 kVA	3 MVA transformer in aged condition. 1.5 MVA backup available on site (This will not cover full load situations) (Backup will also not phase so an outage is needed to transfer load). In practical terms this means (N). Old backup unit for emergencies only. Will not supply heavy load and does not phase. Emergency use only. Will be decommissioned and replaced with Piripiri transformer in the planning period. In practical terms this means (N).
Mahoenui Zone Substation	1 @ 3000 kVA	Light load backup available from 11kV network. In practical terms this means (N).
Manunui Zone Substation	1 @ 5000 kVA	Light load backup available from 11kV network. In practical terms this means (N).
Maraetai Zone Substation	1 @ 5000 kVA	Light load backup available from 11kV network. This backup will not support the milking load in the area. In practical terms this means (N).
Marotiri Zone Substation	1 @ 3000 kVA	Light load backup available from 11kV network. This backup will not support the milking and industrial load in the area. In practical terms this means (N).
Mokai Zone Substation	1 @ 7500 kVA	Light load backup available from 11kV network. In practical terms this means (N).
National Park Zone Substation	1 @ 3000 kVA	Light load backup available from 11kV network. In practical terms this means (N).
Nihoniho Zone Substation	1 @ 1500 kVA	Light load backup from 11kV system. In practical terms this means (N).
Oparure Zone Substation	1 @ 3000 kVA	Principally supplies an industrial site. Forward plan is to utilise transformer more for supplying into local 11kV network. Light load backup available. In practical terms this means (N).
Otukou Zone Substation	1 @ 500 kVA	No backup or alternative feed security. In practical terms this means (N).
Piripiri Zone Substation	1 @ 1500 kVA	Old transformer was decommissioned in December 2010. Backup possible by reconfiguring Taharoa 33kV line and operating at 11kV. Constructed for Speedys Road Hydro and replaces Piripiri Zone Substation. In practical terms this means (N).
Taharoa Zone Substation	3 @ 5000 kVA	Medium load backup available from 11kV network. In practical terms this means (N-1).
Tawhai Zone Substation	1 @ 5000 kVA	Light load backup available from 11kV network. In practical terms this means (N).
Te Anga Zone Substation	1 @ 2000 kVA	Site has firm line and transformer capacity in theory. It does have a single 11kV bus with no bus coupler. The site is very exposed and reliability due to weather extremes is an issue. In practical terms this means (N).
Te Waireka Zone Substation	2 @ 10000 kVA	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 Zone Substation	1 @ 1250 kVA	33kV to 400V transformer injecting into the 400V network. This is stepped up to give a low load low cost backup to the main 33kV to 11kV transformer for emergencies or during maintenance. In practical terms this means (N).

ZONE SUBSTATION SECURITY INFORMATION		
Site	**Transformers**	**Security Information**
		No transformer or 11kV backup. Limited backup via 33kV to 400V step-up to 11kV. In practical terms this means (N).
Tuhua Zone Substation	1 @ 1500 kVA	Full load backup from 11kV system. In practical terms this means (N-1) transformers.
Turangi Zone Substation	2 @ 5000 kVA	Site has two transformers with firm transformer capacity but the 33kV supply and 11kV outgoing configuration is weak. There is no 11kV backup available. In practical terms this means (N-1) transformers.
Waiotaka Zone Substation	1 @ 1500 kVA	Modular substation 75% backed up from Turangi 11kV. In practical terms this means (N).
Wairere Zone Substation	2 @ 2500 kVA	One transformer capacity and 11kV network connections will support connected load customers but not generation customers. In practical terms this means (N-1) transformers.
Waitete Zone Substation	3 @ 5000 kVA	Normal operating loads are in the 6 to 7 MVA range. The site has firm capacity in its present configuration. Limited backup is available from the 11kV network. In practical terms this means (N-1) transformers.
Whakamaru Point of Supply	1 @ 23000 kVA	Mighty River Power owns the transformer and TLC use the tertiary winding on the transformer. Backed up from Atiamuri. Note: this is a non standard arrangement put in place to lower and avoid Transpower charges for this area. In practical terms this means (N).

TABLE 3.7: EXTENT TO WHICH INDIVIDUAL ZONE SUBSTATIONS HAVE (N-X) SUB-TRANSMISSION SECURITY

3.2.5 Configuration Description of the Distribution System including the extent to which it is underground

3.2.5.1 Distribution 11 kV lines

The major distribution assets are 11 kV overhead lines. Table 3.8 describes these assets on a feeder-by-feeder basis.

11 kV DISTRIBUTION LINES				
Line	**OH Length (km)**	**Description**	**UG Length (km)**	**Purpose of Cable**
Aria	77.17	Aria rural area		
Benneydale	133.81	South east of Te Kuiti, Benneydale, Mangapehi Generation and Crusader Meats	0.07	Cable out of zone substation
Caves	65.18	Waitomo village and rural area to the west.	0.30	Cable out of zone substation
Chateau	0.00	Whakapapa Ski field and village. About 60% is heavy armoured cable.	28.60	Cable on mountain
Coast	84.29	Remote rural area around Marokopa		
Gravel Scoop	88.73	South east of Otorohanga	0.22	Cable out of zone substation
Hakiaha	3.82	Central area of Taumarunui	1.93	Cable in Taumarunui CBD
Hangatiki East	19.31	Area east of Hangatiki	0.07	Cable out of zone substation
Hirangi	1.50	SWER feeder to semi residential area around Turangi	0.15	Cable into substation
Huirimu	44.46	Supply to rural area south of Arohena		
Kuratau	53.30	Supply to Kuratau Village area	3.56	Cable in parts of township
Mahoenui	104.01	Supply to Mahoenui and surrounding rural areas	0.10	Cable to ground mount transformers in Mokau and Awakino
Maihiihi	107.79	Rural area north east of Otorohanga	1.06	Cable out of zone substation
Mangakino	20.34	Supply to Mangakino	2.17	Cable out of zone substation
Manunui	86.47	Rural area to south and east of Taumarunui	0.82	Cable to ground mount transformers in Manunui
Matapuna	14.75	Supply to western side of Taumarunui	2.02	Cable in urban area of Taumarunui
McDonalds	39.52	Rural area to the south of Otorohanga	0.80	Cable to ground mount transformers
Miraka	0.20	Supply to Mokai Energy Park and Miraka Milk Plant area	0.71	Cable to new subdivision
Mokai	81.03	Mokai rural area including western bays area of Lake Taupo	1.88	Cable to new subdivision
Mokau	132.31	Mokau coastal area		
Mokauiti	74.17	Rural area south west of Piopio		
Motuoapa	1.86	Supply to Motuoapa area	0.64	Cable to new subdivision
National Park	43.09	Supply to the National park area including the village	0.19	Cable to ground mount transformers in village
Nihoniho	26.63	Supply to the Nihoniho and Matiere areas		

11 kV DISTRIBUTION LINES				
Line	**OH Length (km)**	**Description**	**UG Length (km)**	**Purpose of Cable**
Northern	108.78	Area north of Taumarunui	2.97	Cable in urban area of Taumarunui
Ohakune Town	9.97	Ohakune town supply	3.49	Cable in Ohakune CBD
Ohura	174.36	Ohura and surrounding remote rural areas	0.13	Cable to ground mount transformers
Ongarue	127.63	Large rural area around Ongarue		
Oparure	74.95	Supply to an area west of Te Kuiti	5.42	Cable in urban area of Te Kuiti
Oruatua	2.90	Eastern side of Lake Taupo, north of Motuoapa	1.70	Cable to new subdivision
Otorohanga	51.72	Supply to most of town plus rural area to southwest	1.35	Cable in CBD of Otorohanga and out of zone substation
Otukou	5.75	Area around Sir Edmund Hillary Outdoor Pursuits Centre		
Paerata	3.37	Supply to Mokai Energy Park and Glasshouse and other customers	0.45	Cable to new subdivision
Piopio	52.83	Supply to Piopio village and surrounding rural area to north	0.10	Cable to ground mount transformers in village
Pureora	52.45	West of Whakamaru including supply to Crusader Meats	0.06	Cable out of zone substation
Rangipo / Hautu	32.79	Supply to areas east of Turangi	6.11	Cable across Tongariro River and at prison
Rangitoto	76.57	Area west of Te Kuiti	2.66	Cable in urban area of Te Kuiti
Raurimu	171.17	Raurimu village and rural areas to east, west and south		
Rural	4.71	Rural area surrounding Taharoa	0.03	Cable to ground mount transformers
Southern	124.29	Area south of Manunui including connection for Piriaka distributed generation		
Tangiwai	88.67	Area east of Ohakune	1.91	Cable to subdivision
Te Kuiti South	24.44	Part of Te Kuiti town and rural area to south	1.11	Cable from substation and in urban area of town
Te Kuiti Town	1.26	Central area of Te Kuiti	0.78	Cable from substation and in urban area of town
Te Mapara	79.78	Area south east of Piopio	0.10	Cable from substation
Tihoi	63.27	Western bays area - Lake Taupo		
Tirohanga	63.53	Western bays area - Lake Taupo	4.88	Cable to subdivision
Tokaanu	0.00	Tokaanu town and marina	1.21	Cable in urban area and supply to marina
Tuhua	41.19	Remote rural area around Ongarue		
Turangi	0.94	Supply to Turangi Town and surrounding area	7.67	Cable in urban areas

11 kV DISTRIBUTION LINES				
Line	**OH Length (km)**	**Description**	**UG Length (km)**	**Purpose of Cable**
Turoa	35.01	Turoa ski field and urban rural area to bottom of mountain	24.21	Cable in urban area and at ski field
Waihaha	92.73	Area around south western of Lake Taupo	2.31	Cable to Whareroa holiday area
Waiotaka	9.01	Supply to prison and area east of Turangi	1.18	Cable at prison
Waitomo	10.40	Area north of Te Kuiti and major lime plant	0.70	Cable from substation and urban area of Te Kuiti
Western	133.73	Rural area north west of Taumarunui	1.19	Cable from substation and in urban area of Taumarunui
Whakamaru	85.87	Whakamaru village and surrounding dairying areas	0.27	Cable from substation
Wharepapa	106.62	Large rural dairying area west of Arohena	0.48	Cable to transformer
Total	**3,214.43**		**117.76**	

TABLE 3.8: DISTRIBUTION OF 11 KV DISTRIBUTION LINES

3.2.5.2 SWER systems configuration description

Table 3.9 lists and describes the SWER systems used by TLC. All except the Tokaanu River and Pihanga system operate at 11 kV to earth. The Tokaanu River and Pihanga systems operate at 6.6 kV to earth. All SWER systems are fed by isolation transformers. Many of the systems have back feed options, which generally are not in phase and all switching has to be completed with supply removed.

SWER SYSTEM CONFIGURATION				
Feeder	**Location**	**Transformer ID**	**Isolation TX kVA Rating**	**Total kVA of Connected Transformers**
Aria	Kumara Road	T1948	200	415.00
Benneydale	Waimiha Road	T1454	100	252.50
Benneydale	Kopaki Road	T2506	100	356.00
Caves	Kokakoroa road	T1185	15	75.00
Coast	Mangatoa Road	T2363	100	247.50
Hirangi	Hirangi	10S05	100	202.50
Kuratau	Pukawa	09R02	100	415.00
Kuratau	Waihi	09R27	200	230.00
Kuratau	Waihi Pukawa Trust	T4233	25	30.00
Kuratau	Parerohi Grove	T4282	100	235.00
Mahoenui	Pungarehu Road	T1453	100	118.00
Mahoenui	Mangaotaki Road	T1692	68	280.50
Mahoenui	Mangaoronga Road	T1865	100	238.00
Mahoenui	Haku Road	T2520	50	168.00
Manunui	Waituhi	07K11	100	147.50
Manunui	Kirton Road	08J07	200	594.00
Manunui	Ngapuke	08L17	200	693.00
Mokau	Manganui road	T2166	100	530.50
Mokau	Mohokatino road	T2177	100	222.50
Mokau	Clifton road	T2194	100	180.00
Mokau	SH40 - Tongaporutu	T2208	100	425.50
Mokauiti	Mokauiti road	T827	200	578.00
Nihoniho	Nihoniho	06E01	100	308.50
Northern	Okahukura	06H11	200	680.00
Northern	Hikurangi	T4055	200	805.00
Ohura	Waitaanga	07D08	200	448.00
Ohura	Huia road	07D11	100	313.00
Ohura	Waitewhena	07D16	100	258.00
Ohura	Tatu	09C05	200	368.00
Ohura	Opatu	10E09	100	513.00
Ohura	Aukopae	T4130	100	210.00
Ongarue	Waimiha	02K08	100	430.00
Ongarue	Koromiko	02K16	100	382.50
Ongarue	Ongarue	04I01	100	668.50

SWER SYSTEM CONFIGURATION				
Feeder	**Location**	**Transformer ID**	**Isolation TX kVA Rating**	**Total kVA of Connected Transformers**
Ongarue	Tapuiwahine	T4128	100	385.50
Oruatua	Waitetoko	09U12	100	513.00
Oruatua	Tauranga-Taupo	T4087	25	40.00
Otukou	Otukou	12O01	100	456.00
Otukou	Mangatepopo Intake	T4162	25	25.00
Rangipo / Hautu	Tokaanu river	T4133	25	40.00
Rangipo / Hautu	Korohe	T4172	100	250.00
Rangitoto	Gardiner road	T678	25	25.00
Raurimu	Retaruke 1 (lower)	13I10	100	533.00
Raurimu	Ruatiti	T4077	100	511.50
Raurimu	Retaruke 2 (upper)	T4132	100	375.00
Southern	Tunanui	09K02	100	342.50
Southern	Makokomiko	09K25	100	310.00
Southern	Otapouri	10K14	200	601.00
Southern	Kaitieke	11K11	100	327.50
Southern	Oio Road	12K08	100	351.00
Southern	Kawautahi	T4239	200	628.50
Te Mapara	Main South Road - Te Kuiti	T1777	100	343.50
Te Mapara	SH4 - Aramatai	T1829	100	440.50
Tihoi	Tihoi	T1618	200	630.50
Tokaanu	Tokaanu Zone sub	T4271	50	100.00
Tuhua	Matiere	05F14	200	639.00
Tuhua	Tuhua	05G03	100	313.50
Waihaha	Waihaha	04Q06	200	442.50
Waihaha	Kuratau	07Q14	200	682.50
Waihaha	Karangahape road	T4193	200	673.50
Waiotaka	Hautu	10S18	100	150.00
Western	Pongahura	08H03	100	520.00
Western	River road	08I21	200	581.00
Western	Kirikau	09H01	100	483.00
Western	Otunui	T4131	100	375.00

TABLE 3.9: DESCRIPTION OF SWER LINES

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 3.9 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.

3.2.5.3 11 kV cables

Included in distribution feeder assets in Table 3.8 are 11 kV cables.

These cables are dispersed throughout the network but the areas with most significant cabling are:

- Feeders coming out of Te Waireka (Otorohanga), Waitete (Te Kuiti) and Borough (Taumarunui) zone substations.
- Parts of Taumarunui.
- Turangi town (ex hydro construction town).
- Whakapapa Ski Field.
- Turoa Ski Field.
- Recent subdivisions.
- Short sections connecting overhead lines to ground mounted transformers. (See earlier 11 kV feeder descriptions for more specific detail.)
- The Mokai Energy Park.

About 50% of The Lines Company 11 kV cable is associated with the ski field supplies. Much of this cabling has been laid directly on solid rock and uses heavily armoured cables.

Much of the ski field cabling installation 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.

3.2.5.4 Distribution switchgear

Distribution switchgear and control equipment is spread throughout the network. Table 3.10 summarises the identified distribution switchgear and control assets.

11 kV DISTRIBUTION SWTICHGEAR AND CONTROL ASSETS	
Type of Link	**Number**
11 kV Air Break Switches	645
11 kV Circuit Breakers	28
11 kV Fault Thrower Switches	8
11 kV Fused Switches	848
11 kV Load Break Switches	146
11 kV Reclosers	111
11 kV RTE Integrated Transformer Switches	60
11 kV Sectionalisers	78
11 kV Solid Links	447
11 kV Transformer Fuses	5215

TABLE 3.10: 11 KV DISTRIBUTION SWITCHGEAR AND CONTROL ASSETS

3.2.6 Brief Description of the Network's Distribution Substation Arrangements

The TLC network uses distribution transformer arrangements similar to most New Zealand networks.

3.2.6.1 Overhead Distribution Substation 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. The transformer is normally pole mounted. Supply away from the transformer is usually protected with low voltage fuses at about 50% of sites. Transformer sizes typically range from 5 kVA to 200 kVA.

3.2.6.2 Ground Mounted Transformers

Most ground-mounted transformers on the TLC network are tapped off an overhead line via 11 kV cut-out fuses. For lengths of cable greater than 100 metres distribution standards require some form of 3-phase isolation is used to stop Ferro resonance effects.

Cables are normally protected with riser class lightning arrestors at the overhead line end. Various transformer housing arrangements have been used to house the transformers, i.e. from modified garden sheds to I tanks. Most modern types are mainly housed in manufacturers modular I tanks or double door configuration depending on what is most suitable for a particular location. Most low voltage circuits away are fused and many installations have MDIs and transformer isolators. (Current distribution standards require transformer isolators, MDI's and for each circuit away to be protected).

Historically, up to ten transformers have been supplied from one set of 11 kV cut-out fuses protecting daisy-chained arrangements. Sometimes "dry well" fuses have been installed at each individual transformer. The present standard is to install Magnafix or equivalent ring main equipment and rotary transformer switches at alternate sites when connecting units in series. Vacuum non SF6 gas 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 mains minimises costs whilst allowing hazard control expectations to be met).

The identified transformer and substation site assets are summarised in Table 3.11.

DISTRIBUTION TRANSFORMER AND SUBSTATION SITE ASSETS		
Phases	**Description**	**Number**
1	Ground Mounted	10
1	Pole Mounted	3,041
2	Pole Mounted	199
3	Ground Mounted	473
3	Pole Mounted	1,490

TABLE 3.11: DISTRIBUTION TRANSFORMER AND SUBSTATION SITE ASSETS

Note: A number of sites have transformers operating in parallel. The cost relativity of modern transformers means that most new sites tend to have one transformer as opposed to two operating in parallel. Industrial sites do however usually have several transformers supplying various load centres around the plant.

3.2.7 400 Volt Systems

3.2.7.1 400 Volt Distribution Systems

The majority of the LV network is overhead line utilising bare copper (Cu) and aluminium (Al) conductors. An increasing proportion however will become insulated as older conductors are renewed over time as present distribution standards require low voltage overhead conductors to be insulated.

A simplified breakdown of the LV assets is shown in table 3.12.

LOW VOLTAGE DISTRIBUTION ASSETS	
Description	**Quantity**
LV Poles - Concrete	717 units
LV Poles - Wood	4569 units
LV Overhead Circuit	274.5 km
LV Underground Circuit	129.3 km
LV Streetlight Circuit	48.3 km
Pillar Boxes	4022 units

TABLE 3.12: BREAKDOWN OF LV ASSETS

Low voltage underground cables exist, to some extent, in most township areas. Turangi town has the most extensive low voltage cable network.

The identified cabling assets consist of 177.6 km of low voltage cables and 4022 pillar boxes. As discussed in earlier sections work is underway to improve the accuracy of LV data.

3.2.7.2 Customer Service Connection Assets

The identified customer service connection assets, excluding meters and relays, are summarised in Table 3.13.

CUSTOMER SERVICE CONNECTION ASSETS	
Description	**Number**
Overhead	20,422
Underground	3,893

TABLE 3.13: CUSTOMER SERVICE CONNECTION ASSETS

As discussed in earlier sections work is proposed to improve the accuracy of connection assets.

3.2.8 Overview of Secondary Assets such as Ripple Injection systems, SCADA and Telecommunications systems

3.2.8.1 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 Lester Abbey SCADA system. The Controller decides on the need to shed and restore load. Telegrams are generated at the plant controller level.

Table 3.14 lists the injection plants, frequencies, and injection voltages.

INJECTION PLANT LOCATION, TYPE, FREQUENCY AND VOLTAGE			
Location	**Plant Type**	**Frequency**	**Voltage**
Arohena	Landis Gyr Load Control	725Hz	11kV
Gadsby Road	Landis Gyr load control	725Hz	11kV
Maraetai	Landis Gyr load control	725Hz	11kV
Te Waireka	Landis Gyr load control	725Hz	11kV
Wairere	Landis Gyr load control	725Hz	11kV
Waitete	Landis Gyr load control	725Hz	11kV
Hangatiki	Landis Gyr	317Hz	33kV
Ohakune	Zellweger	317Hz	33kV
Ongarue	Zellweger	317Hz	33kV
National Park	Zellweger	317Hz	33kV
Tokaanu	Zellweger	317Hz	33kV
Whakamaru	Landis Gyr	317Hz	33kV

TABLE 3.14: INJECTION PLANT LOCATIONS, TYPES, FREQUENCIES AND VOLTAGES

The high frequency (725Hz) and relatively low power output of the 11kV Landis and Gyr legacy plants results in marginal to no signal being available for about 300 customers at Hangatiki and 500 customers at Marotiri. To overcome this problem, two new 317Hz 33kV plants were commissioned in 2010.

The 2009 and 2010 AMPs included an allowance to exchange and renew the 725 Hz relays with 317 Hz devices. This initiative has been substantially modified to TLC's intent to deploy 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 five, possibly ten, years. The priorities for this deployment have however remained unchanged in that TLC needs to change frequency on the northern area to ensure all customers are receiving a reliable load control signal. The new units are physically enclosed in 40 foot containers to ensure they are modular and have adequate security.

The old Landis and Gyr plants will be able to be decommissioned once the advanced meters have been installed. TLC's future network vision is to find and develop more beneficial ways to run load control plants to improve network efficiency in conjunction with its demand based billing. i.e. The on-going development of the network to utilise smart or advanced network technologies. The stage currently being tested is the additional functionality required in the head end load control calculator to be able to receive local, zone substation and regional inputs and make various decisions based on this information.

3.2.8.2 SCADA Systems

The TLC network uses a Lester Abbey central control system and RTUs to automate approximately 35 zone substations, 12 load control plants and about 90 field devices and two investor owned generators. In addition it 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.

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. More detail on the radio communications system is included in the following sections.

3.2.8.3 Radio Communications Equipment

TLC operates a network of six E-Band (150 – 155 MHz), radio repeaters providing voice communication throughout the operational area.

Eight further repeaters divided across three sub communication networks provide a complimentary low speed (1200bps) SCADA transmission platform to access the 100 plus remote terminal units. Network diagrams for TLC's voice and SCADA networks are included in Figures 3.6a and 3.6b.

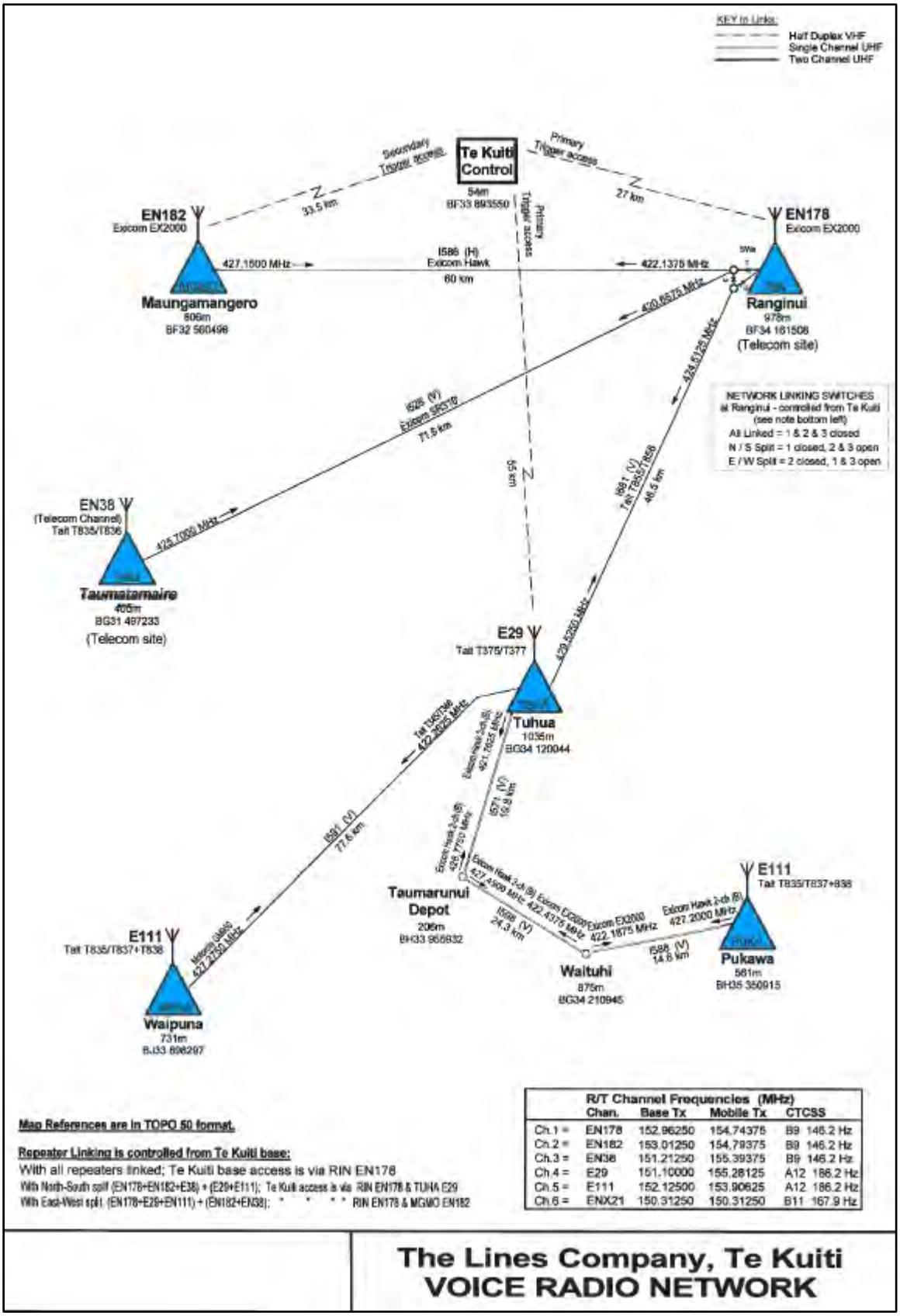


FIGURE 3.6A: TLC VOICE RADIO NETWORK

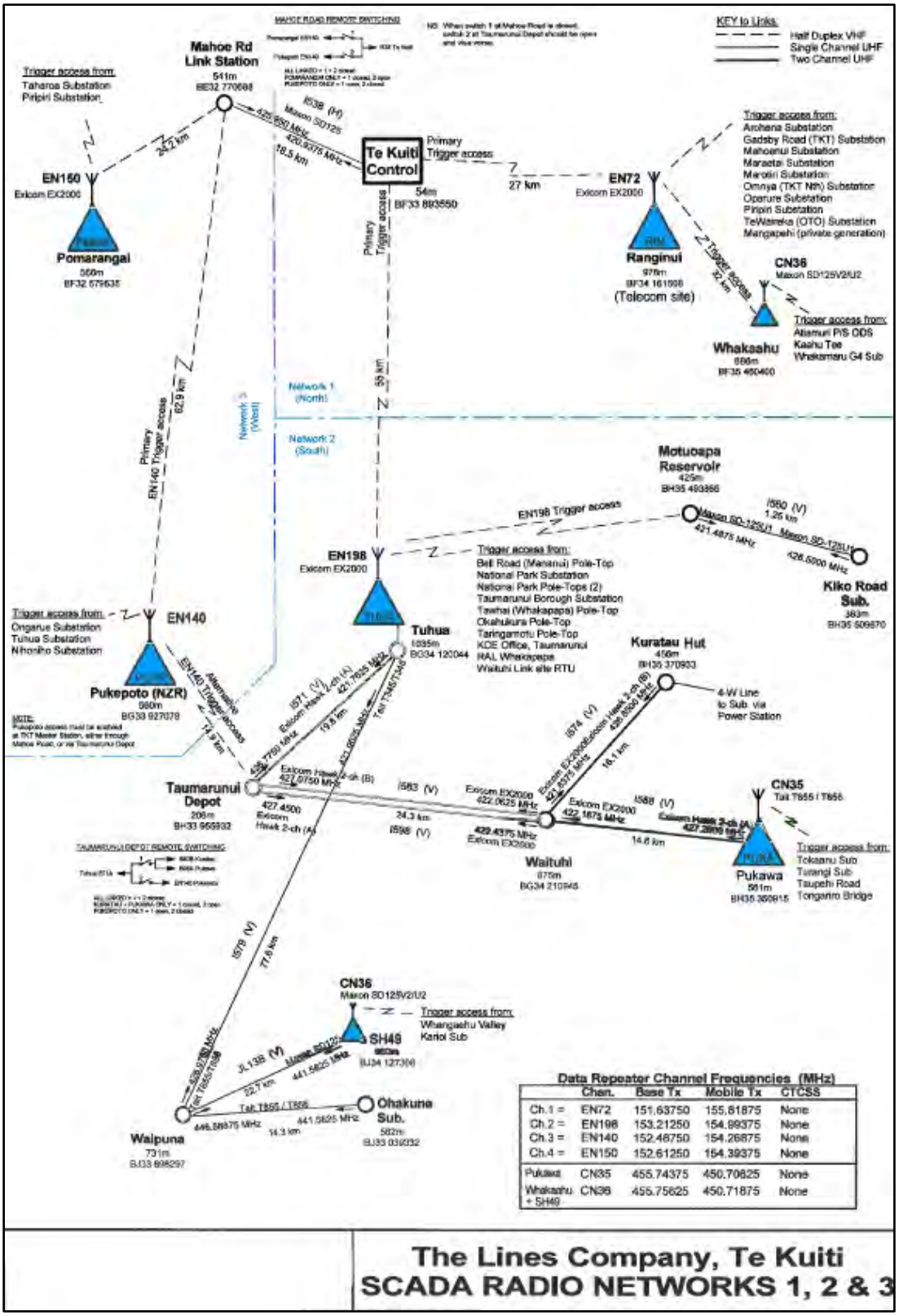


FIGURE 3.6B: TLC SCADA RADIO NETWORK

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. The plan is to systematically connect the voice then the data system to 12.5 kHz band width digital systems. Allowances included in Section 7 of this Plan will fund this development using TDMA technology.

3.2.8.4 Emergency Generator and Injection Transformer

The Lines Company owns a mobile generator, protection transformer, and circuit breaker capable of injecting into the 11 kV network under emergency or shutdown conditions.

The unit consists of:

- 8-ton carrying capacity truck.
- 165 kVA, 400V generator.
- 150 kVA star-delta (Yd) 11 kV to 400 Volt transformer.
- NULEC 11 kV circuit breaker.
- Various connection leads and plugs; both 11 kV and 400 Volt.
- Road signage and emergency lighting.

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.

3.2.8.5 Capacitor Banks

TLC has two capacitor 11 kV banks. These each consist of:

- Controller.
- Circuit Breaker.
- 1 MVAr 11 kV capacitor bank.
- Trailer.
- Connection leads.
- Associated hazard control equipment.

These units are used as an alternative network support tool to generators; i.e. add capacity to backup supplies without the need to bring in expensive generators.

3.2.9 Modular Substations

TLC has developed a modular, low cost way of establishing zone substations. The first substation was installed in 2006/07 and a further two were commissioned in 2008 and a fourth in 2010. 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 concept has the following advantages:

- Environmentally acceptable. Resource consents are much more easily obtained than conventional construction.
- Modular and provides an alternative to large central substations.
- Easily transportable.
- Reduces and controls fault currents as compared to large centralised substations.
- Very secure.
- Suitable for industrial sites. Customers can more easily understand what capital investment their contributions are funding.
- Is ideal for supplying extra capacity into holiday areas or quickly moving to reinforce a legacy zone substation.
- Cost is 30 to 50% less than historical ways of constructing a zone substation.
- Commissioning and teething issues when being put into service are less than historical substations mostly due to the unit's simplicity.
- Lower operating costs and smaller land footprint.

The three initial units constructed have now been in service for 5 to 6 years and have operated better than expectations. 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.

3.2.10 Metering Assets

TLC, through a subsidiary company, owns the majority of customer meters and relays. It also owns interconnection metering assets at Whakamaru, Mokai, (commissioned June 2011), 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.

Section 4

4. Network Assets by Category

4.1 Description of the Network Assets by Category including Age Profile and Condition Assessment

4.1.1 Assets owned by the disclosing entity but are installed at bulk supply points which are owned by others

TLC has some assets at bulk supply points which are owned by other entities. These assets are located at:

Transpower Grid Exit Points
- Hangatiki
- National Park
- Ongarue
- Tokaanu

Alternative Supply Points
- Atiamuri
- Whakamaru

4.1.1.1 Hangatiki GXP

Voltage Level
33 kV and 11 kV

Description and Quantity of Assets
TLC equipment located at the Hangatiki grid exit point includes terminal spans into the site and a 5 MVA 33/11 kV zone substation. The zone substation includes transformer bunding and a disused historic Transpower substation building that houses indoor 11 kV switch gear, relays, SCADA, and batteries.
Cable into and out of the 11 kV switchgear is located on the site. A short length of fibre cable is also present to transport data from the Transpower equipment into the TLC RTU.
A new 317 Hz ripple injection plant housed in a 40 foot container was commissioned at the site in 2010. Two additional 33kV line reclosers were added as part of this project and the hazard control programme.

Age Profile
The 2012 average age profile of this equipment is 16 years.

Condition of Assets
The condition of assets at the Hangatiki grid exit point is good. DGA oil test results indicate that the 5 MVA transformer is in good serviceable condition. Equipment at the site has been reliable and provided acceptable levels of service.

4.1.1.2 National Park GXP

Voltage Level
33 kV and 11 kV

Description and Quantity of Assets
The assets at the National Park Transpower grid exit include a ripple injection plant and a 33/11 kV 3 MVA substation. Associated equipment includes SCADA, structures, and site development.
Age Profile
The 2012 average age profile of this equipment is 17 years.

Condition of Assets

The site currently falls short of current hazard control, environmental and operating expectations. Included in the plan for this year is to install a new modular substation at the site. The 33 kV switchgear would be rationalised, upgraded and housed in the same container. In conjunction with this, the ripple plant will also be containerised and the 11kV feeder switchgear upgraded.

4.1.1.3 Ongarue GXP

Voltage Level
33 kV

Description and Quantity of Assets
The equipment is located at the Transpower grid exit point. It consists of termination spans, bypassing switchgear, and a ripple injection plant and site development including security fencing.
The equipment is located on Transpower land.

Age Profile
The 2012 average age profile of this equipment is 17 years.

Condition of Assets
The equipment on this site is in average to good condition. No reliability problems are currently being experienced.
TLC load control equipment and radios were relocated out of the Transpower building and renewed in 2007 to overcome complex access requirements. This equipment is now located in a container adjacent to the Transpower site.

4.1.1.4 Tokaanu GXP

Voltage Level
33 kV

Description and Quantity of Assets
The equipment located at the Transpower and Genesis Energy Tokaanu site includes a load control plant and 33 kV switchgear.

Age Profile
The 2012 average age profile of this equipment is 15 years.

Condition of Assets
Assets at this site are in good condition and there have been no operational issues. There is however, a low risk/priority concern about the closeness of 33 kV jumper connections to the fence in the ripple control inductor and capacitor structure.

4.1.1.5 Atiamuri Supply Point

Voltage Level
33 kV and 11 kV

Description and Quantity of Assets
The configuration at Atiamuri is unique and described in earlier sections of this Plan.
The assets at this site owned by TLC include:

- 33 kV circuit breaker, protection, and controls.
- 10 MVA step up 11 kV to 33 kV transformer.
- 11 kV cabling.
- RTU and other associated equipment.

This equipment is sited on Mighty River Power land and leased to Transpower from Mighty River Power.

Age Profile
The 2012 average age profile of this equipment is 19 years.

Condition of Assets
Included in this plan is the replacement of the 33 kV circuit breaker which is in poor condition and no longer reliable. Also included in the plan is the installation of cooling fans on the 10 MVA step-up transformer. This is required due to the transformer overheating during peak loading.

4.1.1.6 Whakamaru Supply Point

Voltage Level
33 kV and 11 kV

Description and Quantity of Assets
The configuration at Whakamaru is unique and described in earlier sections of this Plan.

The assets at this site owned by TLC include:

- Tertiary winding in a 220/110/33 kV transformer.
- Protection associated with taking 33 kV supply from this transformer. This includes an earthing transformer.
- SCADA and other communication equipment.
- Electricity Commission rules compliant metering.
- 33 kV circuit breaker.

This equipment is sited on Mighty River Power land adjacent to the Whakamaru Transpower substation.
A new 317 Hz ripple injection plant housed in a 40 foot container was commissioned at the site in 2010. An additional 33 kV recloser was added to supply this plant.

Age Profile
The 2012 average age profile of this equipment is 7 years.

Condition of Assets
This equipment is in good condition. Issues surrounding a bushing failure on a new Schneider “dog box” 33 kV circuit breaker have now been resolved.

4.1.2 Sub-transmission Network 33 kV

4.1.2.1 Sub-transmission Lines

Table 4.1 lists the sub-transmission feeders, length, voltage and description, average conductor age and overall condition.

Feeder	Voltage & Description	Average Conductor Age (yrs)	Condition
Gadsby / Wairere 33 Length 34.6 km	33 kV. Part of ringed network. Te Kuiti, Wairere generation and surrounding industrial areas to Hangatiki GXP.	30	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 components failure. A substantial number of insulators have been changed from 33 kV to 44 kV ratings.
Gadsby Rd 33 Length 16.4 km	33 kV. Part of ringed network. Te Kuiti, Wairere generation and surrounding industrial areas to Hangatiki GXP.	43	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.
Lake Taupo 33 Length 46.9 km	33 kV. Spur line connecting Tokaanu GXP to the Kiko Road, Awamate Road and Waiotaka substations.	48	Line has almost been rebuilt over the last decade. It was originally unable 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 river crossing over the sensitive Tongariro River is of less than ideal design and is a risk to trout fishermen who use conductive fishing lines on the Tongariro River. Work to eliminate this hazard has been included in the plan.
Mahoenui 33 Length 22.6 km	33 kV. Spur line between Mahoenui and Wairere. Supplies long 11 kV spur lines after transformation at Mahoenui. Distributed Generation resource exists in the area.	36	Much of the feeder was upgraded in 1994. Lighter type of construction than the lines described above. 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.
National Park / Kuratau 33 Length 59.5 km	33 kV. 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.	58	Line has been split into two sections. The section between National Park and the Tawhai Substation supplies the Chateau and Whakapapa ski fields. The 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.
National Park 33 Length 0.04 km	33 kV. Short length of spur line connecting National Park GXP to zone substation.	40	Short length of line at GXP in reasonable condition.

Feeder	Voltage & Description	Average Conductor Age (yrs)	Condition
Nihoniho 33 Length 14.6 km	33 kV. Spur line connecting Ongarue GXP to Nihoniho zone substation.	33	Aged low strength line that has been partly renewed. Low cost design that has been patched up. Has had problems with magpies, hardware failure and insulator flashover due to fertiliser build-up.
Ongarue / Taumarunui 33 Length 18.6 km	33 kV. Main line supplying Taumarunui from the Ongarue GXP.	29	Low strength line that was last strengthened about 15 years ago. As part of next renewal cycle, the line will be strengthened further in 2013/14. Most of the line is in very steep, inaccessible hill country. Has had problems with magpies, hardware failure and insulator flashover due to fertiliser build-up.
Taharoa A 33 Length 57.1 km	33 kV. Supply to iron sand extraction at Taharoa and future DG sites (West Coast Wind and Hydro Customer requested and funded). Some local rural supply also.	42	Well Designed Line that over the last few years has been extensively renewed for parts of its length. 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 customer if they wish on improved level of reliability.
Taharoa B 33 Length 47.9 km	33 kV. Supply to iron sand extraction at Taharoa and Distributed Generation sites. (West Coast Wind and Hydro - Customer requested and funded). Some local rural supply also.	32	Well-designed line that over the last few years has been extensively renewed for part of length. 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.
Taumarunui / Kuratau 33 Length 38.5 km	33 kV. 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.	57	Line has adequate size conductor ,but poles well under strength for today's environment. Ideally all poles need replacing to increase line strength. As a stopgap measure it is proposed to replace every 5th pole as part of on-going programmes to increase line strength. This project is planned for 2013/14. The poles are also very short and the line has a number of ground to conductor clearance issues.
Te Kawa St 33 Length 13.4 km	33 kV. One of two lines supplying north from Hangatiki to the Otorohanga area. Loadings and security requirements show that the line is needed.	45	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.

Feeder	Voltage & Description	Average Conductor Age (yrs)	Condition
Te Waireka Rd 33 Length 8.7 km	33 kV. One of two lines supplying north from Hangatiki to the Otorohanga area. Loadings and security requirements show that the line is needed.	49	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.
Tokaanu / Kuratau 33 Length 16.1 km	33 kV. Interconnecting line between the Tokaanu GXP and Kuratau marshalling site. Normally supplies Kuratau zone sub and is a backup for the connection of the Kuratau area DG to the grid. Also used to back up National Park and Ongarue.	50	Line has adequate size conductor but poles well under strength for today's environment. Initial strengthening work commenced in 2012 and is near completion. The work undertaken also addresses a number of ground to conductor clearance issues on the line.
Tuhua 33 Length 0.1 km	33 kV. Few metres of spur line connecting Ongarue GXP to Tuhua zone substation.	45	Short length of line that has been partly renewed. There have been no recorded failures on this short section of line.
Turangi 33 Length 3.1 km	33 kV. Spur line connecting Tokaanu GXP to the Turangi zone substation.	53	Line has recently been renewed. Includes a number of iron rails. Old but in renewed condition.
Waitete 33 Length 10.8 km	33 kV. Part of ringed network. Te Kuiti, Wairere generation and surrounding industrial areas to Hangatiki GXP.	32	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.
Whakamaru 33 Length 95.2 km	33 kV. Connects Atiamuri and Whakamaru supply points to Arohena, Maraetai, Kaahu and Marotiri zone substations.	49	Originally constructed as a 50kV transmission line. Purchased by TLC in 2002 and has since been operated at 33kV. As part of the conversion process, aged conductor where changed and smaller 33kV insulators fitted.

TABLE 4.1: VOLTAGE, DESCRIPTION, AGE AND CONDITION OF 33 KV SUB-TRANSMISSION ASSETS

A profile of the sub-transmission 33 kV feeder average conductor age is shown in Figure 4.1.

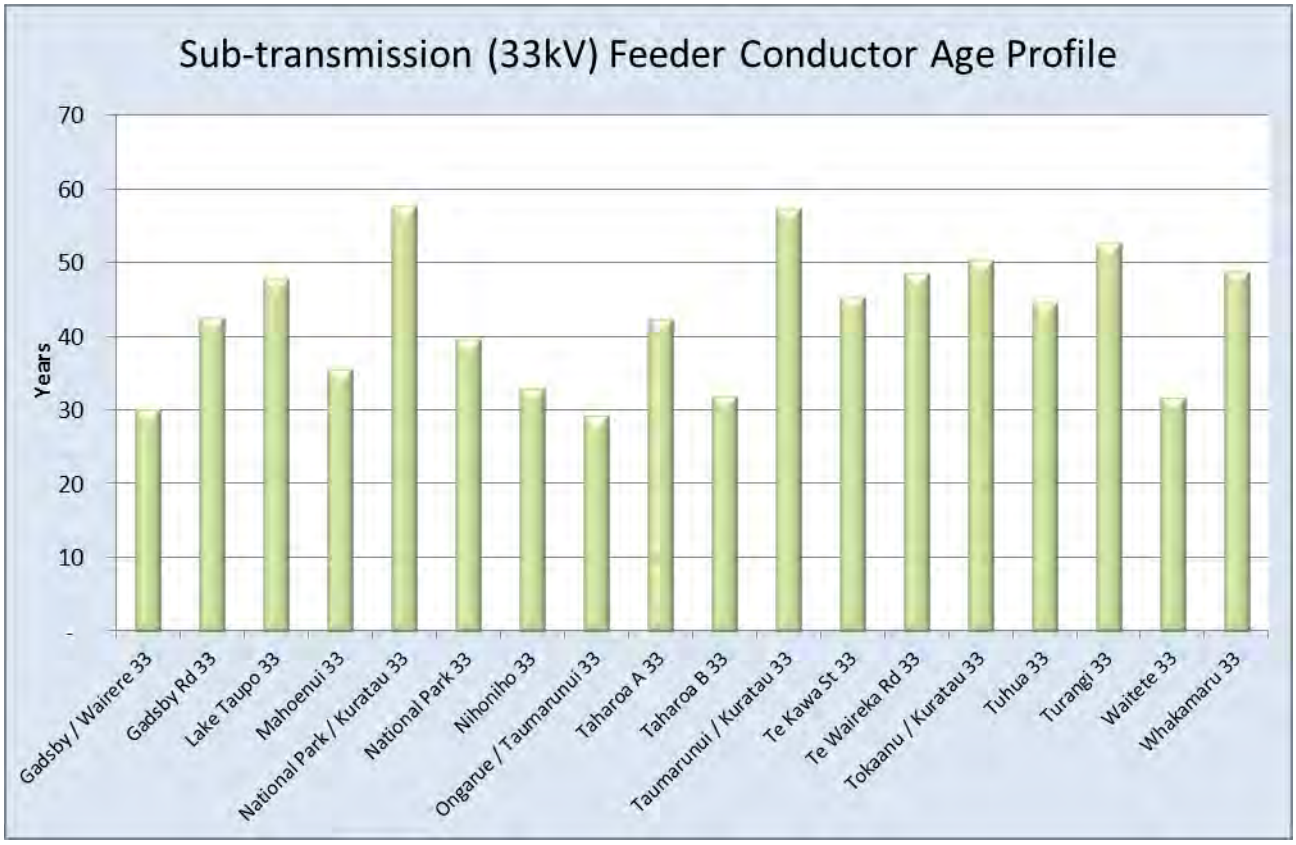


FIGURE 4.1: CONDUCTOR AVERAGE AGE PROFILE OF 33 KV SUB-TRANSMISSION LINES (YEARS)

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. This will ensure there is no shock to replace the entire assets over and above what is presented in this Plan provided the 15-year inspection and renewal cycle is continued and emergent problems are repaired when they occur. The renewal programme will result in continuous asset technology upgrade, i.e. the latest technology and materials etc. will be used for renewals.

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

1. *Insulator failure*

   The most common failure mode for 33 kV lines in the TLC network is insulator corona discharge to flashover, due mainly to fertiliser build-up. This problem is particularly acute with the smaller insulators equivalent to the NZI3370W that industry accepted as a standard insulator about 20 to 30 years ago.

2. *Flashover due to magpies on cross arms*

   Similar to 1 above with the corona to flashover being advanced when a magpie is in parallel with the insulator. Again, this problem is worst on lines constructed or upgraded in the last 20 years where smaller insulators have been used.

3. *Failure of Air Break Switches*

   A series of problems have arisen in recent times with 1980s manufactured 33 kV NZI 4-bolt insulators on 33 kV switches. These are a multi-piece insulator that, after about 20 years' service, are failing due to expansion of the cement that holds them together.

4. *Lightning arrestors*

   Earlier model distribution class arrestors are prone to failure and make it difficult to find earth faults.

5. *Trees*

   All overhead lines are prone to tree faults. Even though considerable effort has been put into clearing 33 kV lines, from time to time an event still occurs.

6. *Slips*

   Slips are common in the clay hills of the King Country. These slips often dislodge poles and cause faults, or on occasion bring trees into the lines.

7. *Pole and cross arm failure*

   The lines inspection and pole-testing programme has substantially reduced these events but from time to time, they still occur.

8. *Insulator wire ties*

   Failures of wire ties that hold wires on insulators can occur, especially in areas exposed to high winds and snow or vibration.

9. *Wire clashes*

   Wire clashing to conductor failure occurs from time to time. The cause of this is usually related to the original line designs. Due to the rugged country, conductor spacing's often end up too close and clash during high wind events or during the passage of fault currents.

Figure 4.2 illustrates corona discharge typical of that caused by a fertiliser build-up on a 33 kV insulator.

FIGURE 4.2: EXAMPLE OF CORONA DISCHARGE ON FERTILISER POLLUTED 33 KV INSULATOR

4.1.2.2 Zone Substations

Table 4.2 lists the zone substation locations, voltage, description and condition in the sub-transmission network. The age shown reflects the number of years since the zone substation was commissioned. Zone substation housing, where applicable, is detailed in the Condition/Housing column.

ZONE SUBSTATIONS – DESCRIPTION, AGE AND CONDITION			
Zone Substation	**Description**	**Age of Substation**	**Condition/Housing**
Arohena ZSub211	33 kV to 11 kV zone substation. Single unit site ex Transpower point of supply. Very limited 11 kV backup at light loads.	27	Maintained ex Transpower site. Has bunding and oil separation. The zone substation has weatherboard housing for the relay room.
Awamate ZSub519	33 kV to 11 kV zone substation. Modular substation with backup from Turangi at light loads.	5	New containerised asset performing better than expectations.
Borough ZSub508	33 kV to 11 kV zone substation. Two unit site able to supply full load short term on one unit. Two supplies available for 33 kV. Medium load backup at 11 kV with some transfer and embedded generation.	23	Average condition. Bunded with manual outlet valve. Site can flood. Single 11 kV busbar. 33 kV protection and switchgear needs reviewing. Housed assets are enclosed in a concrete block building.
Gadsby Road ZSub205	33 kV to 11 kV zone substation. Single unit site on north side of Te Kuiti. Two alternative 33 kV supplies running as closed ring. Medium load 11 kV alternatives.	36	Well build site. Reasonable condition. Has bunding and oil separation. Does not have earthquake constraints. Housed assets are enclosed in a concrete block building.
Hangatiki ZSub204	33 kV to 11 kV zone substation. Single unit site at Transpower point of supply. Two alternatives for 33kV running as closed ring with very short spur to sub bus. 11kV backup at medium loads.	18	Well built site. Reasonable condition. Has bunding but no oil separation. The site includes concrete block transformer housing.
Kaahu Tee ZSub216	33 kV to 11 kV zone substation. Modular substation with backup from Marotiri and Maraetai.	4	New containerised asset performing better than expectations.
Kiko Road ZSub518	33 kV to 11 kV zone substation. Single unit site. Single 33 kV line supply. No 11 kV alternatives.	11	New condition. Bunded with automatic Aqua Sentry Device.
Kuratau 33	Switchyard Switching site close to Kuratau Village Substation.	32	Switching site with various structures and switchgear. Some of the switchgear has been renewed. Remainder of old equipment included in renewal programmes.
Kuratau ZSub509	33 kV to 11 kV zone substation. Single unit site. Three 33 kV supplies. No 11kV alternative. Local embedded generation if water available.	12	New condition. Bunded with manual outlet valve.

ZONE SUBSTATIONS – DESCRIPTION, AGE AND CONDITION			
Zone Substation	**Description**	**Age of Substation**	**Condition/Housing**
Mahoenui ZSub 209	33 kV to 11 kV zone substation. Single unit. Single 33 kV line. Backup at light loads.	26	Average TLC zone site. Reasonable condition. Has bunding and separation. 11 kV circuit breaker was replaced in 2012 to increase reliability.
Manunui ZSub510	33 kV to 11 kV zone substation. Single unit site. Two 33 kV supplies available. Light to medium load 11 kV backup.	27	Average condition. Bunded with in ground separator. Improvements included in plan.
Maraetai ZSub210	33 kV to 11 kV zone substation. Single unit ex Transpower point of supply. Single 33 kV line. 11 kV backup at medium loads. Modification made to 24VDC actuators supplied from the 2 x 24 VDC cells.	25	Well maintained ex Transpower site. Good condition site. Has oil separation and bunding. Has aging incoming 33 kV breaker.
Marotiri ZSub212	33 kV to 11 kV zone substation. Single unit ex Transpower point of supply. Single 33 kV line 11kV backup at light loads.	23	Well maintained ex Transpower site. Good condition site. Has oil separation and bunding. Loading is at full or greater than rating. Housed assets are enclosed in a weatherboard building.
Mokai ZSub3358	11 kV to 11 kV zone substation. Fault reducing transformer, regulator container and other assets. Light load 11 kV backup.	2	Semi containerised asset – has oil separation and bunding.
National Park ZSub510	33 kV to 11 kV zone substation. Single unit site. Two 33 kV supplies. Medium load 11 kV backup.	37	Poor condition. No bunding or oil separation. Improvements are included in the plan.
Nihoniho ZSub503	33 kV to 11 kV zone substation. Single unit site. Single 33 kV supply. Light to medium load 11 kV backup.	37	Poor condition. No bunding or oil separation. Has hazard constraint. Improvements included in plan.
Oparure ZSub208	33 kV to 11 kV zone substation. Single unit mostly supplying specific customer. (Limestone processing). Single 33 kV line spurred off closed ring.	19	Good condition. Operating in harsh environment at Quarry. No bunding or separation.
Otukou ZSub512	33 kV to 11 kV zone substation. Single unit site. Two 33/11 kV supplies. No 11 kV backup.	14	Average condition. No bunding or oil separation. Improvements included in plan.
Piripiri	Switchyard. Transformer failed in 2010. Load in area picked up by Te Anga substation.	32	Now used as a switching station.
Taharoa ZSub201	33 kV to 11 kV zone substation. Three units supplying iron sand extraction and local load. Two 33kV lines operating as closed ring.	35	Poor condition. Operating in harsh environment on beach. Has oil separation and bunding. Has a metering compliance and hazard issues. 15 MVA capacity at site.
Tawhai ZSub513	33 kV to 11 kV zone substation. Single unit site. Two 33 kV supplies. Light to medium 11 kV backup.	36	Average condition. No bunding or oil separation. Improvements included in plan.

ZONE SUBSTATIONS – DESCRIPTION, AGE AND CONDITION			
Zone Substation	**Description**	**Age of Substation**	**Condition/Housing**
Te Anga ZSub520	33 kV to 11 kV zone substation. Modular substation with backup from Taharoa.	2	New containerised asset performing to expectations.
Te Waireka ZSub203	33 kV to 11 kV zone substation. Two unit site with one unit able to carry full load. Two 33 kV lines operating as closed ring. Medium load 11 kV backup available.	27	Average to good condition. Oil separation and bunding. Single busbar. Aging oil filled switchgear. Feeder loadings are high. Protection old and needs review. Diversity for busbar arrangement included in plan. The zone substation includes brick housing.
Tokaanu Village ZSub507	33 kV to 11 kV zone substation. Single unit site. Single 33 kV line. No 11 kV backup.	16	Good condition. Improvements included in plan.
Tuhua ZSub502	33 kV to 11 kV zone substation. Single unit site. Single 33 kV line close to Transpower point of supply. Light to medium 11 kV backup.	33	Poor condition. No bunding or oil separation. Has hazard constraint. Improvements included in plan.
Turangi ZSub505	33 kV to 11 kV zone substation. Two unit site. Single 33 kV line. No 11 kV backup.	19	Improved condition. Work has commenced on upgrading protection and addressing hazards.
Waiotaka ZSub511	33 kV to 11 kV zone substation. Modular substation with backup from Turangi.	7	New containerised asset - performing better than expectations.
Wairere ZSub207	33 kV to 11 kV zone substation. Two unit site in conjunction with embedded generation. Limited 11kV backup. Supply will island.	34	Average condition. Bunded with manual outlet valve. Protection and 33kV bus arrangement needs reviewing. The switchroom is enclosed in a brick building.
Waitete ZSub206	33 kV to 11 kV zone substation. Three unit site. Able to supply full load with some 11 kV transfer and embedded generation. Two 33 kV lines running in closed ring.	39	Good condition. Modifications including new bunding, oil separation and earthquake restraints have commenced. Housed assets are enclosed in a brick building.

TABLE 4.2: VOLTAGE, DESCRIPTION, AGE AND CONDITION OF SUB-TRANSMISSION ZONE SUBSTATIONS

An age profile of zone substations – based on year of commissioning - is given in Figure 4.3.

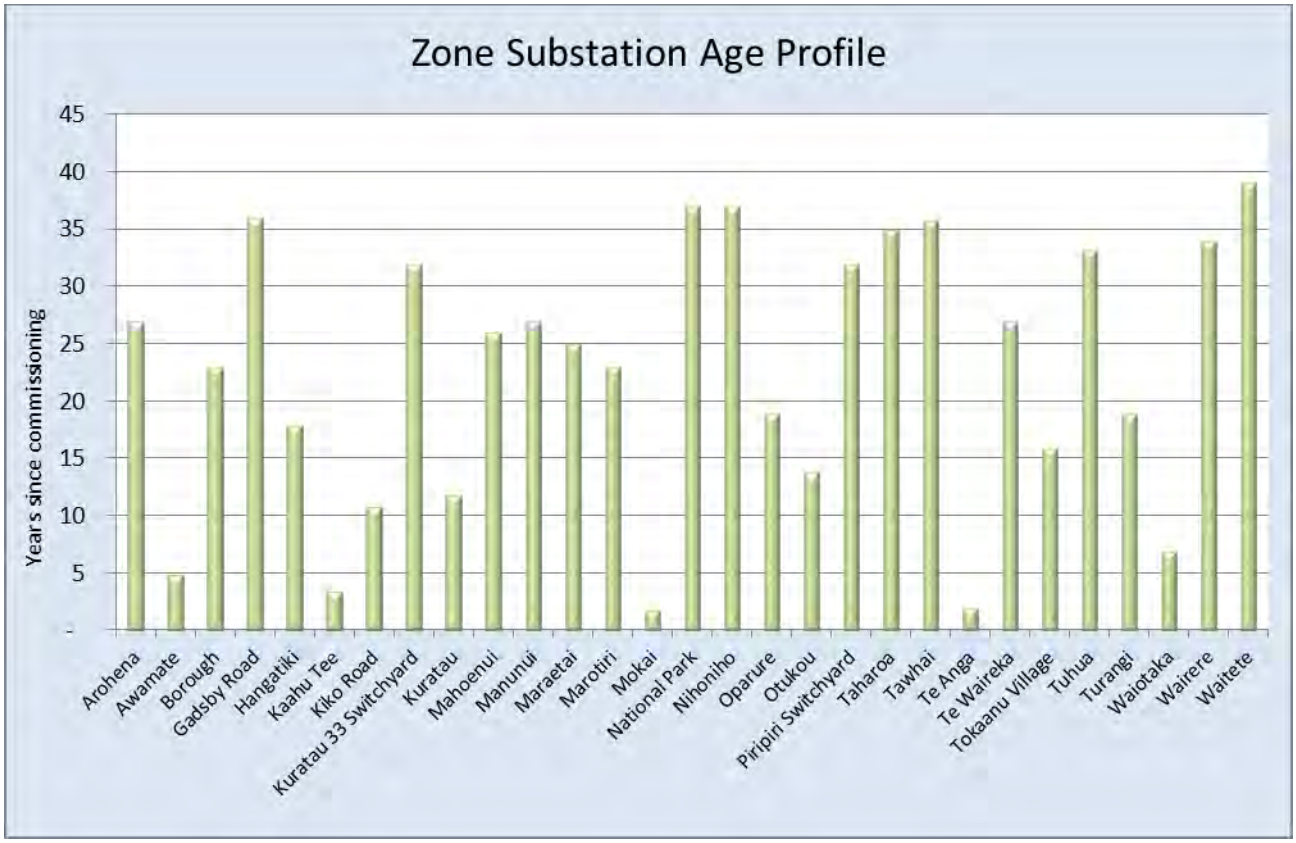


FIGURE 4.3: AGE PROFILE OF ZONE SUBSTATIONS

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 renewal programme will result in continuous asset technology upgrade, i.e. the latest technology and materials etc. will be used for renewals.

The Plan allows for switchgear and control systems to be renewed on a continual basis. The systemic issues that lead to the premature replacement of zone substation assets or parts of these assets include:

1. *Air Break Switches*

   As outlined in line failures, there is a batch of switches with insulators manufactured by New Zealand Insulators in the 1980s that from time to time crack and fall apart.

2. *Control equipment*

   Voltage control relays and protection relays tend to fail at the rate of two to three per year. When this occurs, units are replaced with modern equivalents.

3. *Fault Throwers*

   Unreliable, and often fall apart when they are reset. The improvement and cost of circuit breaker technology along with increasing fault levels means these devices are unreliable and creating hazards.

4. *Batteries*

   A number of batteries and battery chargers have failed in the past. The number of failures has reduced now that a renewal programme is in place.

4.1.2.3 Power Transformers

Table 4.3 lists the Power Transformers in the sub-transmission network. The table details location, voltage ratio, capacity, identity, transformer and tap changer manufacturer, age and condition of these assets.

SUB-TRANSMISSION POWER TRANSFORMERS – DESCRIPTION AND CONDITION							
Zone Substation	**Voltage Ratio**	**Capacity**	**Identity**	**Manufacturer**	**Tap Changer**	**Age / Year Commissioned**	**Condition**
Arohena	33kV / 11kV	3.0 MVA	211T1	Alstom	Associated Tap Changer	11 yrs (2002)	2010 oil test result show the condition of the unit is acceptable.
Atiamuri	33kV / 11kV	10.0 MVA	215T5	Alstom	Fixed Tap	11 yrs (2002)	2010 oil test result show the condition of the unit is acceptable.
Awamate	33kV / 11kV	2.0 MVA	T4274	ETEL Limited	Line Regulator	4 yrs (2008)	New Unit. 2010 oil test result show the condition of the unit is acceptable.
Borough	33kV / 11kV	5.0 MVA	508T1	Bonar Long & Co	Ferranti	48 yrs (1965)	2008 Oil refurbished. Unit is being refurbished at time of writing.
Borough	33kV / 11kV	5.0 MVA	508T2	Bonar Long & Co	Ferranti	48 yrs (1965)	Oil test in 2004 show that half-life maintenance is required. 2008 oil refurbished. Feb 2010 half-life refurbishment was carried out. 2010 oil test result show the condition of the unit is acceptable.
Gadsby Road	33kV / 11kV	5.0 MVA	205T6	Turnbull & Jones	Hawker Siddeley	7 yrs (2006)	Transformer rebuilt in 2005 after a major failure. 11 kV windings replaced. Unit totally stripped and dried. 2010 oil test result show the condition of the unit is acceptable.
Hangatiki	33kV / 11kV	5.0 MVA	204T1	Tyree	Associated Tap Changer	21 yrs (1992)	2010 oil test result show the condition of the unit is acceptable for a transformer of this age.
Kaahu Te	33kV / 11kV	2.4 MVA	216T1	ETEL Limited	Line Regulator	4 yrs (2009)	2010 oil tests are marginally acceptable. Transformer to be sent back to manufacturer for refurbishment under warranty.
Kiko Road	33kV / 11kV	3.0 MVA	518T1	Alstom	Associated Tap Changer	12 yrs (2001)	2010 oil test result show the condition of the unit is acceptable.
Kuratau	33kV / 11kV	3.0 MVA	509T1	Hawker Siddeley	Hawker Siddeley	58 yrs (1955)	Transformer relocated from Taharoa. Condition under question. Tank has been refurbished and oil reclaimed Transformer is being monitored closely. Emergency back put on site in case of failure.
Kuratau	33kV / 11kV	1.5 MVA	509T2	Turnbull & Jones	Fuller	3 yrs (2009)	2010 oil test result show the condition of the unit is marginally acceptable. Oil reclamation required. Allowances for this work have been included in plan period estimates.

SUB-TRANSMISSION POWER TRANSFORMERS – DESCRIPTION AND CONDITION							
Zone Substation	**Voltage Ratio**	**Capacity**	**Identity**	**Manufacturer**	**Tap Changer**	**Age / Year Commissioned**	**Condition**
Mahoenui	33kV / 11kV	3.0 MVA	209T1	Brush	Brush	47 yrs (1966)	2003 Oil refurbished. 2010 oil test result show the condition of the unit is acceptable.
Manunui	33kV / 11kV	5.0 MVA	510T1	Bonar Long & Co	Ferranti	48 yrs (1965)	Oil refurbished 2003. Acceptable operation at this time . Unit is due for half-life refurbishment. Allowances for this work have been included in plan period estimates.
Maraetai	33kV / 11kV	5.0 MVA	210T11	Alstom	Associated Tap Changer	12 yrs (2001)	2010 oil test result show the condition of the unit is acceptable.
Marotiri	33kV / 11kV	3.0 MVA	212T1	Alstom	Associated Tap Changer	12 yrs (2001)	2010 oil test result show the condition of the unit is acceptable.
Mokai	11kV / 11kV	7.5 MVA	T3358	ABB Transformers	Fixed Tap	2 yrs (2011)	New transformer. Commissioning oil test results show the condition of the transformer is good.
National Park	33kV / 11kV	3.0 MVA	501T1	Bonar Long & Co	Associated Electrical Industries (AEI)	46 yrs (1967)	Oil test marginally acceptable. Unit is coming due for half-life refurbishment. Allowances for this work have been included in plan period estimates.
Nihoniho	33kV / 11kV	1.5 MVA	503T1	ETEL Limited	Line Regulator	3 yrs (2010)	2010 oil tests are marginally acceptable. Transformer to be sent back to manufacturer for refurbishment under warranty.
Oparure	33kV / 11kV	3.0 MVA	208T1	ABB Transformers	ABB	19 yrs (1994)	2010 oil test result show the condition of the unit is acceptable.
Otukou	33kV / 11kV	0.5 MVA	512T1	Turnbull & Jones	Line Regulator	26 yrs (1987)	Acceptable condition.
Taharoa	33kV / 11kV	5.0 MVA	201T8	Turnbull & Jones	Associated Tap Changer	34 yrs (1979)	2004 oil refurbished. 2010 oil test result show the condition of the unit is acceptable.
Taharoa	33kV / 11kV	5.0 MVA	201T9	Turnbull & Jones	Fuller Electrical	42 yrs (1971)	2010 oil test result show the condition of the unit is acceptable. Relocated during 2008 from Kuratau.
Taharoa	33kV / 11kV	5.0 MVA	201T10	Turnbull & Jones	Associated Tap Changer	42 yrs (1971)	2005 oil refurbished. 2010 oil test result show the condition of the unit is acceptable.
Tawhai	33kV / 11kV	5.0 MVA	513T1	Bonar Long & Co Ltd	Ferranti	47 yrs (1966)	Oil tests are marginally acceptable. Transformer is due for half-life refurbishment. Allowances for this work have been included in the plan period estimates .
Te Anga	33kV / 11kV	2.4 MVA	T3326	ETEL Limited	Line Regulator	2 yr (2011)	New transformer performing better than expectations.

SUB-TRANSMISSION POWER TRANSFORMERS – DESCRIPTION AND CONDITION							
Zone Substation	**Voltage Ratio**	**Capacity**	**Identity**	**Manufacturer**	**Tap Changer**	**Age / Year Commissioned**	**Condition**
Te Waireka	33kV / 11kV	10.0 MVA	203T3	Alstom Transformer Division	Fuller Electrical	12 yrs (2001)	This transformer failed during 2005 due to a poorly made crimp connection on the 33kv delta winding jumpers. The unit had to be detanked, all the connections repaired in the unit, dried and retanked. 2010 oil test result show the condition of the unit is acceptable.
Te Waireka	33kV / 11kV	10.0 MVA	203T4	Alstom Transformer Division	ABB	17 yrs (1996)	2010 oil test result show the condition of the unit is acceptable.
Tokaanu Village	33kV / 11kV	1.3 MVA	507T1	ABB Transformers	Fuller Electrical	17 yrs (1996)	2010 oil test result show the condition of the unit is acceptable.
Tuhua	33kV / 11kV	1.5 MVA	502T1	Bonar Long & Co Ltd	Line Regulator	51 yrs (1962)	2004 oil refurbished. 2010 oil test result show the condition of the unit is acceptable.
Turangi	33kV / 11kV	5.0 MVA	505T1	English Electric	Fuller Electrical	52 yrs (1961)	Oil test marginally acceptable. Half-life maintenance of transformer is due and included in plan.
Turangi	33kV / 11kV	5.0 MVA	505T3	English Electric	Fuller Electrical	49 yrs (1964)	2010 oil test result show the condition of the unit is acceptable.
Waiotaka	33kV / 11kV	1.5 MVA	511T1	ETEL Limited	Line Regulator	7 yrs (2006)	2010 oil tests are marginally acceptable. Transformer to be sent back to manufacturer for refurbishment under warranty.
Wairere	33kV / 11kV	2.5 MVA	207T11	Metro-Vickers	Associated Tap Changer	33 yrs (1980)	2010 oil test result show the condition of the unit is acceptable.
Wairere	33kV / 11kV	2.5 MVA	207T12	Metro-Vickers	Associated Tap Changer	33 yrs (1980)	2010 oil test result show the condition of the unit is acceptable.
Waitete	33kV / 11kV	5.0 MVA	206T1	English Electric	Fuller Electrical	52 yrs (1961)	2003 oil refurbished. 2010 oil test result show the condition of the unit is acceptable.
Waitete	33kV / 11kV	5.0 MVA	206T2	English Electric	Fuller Electrical	52 yrs (1961)	2003 oil refurbished. 2010 oil test result show the condition of the unit is acceptable.
Waitete	33kV / 11kV	5.0 MVA	206T3	Metro-Vickers	Metro-Vickers	58 yrs (1955)	Spare network 5 MVA transformer. Was temporarily put into Waitete as part of 2007 programme. Configuration allows easy removal and transportation to another site in an emergency. 2010 oil test result show the condition of the unit is acceptable.

TABLE 4.3: SUB-TRANSMISSION POWER TRANSFORMERS: DESCRIPTION AND CONDITION

Figure 4.4 summarises the age profile of TLC's sub-transmission power transformers.

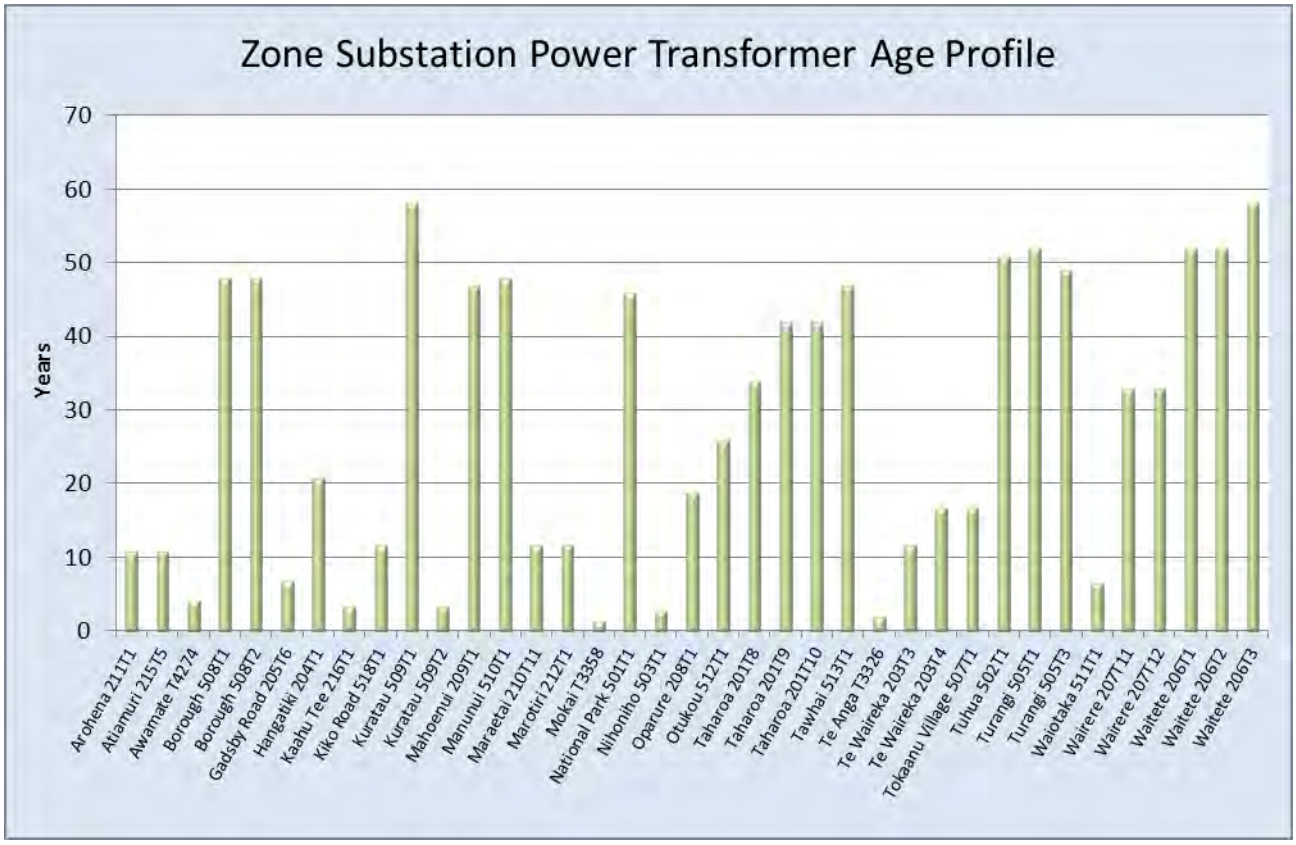


FIGURE 4.4: AGE PROFILE OF ZONE SUBSTATION POWER TRANSFORMERS

It is expected that the age profile of zone substation transformers will stay spread with a flow of new modular units into the lower age section. Older units as listed in Table 4.4 will be refurbished to extend their life. (Allowances are included in plan estimates.)

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. If the older solid units are serviced, experience shows that they will perform very well and will likely give continuing good service. This is, however, subject to other variables such as tank, paper, tap-changer, and other components' condition.

A relatively new 10 MVA T3 unit at Te Waireka failed due to a poor connection in 2003. It was likely that this connection was substandard since manufacture. Areva, the manufacturer of this product, was not prepared to fund any of the repairs.

Changes over the last few years have meant there are now effectively two 5 MVA units that can be re-deployed in an emergency. (One each from Waitete and Turangi.) Refurbishment of the older units and deployment of a number of new modular substations will mean that no sudden shock to replace a number of units will likely result.

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.

4.1.2.4 Sub-transmission Switchgear

Table 4.3 lists the quantity, location and condition of the sub-transmission (33 kV) switchgear assets. Of the figures shown, some of the assets are located in zone substations and others are on sub-transmission lines.

33 kV SWITCHGEAR ASSETS – DESCRIPTION, QUANTITY AND CONDITION		
Description	**Location/Qty**	**Condition**
Air Break Switches	Line ..... 71 Zsub 81	Ages and condition vary. Switches are renewed when they are no longer serviceable.
Load Break Switches	Zsub 3	Ages and condition vary. Switches are renewed when they are no longer serviceable.
Circuit Breakers	Zsub .. 135	Ages and condition vary. Switches are renewed when they are no longer serviceable.
Fault Throwers	Line 9	These devices are in poor condition and the Plan includes programmes to replace them with circuit breakers.
Fused Switches	Zsub 6	Ages and condition vary. Switches are renewed when they are no longer serviceable.
Fused Links	Line ..... 12 Zsub 4	Ages and condition vary. Switches are renewed when they are no longer serviceable.
Reclosers	Line ..... 6 Zsub 4	Mostly new condition
Solid Links	Line ..... 51 Zsub 19	Ages and condition vary. Switches are renewed when they are no longer serviceable.
Transformer Fuses	Line 2	Ages and condition vary. Fuses are renewed when necessary.

TABLE 4.4: DESCRIPTION, QUANTITY AND CONDITION OF SUB-TRANSMISSION SWITCHGEAR ASSETS

Figure 4.5 gives an indication of the age profile of sub-transmission switchgear.

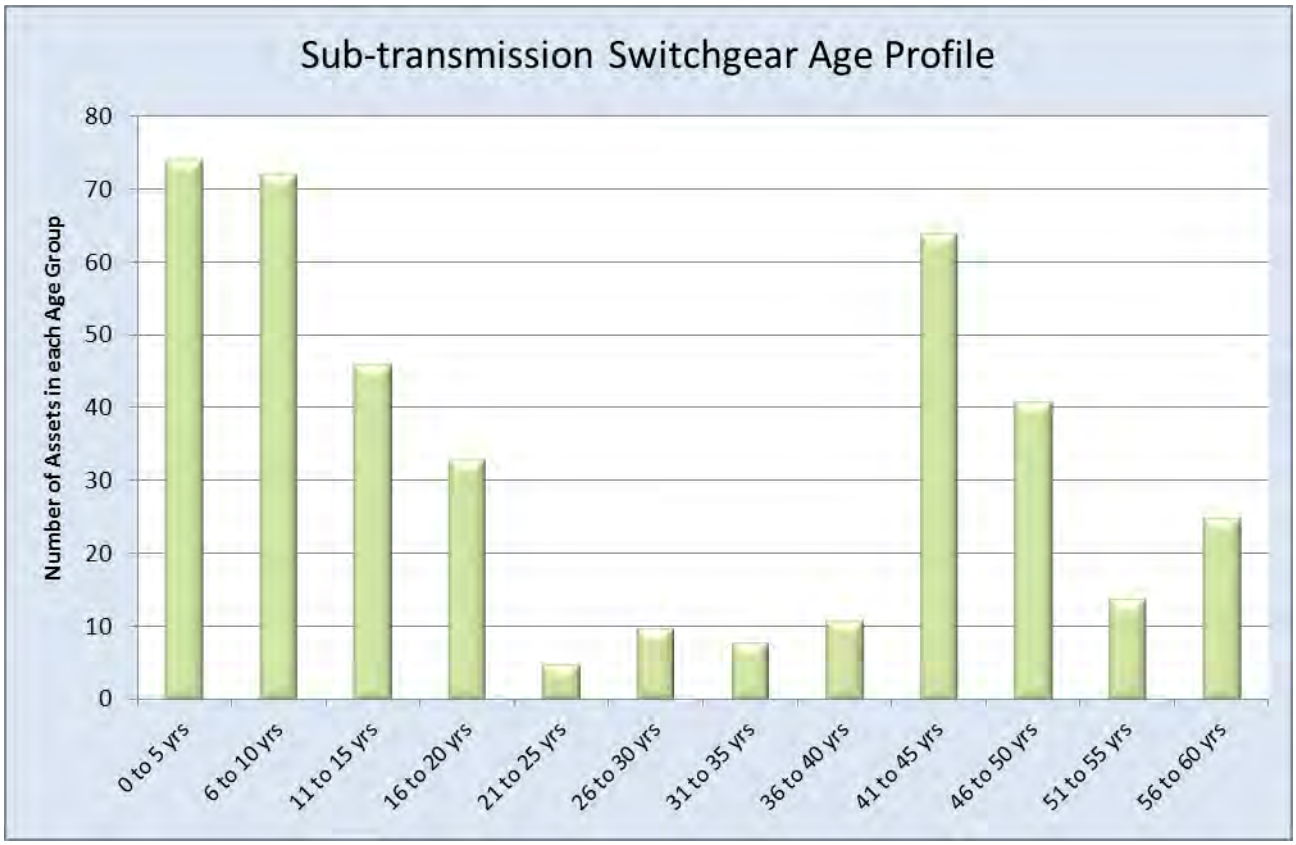


FIGURE 4.5: AGE PROFILE OF SUB-TRANSMISSION SWITCHGEAR

The age profiles of 33 kV switchgear has improved and will continue to follow the trend shown in figure 4.5 during the planning period with new units replacing the older ones as part of the renewal programme.

The renewal programme will also result in a continuous asset technology upgrade. Modern, low maintenance equipment with electronic controls will improve the overall asset performance and lower the maintenance costs of switchgear over time.

The condition of sub-transmission switchgear varies widely from relatively modern equipment to very old items. Generally, equipment operates satisfactorily and any that is found to be unserviceable is renewed.

The main causes of premature failure of these assets have been over voltages, mechanical linkage problems, and corrosion in extreme environments. A number of early electronic and electro-mechanical relays controlling this equipment have failed. Over voltages are likely to have been caused by lightning and switching surges.

4.1.2.5 Sub-transmission Cable

The TLC sub-transmission network contains 1.7km of XLPE (Cross-Linked Polyethylene Insulation) cable. This is primarily is associated with zone substations. The cable is of mostly in good condition, with half of it commissioned in the last 5 years.

4.1.3 Distribution Network 11 kV

4.1.3.1 Distribution feeders

The network 11 kV distribution feeders are detailed below in table 4.5. The table includes voltage, location description, feeder length, average age of overhead conductor, ICP connections and condition notes. The distribution feeder length is the total of both overhead and underground.

11kV DISTRIBUTION FEEDERS – DESCRIPTION, LENGTH, AGE, ICP's and CONDITION/NOTES					
Feeder	**Location Description**	**Length (km)**	**Average OH Conductor Age (yrs)**	**Feeder ICPs**	**Condition/Notes**
Aria FED114 (11 kV)	Aria rural area	77.2	42	260	Average condition rural feeder. Constructed predominantly on 10/2KN concrete poles. Problems have been experienced in recent times with low creepage distances 1950's insulators discharging to pin and cracking causing auto-recloses when it rains. Some renewal work has been completed.
Benneydale FED103 (11 kV)	South east of Te Kuiti, Benneydale, Mangapehi Generation and Crusader Meats	134.7	47	476	Long feeder with rural, industrial and distributed generation connections. Has four regulators in series being run to the maximum. Has been substantially renewed. Travels through moderate hill country and includes many long spans with some close conductor phase spacings.
Caves FED101 (11 kV)	Waitomo village and rural area to the west.	65.5	44	319	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. Insulators are also 1950's low creepage distance and problems of cracking and auto-reclosing during rain periods are experienced.
Chateau FED419 (11 kV)	Whakapapa Ski field and village	28.6	-	138	Supply to Chateau and Whakapapa Ski Field. Overhead sections renewed and replaced with cable. About 60% is heavy armoured cable.
Coast FED125 (11 kV)	Remote rural area around Marokopa	84.3	27	320	Several asset groups renewed. Generally aging rural feeder with parts exposed to severe coastal conditions. Mostly small ACSR conductor that is showing corrosion problems in some areas. Poles predominantly 10/2KN concretes and iron rails with low creepage distance insulators and problems of cracking and auto reclosing during rain are experienced. Difficult feeder to automate due to lack of communication signals from existing repeaters.
Gravel Scoop FED109 (11 kV)	South east of Otorohanga	88.9	52	526	Average condition rural feeder supported by a mixture of wooden poles and 10/2KN concretes. Sections have been renewed.

11kV DISTRIBUTION FEEDERS – DESCRIPTION, LENGTH, AGE, ICP's and CONDITION/NOTES					
Feeder	**Location Description**	**Length (km)**	**Average OH Conductor Age (yrs)**	**Feeder ICPs**	**Condition/Notes**
Hakiaha FED401 (11 kV)	Central area of Taumarunui	5.7	50	298	Supplies central area of Taumarunui and is partly underground. Becomes a rural feeder when it leaves town boundary. 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 (11 kV)	Area east of Hangatiki	19.8	44	72	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.
Hirangi FED405 (11 kV SWER)	SWER feeder to semi residential area around Turangi	1.6	43	369	Totally SWER feeder on outskirts of Turangi. Average condition. Some renewal work completed.
Huirimu FED121 (11 kV)	Supply to rural area south of Arohena	44.5	43	156	Average condition in dairying and dry stock area. Most of 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 (11 kV)	Kuratau	56.8	34	1311	Extensive renewal and strengthening completed.
Mahoenui FED113 (11 kV)	Supply to Mahoenui and surrounding rural areas	104.1	27	275	Average condition. Most of feeder is supported on 10/2KN concrete poles. Some renewal work completed.
Maihiihi FED111 (11 kV)	Rural area north east of Otorohanga	109.0	39	894	Rural feeder supplying dairying load. Has been mostly renewed over the last 10 years. Average to good condition.
Mangakino FED118 (11 kV)	Supply to Mangakino	22.5	45	489	Average condition. Some asset groups have been renewed. Mixture of poles.
Manunui FED408 (11 kV)	Rural area to south and east of Taumarunui	87.3	53	579	Supply to Manunui village and rural area. Generally in reasonable condition but design is inherently light. Poles mainly 10/2KN concrete and iron rails. Incorporates the old Affco Feeder. Renewal work and some upgrading is planned.
Matapuna FED404 (11 kV)	Supply to western side of Taumarunui	16.8	38	1040	Good condition (once renewals completed). Mostly supported by concrete poles with 10/2KN strength ratings. Renewal of rural section completed or underway.

11kV DISTRIBUTION FEEDERS – DESCRIPTION, LENGTH, AGE, ICP's and CONDITION/NOTES					
Feeder	**Location Description**	**Length (km)**	**Average OH Conductor Age (yrs)**	**Feeder ICPs**	**Condition/Notes**
McDonalds FED110 (11 kV)	Rural area to the south of Otorohanga	40.3	71	448	Supplies dairying and industrial load. Design is weak with long spans of larger size ACSR on 10/2KN concrete and iron rails. Insulators are 1950's low creepage distance and problems of cracking and auto-reclosing during rainy periods are experienced. Feeder has a voltage problem. Overall in average condition with some renewal work completed.
Miraka FED131 (11 kV)	Part of Mokai Energy Park	0.9	2	2	Newly constructed as part of energy park. About 50% is underground utilising heavy conductor.
Mokai FED123 (11 kV)	Mokai rural area including western bays area of Lake Taupo	82.9	37	313	Average condition. Mostly supported on mixture of hardwood and concrete 10/2kn poles. Some renewal work completed. Consists of some long spans with close conductor spacings that can clash in wind. Insulators are also mostly 1950's low creepage distance type that are susceptible to cracking and causing auto-reclosing when it rains. Some renewal work completed; more planned.
Mokau FED128 (11 kV)	Mokau coastal area	132.3	38	651	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.
Mokauiti FED115 (11 kV)	Rural area south west of Piopio	74.2	40	171	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. Insulators are mostly 1950's low creepage distance types than are susceptible to cracking and causing auto-recloses when it rains. Some asset groups have been renewed.
Motuoapa FED425 (11 kV)	Supply to Motuoapa area	2.5	12	413	East Taupo. Partly renewed and partly very old construction. Old construction will be renewed as part of 15 years renewal programme. Overall average condition.
National Park FED411 (11 kV)	Supply to the National park area including the village	43.3	46	378	Partly renewed, partly in very poor condition with long spans of light conductor on 10/2KN concrete and iron rails. Will be renewed and poles strengthened as part of 15 year line programme. Overall in average condition.
Nihoniho FED412 (11 kV)	Supply to the Nihoniho and Matiere areas	26.6	50	61	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.)
Northern FED402 (11 kV)	Area north of Taumarunui	111.7	37	1247	Average condition. Is a long feeder. Some asset group 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.

11kV DISTRIBUTION FEEDERS – DESCRIPTION, LENGTH, AGE, ICP's and CONDITION/NOTES					
Feeder	**Location Description**	**Length (km)**	**Average OH Conductor Age (yrs)**	**Feeder ICPs**	**Condition/Notes**
Ohakune Town FED414 (11 kV)	Ohakune town supply	13.5	36	895	Urban supply to Ohakune that is generally in average condition. Several security improvement projects have been completed and more are proposed to bring feeder up to industry standard for a supply to a popular tourist area. Some renewal /strengthening work has been completed; more is planned.
Ohura FED413 (11 kV)	Ohura and surrounding remote rural areas	174.5	48	377	Lightly constructed feeder in remote area. Feeder overall is in average condition. 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 and not over investing on lines in a very remote area. Supplies several interconnecting SWER systems.
Ongarue FED421 (11 kV)	Large rural area around Ongarue	127.6	50	263	Lightly constructed feeder in remote area. Feeder overall is in average condition. Has low customer density and a declining population base. The area it covers is a large section of a remote part of the King Country. Designs associated with renewal have to focus on maximum improvement for spend and not over investing on lines in a very remote area. Supplies several interconnecting SWER systems. (Some renewal work has been completed.)
Oparure FED107 (11 kV)	Supply to an area west of Te Kuiti	80.4	29	927	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.
Oruatua FED417 (11 kV)	Eastern side of Lake Taupo, north of Motuoapa	4.6	16	391	East Taupo. Partly renewed and partly very old construction. Old construction will be renewed as part of 15 year renewal programme.
Otorohanga FED112 (11 kV)	Supply to most of town plus rural area to southwest	53.1	28	1152	Overhead urban and rural feeder. Urban area in average condition. 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.
Otukou FED418 (11 kV)	Area around Sir Edmund Hillary Outdoor Pursuits Centre	5.7	39	93	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.

11kV DISTRIBUTION FEEDERS – DESCRIPTION, LENGTH, AGE, ICP's and CONDITION/NOTES					
Feeder	**Location Description**	**Length (km)**	**Average OH Conductor Age (yrs)**	**Feeder ICPs**	**Condition/Notes**
Paerata FED130 (11 kV)	Part of Mokai Energy Park	3.8	2	9	Mostly new - constructed as part of energy park supply. It does include some older sections that were part of the Mokai feeder.
Piopio FED116 (11 kV)	Supply to Piopio village and surrounding rural area to north	52.9	33	458	Rural settlement and rural supply. Good condition. Feeder does have long spans with close conductor spacings. It is predominantly supported by 10/2KN concrete poles. Some renewal completed.
Pureora FED119 (11 kV)	West of Whakamaru including supply to Crusader Meats	52.5	38	169	Average condition. Parts have been renewed. Supplies dairying and industrial load. Medium size conductor on mix of wooden and 10/2KN concrete poles. Has had some asset group renewal work completed. Ideally two more regulators and some upgrading is needed to support voltage levels. (Regulators are included in the plan.)
Rangipo / Hautu FED424 (11 kV)	Supply to areas east of Turangi	38.9	48	854	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.
Rangitoto FED106 (11 kV)	Area west of Te Kuiti	79.2	51	730	Average condition. Some renewal work completed. Mixture of concrete 10/2KN, wooden and iron rail poles. Has some long spans with close conductor spacings.
Raurimu FED410 (11 kV)	Raurimu village and rural areas to east, west and south	171.2	42	305	Average to poor condition. Line has some major SWER lines connected that go deep into the King Country. The feeder is predominantly supported by iron rails. Limited income is available from this extremely rugged and remote area.
Rural FED126 (11 kV)	Rural area surrounding Taharoa	4.7	41	116	Average to poor condition rural feeder but exposed to 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. Some asset group renewal work is completed. Feeder has small customer numbers and renewal is balanced against returns.
Southern FED409 (11 kV)	Area south of Manunui including connection for Piriaka distributed generation	124.2	46	616	Generally in good condition. Much of the feeder has conjoint SWER systems. Predominantly supported on 10/2KN concrete poles. Has a number of long spans that are prone to clashing during periods of high wind speeds. Some renewal work has been completed.
Tangiwai FED416 (11 kV)	Area east of Ohakune	90.6	41	650	Average condition. This feeder is located in a moderate to heavy snow area. The inherent design has no allowance for ice loadings. Some asset group renewal work has been completed . The poles are either iron rails or 10/2KN concretes.

11kV DISTRIBUTION FEEDERS – DESCRIPTION, LENGTH, AGE, ICP's and CONDITION/NOTES					
Feeder	**Location Description**	**Length (km)**	**Average OH Conductor Age (yrs)**	**Feeder ICPs**	**Condition/Notes**
Te Kuiti South FED104 (11 kV)	Part of Te Kuiti town and rural area to south.	25.6	44	577	Average condition feeder principally supported on 10/2kN concrete poles. Has a number of long spans that are prone to clashing during periods of high wind speed. Have also had a number of problems with 1950's short creepage distance insulators that discharge to pins, crack and cause auto-reclosing during rain. Some renewal work completed.
Te Kuiti Town FED105 (11 kV)	Central area of Te Kuiti	2.0	42	151	Average condition. Mostly supported by 10/2KN concrete poles. Has a mix of AL and CU conductors. Suffers from joint failure when exposed to through fault currents. Some renewal work completed.
Te Mapara FED117 (11 kV)	Area south east of Piopio	79.9	41	229	Rural feeder in good condition. Some asset groups have been renewed. Mixture of wooden and concrete poles. Some renewal work completed.
Tihoi FED124 (11 kV)	Western bays area Lake Taupo	63.3	43	209	Average condition. Parts of feeder have an on-going tree problem due to a large number of tree blocks owned by absentee landowners. Some renewal work completed.
Tirohanga FED129 (11 kV)	Western bays area Lake Taupo	68.4	45	230	Average condition. Some renewal work completed; more underway.
Tokaanu FED420 (11 kV)	Tokaanu	1.2	-	84	Mainly underground cable. Good condition. Renewal work completed.
Tuhua FED422 (11 kV)	Remote rural area around Ongarue	41.2	55	149	Average condition remote rural feeder supplying remote area. Has a number of SWER lines connected towards its ends. Supported by mostly 10/2KN concrete poles and iron rails. Some renewal work has been completed.
Turangi FED423 (11 kV)	Supply to Turangi Town and surrounding area	8.6	48	1100	Mostly underground feeder supplying Turangi town. The overhead section that supplies the underground is currently a double circuit. This is being changed to a single circuit which will remove excessive load on the poles.
Turoa FED415 (11 kV)	Turoa ski field and urban rural area to bottom of mountain	59.2	46	435	Main purpose is supply to Turoa ski field. The feeder is constructed with heavy conductor on moderate strength poles. There are one or two long spans where there are inadequate conductor spacings. The overall condition is good but the line is generally constructed under strength for the heavy snow area it is in. Some strengthening and renewal work has been completed.

11kV DISTRIBUTION FEEDERS – DESCRIPTION, LENGTH, AGE, ICP's and CONDITION/NOTES					
Feeder	**Location Description**	**Length (km)**	**Average OH Conductor Age (yrs)**	**Feeder ICPs**	**Condition/Notes**
Waihaha FED426 (11 kV)	Area around south western of Lake Taupo	95.0	43	315	Part of feeder is in good condition, part in poor condition. The poor section was once part of the original 33kV single phase and 11kV SWER arrangement that supplied the area. The lines are mostly supported on 10/2KN concrete poles and iron rails. Spans are long and conductor sizes are small. Expenditure needed on renewals is hard to justify. Some renewal work has been completed.
Waiotaka FED427 (11 kV)	Waiotaka	10.2	20	8	Originally part of the Rangipo / Hautu feeder. New container substation was commissioned in 2007 to provide security of supply to prison and surrounding area. Average condition. Some renewal work has been completed.
Waitomo FED108 (11 kV)	Area north of Te Kuiti and major lime plant	11.1	42	437	Average condition rural feeder supplying part of Te Kuiti town and rural area to the north. Medium size conductor mostly supported on 10/2KN concrete poles. Has some larger spans with close conductor spacing. Some renewal work completed.
Western FED403 (11 kV)	Rural area north west of Taumarunui	134.9	54	416	Supplies part of Taumarunui and travels west along the Whanganui River until breaking into a number of SWER systems. Asset group sections have been renewed and security has been increased by establishing a link to the Northern feeder. Generally in poor condition with lines being mainly supported by 10/2KN concrete poles and iron rails. Some renewal work has been completed.
Whakamaru FED120 (11 kV)	Whakamaru village and surrounding dairying areas	86.1	30	577	Rural feeder supplying dairying area and ex NZED Whakamaru Village. Sections have been renewed. Overall feeder is in average condition.
Wharepapa FED122 (11 kV)	Large rural dairying area west of Arohena	107.1	49	404	Long rural feeder supplying dairying area. Includes a large amount of 16sq.mm Cu conductor supported on iron rail and hardwood poles. Some asset group renewal work completed. Additional automated switches were installed as part of the 2006/07 programme to try and improve reliability in this area. Some renewal work completed. Renewal of conductors is included in the plan.
Winstones FED428 (11 kV)	Area east of Ohakune	0.1	23	3	Part of Ohakune feeder. Good condition; renewal is planned in the future.

TABLE 4.5: 11 KV DISTRIBUTION FEEDERS, DESCRIPTION, LENGTH, AGE, ICP'S AND CONDITION/NOTES

Age Profiles

The overhead conductor age profile for the 11 kV Distribution feeder network is shown in Figure 4.6. The vertical access indicates the number of kilometres of line in each age group.

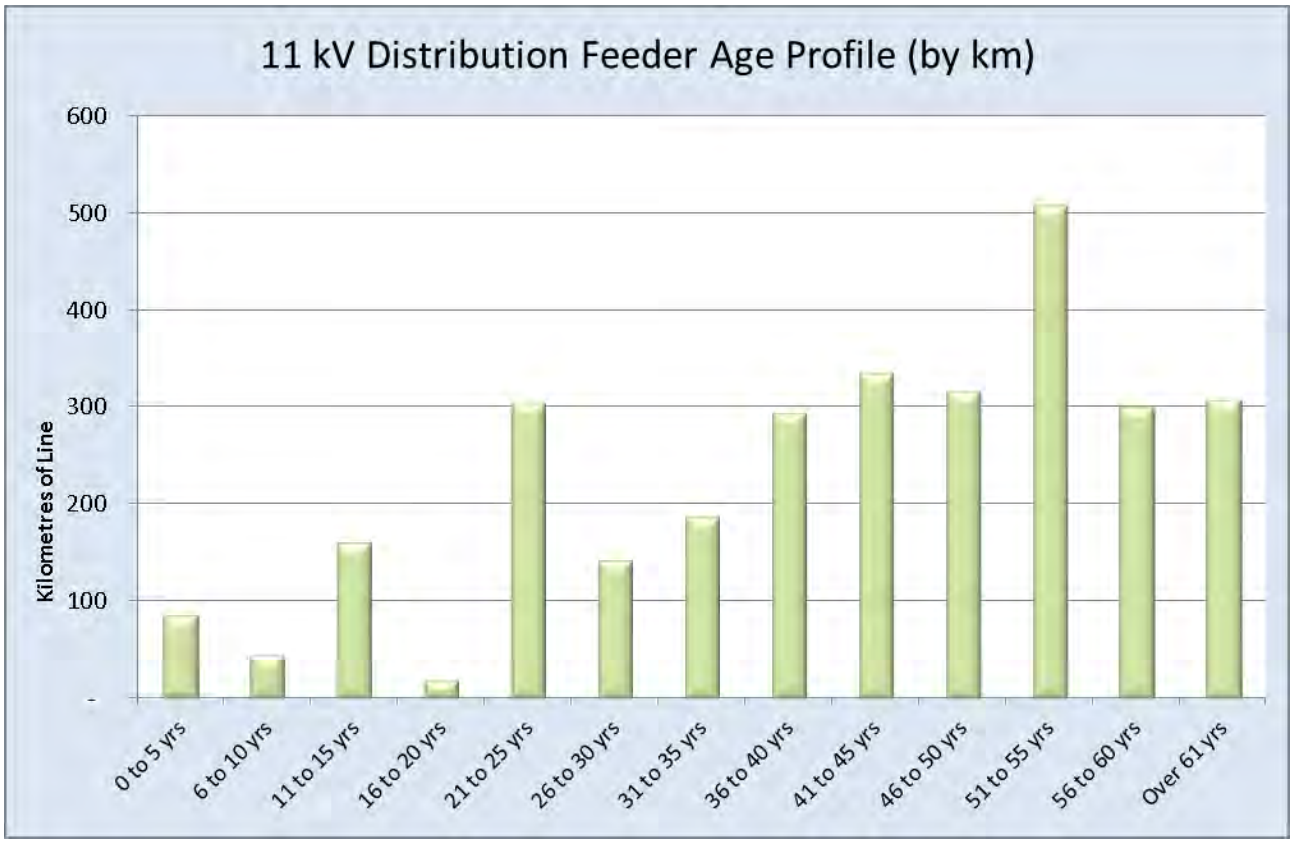


FIGURE 4.6: AGE PROFILE OF 11 KV FEEDERS BY KILOMETRE

The present development and renewal strategies will encourage the age profile to trend toward more kilometres in younger age groups. This will ensure there is no shock to replace entire assets provided the 15-year inspection and renewal cycle is continued and emergent problems are repaired when they occur. The renewal programme will result in continuous asset technology upgrade, i.e. the latest technology; materials, etc. will continually be used for renewals.

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 cause significant problems with overhead lines.

2. *Connection failures*

   Most conductor connection failures occur with jumpers between lines or on to equipment such as dropout fuses or Air Break Switches. The major cause of these is poor workmanship and inappropriate equipment. Most problems occur when dissimilar metals are involved. A large number of problems occur after the passage of fault current.

3. *Insulators*

   Historically two types of insulators have been used on 11 kV networks in New Zealand. These are the 821 and 1130 categories. The 821 have lower technical ratings than the 1130. The most significant of these ratings is the creepage distance; 185mm as opposed to 250mm. Most of the TLC network including SWER systems has been constructed with the 821 insulators. After 40 years of exposure to the King Country environment, most of which receives regular fertiliser applications, these insulators fail. Finding failed insulators (that normally crack due to pin corrosion initiated by corona discharge) is very difficult with presently available testing tools.

Figure 4.7 illustrates a typical 1950's 821 insulator that has discharged to the pin and then cracked.

FIGURE 4.7: EXAMPLE OF AN 821 INSULATOR THAT HAS DISCHARGED TO PIN.

4. *Conductor failures*

   Span lengths in the TLC networks tend to be long as lines go from hilltop to hilltop. Cross arm lengths by industry standards are short. This leads to conductor clashing mid-span either caused by wind, birds, or trees pushing wires together. After a period of clashing and recloses, wires burn through and fall to the ground. Adding to this problem, many of the older conductors in the northern network are copper. Copper work hardens and becomes brittle with age. After clashing, conductor failures can become common.

   Clashing can cause protection to operate incorrectly. Often a substation breaker will operate instead of a field recloser because of clashing between the two caused by fault current passage into a remote fault. Joints in conductors often fail after the passage of fault current. Fault current has to be controlled to minimise these effects.

Many of the rural feeders in the TLC network were constructed by farmers using short poles to establish supply into rural areas. This very minimal, low cost approach does sometimes result in conductor-to-ground clearances falling to below those stated in codes of practice. Sometimes these low conductors get tangled in machinery such as maize harvesters and conductor damage occurs.

5. *Cross arm failures*

   Most cross arm failures are caused by old age and rot.

6. *Pole failures*

   Old age, rot, lack of staying, corrosion and poor design cause pole failures.

7. *Private lines*

   Approximately 800km of 11 kV lines connected to the TLC network are classified as private lines. This means responsibility for maintaining these lines rests with the landowner. Landowners are often reluctant to carry out maintenance.

   Private lines are fused at tap off when they are found to be causing problems or as part of the 15 year renewal programmes. Lines inspectors assess private lines when inspecting as part of the 15 year cycle. This information is passed onto line owners so that they can approach a contractor and get repairs completed.

   Lines inspectors recheck known private line problems after a reasonable period and if they have not been repaired, then further follow-up results. This includes discussing the issue with the owner again and, if still no response, then TLC may disconnect and/or notify the Energy Safety regulator.

   The new Electricity (Safety) Regulations outline private line responsibilities more clearly than the previous legislation. Specifically the fines for non-compliance are now attached to the individual regulations.

4.1.3.2 Distribution Cables

Voltage

Most of the distribution cable connected to the TLC network operates at 11 kV. There are a number of sections of 11 kV cable connected to SWER lines that operate at 11 kV to earth and 6.6 kV to earth.

Description and qualities of assets

Distribution cables are dispersed throughout the network. The areas with most significant cabling are:

- Feeders coming out of Te Waireka (Otorohanga), Waitete (Te Kuiti), and Borough (Taumarunui) zone substations.
- Parts of Taumarunui.
- Parts of Ohakune.
- Turangi Town (ex hydro construction town).
- Whakapapa Ski Field.
- Turoa Ski Field.
- Small sections of feeders under Transmission lines or into/away from modular substations.
- Recent subdivisions.
- Short sections of cable into ground mounted substations.

The sum of cabling on the two ski fields equates to about 50% of The Lines Company cable reticulation. Earlier table 4.5 lists the individual feeders and the lengths of cable included in each feeder. Table 4.6 summarises cable data by voltage.

DISTRIBUTION CABLE SUMMARY		
Description	**Voltage**	**Total km**
Distribution Underground XLPE or PVC cable	6.6 kV	1.2
Distribution Underground XLPE or PVC cable	11 kV	116.9

TABLE 4.6: DISTRIBUTION CABLE VOLTAGE AND LENGTH

Key:
XLPE - Cross-Linked Polyethylene Insulation
PVC - Polyvinyl Chloride Insulation

Age Profiles

The overall age profile of distribution cables is illustrated in Figure 4.8.

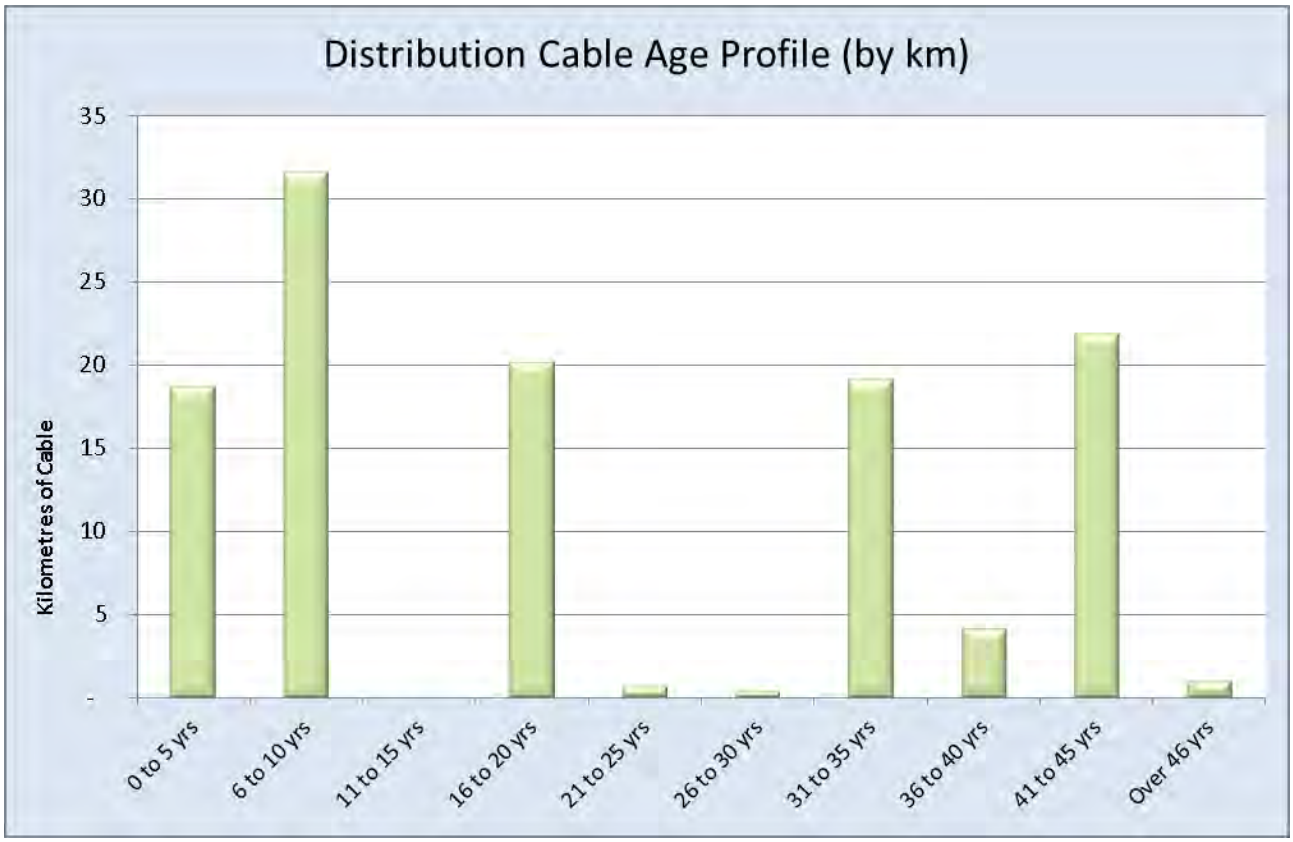


FIGURE 4.8: AGE PROFILE OF DISTRIBUTION CABLES

The age of cables corresponds to subdivision activity and ski field development.

Condition of Assets

Much of TLC's legacy distribution cabling is older generation XLPE cable. Many low quality terminations have been renewed over the last few years. Generally, TLC's cable assets are in average industry condition. Sections of cable that cause problems are being renewed (normally as part of "emergent works" – see Sections 7 and 8). This will ensure there is no funding shock to replace entire assets.

Most of the ski field cables consist 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. Snow groomers damage these cables from time to time.

4.1.3.3 Distribution Poles

Voltage Levels

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.

Distribution and Quantity of Assets

Distribution poles are dispersed across the entire network. Table 4.7 indicates the number and composition of distribution poles as well as those on the sub-transmission and low voltage networks.

NETWORK POLE SUMMARY			
Description	**Wood**	**Concrete/Steel**	**Total**
11 kV Distribution Network (including 11 kV SWER)	9,161	17,965	27,126
33 kV Sub-transmission Network	1,689	1,970	3,659
400 V Low Voltage Network	4,569	717	5,286

TABLE 4.7: NETWORK POLE SUMMARY

Age Profile

The overall age profile of all poles is illustrated in Figure 4.9.

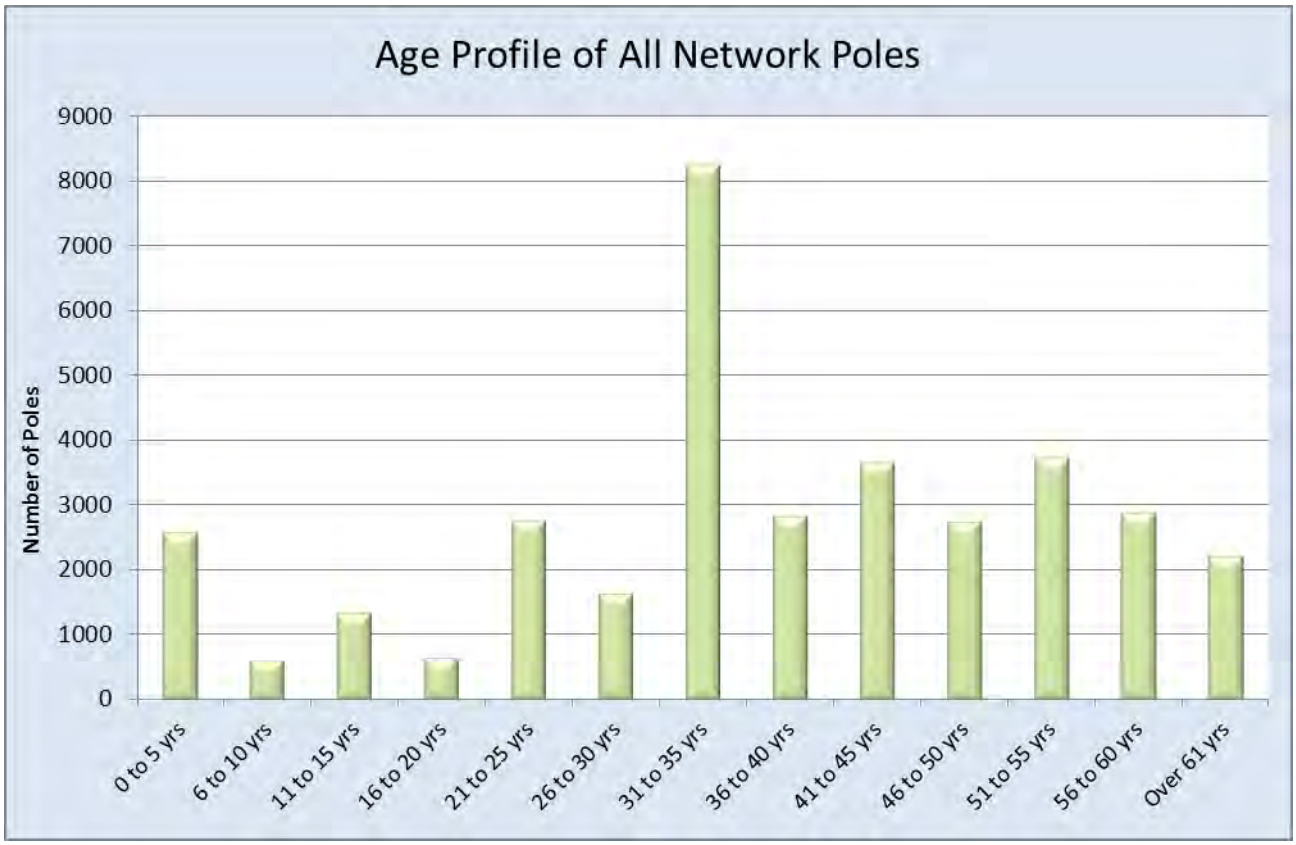


FIGURE 4.9: AGE PROFILE OF ALL NETWORK POLES

Condition of Assets

Approximately 60% of concrete or steel poles on the network are in good to average condition. The figure is lower for wooden poles, being around 40%. The 15-year inspection cycle aims to ensure there is no shock to replace large numbers of poles within limited timeframes. This is achievable provided the inspections and renewals continue, and emergent problems are dealt with as they occur.

4.1.3.4 Distribution Transformers

Voltage Levels

Except for a few 6.6 kV to 240 V and 33 KV to 415 V units, all of TLC distribution transformers are 11 kV to 415/240 Volt.

Distribution and Quantity of Assets

The majority of TLC's distribution transformers are 30 kVA or less, 11 kV to 240 V. These units are standard pole hanging transformers. The pole hanging stock includes various transformers up to and including 200 kVA.

There are approximately 400 ground-mounted transformers, in various configurations; from exposed bushing units in sheds through to modern enclosed "I" tank units. This population is similar to other network companies' stock.

TLC also has a stock of about 65 11/11 kV transformers used to supply the 60 SWER systems connected to the network.

The distribution transformers are summarised in Table 4.8.

DISTRIBUTION TRANSFORMER SUMMARY	
Transformer Description	**Total Number**
Pole Mounted Single/Two Phase	
Up to and including 15 kVA	2725
30 kVA	408
60 kVA	47
100 kVA	44
> 100 kVA	16
Pole Mounted Three Phase	
Up to and including 50 kVA	1262
100 kVA	180
200 kVA	32
300 kVA	14
>=500 kVA	2
Ground Mounted Single Phase	
Up to and including 200kVA	10
Ground Mounted Three Phase	
Up to and including 85kVA	48
100 kVA	55
200 kVA	178
300 kVA	113
500 kVA	33
>500 kVA	36

TABLE 4.8: DISTRIBUTION TRANSFORMER SUMMARY

Age Profile

Figure 4.10 indicates TLC's distribution transformer age profile.

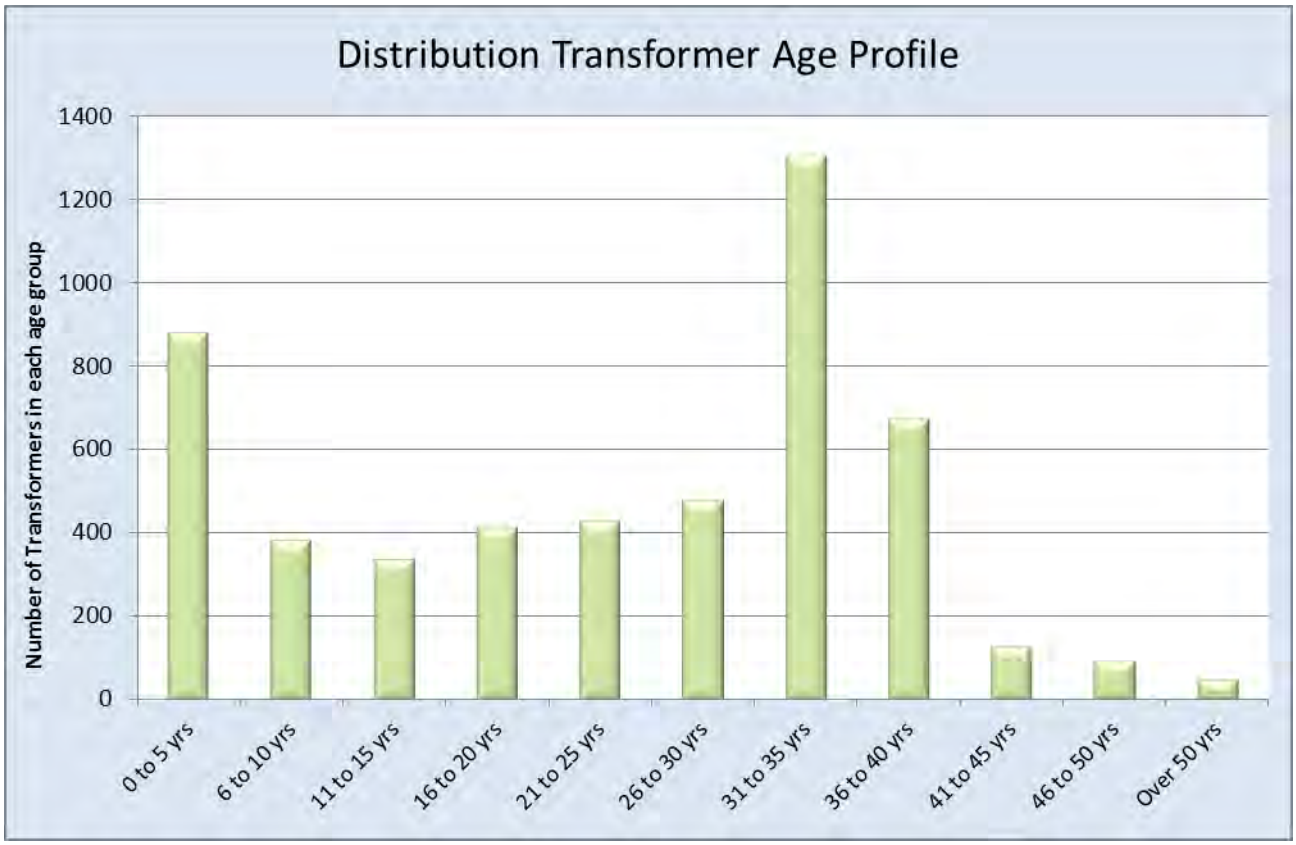


FIGURE 4.10: DISTRIBUTION TRANSFORMER AGE PROFILE

It is expected that the age profile of distribution transformers will shift slightly to the newer end of the graph as the renewal programme runs through the planning period. This will ensure there is no shock to replace large numbers of transformers at once provided the 15-year inspection and hazard control renewal cycle is continued.

Note: TLC is not scrapping transformers that can be refurbished or reused. Only transformers that are old, in poor condition or have failed and are not economic to repair are being written off. (See lifecycle section for more details on this.)

Condition of Assets

The distribution transformer stock is in average condition.

There are a number of reasons why transformers fail prematurely. The reasons for failures include:

- Lightning strike
- Accident (vehicle, vegetation)
- Water damage
- Broken bushings
- Fault current passage
- Corroded cases

4.1.3.5 11 kV Switchgear

Voltage Level

The switchgear detailed in this section is that associated with the distribution of voltage of 11 kV. It excludes sub-transmission and zone substation equipment.

Description and Quantity of Assets

Table 4.9 describes the type and quantity of distribution switchgear assets. The figures include the 221 switchgear assets contained in the 68 Ring Main Units on the distribution network.

11 kV DISTRIBUTION SWTICHGEAR AND CONTROL ASSETS	
Type of Link	**Number**
11 kV Air Break Switches	645
11 kV Circuit Breakers	28
11 kV Fault Thrower Switches	8
11 kV Fused Switches	848
11 kV Load Break Switches	146
11 kV Reclosers	111
11 kV RTE Integrated Transformer Switches	60
11 kV Sectionalisers	78
11 kV Solid Links	447
11 kV Transformer Fuses	5215

TABLE 4.9: 11 KV DISTRIBUTION SWITCHGEAR AND CONTROL ASSETS

Age Profiles

Figure 4.11 indicates the age profile of 11 kV distribution switchgear assets.

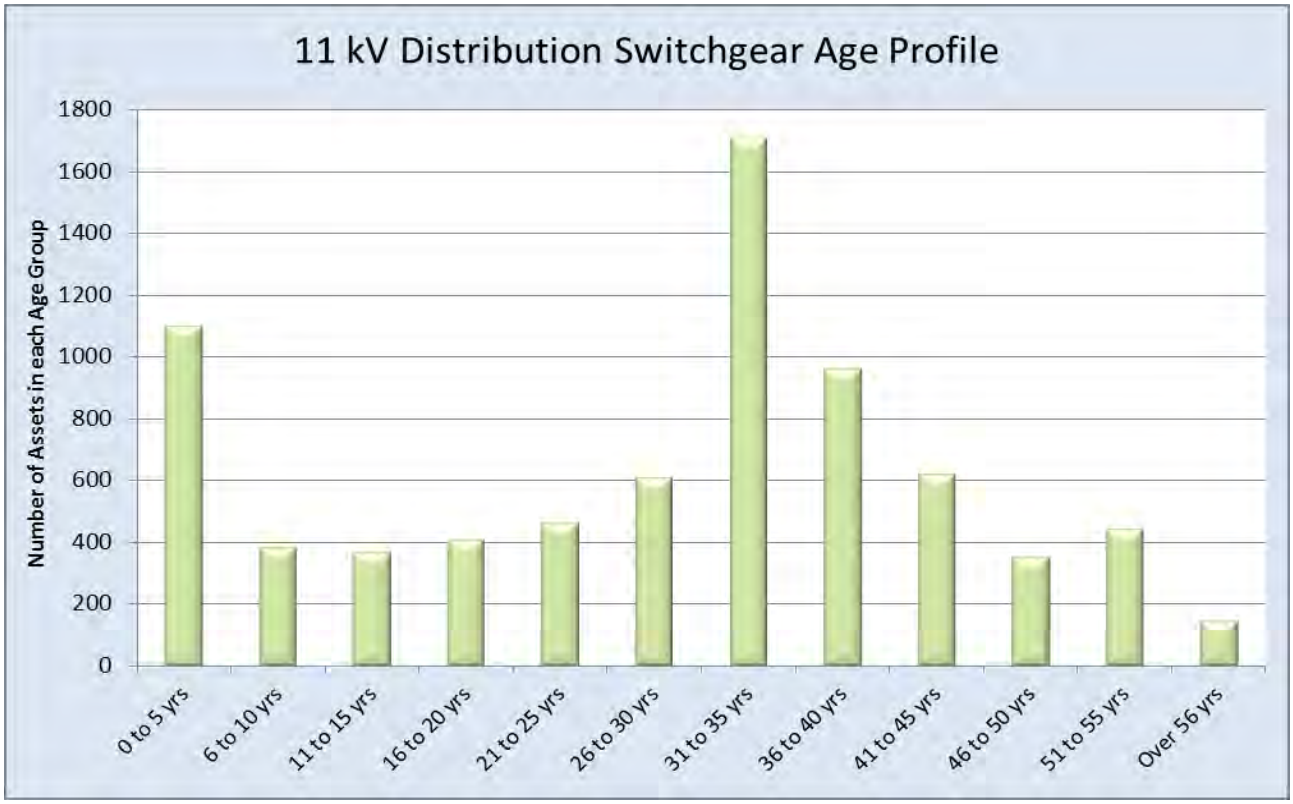


FIGURE 4.11: AGE PROFILES OF 11 KV SWITCHGEAR ASSETS

The new switchgear coming into the network as part of the renewal programme has shifted the age profile to the left of the chart as compared to earlier years. (Older units are also being renewed on failure and as part of the 15-year line renewal programme.) This will ensure there is no shock to replace large numbers of switches provided the renewal programme is continued and emergent problems are repaired when they occur. The renewal programme will also result in continuous asset technology upgrades, i.e. the latest technology, materials etc.

Condition of Assets

The distribution 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 have been found to be:

- Poor manufacturing quality.
- Poor connections.
- Corrosion.

Figure 4.12 illustrates a typical mode of corrosion failure with dropout fuses.

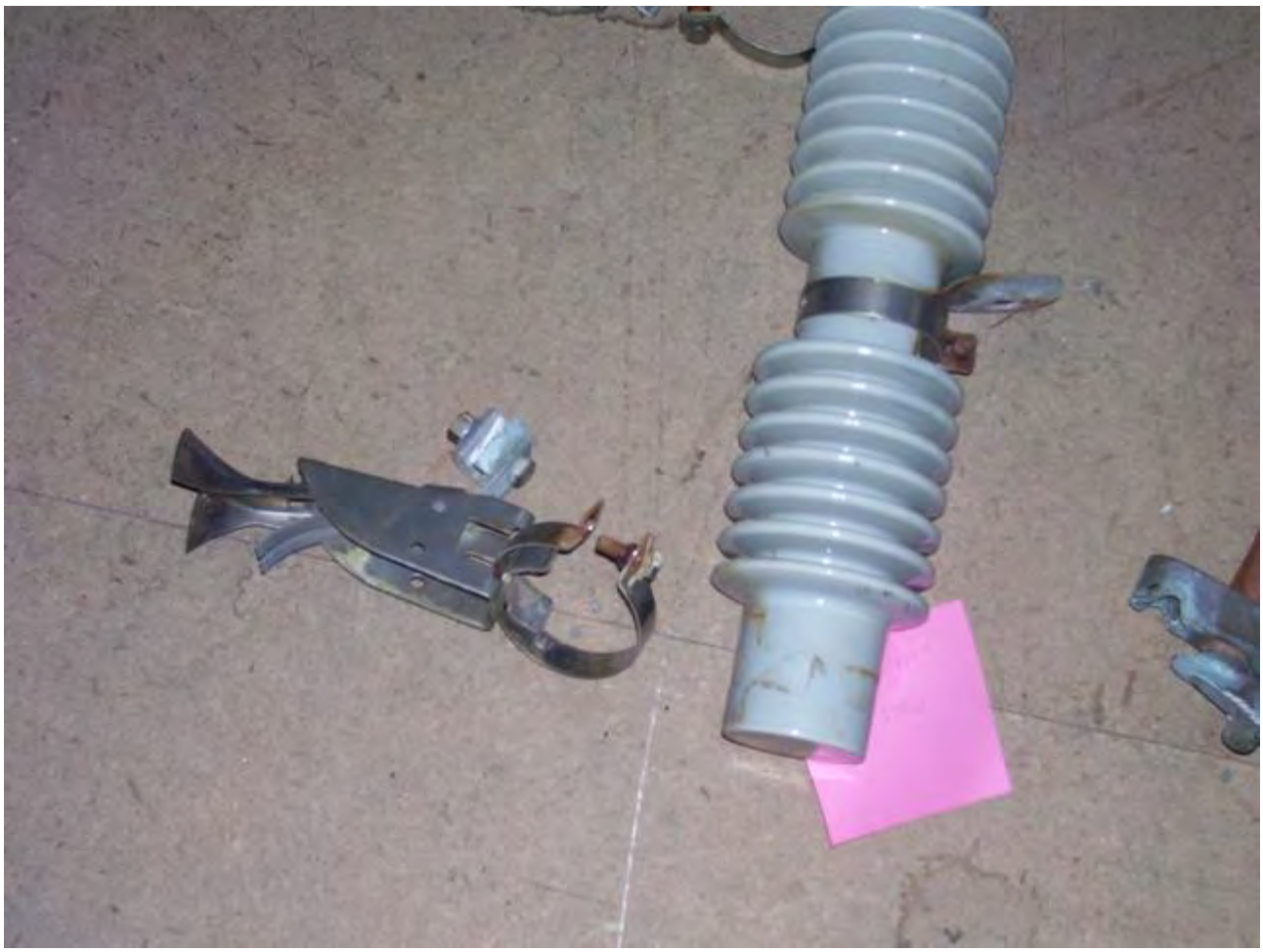


FIGURE 4.12: EXAMPLE OF FAILURE OF A DROPOUT FUSE.

Air break switches generally give problems with electrical connections onto the units and operating mechanisms. Most other switchgear has been found to perform to manufacturers' specifications.

4.1.4 Distribution Network Low Voltage

Voltage Level

The voltage level of the low voltage network is 400/230V.

Description and Quantity

TLC records of the low voltage network vary in terms of data accuracy. There are good records of recent work. Records of overhead rural and older urban network can be incomplete and in these situations are based on best estimates.

More detail of LV systems is being collected as part of inspections associated with the renewal programme. This data is being progressively entered into the network data system. Table 4.10 lists the estimated quantities of assets on the low voltage network.

LOW VOLTAGE DISTRIBUTION ASSETS	
Description	**Quantity**
LV Poles - Concrete	717 units
LV Poles - Wood	4569 units
LV Overhead Circuit	274.5 km
LV Underground Circuit	129.3 km
LV Streetlight Circuit	48.3 km
Pillar Boxes	4022 units

TABLE 4.10: ESTIMATED QUANTITIES OF LOW VOLTAGE DISTRIBUTION ASSETS.

Low voltage underground cables exist to some extent in most township areas. Turangi town has the most extensive low voltage network. As mentioned previously, there are few low voltage ties in these networks.

The low voltage underground assets include pillar boxes (service boxes) of which TLC has approximately 4022 units.

Age Profiles

The age profile of LV overhead lines is indicated in Figure 4.13.

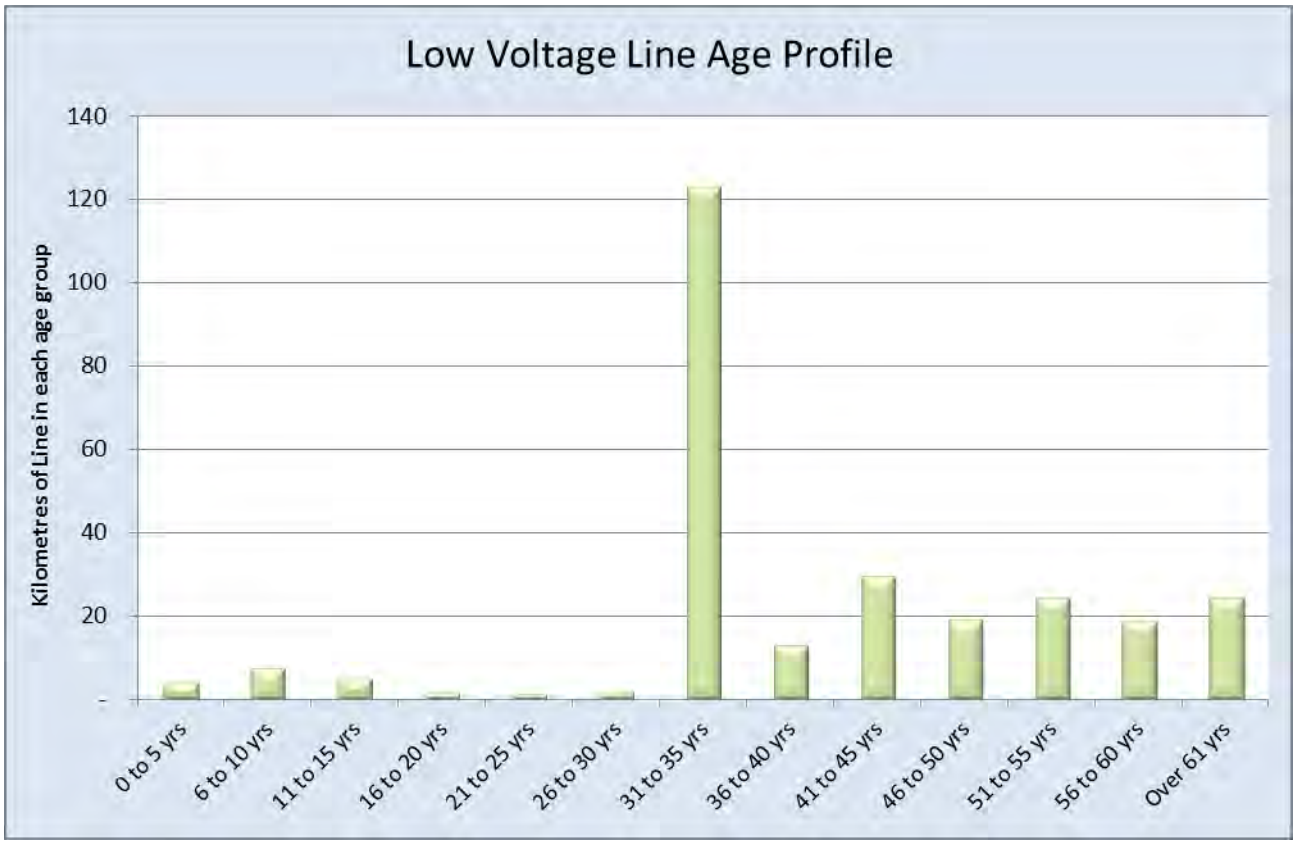


FIGURE 4.13: AGE PROFILES OF LV LINES

The estimated age profiles of LV lines will generally tend to move and shadow the pattern of 11 kV lines during the planning period.

Low voltage lines and related equipment especially service boxes are being inspected and renewed. Overhead systems form part of the 15-year line renewal programmes. Service boxes form part of the 5-year programme. This will ensure there will be no shocks to replace the entire low voltage assets provided the 5 and 15 year inspections and renewal cycle is continued and emergent problems are dealt with when they occur. The Plan includes renewal of sections of poor LV conductor in several holiday areas.

Condition of Assets

Low voltage overhead systems were traditionally not constructed with covered conductor. To solve clashing problems in high winds, spacers have been fitted in many places.

Historically LV systems were not designed with back feeds. Underground systems can suffer from poor workmanship with often little labelling and with cable routes being quite different to records. Inspections and renewals are improving this situation.

TLC has inspected, numbered, and recorded its service boxes. This inspection revealed a number that were a significant hazard to the public and staff. These boxes have been renewed and repaired. Further repairs of boxes that present a medium to low risk hazard have been included in plans.

Underground cabling systems installed in Ohakune, and most of the southern network, during the 1970's and 1980's consist of solid core, double pass, PVC insulated single core, solid aluminium cables. Often no marking or mechanical protection was installed above cables in trenches. These are prone to corrosion and mechanical damage.

4.1.5 Description of Supporting or Secondary Systems

4.1.5.1 Capacitor Banks

TLC has two capacitor 11 kV banks. These each unit consists of a controller, circuit breaker, 1 MVAr 11 kV capacitor bank, trailer, connection leads and associated hazard control equipment. These units are both in good, as new condition and are less than a year old.

4.1.5.2 Load Control (Ripple Injection) Plants

Table 4.11 provides information describing the Load Control (Ripple Injection) plants.

LOAD CONTROL PLANT SUMMARY						
Location	**Design**	**Freq**	**Voltage**	**Age**	**Mechanism**	**Condition**
Arohena	Landis & Gyr	725 Hz	11 kV	47	Motor Generator and mechanical contactors	Operational (Old Plant). A further 5 years of operation will be needed as relays are replaced with advanced meters.
Gadsby Road	Landis Gyr	725 Hz	11 kV	16	Motor Generator and mechanical contactors	Operational (Old Plant). A further 5 to 10 years of operation will be needed as relays are replaced with advanced meters.
Hangatiki	Landis Gyr	317 Hz	33 kV	2	Modern Electronic	New
Maraetai	Landis Gyr	725 Hz	11 kV	16	Motor Generator and mechanical contactors	Operational (Old Plant). A further 5 years of operation will be needed as relays are replaced with advanced meters.
National Park	Zellweger	317 Hz	33 kV	5	Electronic	Good
Ohakune	Zellweger	317 Hz	33 kV	5	Electronic	Good
Ongarue	Zellweger	317 Hz	33 kV	5	Electronic	Good
Te Waireka	Landis Gyr	725 Hz	11 kV	16	Motor Generator and mechanical contactors	Operational (Old Plant). A further 5 to 10 years of operation will be needed as relays are replaced with advanced meters.
Tokaanu	Zellweger	317 Hz	33 kV	2	Electronic	Good
Whakamaru	Landis Gyr	317 Hz	33 kV	3	Modern Electronic	Good
Wairere	Landis Gyr	725 Hz	11 kV	17	Motor Generator and mechanical contactors	Operational (Old Plant). A further 5 to 10 years of operation will be needed as relays are replaced with advanced meters.
Waitete	Landis Gyr	725 Hz	11 kV	16	Motor Generator and mechanical contactors	Operational (Old Plant). A further 5 to 10 years of operation will be needed as relays are replaced with advanced meters.

TABLE 4.11: SUMMARY DESCRIPTION OF LOAD CONTROL PLANT

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. As outlined earlier, 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 4.14 indicates the age of load control plants.

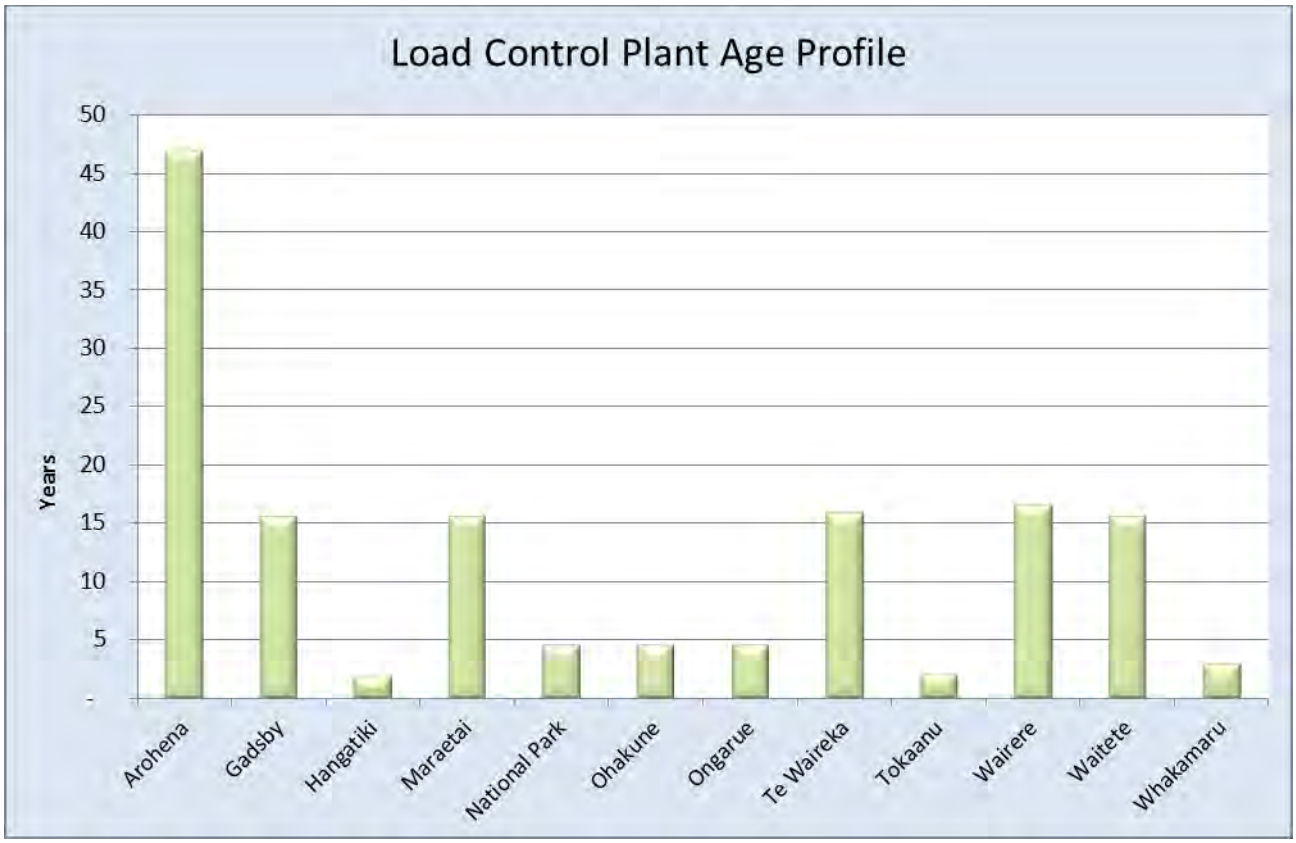


FIGURE 4.14: AGE PROFILES OF LOAD CONTROL PLANTS

The commissioning of two new 33 kV injection plants at Hangatiki and Whakamaru will, in the long term, replace the six 725 Hz plants and create a change in the age profile. Labour for replacing relays in the northern area is included is the planning period estimates. Note: This has been delayed slightly to better align with more demand metering rollouts.

A full evaluation of the economics of renewing the northern plants was completed during 2008/2009.

This study showed that renewal of the northern plants during 2009/10 was justified. Part of this justification came from the benefits that occur from TLC's unique demand based billing. The evaluation included benefits from:

- Reduced transmission connection charges.
- Costs associated with maintaining and operating present system.
- Reduced income from inability to control and set demand charges.

The study excluded difficult to quantify values such as income from the load reduction market, benefits from being able to use capacitors to improve asset utilisation by reducing reactive power flows and the gains that will come from being able to control load at a feeder level.

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. (The forward plan does address this issue.)

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

1. *Lack of signal*

   At 725Hz, signal propagation through a distribution network is complex. This frequency sets up many series resonance circuits that absorb the signal and stops receivers working. This resonant frequency issue also stops TLC using capacitors in the distribution network to reduce reactive power flows and improve voltages for greater asset utilisation.

2. *Loss of communication network*

   Sending of automatic load control signals is dependent on the communication network between the master station and individual plants. If the communication network fails, signals cannot be sent.

3. *Failure in load rhythm generator*

   The TLC systems rely on rhythms being generated in local RTUs. From time to time software problems stop these rhythms being generated.

4. *Failure of plant hardware*

   This is normally associated with the older high frequency plants that contain a number of contactors and rotating plant.

5. *Resonance on SWER systems*

   The 725 Hz system causes series resonance to occur on some SWER systems. The amplified ripple signal causes lights to flash off and on, and interferes with other electronic equipment.

6. *Load calculator software and hardware*

   From time to time there are problems with the load calculator software and hardware. These usually occur when software updates are installed or hardware is renewed.

4.1.5.3 Voltage Regulators

Table 4.12 provides information describing location, number of phases, units and age of voltage regulators.

VOLTAGE REGULATORS – DESCRIPTION, UNITS AND AGE			
Location	**Description**	**Units**	**Average Age**
Awamate Road	1ph 150 Amp Voltage Regulator	2	4
Benneydale	1ph 200 Amp Voltage Regulator	2	8
Bodley Road	1ph 200 Amp Voltage Regulator	2	8
Burns Street	1ph 300 Amp Voltage Regulator	2	2
Huirimu	1ph 150 Amp Voltage Regulator	2	1
Kaahu Tee Sub	1ph 150 Amp Voltage Regulator	2	4
Kopaki	3ph 3 MVA Voltage Regulator	1	53
Maihiihi	1ph 200 Amp Voltage Regulator	2	7
Mohakatino	3ph 750 kVA Voltage Regulator	1	53
Mokai	1ph 150 Amp Voltage Regulator	2	4
Mokai Geothermal	1ph 300 Amp Voltage Regulator	2	2
Nihoniho	3ph 1.5 MVA Voltage Regulator	1	49
Otukou Sub	1ph 60 Amp Voltage Regulator	2	28
Puketutu	1ph 200 Amp Voltage Regulator	2	7
Ranganui Road	1ph 100 Amp Voltage Regulator	2	10
Rangitoto Road	1ph 3 MVA Voltage Regulator	2	1
Scott Road	1ph 200 Amp Voltage Regulator	2	6
Soldiers Road	1ph 200 Amp Voltage Regulator	2	14
Taumatamaire	1ph 200 Amp Voltage Regulator	2	8
Te Anga	1ph 150 Amp Voltage Regulator	2	2
Te Kura Road	1ph 200 Amp Voltage Regulator	2	1
Tirohanga	1ph 150 Amp Voltage Regulator	2	4
Tuhua	3ph 5 MVA Voltage Regulator	1	62
Turoa Ski Base	1ph 200 Amp Voltage Regulator	3	7
Waiotaka Sub	1ph 100 Amp Voltage Regulator	2	7
Waipapa Road	1ph 4 MVA Voltage Regulator	2	1
Whakapapa Tavern	1ph 300 Amp Voltage Regulator	2	9
Whakapapa Water Tower	1ph 200 Amp Voltage Regulator	2	17
Whangaehu Valley Road	1ph 200 Amp Voltage Regulator	2	14
Whatauri Road	1ph 200 Amp Voltage Regulator	2	3
Whibley Road	3ph 2 MVA Voltage Regulator	1	53

TABLE 4.12: VOLTAGE REGULATOR SUMMARY

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.

Figure 4.15 illustrates the voltage regulator age profile.

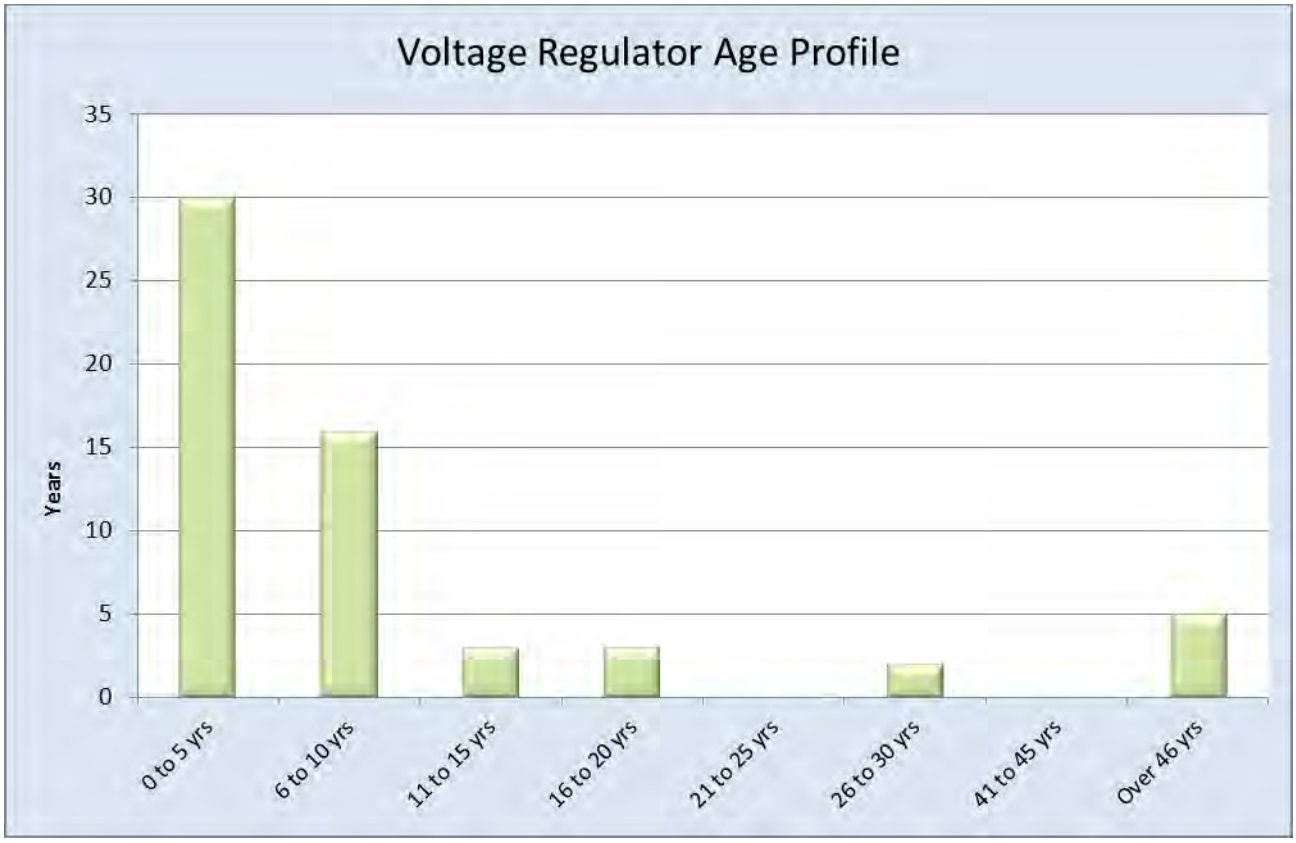


FIGURE 4.15: REGULATOR AGE PROFILES

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.

4.1.5.4 SCADA and Voice Communication

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.

An indication of the age profile of this equipment is illustrated in Figure 4.16.

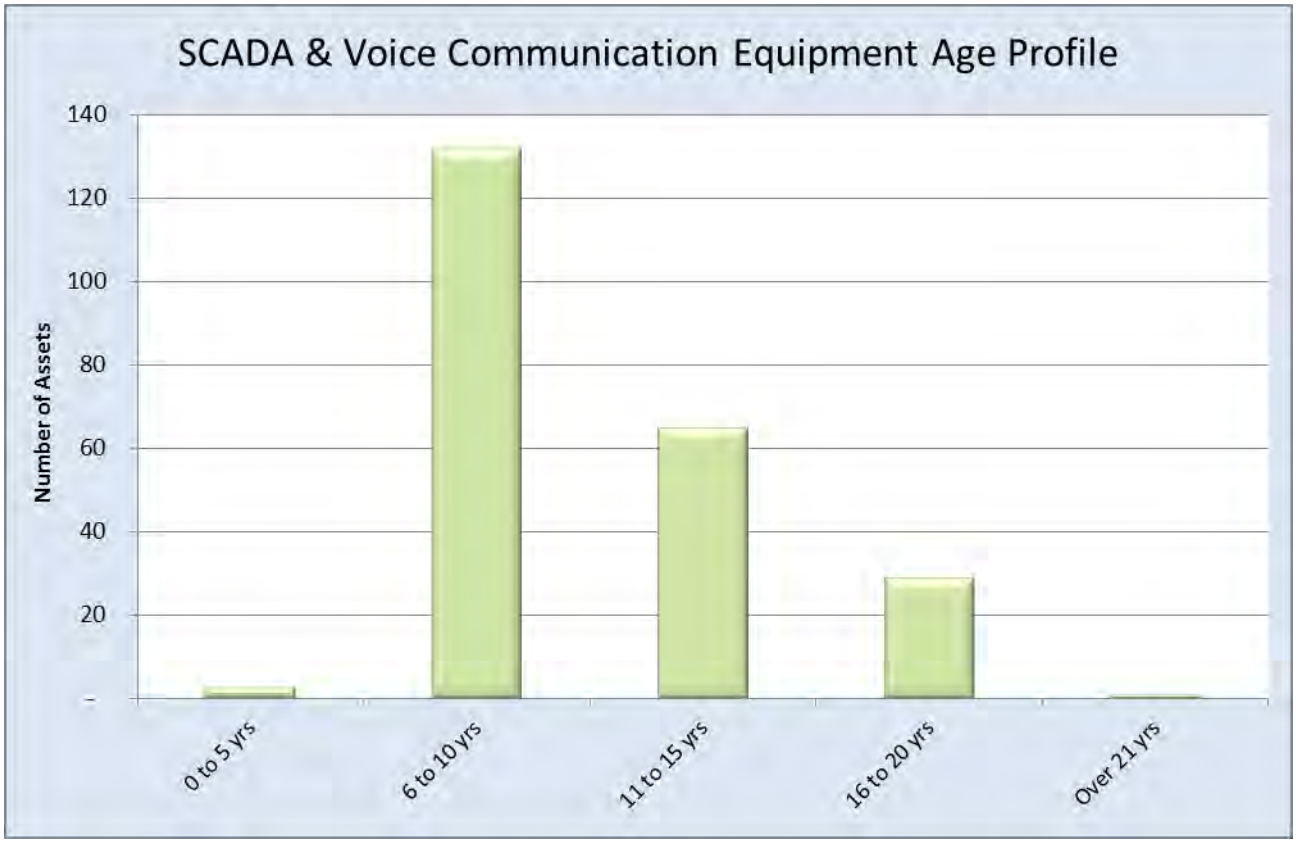


FIGURE 4.16: SCADA AND VOICE COMMUNICATION EQUIPMENT AGE PROFILES

The strategy to renew equipment and keep the technology current will mean no sudden shock to replace the entire system. The system is in good 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 most common issues that cause the system not to operate include:

- Loss of communication.
- Software lockups; is normally related third party equipment.
- Loss of power supplies to RTUs etc.
- Installation configuration errors.

The equipment and system is considered reliable and low cost by industry standards. It is not necessary to employ a dedicated technician or engineering support. An external specialist technician is hired in for about 1 day per month.

4.1.5.5 Communication Equipment

4.1.5.5.1 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 repeater site locations and description, age and condition of this equipment are listed in Table 4.13. Table 4.14 lists other SCADA and radio communication equipment locations. Both tables exclude voice radio communication equipment, which are listed in Table 4.15.

SCADA REPEATER EQUIPMENT SUMMARY		
Location and Description	**Age**	**Condition**
Mahoe Road: Radio Componentry	6	Good operational condition
Mahoe Road: Other Ancillaries		
Motuoapa Reservoir: Radio Componentry	12	Good operational condition
Motuoapa Reservoir: Other Ancillaries		
Ohakune: Radio Componentry	3	Good operational condition
Ohakune: Other Ancillaries		
Pomerangi: Radio Componentry	5	Good operational condition
Pomerangi: Other Ancillaries		
Pukawa: Radio Componentry	7	Good operational condition
Pukawa: Other Ancillaries		
Pukepoto: Radio Componentry	8	Good operational condition
Pukepoto: Other Ancillaries		
Ranginui: Radio Componentry	16	Good operational condition
Ranginui: Other Ancillaries		
Taumarunui Depot: Radio Componentry	3	Near new
Taumarunui Depot: Other Ancillaries		
Tuhua: Radio Componentry	14	Good operational condition
Tuhua: Other Ancillaries		
Waipuna: Radio Componentry	4	Good operational condition
Waipuna: Other Ancillaries		
Waituhi: Radio Componentry	9	Good operational condition
Waituhi: SCADA & Radio Communication Equipment		
Whakaahu: Radio Componentry	10	Good operational condition
Whakaahu: Other Ancillaries		

TABLE 4.13: SCADA REPEATER EQUIPMENT SUMMARY.

The age profile indication of the repeater equipment is illustrated in Figure 4.17.

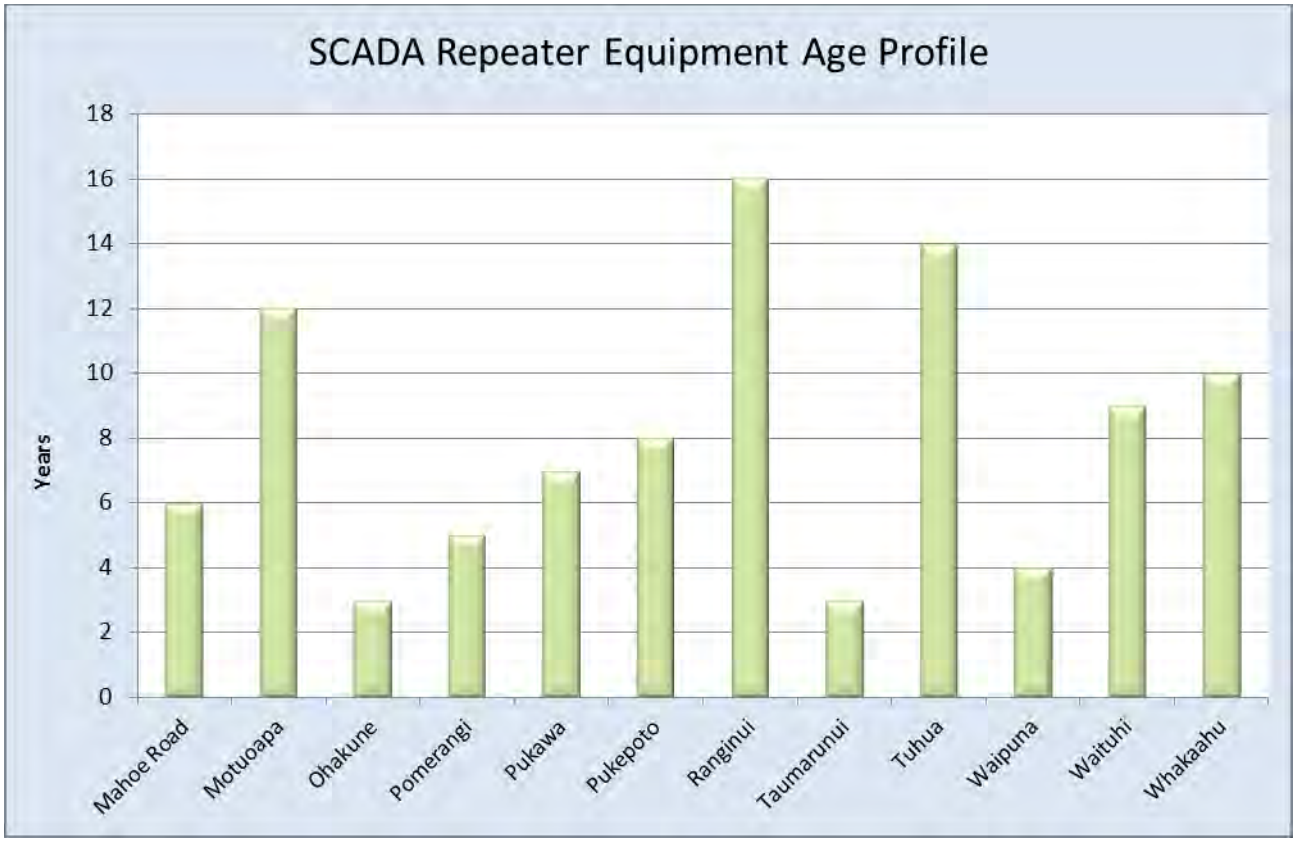


FIGURE 4.17: AGE PROFILE OF DATA COMMUNICATION EQUIPMENT

OTHER SCADA COMMUNICATION EQUIPMENT			
Locations			
Aria	Kiko Road	Oparure	Taumarunui/Kuratau
Arohena	Kuratau	Otorohanga	Tawhai
Atiamuri	Mahoenui	Otukou	Te Waireka
Awakino	Maihiihi	Piopio	Tihoi
Awamate	Mangapehi	Piriaka	Tirohanga
Benneydale	Manunui	Piripiri	TLC Control
Borough	Maraetai	Pureora	Tuhua
Caves	Marotiri	Rangipo/Hautu	Turangi
Chateau	Master Station	Rangitoto	Waiotaka
Gadsby	McDonalds	Raurimu	Wairere
Gravel Scoop	Mokau	Ruapehu Alpine Lifts	Waitete
Hangatiki	National Park	Southern	Whakamaru
Huirimu	Nihoniho	Taharoa	Wharepapa
Kaahu	Northern	Tangiwai	Winstones
KCE Office	OMYA		

TABLE 4.14: OTHER SCADA COMMUNICATION EQUIPMENT LOCATION.

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. It is reliable and has been maintained in good condition.

The age of communication equipment will remain relatively constant during the planning period.

Equipment has been assessed and allowances are included in the Plan for constant renewal of equipment. This means that there will be no sudden shock to replace the entire asset. The renewal programme will result in continual technology upgrade.

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. Other technologies such as high-speed digital systems would not be as cost effective.

The main causes of failure are external influences such as lightning strikes and the occasional hardware, power supply or software failure.

4.1.5.5.2 Voice Radio Communication Equipment

A frequency modulated voice communication system consisting of six repeaters, linking equipment, and radios in the mobile fleet, are owned and operated by TLC. The location, description and age of primary radio componentry and condition of this equipment are listed in Table 4.15.

VOICE RADIO COMMUNICATION EQUIPMENT SUMMARY	
Location and Description	**Primary Component Age**
Maungamangero: Radio Componentry and Other Ancillaries	16
Pukawa: Radio Componentry	7
Pukawa: Voice Equipment	8
Ranginui: Voice Equipment	9
Taumarunui Depot: Voice Equipment	10
Taumatamaire: Voice Equipment	10
Te Kuiti Control: Radio Componentry and Other Ancillaries	16
Tuhua: Radio Componentry and Other Ancillaries	14
Waipuna: Radio Componentry and Other Ancillaries	4
Waituhi: Voice Equipment	8

TABLE 4.15: LOCATION, AGE AND CONDITION OF VOICE RADIO EQUIPMENT

The radio repeater sites are necessary for voice communication throughout the region. The use of other communication, such as trunked radio and cell phone equipment is 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. Equipment has been assessed and allowances are included in the Plan to renew aged equipment. This ensures there will be no sudden shock to replace the entire radio network. The renewal programme will result in continuous technology upgrades, including a digital voice system with some job dispatch data functionality. TLC has three voice repeater sites that need to be replaced due to the MED (Ministry of Economic Development) requirement to move from 25 kHz to 12.5 kHz wide channels. These upgrades are to be completed by 2014, a year ahead of the 2015 deadline. The main cause of failure of voice radio equipment is external influences such as lightning strikes.

4.1.5.6 Metering systems

The network section of TLC does not own customers' meters. Meters are owned by a subsidiary company. The network however will be required to fund the labour content of the advanced meter rollout that will replace most of the relays that were transferred to the RAB.

The TLC network owns five grid exit point metering installations. The first of these is at the Whakamaru supply site. The equipment includes:

- 33 kV / 110 V potential transformer.
- Metering grade current transformers.
- Half hour meter and remote reading equipment.

The second is at the Tangiwai Winstones Mill interconnection between the mill network and the TLC network.

This equipment includes:

- 11 kV / 110 V potential transformer.
- Metering grade current transformers.
- Half hour meter with remote reading equipment.

The remaining three are associated with the Mokai Energy Park and have only recently been commissioned.

The Whakamaru equipment was installed in 2002 and Tangiwai in 2004.

Most problems with metering equipment are associated with aged meters and damage to the HV bushings of potential and current transformers and cell phone communication problems.

4.1.5.7 Power factor correction plant

TLC does not own any fixed power factor correction plant. It is focusing on demand side power factor correction. TLC has recently purchased two 1 MVAr 11 kV capacitor banks to be used for voltage support during the use of network alternative feeds.

4.1.5.8 Emergency generator

TLC owns a mobile generator, protection transformer, and circuit breaker capable of injecting into the 11 kV network during planned and unplanned events. Other sections in this Plan include a description of the equipment. This equipment was purchased in 2003 and is in good condition. Most problems with this equipment are caused by operator error.

4.1.6 Overall Summary

Overall the renewal investment is required in the primary assets: Lines and substations to ensure hazards are controlled and the systems operate reliably. The secondary systems are generally of a newer age and in good condition.

The proceeding sections include considerable specific detail on individual asset categories as required by the disclosure prescription. Table 4.16 summarises this information:

TLC NETWORK – SUMMARY OF AGE AND CONDITION		
Asset Category	**Age Summary**	**Summary Conditions**
Assets at Bulk Supply Points	Mid Age Range	Good operating condition.
Sub-transmission		
Lines	Northern Area: Mid Range	Generally good design and average condition. Most first cycle renewal work is completed and more planned. Lines historically generally tend to have better poles but smaller conductors when compared to the Southern area.
	Southern Area: Older	Under strength design and poor condition in terms of poles. Conductors tend to be larger than the Northern network. Most first cycle renewal work is completed and more planned.
Substation &Transformers	Sites Aging	Older sites need renewal and refurbishment, including transformers and switchgear. Overall substations are in need of on-going renewal.
Distribution Systems		
Lines	Aged Assets	Many assets in need of renewal. Renewal programmes are underway.
Transformers	Average Ages	A number of larger sites have hazard control expenditure needs. Smaller sites; industry typical. Extensive SWER (earthing) systems require additional renewal and maintenance. Plans and programmes are underway to address these needs.
Switchgear	Average to Old Age	Renewal as part of general line renewal. Problems with drop-out fuse connections being addressed by better quality. Renewal plans are in place.
Low Voltage System	Old Age	Many in poor condition and requiring major renewal.
Supporting or Secondary System	Average Age	Good condition.

TABLE 4.16: SUMMARY OF AGE AND CONDITION OF THE TLC NETWORK

4.1.7 Justification of Assets

The Sub-transmission and distribution systems operated by TLC have been developed over the years to meet activities of the regions and the electricity needs of customers. As a general comment, the region covered by TLC has more of a lack of assets than overbuild.

Electricity was reticulated to the King Country at the lowest possible cost through the extensive use of innovative methods such as Single Wire Earth Return reticulation. For many years, supply to isolated areas was from local small hydro generators remote from any grid exit point connections. Other areas were developed for construction, forestry, mining, and mountain communities. All were reticulated using technologies and engineering solutions to meet the needs of the times.

This history and development pattern of the local regions is the reason why many of the assets exist and are where they are today. As time has gone on the originally installed assets have continually been modified to meet the needs of the various communities. TLC assets have not generally been subject to the effects of the property booms like other areas in the country. Therefore, equipment has not been replaced as part of growth upgrades.

Some of the community changes have been significant; for example, Turangi has changed from a large construction community into a tourist, holiday, and prison support town. In the rural areas there has been both farm rationalisation and dairying development taking place.

Because of the history, there are examples where assets do not comply with present day technical, engineering, and industry codes, although they would have been built to the requirements at the time of construction. It was usual for regulation and code changes to permit existing assets to remain, legally, in use until replaced.

As discussed in other sections plans are underway to replace legacy equipment that does not comply with present day hazard control expectations. The rugged terrain, remote farming communities, and commercial development will have a continued bearing on asset configuration and the cost of operation.

Productive land use in the King Country is reliant on the regular applications of fertiliser, often by planes and helicopters. Some of this fertiliser is not only corrosive but also relatively conductive when mixed with water. The consequence of this is that hardware must be of the more expensive pollution-resistant type.

The RAB valuation did not include any optimisation of assets except that of SWER isolation transformers. These were optimised out to bring the valuation of SWER lines into line with two wire systems as allowed under the 2004 ODV valuation rules.

4.1.8 Justification for Sub-transmission Assets

4.1.8.1 Connection/supply points

As outlined previously, the network consists of three 33 kV regions (North Western, North East (River) and Central) and an 11 kV region directly connected to a grid exit point (Ohakune). The justification for each of these grid exit points is as follows:

4.1.8.2 North Western (Hangatiki)

The Hangatiki GXP provides capacity to the region that could not be served at 33 kV or 11 kV, as it is 54km as the crow flies from the Ongarue GXP and 58km from the Whakamaru connection point.

Physically, some very rugged country separates Ongarue and Hangatiki, and the Rangitoto Mountain Range and the Pureora Forest separates Whakamaru and Hangatiki. The system load (sum of distributed generation and Grid Exit import) is over 30 MVA.

At times, depending on the availability of generation and industrial consumption, demand at this grid exit point fluctuates between almost zero (400 kVA) and over 30 MVA. Industrial customers, especially the Taharoa Iron Sands ship loading 50km to the west, have the biggest influence on demand. Given the distances involved and the loads, the grid exit point assets would be difficult to eliminate.

4.1.8.3 North Western (River) (Whakamaru and Atiamuri)

The Whakamaru supply point, in addition to being 58km from Hangatiki, is 65km from Ongarue across the Pureora Forest Park and mountain range. Atiamuri is a backup supply for this area and this is operated at times in a complex arrangement.

There is currently little industrial load in this region; however, it is expected that more will be attracted, particularly around the Mokai geothermal complex. Mangakino and Whakamaru villages are the only closely settled areas. Most of the load is rural and associated with dairy farming. This creates daily and seasonal peaks.

The recently commissioned Energy Park supply is also in this area. This supply connects directly to the Mokai geothermal plant and is necessary to supply the energy intensive industries in the park. The park is located about 20 km from Whakamaru, and as such taking a 10 MVA supply from the adjacent geothermal generation is much more cost effective than constructing/upgrading lines over this distance. Supply is also much more reliable and secure than it would be on a single spur type set up.

4.1.8.4 Central

The GXPs supplying this network are Ongarue, National Park, and Tokaanu. The distances involved, loadings connected distributed generation, and conductor sizes justify these GXPs. For example, Ongarue to Tokaanu is 72km, Tokaanu to National Park is 68km, and National Park to Ongarue is approximately 60km.

4.1.8.5 Ohakune

The Ohakune region is isolated from the rest of the TLC network by Mt Ruapehu. The area has a single shared GXP supplying the region at 11 kV (the grid exit point is shared with Powerco for its customers at Raetihi). A very light load backup supply is available from the Winstone Pulp Mill 11 kV network at Karioi.

The customers in the region have funded this low-load backup link. This has insufficient capacity for the operation of the Turoa Ski Field and is only used outside of the ski season.

The major activities in the area are the ski field, its related accommodation, and carrot processing. Some relatively large scale dairying has been established in recent times.

4.1.8.6 Justification for sub-transmission 33 kV lines

The justification for the use of 33 kV Sub-transmission is the product of the kVA x km, as even though the loads are often light, the distances are usually large. Table 4.17 prescribes the use of the line and from this, the justification has been deduced and summarised.

USE AND JUSTIFICATION OF 33 KV LINE ASSETS			
Asset	**Use: Present and likely at the end of the planning period**	**Justified**	**Able to be replaced with a smaller capacity asset?**
Gadsby / Wairere 33	Part of ringed network. Te Kuiti, Wairere generation and surrounding industrial areas to Hangatiki GXP.	Yes	No
Gadsby Rd 33	Part of ringed network. Te Kuiti, Wairere generation and surrounding industrial areas to Hangatiki GXP.	Yes	No
Lake Taupo 33	Spur line connecting Tokaanu GXP to the Kiko Road, Awamate Road and Waiotaka substations.	Yes	No
Mahoenui 33	Spur line between Mahoenui and Wairere. Supplies long 11 kV spur lines after transformation at Mahoenui. DG resource exists in the area is under investigation.	Yes	No
National Park / Kuratau 33	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 diversion race controls.	Yes	No
National Park 33	Short length of spur line connecting National Park GXP to zone substation.	Yes	No
Nihoniho 33	Spur line connecting Ongarue GXP to Nihoniho zone substation.	Yes	No
Ongarue / Taumarunui 33	Main line supplying Taumarunui from the Ongarue GXP.	Yes	No
Taharoa A 33	Supply to iron sand extraction at Taharoa and future DG sites (West Coast Wind and Hydro) (Customer requested and funded. Some local rural supply also.	Yes	No
Taharoa B 33	Supply to iron sand extraction Taharoa and future DG sites. (West Coast Wind and Hydro - Customer requested and funded). Some local rural supply also.	Yes	No
Taumarunui / Kuratau 33	Interconnecting line between the Ongarue GXP and the Kuratau marshalling site. Normally loaded with output of Kuratau area DG 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.	Yes	No
Te Kawa St 33	One of two lines supplying north from Hangatiki to the Otorohanga area. Loadings and security requirements show that the line is needed.	Yes	No
Te Waireka Rd 33	One of two lines supplying north from Hangatiki to the Otorohanga area. Loadings and security requirements show that the line is needed.	Yes	No
Tokaanu / Kuratau 33	Interconnecting line between the Tokaanu GXP and Kuratau marshalling site. Normally supplies Kuratau zone sub and is a backup for the connection of the Kuratau area DG to the grid. Also used to back up National Park and Ongarue.	Yes	No

USE AND JUSTIFICATION OF 33 KV LINE ASSETS			
Asset	**Use: Present and likely at the end of the planning period**	**Justified**	**Able to be replaced with a smaller capacity asset?**
Tuhua 33	Few metres of spur line connecting Ongarue GXP to Tuhua zone substation.	Yes	No
Turangi 33	Spur line connecting Tokaanu GXP to the Turangi zone substation.	Yes	No
Waitete 33	Part of ringed network. Te Kuiti, Wairere generation and surrounding industrial areas to Hangatiki GXP.	Yes	No
Whakamaru 33	Connects Atiamuri and Whakamaru supply points to Arohena, Maraetai, Kaahu and Marotiri zone substations.	Yes	No

TABLE 4.17: USE AND JUSTIFICATION OF 33 KV LINE ASSETS

4.1.8.7 Justification for zone substation assets

The zone substation assets are sprinkled through a large, sparsely populated area. All sites are justified and removing any would create problems with maintaining statutory voltages, customers' reliability expectations and supplying existing loads.

Table 4.18 summarises the justification for the zone substation assets:

ZONE SUBSTATION JUSTIFICATION		
Site	**Purpose**	**Justification**
Arohena	Supply to Arohena dairying area.	Well-loaded 3 MVA single unit substation supplying the dairying area around Arohena and Wharepapa. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is simple with a single incoming and two outgoing circuit breakers. It would be difficult to replace it with a more cost-effective design.
Atiamuri	Step up site for alternative supply to Whakamaru area.	Single unit connecting 33 kV network to 11 kV generation bus at Atiamuri. The site forms part of the Mighty River Power Atiamuri site. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is simple with a single outgoing 33 kV breaker and an 11 kV circuit breaker onto the Mighty River Power generation busbar. It would be difficult to rationalise this with a more cost-effective configuration.
Awamate Road	Supply to part of Turangi	Container substation with 2 MVA transformer backs up the Turangi substation and supplies local area. The configuration is low cost and it would be difficult to rationalise with a more cost effective arrangement.
Borough	Main supply to Taumarunui.	Two-unit site supplying the majority of Taumarunui and the surrounding rural areas. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is simple with the grid exit point circuit breaker at Ongarue providing incoming protection via a fault thrower, earthing switch at the substation. There are two incoming circuit breakers and a two 11 kV busbars with two outgoing circuit breakers and a bus tie on each bus. It would be difficult to rationalise this with a more cost-effective configuration. It would ideally warrant a more complex and expensive arrangement.
Gadsby Road	Supply to North end of Te Kuiti.	Single unit with the primary loads being the north end of Te Kuiti; saw milling, dairying and a large rural dry stock area to the west of Te Kuiti. Load is growing on this site, principally caused by the expansion of industrials. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The substation configuration is simple with a single 11 kV bus and three outgoing circuit breakers. It would be difficult to rationalise this with a more cost-effective configuration.
Hangatiki	Supply to Waitomo Caves area.	Single unit with the primary loads being the Waitomo Caves tourist area, limestone processing, and dairying. The substation is located adjacent to the Hangatiki grid exit point. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The substation configuration is simple with the grid exit point 33 kV breaker responsible for isolating the 33 kV and a simple single indoor bus arrangement for the 11 kV with two outgoing circuits. It would be difficult to rationalise this with a more cost-effective configuration.
Kaahu Tee	Supply to part of Marotiri area	Installed to reduce loading on Marotiri and bring loading back to within transformer rating. Also assists in overcoming voltage problems in area. A more cost effective network would not result if the substation were eliminated or reduced in voltage. The configuration is low cost and it would be difficult to rationalise this with a more cost effective configuration.

ZONE SUBSTATION JUSTIFICATION		
Site	**Purpose**	**Justification**
Kiko Road	Supply to the Eastern side of Lake Taupo.	3 MVA single unit substation supplying Eastern side of Lake Taupo. Holiday loadings in this area have been increasing and are continuing to grow. A more cost-effective network would not result if the substation were eliminated or reduced in voltage The configuration is simple with single incoming and outgoing circuit breakers. It would be difficult to replace it with a more cost-effective design.
Kuratau	Supply to the rural area at the South end of Lake Taupo including surrounding rural area.	Single unit substation and major 33 kV switching point on TLC network. It is the junction point between 33 kV lines coming from three grid exit points and the injection site for the 6 MVA Kuratau distributed generation plant. The zone substation provides supply to the local rural area including most of the West Taupo area and the holiday areas including Kuratau and Omori. The number of residences in this area continues to grow. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration of the 33 kV marshalling area and the zone substation is relatively simple. It would be difficult to replace it with a more cost-effective design.
Mahoenui	Supply to Mokau, Awakino, Tongaporutu, and remote rural areas inland.	Small simple site supplying surrounding rural area and long 11 kV line down through the Awakino Gorge and the rural settlements of Awakino, Mokau, and Tongaporutu. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is simple with single incoming and outgoing circuit breakers. It would be difficult to replace it with a more cost-effective design.
Manunui	Supply to rural area South of Taumarunui.	Single unit substation approximately 6.5km south of Taumarunui town. It is an injection point into the 33 kV network for the output of the Piriaka distributed generation plant. Plans are included in the planning period to increase the 11kV transfer capacity from this site back in to Taumarunui, given that the main Taumarunui substation (Borough) has been identified as a high risk of flooding site. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is simple with one incoming and two outgoing circuit breakers. It would be difficult to replace it with a more cost-effective design. If anything, an additional circuit breaker could be warranted.
Maraetai	Supply to Whakamaru area.	Single unit site supplying the Whakamaru and Mangakino villages, surrounding dairy areas and local service supplies to four Mighty River Power Waikato hydro sites. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is simple 11 kV bus supplying eight outgoing circuits. There is an incoming 33 kV breaker, outgoing 11 kV breaker and two bus section isolators. The switchgear is ground-mounted outdoor equipment and it would be difficult to rationalise this with a more cost-effective configuration. A more complex arrangement could be warranted.
Marotiri	Supply to Mokai and west Taupo area.	Well-loaded 3 MVA single unit substation supplying the dairying, lifestyle, and horticulture areas of Marotiri, Mokai, and Tihoi. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is simple with single incoming and two outgoing circuit breakers. It would be difficult to replace it with a more cost-effective design. If anything, an additional circuit breaker could be warranted.
Mokai	Supply to Mokai Energy Park.	Single unit site with an 11 kV – 11 kV fault reducing transformer supplying the Mokai Energy Park. The Energy Park is directly connected to the Tuaropaki Power 120 MW geothermal plant. The network interconnects with TLC network and 2-way energy transfer is possible. It would be difficult to replace it with a more cost-effective option.

ZONE SUBSTATION JUSTIFICATION		
Site	**Purpose**	**Justification**
National Park	Supply to National Park village and surrounding rural area.	Single unit supplying National Park village. Load gets up to about 2 MVA during winter when accommodation is full. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is simple with single incoming and outgoing circuit breakers. It would be difficult to replace it with a more cost-effective design.
Nihoniho	Supply to Ohura and surrounding large rugged remote idea.	Small site: 15km from point of supply in rugged terrain. Substation cannot be eliminated if load at end of planning period is to be supplied. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is very simple with a single transformer and separate regulator. It would be difficult to replace it with a more cost-effective design.
Otukou	Supply to rural Otukou and Outdoor Pursuits Centre.	Small site: Would require the reconstruction of 15.2km of conjoint 33/11 kV line. Existing 33 kV line would have to be totally rebuilt for this distance, as present poles are very low. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is very simple with a single outdoor overhead busbar. It would be difficult to replace it with a more cost-effective design.
Taharoa	Supply to Iron Sand processing and ship loading.	A three-unit site set up to supply the Taharoa iron sand extraction plant. The site has (n-1) capacity. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is simple with a single 11 kV bus bar and 12 outgoing circuits. It would be difficult to rationalise this with a more cost-effective configuration.
Tawhai	Supply to Whakapapa village and ski area.	Single unit with the primary load being the Whakapapa Ski Field and village. Present loads and plans for the ski field are starting to push this site and will push it further in the future. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The substation configuration is simple, with single 33 kV incoming and 11 kV outgoing breakers plus a 33 kV line breaker looking at the forward and reverse protection of the outgoing 33 kV line. It would be difficult to rationalise this with a more cost-effective configuration. It would be easy to warrant a more expensive solution.
Te Anga	Supply to Te Anga and Marokopa	Small site supplying coastal area including the Southern side of Kawhia harbour. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. (The site has recently been relocated to facilitate the more economic connection of a 2 MVA distributed generation scheme at Speedys Road.) The configuration is simple with single incoming and outgoing circuit breakers. It would be difficult to replace it with a more cost-effective design.
Te Waireka	Supply to Otorohanga.	Two unit site supplying Otorohanga and surrounding rural areas. A (n-1) transformer capacity is available. A more cost effective network would not result if the substation were eliminated or reduced in voltage. There are two incomers and four outgoing circuits of a single 11 kV bus. It would be difficult to rationalise this with a more cost-effective configuration.

ZONE SUBSTATION JUSTIFICATION		
Site	**Purpose**	**Justification**
Tokaanu	Supply to Tokaanu village.	Small site supplying Tokaanu town. In an ideal "green fields" situation the architecture of this area would be different. This is, however, not possible given that lines would have to be constructed over some very sensitive Maori land. The probability of achieving this is virtually zero. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration at the site is very simple with a single 33 kV circuit breaker and ring main used for 11 kV switchgear. It would not be possible to replace it with a more cost-effective design.
Tuhua	Supply to rugged remote rural area around Tuhua.	Small site next to the Ongarue point of supply. Cannot be eliminated if supply to areas north of Taumarunui such as Ongarue is to be maintained given the supply from the grid exit point at 33 kV. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. The configuration is very simple with a single transformer and separate regulator. It would be difficult to replace it with a more cost-effective design.
Turangi	Supply to Turangi town.	Two unit site supplying Turangi and surrounding rural areas. Backup supply was put into place a few years ago to allow the site to be removed from service and hazard minimisation/elimination projects to be completed. Without this backup n-1 capacity and security was not available to Turangi. A more cost-effective solution would not result if the substation were eliminated or reduced in voltage. The configuration is simple with the remote 33 kV breaker used for 33 kV isolation and an outdoor overhead 11 kV bus with two outgoing circuit breakers. It would be difficult to rationalise this with a more cost-effective configuration.
Waiotaka	Supply to Hautu Prison	Container substation with 1.5/1.8 MVA transformer. Funded principally by the Corrections Department. The configuration is low cost and it would be difficult to rationalise this with a more cost effective configuration. The unit also provides about 50% of the backup for Turangi.
Wairere	Supply to Piopio and DG connections.	Two-unit site and injection point for 6.2 MVA of generation from the Wairere and Mokauiti distributed generation stations. The five outgoing rural feeders head off in different directions into the central King Country. A more cost-effective network would not result if the substation were eliminated or reduced in voltage. Relatively complex site with distributed generation and load control connected to 33 and 11 kV bus bars. The 33 kV configuration consists of a double bus and the 11 kV is interconnected outdoor and indoor arrangement. It would be difficult to rationalise this with a more cost-effective configuration.
Waitete	Supply to majority of Te Kuiti and surrounding rural area.	Three-unit site supplying majority of Te Kuiti and surrounding rural areas. A big portion of the load from this site is the Te Kuiti industrial area consisting of a number of industries including a sawmill, and two meat-processing plants. A more cost-effective network would not result if the substation were eliminated or reduced in voltage.

TABLE 4.18: JUSTIFICATION FOR ZONE SUBSTATIONS

4.1.8.8 Justification for Zone Substation Transformers

Detailed in Table 4.19 is the justification for transformer sizing at zone substations.

JUSTIFICATION FOR TRANSFORMER SIZING AT ZONE SUBSTATIONS			
Site	**Existing Transformer Size (MVA)**	**Present Loading (MVA)**	**Comment**
Arohena	1 x 3	2.38	New transformer supplying dairying area.
Atiamuri	1 x 10	10.00	Step up transformer for complex river system.
Awamate Road	1 x 2	1.49	New transformer backing up Turangi.
Borough	2 x 5	8.46	Old transformers supplying Taumarunui.
Gadsby Road	1 x 5	4.27	Refurbished transformer supplying industrial load.
Hangatiki	1 x 5	3.73	Modern transformer supplying mostly industrial load.
Kaahu Tee	1 x 2.4	1.43	New transformer backing up Arohena.
Kiko Road	1 x 3	1.52	Area has increasing holiday home load.
Kuratau	1 x 3, 1 x 1.5	2.76	Old transformer supplying holiday area. New transformer to support load to growth area.
Mahoenui	1 x 3	0.76	Old transformer in remote area.
Manunui	1 x 5	2.21	Old transformer supplying declining area. Provides DG connection.
Maraetai	1 x 5	3.81	New transformer supplying dairy area.
Marotiri	1 x 3	3.01	Additional site to reduce load established. (Kaahu Tee).
Mokai	1 x 7.5	2.23	
National Park	1 x 3	2.74	Old transformer supplying holiday area.
Nihoniho	1 x 1.5	0.61	New transformer is on order after original unit (1.5MVA) destroyed by lightning). To be installed by year end.
Oparure	1 x 3	1.43	Modern transformer supplying industrial load.
Otukou	1 x .5	0.30	Remote area.
Taharoa	3 x 5 (Customer requested reliability)	8.80	1970's transformers supplying industrial load.
Tawhai	1 x 5	4.36	Old transformer supplying Whakapapa.
Te Anga	1 x 2.4	2.19	DG in area has recently reduced load.
Te Waireka	2 x 10	10.75	Modern transformers supplying Otorohanga.
Tokaanu	1 x 1.25	0.21	Old transformer.
Tuhua	1 x 1.5	1.03	Old transformer in remote area.
Turangi	2 x 5	4.46	Old transformers supplying Turangi.
Waiotaka	1 x 1.5	0.48	New transformer supplying correctional facility.
Wairere	2 x 2.5	3.05	Connects Wairere Falls generation.
Waitete	3 x 5	9.68	Old transformers supplying Te Kuiti.

TABLE 4.19: JUSTIFICATION FOR TRANSFORMER SIZING AT ZONE SUBSTATIONS

4.1.9 Justification for Distribution Feeders

Table 4.20 provides justification details on each of the 11 kV feeders:

11 kV FEEDER JUSTIFICATION				
Feeder	**Conductor Range**		**Length (km)**	**Comments**
	Max	**Min**		
NORTHERN AREA				
Aria	Mink	Squirrel	78	Long rural feeder with dairying and SWER lines. Conductor size required for volt drop.
Benneydale	Dingo	7/064 Cu	135	Long feeder with industrial, rural and distributed generation load. Larger conductor sizes could easily be justified as it has four regulators in series.
Caves	Mink	7/064 Cu	65	Conductor size needed for voltage drop and backup current loading.
Coast	7/16 Cu	Mullet	84	Rural feeder supplying coastal settlements. SWER systems and distributed generation connected.
Gravel Scoop	Mink	Squirrel	89	Long feeder with dairying load.
Hangatiki East	Mink	7/064 Cu	20	Conductor size required for load and voltage drop (fully loaded).
Huirimu	Ferret	Squirrel	45	Rural feeder. Backup for Pureora feeder.
Mahoenui	Mink	Squirrel	104	Rural and backup for Mahoenui sub. Conductor size is adequate for purpose.
Maihiihi	Mink	Squirrel	109	Urban and rural feeder. Well loaded. Has two regulators in series. (Will need strengthening during planning period, included in estimates).
Mangakino	Mink	Squirrel	23	Supply to Mangakino town. Conductor size for supplying neighbouring dairying load.
McDonalds	Mink	Squirrel	40	Feeder supplying industrial and dairying load.
Miraka	Dingo	Dingo	1	Supply to Mokai Energy Park. Conductor size is adequate for purpose.
Mokai	Ferret	Flounder	83	Long rural feeder and backup supply for Tihoi feeder. Growth area with dairying and lifestyle blocks and geothermal development.
Mokau	Mink	Squirrel	132	Long rural feeder with coastal holiday settlements. SWER systems connected. Conductor size required for voltage drop. The feeder has two regulator sites for voltage support.
Mokauiti	Mink	Squirrel	74	Long rural feeder with SWER lines. Conductor size required for volt drop.
Oparure	Mink	Squirrel	81	Partly urban and rural feeder. Used in emergencies to start and synchronise Wairere generation. Also has some industrial load.
Otorohanga	Mink	Squirrel	53	Urban and rural load. Supplies Otorohanga CBD, residential and some industrial areas. Not possible to reduce conductor sizes.

11 kV FEEDER JUSTIFICATION				
Feeder	**Conductor Range**		**Length (km)**	**Comments**
	Max	**Min**		
Paerata	Squirrel	Dog	4	Supply to Mokai Energy Park. Conductor size is adequate for purpose.
Piopio	Mink	Squirrel	53	Rural feeder and supply to Piopio town. Conductor size required for volt drop.
Pureora	Mink	Squirrel	52	Long rural feeder supplying dairying and industrial load. Has two regulators (a further two regulators and some re-conductoring have been included in planning period estimates. Dependent on customer load increases).
Rangitoto	Mink	Flounder	79	Industrial and rural feeder that can be paralleled to others. Could warrant larger conductor due to industrial load.
Te Kuiti South	7/083 Cu	7/064 Cu	26	Partly urban and rural feeder. Used in emergencies to start and synchronise Wairere generation. Could justify larger rather than smaller conductor size.
Te Kuiti Town	7/083 Cu	7/064 Cu	2	Supplies CBD and links to other feeders.
Te Mapara	Mink	Squirrel	80	Rural feeder with SWER lines. Conductor size required for volt drop.
Tihoi	Mink	Squirrel	63	Long rural feeder and backup supply for Whakamaru feeder. Growth area with dairying.
Tirohanga	Ferret	Squirrel	69	Supply rural dairying area. Conductor size needed for voltage drop. Has one regulator in series.
Waitomo	Mink	Squirrel	12	Partly urban and rural feeder.
Whakamaru	Mink	Squirrel	86	Rural feeder supplying dairying load and villages. Dependent on customer load increases.
Wharepapa	Ferret	Squirrel	107	Long rural feeder supplying dairying load. Links into Maihiihi feeder to provide a backup for Arohena area.
SOUTHERN AREA				
Chateau	Mink	Flounder	29	Supplies large load on ski fields.
Hakiaha	7/16 Cu	Ferret	6	Supplies industrial CBD of Taumarunui. Conductor size adequate.
Hirangi	Ferret	Ferret	2	Totally SWER feeder on the outskirts of Turangi.
Kuratau	Ferret	Squirrel	57	Supplies holiday homes and rural area. Comes under pressure due to voltage drop during holiday periods. SWER systems connected.
Manunui	Mink	Flounder	87	Rural and urban area. Links with two Taumarunui feeders for backup. Conductor sizes marginally adequate. SWER systems connected.
Matapuna	7/16 Cu	Flounder	17	Urban and rural feeder.
Motuoapa	Mink	Flounder	2	Supplies rural area hand holiday homes around Lake Taupo. Conductor size needed for construction strength.
National Park	Mink	Flounder	43	Rural and urban feeder. Conductor sizes marginally adequate.

11 kV FEEDER JUSTIFICATION				
Feeder	**Conductor Range**		**Length (km)**	**Comments**
	Max	**Min**		
Nihoniho	Ferret	Flounder	27	Rural feeder. SWER systems connected.
Northern	Dog	Flounder	111	Urban and rural feeder. SWER systems connected. Conductor size required for loading and voltage drop.
Ohakune	Dog	Squirrel	13	Urban and rural feeder. Supplies bulk of Ohakune CBD. Peaks during ski season. Has inadequate conductor size in some locations for physical snow and electrical loadings.
Ohura	Ferret	Flounder	174	Rural feeder. SWER systems connected.
Ongarue	Ferret	Flounder	128	Extensive rural feeder with a large number of SWER lines.
Oruatua	Mink	Flounder	5	Growth area, supplies a number of lake front holiday homes with fluctuating demand. Conductor sizes are required for peak loading.
Otukou	Ferret	Flounder	6	Small rural feeder.
Rangipo/Hautu	Mink	Flounder	39	Supplies part of Turangi town and both prisons, plus SWER on end of feeder. Mink required for load and voltage drop.
Raurimu	Mink	Flounder	171	Rural feeder with long SWER systems connected. Conductor sizes marginally adequate.
Rural	Flounder	Mullet	5	Remote rural feeder supplying Taharoa village and surrounding area.
Southern	Dog	Flounder	124	Rural feeder. Links with National Park. Conductor sizes marginally adequate. SWER systems connected.
Tangiwai	Dog	Flounder	91	Supplies part of Ohakune town and a large rural area. Backup supply from Winstones POS.
Tokaanu	3 Core 35mm cable		1	Supply to Tokaanu town.
Tuhua	Ferret	Flounder	41	Extensive rural feeder with a large number of SWER lines.
Turangi	Mink	Flounder	9	From substation to underground reticulation supplying the CBD and most of the residential area.
Turoa	Dog	Flounder	60	Supplies ski field, urban and rural areas. Has 3 regulators in series. A further regulator will be needed during planning period. Conductor is marginally adequate.
Waihaha	Flounder		95	Supplies holiday homes and rural area. SWER systems connected.
Waiotaka	Ferret	Flounder	10	Supplies Hautu Prison complex. Back up for Rangipo/Hautu.
Western	Mink	Flounder	135	Urban and rural feeder. SWER systems connected. Conductor size required for loading and voltage drop.

TABLE 4.20: 11 KV FEEDER JUSTIFICATION

4.1.10 Justification for Distribution Voltage Control Devices

The supply from 33 kV grid exit points is unregulated and generally complies with the electricity participation codes. To supply customers with the range of voltage as specified by the electricity regulations, closer voltage control is required at the zone substation level. Consequently, there is a need to have voltage control equipment at the zone substation level. Many of the feeders are also of considerable length and there is a need for voltage control devices along these. Distributed generation adds complexity to voltage control schemes and, in the future, it is likely that a greater bucking range will be needed in some areas. The voltage control devices generally used at zone substations provide a 5% buck to a 15% boost. Line regulators generally have a ±10% buck and boost range.

The amount of distributed generation, the length of many of the TLC feeders and the sub-transmission network mean that most voltage control devices are operated across the entire tapping range. There are areas, mostly towards the extremities, of the TLC network where voltages are outside of the limits of the regulations.

All zone substation tap changers are automatic. Modular substations use line regulators in series with simple fixed tap transformers. Table 4.21 provides the details on justification for the TLC 11 kV network regulators.

VOLTAGE REGULATOR JUSTIFICATION	
Location and Regulator Sites	**Reasons for Need**
Awamate Rd Zone Substation 1 site	Part of a modular zone substation that controls voltage to Turangi town.
Benneydale Feeder 4 sites	Lengthy feeder with rural, distributed generation and industrial load. Regulator is working through most of buck and boost range depending on what distributed generation and load are doing. Working in series with Benneydale 1, 2 and 4.
Chateau Feeder 2 sites	Regulator is controlling voltage to Whakapapa ski area . Regulator is working through most of boost range. Lifts, snow making equipment and ski lodges can vary the load dramatically.
Huirimu Feeder 1 site	11 kV feeder supplying dairy area.
Kaahu Tee Zone Substation 1 site	Part of the modular Kaahu Tee substation. Used to boost voltage in dairying and lifestyle subdivision.
Maihiihi Feeder 2 sites	Long 11kv feeder supplying dairying area . Regulator is working through most of boost range to compensate for feeder conductor size.
McDonalds Feeder 1 site	11 kV feeder with large limestone processing plant and dairying load.
Mokau Feeder 2 sites	Long feeder supplying holiday areas of Mokau and Tongaporutu. Regulator is working through most of boost range due to length of feeder and conductor size.
Mokai Feeder 1 site	Heavily loaded dairy area. Forms part of the back up power supply to Mokai Energy Park.
Miraka Feeder 1 site	Supply to the Mokai Energy Park from an unregulated Mokai geothermal station supply to a regulated supply to dairy factory and surrounding customers.
Nihoniho Zone Substation 1 site	Regulates 11 kV from fixed tap transformer. Supplies a largely rural/farming area.
Otukou Zone Substation 1 site	Fixed tap transformer requires regulation on to the 11 kV network.
Pureora Feeder 2 sites	Long feeder with meat processing plant and dairying load. Regulator is towards and looking after meat plant and dairying load. Unit is operating full boost range. Another regulator site could be justified on this feeder.

VOLTAGE REGULATOR JUSTIFICATION	
Location and Regulator Sites	**Reasons for Need**
Rangitoto Feeder 1 site	11 kV feeder supplying dairy area.
Tangiwai Feeder 1 site	11 kV long feeder that is used as a backup supply to Ohakune town and the Karioi pulp mill during Transpower shutdowns of the Ohakune point of supply. Regulators run full boost range.
Te Anga Zone Substation 1 site	Te Anga voltage regulators are a part of a modular zone substation. 150 Amps rated. The advanced controller was required to cope with distributed generation and reverse power flows through the zone substation.
Tirohanga Feeder 1 site	Used to boost voltage to Forest Road area dairy conversions. The need for regulation is due to a legacy issue of small wire sizes in the area.
Tuhua Zone Substation 1 site	Regulates 11 kV from fixed tap transformer. Supplies a largely rural/farming area.
Turoa Feeder 3 sites	Heavy wintertime loading on this feeder requires it to be voltage boosted and regulated mainly due to ski fields and holiday homes used during winter.
Waiotaka Zone Substation 1 site	Part of the modular zone substation serving the prison and surrounding area. Fixed tap transformer.
Whakamaru Feeder 1 site	11 kV feeder supplying dairy area and irrigation load.
Wharepapa Feeder 1 site	11 kV feeder to predominately dairying area with traditional peak morning and night loads.

TABLE 4.21: JUSTIFICATION FOR VOLTAGE REGULATORS

4.1.11 Justification for Reactive Compensators

TLC does not own any fixed reactive compensators. Two mobile 1 MVAr 11 kV capacitor banks have been commissioned for network support. They are justified by the need to have generators of similar capacity to provide reactive power when the network is in an abnormal condition. The cost of a generator as compared to a static capacitor providing reactive power is several factors more expensive.

4.1.12 Justification for Distribution Transformers

Within practical limits TLC distribution transformers are well utilised. The main driver to ensure utilisation is the structure of line charges. As stated in other sections, TLC charges are based on three principal components: capacity, peak and dedicated asset charges. (Customers who are supplied by a transformer that supplies three, or less, customers incur dedicated asset charges.)

This structure means customers who have nominated excessive transformer capacity or size are penalised through charges. Transformer capacity and the amount customers are paying for, and require, are regularly reconciled. This approach results in few stranded oversize transformers on the network that are not installed to meet customers' requests.

4.1.13 Justification for Low Voltage

Most of TLC's low voltage network is overhead. What underground network there is tends to be under-engineered by industry standards. For example, there are rarely links between circuits or substations. As a short-term reliability fix TLC has a mobile generator it uses to provide supply when failures occur in large low voltage cables or spur 11 kV supplies to transformers. Table 4.22 lists the areas where underground low voltage distribution exists, the justification for it and comments on the engineering standard it meets.

LOW VOLTAGE NETWORK JUSTIFICATION		
Area of LV	**Justification**	**Engineering Standard**
Taharoa village	Most cost-efficient way of achieving reticulation originally funded by capital contribution.	Very basic installation. No LV link boxes.
Otorohanga CBD and other town areas	Local body planning criteria. Most cost-efficient means. Some funded by capital contributions.	Basic installation with few LV tie points and little capacity to back-feed.
Te Kuiti CBD and other town areas	Local body planning criteria. Most cost-efficient means. Some funded by capital contributions.	Basic installation with few LV tie points and little capacity to back-feed.
Taumarunui CBD and other town areas	Local body planning criteria. Most cost-efficient means. Some funded by capital contributions.	Basic installation with few LV tie points and little capacity to back-feed.
Turangi town	Local body planning criteria. Most cost-efficient means. Some funded by capital contributions.	Basic installation with few LV tie points and little capacity to back-feed.
Taupo lake edge settlements	Local body planning criteria. Most cost-efficient means. Some funded by capital contributions. Iwi sensitive area.	Basic installation with few LV tie points and little capacity to back-feed.
Whakamaru and Mangakino villages	Local body planning criteria. Most cost-efficient means. Some funded by capital contributions. Iwi sensitive area.	Basic installation with few LV tie points and little capacity to back-feed.

TABLE 4.22: JUSTIFICATION FOR LOW VOLTAGE UNDERGROUND NETWORK

4.1.14 Justification for SCADA Equipment

TLC has an extensive SCADA network made up of equipment that is focused on meeting quality of supply and reliability criteria. That is, its main functions are to transmit alarms, open and close breakers, give feeder loadings, remove and apply auto reclosers and give very basic flagging information when a circuit breaker trips. The communication system behind the SCADA system is relatively low cost analogue with some use of voice channels. The system is based on the Lester Abbey Powerlink product.

Systems that are much more expensive have been observed in some network companies. TLC Engineering and Asset Management staff are unaware how the system could be set up at a lower cost and give the level of reliability that the system provides.

The SCADA system is essential for controlling the network and monitoring the injection of larger distributed generators. In the 1970s and 1980s, network companies were well staffed. Since this time, industry reform has been on-going and staff numbers have been hugely reduced. SCADA has been partly responsible for the improvements in reliability, by increased automation, through this period of change.

SCADA systems also reduce cost. The TLC system carries out approximately 4000 operations p.a. If, on average, each of these operations required a site visit costing $200, then staffing savings of about $800,000 p.a. are being achieved. Once investment and maintenance costs are subtracted, it is estimated the SCADA system produces savings over and above reliability improvements of about $600,000 p.a.

4.1.15 Justification for Load Control Equipment

Load control is a way to improve asset utilisation and reduce load when the network is under stress. How these benefits are best packaged to customers and integrated into the various charging mechanisms is an issue facing the industry especially as more advanced metering develops.

The way load control systems work technically and the propagation of signals through the network is complex. A power system is designed for 50 Hz and when higher frequencies are injected various combinations of lines, cables, transformers and capacitors amplify, or reduce, the level of signal.

The TLC load control system is very basic. The controller is integrated with the SCADA system and uses the same hardware and communication systems.

The northern system is old and uses 725 Hz as the carrier frequency. (Note: A new 317 Hz system has been commissioned, but as the advanced meter/relay rollout will take 5 to 6 years to complete, the old system has to be kept in service for this period). The 725 Hz relays and injection plant are old wide band equipment and there are areas of the network that have marginal to non-operational signal levels.

The southern system has modern solid-state transmitters and receivers operating at 317 Hz. Inputs are received from the GXP, supply points, and larger distributed generators. These are summed in the system load and signals are sent out to control to fixed values of demand at GXPs, generation busbars, zone substations and feeders.

Larger distributed generators receive a rebate for the level of transmission demand their generation enables TLC to avoid.

The load control and SCADA master station is used to record and store system loadings. Time controls are used for tariff signals and daylight sensors are used to drive signals for street lighting. The introduction of the new system, the demand-based charges and an increased rollout of advanced metering does mean there is an incentive for TLC to set up a slightly better channel control structure. This is discussed in more detail in the service levels section. Looking forward TLC needs to control loadings to feeder levels.

It is hard to envisage how a lower cost system that provides reliable control could be implemented. Various options were researched as part of the evaluation of the renewal of the northern system. Power system carriers based on decabit codes with injection at 33 kV were found to be the most effective for present and foreseeable future needs. This included integration with advanced metering systems.

Section 5

5. Service Levels

TLC provides billed connections to about 23,300 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.
- Line business efficiency targets.

The service performance targets in this section are used to:

- 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.
- Over time, they will provide a measure of the effectiveness of the actions taken in accordance with the AMP.

5.1 Customer Oriented Performance Targets

The industry targets such as SAIDI minutes and SAIFI frequency are hard for customers to understand and create averaging effects that do not give enough detail about asset performance in various sectors of the network. TLC also 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 5.1 illustrates the service level areas in geographical layout.

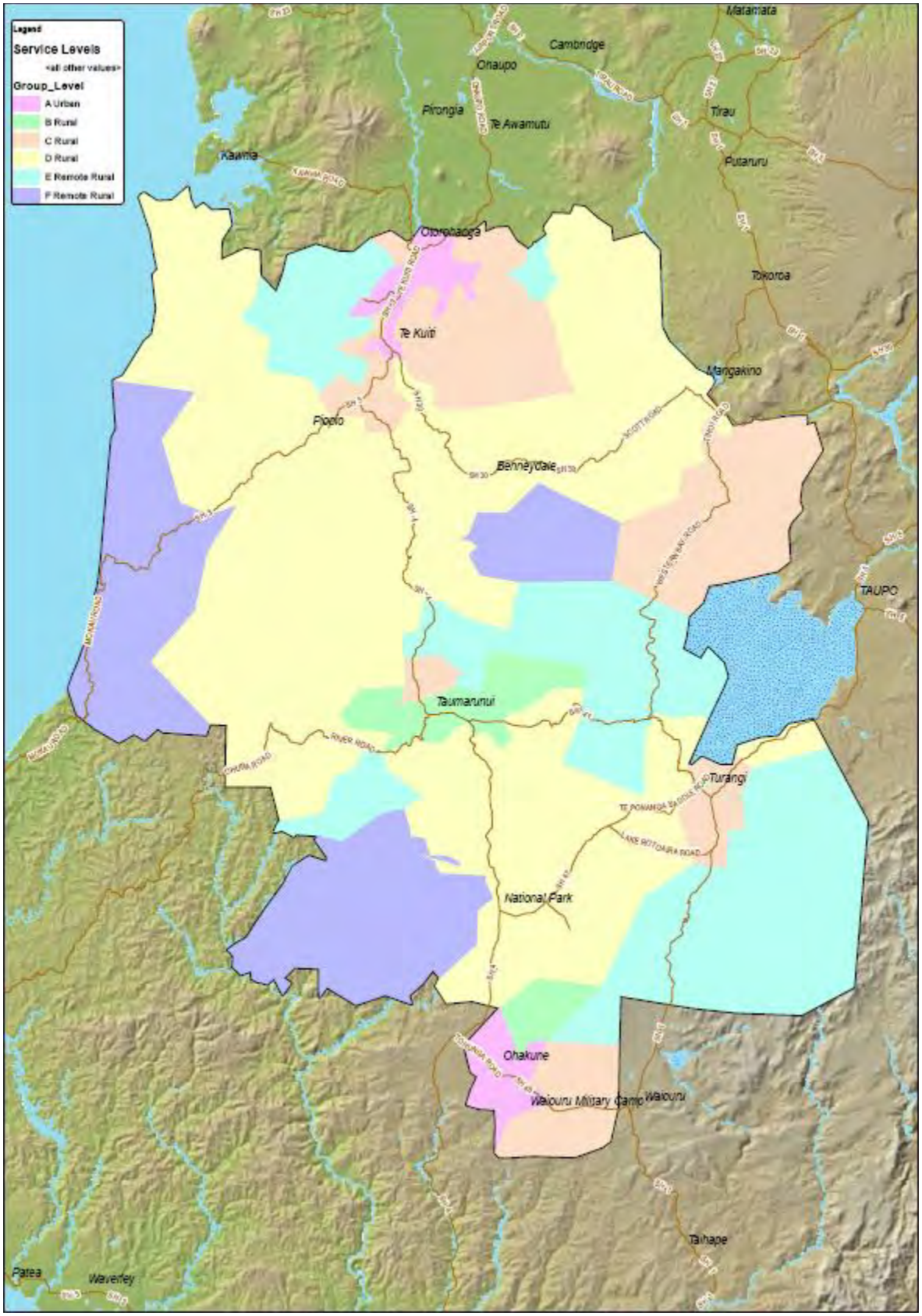


FIGURE 5.1 : SERVICE LEVEL AREAS

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.

A customer survey conducted in 2009 revealed 92% of customers were satisfied with the reliability of their power supply. However there was some slippage in satisfaction with reliability since the last measurements in 2005. Specifically, there was a drop in the proportion of customers who stated they were 'extremely' or 'very satisfied' and an increase in the number of customers who stated they were 'quite satisfied' with respect to SAIDI and SAIFI. This trend is believed to be due to an increase in customer expectations, i.e. as reliability increases, customers' expectations become greater.

TLC is currently in the process of preparing a Commerce Commission Customised Price Path (CPP). If TLC's CPP is approved, it is likely that TLC will prepare an AMP in the next financial year and that the performance targets will have to be varied due to the CPP application. There will be a lower level of live line and generator by-pass work completed. To allow this to happen with minimal disruption TLC will have to develop more innovative and effective outage notification systems. Things being looked at include system that will be supported by the Basix outage calculator such as:

- Text messaging
- Email

This section has been prepared on the assumption of "business as usual" until the application is approved.

Note: All customer orientated 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.

5.1.1 Customer Oriented Performance Targets: Asset Related

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

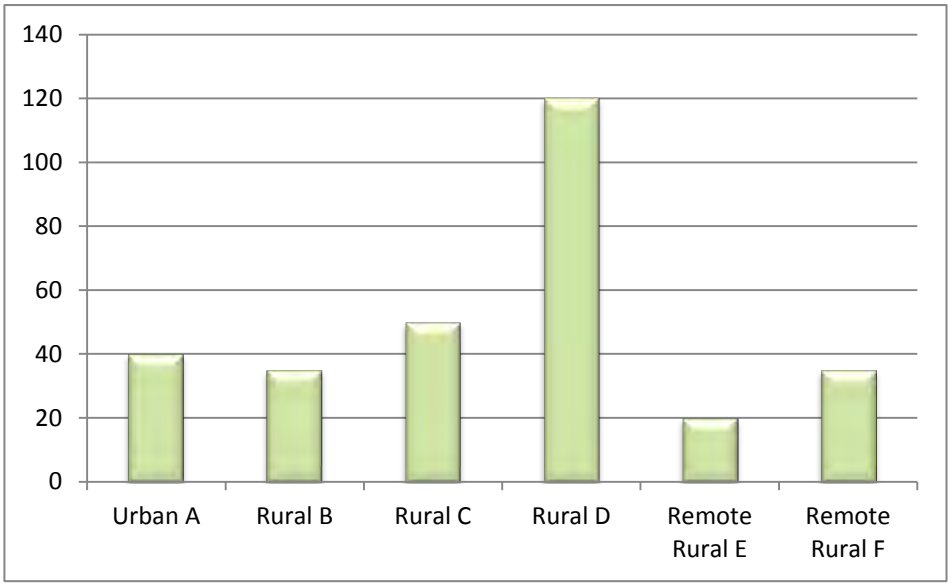
- SAIDI and SAIFI broken down by the 6 service level regions.
- Time to restore supply after an unplanned outage by the 6 service level regions.
- Maximum number of planned shutdowns per year by the 6 service level regions.
- Maximum number of long and short faults per year by the 6 service level regions.

TLC uses the BASIX computer programme to produce reports of the above performance indicators at asset group, service level and other higher reporting levels. The asset group and service level region performance is discussed in the performance section of the AMP (Section 6). These targets are consistent with business strategies and asset management objectives to operate a network that meets customer quality and reliability expectations.

As stated above TLC is currently in the process of preparing a Commerce Commission Customised Price Path (CPP). In the future, it is likely that these targets will have to be varied due to the CPP application. This section has been prepared on the assumption of "business as usual" until the application is approved.

5.1.1.1 SAIDI Targets

Table 5.1 lists the service level and overall SAIDI targets.



SAIDI Target	**40**	**35**	**50**	**120**	**20**	**35**	**TOTAL 300**

TABLE 5.1 : SAIDI TARGETS BY SERVICE LEVEL

At the time of this review it is proposed the SAIDI target will remain the same till financial year 2027/28. (Subject to the CPP application outcome)

The total SAIDI target of 300 minutes has been determined as part of the customer consultation process. The split between planned and unplanned historically has been 97 and 203 minutes respectively. The 300 minute target is lower than the Commerce Commission Decision 685 SAIDI limit (307.69) as calculated by the formulae in the determination document. The breakdown of SAIDI by service level has been determined by data collected in financial year 2009/2010.

Compliance with the Commerce Commission has the potential to increase the cost of TLC's renewal programmes because of the need to use live line work methods and generator by-passes to comply with threshold targets. Work to date has shown that breaches will potentially occur from time to time. This will mainly be caused by repeated days of windy weather that do not quite trigger the normalisation calculation of the Decision 685 formulae. The repeated periods will inflate the result, and cause pressure on renewal outages, i.e. there will be an incentive to minimise renewal outages to reduce the risk of breaching the targets. If the weather patterns are severe in a particular year and the figures are tracking high, then the only method of control is either to constrain renewal and maintenance outages or require work to be done using live line techniques, which will increase costs. Neither outcome is ideal.

Many Customers are indicating they do not want to fund increased costs for planned renewals using live line work methods. Analysis of data has shown that about 25 SAIDI minutes would be added if additional work was completed using lower cost and de-energised methods. Looking forward it is expected that unplanned outage minutes will decrease (as a result of renewal and reliability programmes) and that this will be offset by increased renewal. As a consequence of this, and historical moving averages, the planned and unplanned split targets have been amended to 90 and 210 minutes respectively (Excluding an increase for more de-energised work).

Table 5.2 lists the justification for SAIDI targets based on Consumer, Statutory, Regulatory, Stakeholder and other considerations.

JUSTIFICATION FOR SAIDI TARGETS	
Target and Item	**Justification**
SAIDI Consumer Considerations	Customers have said they are happy with the present level of reliability. As reliability improves customers' expectations change. Customers are now expecting reliability to be maintained or improved although they do not want to pay extra for live line work while renewal is taking place.
SAIDI Statutory Considerations	The heavy renewal programme means that outages will be required or live line techniques will be required to complete the work. Live line work is expensive and often not practical in the King Country. This will result in the need for outages. (Note: Commerce Commission Decision 685 may influence this.) SAIDI is an industry recognised measuring index.
SAIDI Regulatory Considerations	The Electricity (Safety) Regulations 2010 which came into effect on April 1st 2010 provided for the implementation of the Safety Management System, which has subsequently been incorporated into TLC's Distribution Standards. This is designed to prevent serious harm to any member of the public or significant damage to property. These Regulations also provide for the control of worker hazards. Outages are required to achieve this. Protection must be set up to operate/disconnect supply when faults occur. Supply must be turned off to allow renewal. Equipment must be renewed to eliminate/minimise hazards.
SAIDI Stakeholder Considerations	The Trusts have provided feedback requesting that reliability be maintained at present levels. This has also been confirmed by focus group members. Feedback has revealed that customers are not prepared to pay for improved reliability. Recent customer surveys have indicated that customers have an escalating reliability expectation.
SAIDI Other Considerations	The TLC area is remote and rugged in nature. Customers are often long distances from depots via roads that quickly become impassable in bad weather. Distribution Lines travel in direct routes and do not follow roads. Helicopters are often used for fault patrols and repairs. These machines cannot operate in darkness or bad weather. The TLC network has no major population centre to alter the averaging process between urban and rural customers. As a consequence of all these factors, TLC's reliability indices will always be high by industry standards. TLC has researched international papers to identify benchmarks as to the levels of reliability considered acceptable to rural customers. This work concluded that a level of 300 minutes would be considered acceptable in rural areas such as parts of Australia. (TLC customers have also confirmed these values). SAIDI targets have not been reduced over the planning period due to customer wishes to not pay additional margins for live line work. Work has been completed analysing data to Decision 685 criteria for the period 2004/05 to 2009/10. The results of this work were 307.69 SAIDI minutes as the threshold thus confirming that a 300 SAIDI minute target is realistic given the need for increased renewal work.

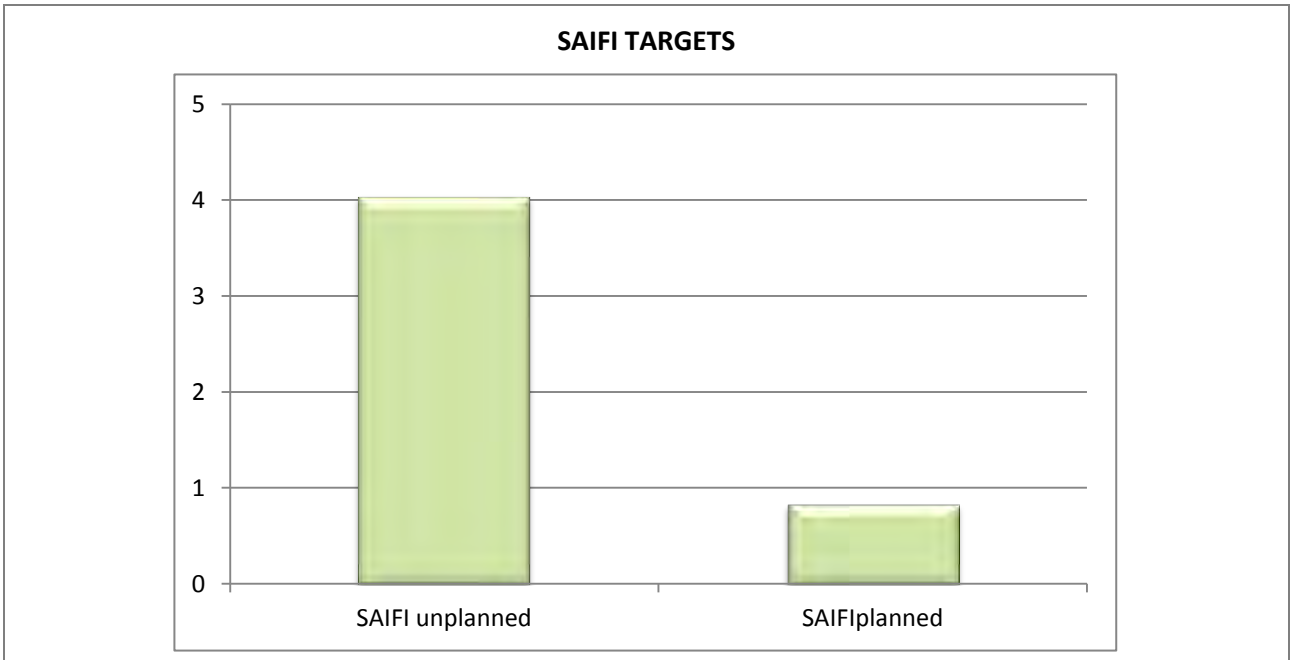
TABLE 5.2 : JUSTIFICATION FOR SAIDI TARGET LEVELS

5.1.1.2 SAIFI Targets

At the time of this review it is proposed the SAIFI target will remain at 4.86 till financial year 2027/28. However TLC is currently in the process of preparing a Commerce Commission Customised Price Path (CPP). In the future, it is likely that the target will have to be varied due to the CPP application. The total SAIFI target (frequency) of 4.86 has been determined as part of the customer consultation process and the need to minimise the cost of renewals by carrying out a proportion of the work de-energised. The split between planned and unplanned SAIFI is 4.03 and 0.83 respectively. As with SAIDI, this target will likely be greater than that determined by the Commerce Commission Decision 685 threshold calculations (4.15) during periods over the planning period. This is due to the fact that Decision 685 threshold is a normalised figure and the SAIFI target is not. Compliance with the determination will add additional cost to TLC's renewal programmes for live line work and generator by-passes.

Due to technical difficulties the SAIFI target 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 5.3 lists the unplanned and planned SAIFI targets.



SAIFI Target	**4.03**	**0.83**	**TOTAL 4.86**

TABLE 5.3 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.

Table 5.4 lists the justification for SAIFI targets based on Consumer, Statutory, Regulatory, Stakeholder and other considerations.

JUSTIFICATION FOR SAIFI TARGETS	
Target and Item	**Justification**
SAIFI Consumer Considerations	Switching surges, and the frequency of outages, often upset customers' electronic equipment. As per SAIDI, customers want the present numbers of outages maintained or improved. However they do not want to pay extra for live line work while renewal is taking place.
SAIFI Statutory Considerations	As per SAIDI, live line work is difficult, costly and often not practical in the King Country. Generators energising lines beyond work sites can be used to reduce SAIDI but may increase SAIFI. Outages have to occur at the end of shutdowns because of synchronising difficulties. A reduced target will be difficult to achieve.
SAIFI Regulatory Considerations	As per SAIDI. Regulatory requirements driven by renewals, electricity governance rules (AUFLS relays) and the like will put pressure on SAIFI performance.
SAIFI Stakeholder Considerations	As per SAIDI and customer considerations.
SAIFI Other Considerations	SAIFI figures are expected to remain high by industry standards due to the nature of the network. TLC has researched international papers to identify international benchmarks as to the levels of reliability considered acceptable to rural customers. This research concluded that an average SAIFI level of 3.91 would be considered acceptable in places such as rural Australia. TLC customers have concurred with this assessment. Due to the heavy renewal programme, the SAIFI frequency target has been incremented by the amount that the heavy renewal programme is expected to cause. Work has been completed analysing data to Decision 685 for the period 2004/05 to 2010/11 (YTD). The results of this work confirm the need for an average 4.86 frequency target given the requirement for increased renewal work.

TABLE 5.4: JUSTIFICATION FOR SAIFI TARGETS

5.1.1.3 Time to Restore Supply

The customer agreed performance times to restore supply after an unplanned outage are listed in Table 5.5 by service level. Achieving these targets is not always possible because of the practical realities of getting the required staff and equipment to site to carry out repairs.

TLC sets targets to measure how often this agreed customer performance is achieved. The targets are set according to 2009/2010 performance. The reason for using the 2009/2010 performance is that this was the first year of reasonably reliable data and it was taken as the base year. This was due to technical difficulties when transferring data from TLC's old database (before 2009 /2010) into the Basix database. The other factor in determining the targets is the time customers will accept for unplanned outages. The measuring index of this target is based on the percentage of events that do not exceed this target. Table 5.5 lists these target figures.

TARGETS: MAXIMUM TIME TO RESTORE SUPPLY						
Service Level Region	**Urban A**	**Rural B**	**Rural C**	**Rural D**	**Remote Rural E**	**Remote Rural F**
Maximum time to restore supply after an unplanned outage (hours)	3	6	6	6	12	12
Target % of events that achieve this agreed performance	95%	90%	90%	90%	90%	90%

TABLE 5.5 TARGETS FOR MAXIMUM TIME TO RESTORE SUPPLY BY SERVICE LEVEL AND THE PERCENTAGE OF EVENTS TO ACHIEVE THE TARGET

Table 5.6 lists the justification for target levels of service related to time taken to restore supply based on Consumer, Statutory, Regulatory, Stakeholder and other considerations.

JUSTIFICATION FOR MAXIMUM TIME TO RESTORE SUPPLY TARGETS	
Item	**Justification**
Consumer Considerations	Customers accept that outages happen from time to time. The maximum time customers will accept for unplanned outages for urban areas is 3 hours, 6 hours for rural areas and 12 hours for remote rural areas. 3 hours has been found to be the upper threshold of urban life styles. 6 hours in rural areas equates to the time between daily milking. 12 hours in remote rural areas equates to the typical timeframe stock water systems become empty, stock determine electric fences are no longer energised and freezers begin to thaw.
Statutory Considerations	There is no Statutory requirement to restore power to areas by set times other than cumulative Commerce Commission thresholds. If it takes longer to restore supply customers often voice frustration by complaints to regulators and other stakeholders.
Regulatory Requirements	There is no Regulatory requirement to restore power to areas by set times. It is often necessary to extend outage times to control hazards.
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	Experience shows that typical maximum time taken to restore supplies is 3 hours for urban areas, 6 hours for rural areas and 12 hours for remote rural areas. There are exceptions and the risk of these times being exceeded is 15% for Urban A and Rural D, 11% for Rural B, 13% for Rural C and Remote Rural F, and 12% for Remote Rural E as detailed in the terms and conditions of supply.

TABLE 5.6: JUSTIFICATION FOR MAXIMUM TIME TO RESTORE SUPPLY TARGETS

5.1.1.4 Maximum Number of Planned Shutdowns per Year by Service Level

The customer agreed maximum numbers of planned shutdowns by the service level are listed in Table 5.7. 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.

As a consequence, TLC sets targets to measure how often this agreed customer performance is achieved. The targets are set according to 2009/2010 performance (base year). The reason for using the 2009/2010 performance is that this was the first year of reasonably reliable data and it was thus taken as the base year. The measuring index of this is based on the percentage of events that complied with this target. Table 5.7 lists these amounts.

TARGETS: MAXIMUM NUMBER OF PLANNED SHUTDOWNS						
Service Level Region	**Urban A**	**Rural B**	**Rural C**	**Rural D**	**Remote Rural E**	**Remote Rural F**
Maximum number of planned shutdowns per year	2	4	6	6	8	10
Target % of events that achieve this agreed performance	95%	90%	90%	90%	90%	90%

TABLE 5.7 TARGETS FOR MAXIMUM PLANNED SHUTDOWNS PER YEAR BY SERVICE LEVEL AND THE PERCENTAGE OF EVENTS TO ACHIEVE THE TARGET

Table 5.8 summarises the justifications for target levels of service related to the maximum number of planned shutdowns per year by service level.

JUSTIFICATION FOR MAXIMUM PLANNED SHUTDOWN TARGETS	
Item	**Justification**
Consumer Considerations	Customers accept that planned shutdowns are necessary; although they do not like repeated outages. Based on feedback from customer focus groups, commercial customers and complaints, the maximum number of planned outages that customers have found to be acceptable are 2 for Urban A, 4 for Rural B, 6 for Rural C and D, 8 for Remote Rural E and 10 for Remote Rural F.
Statutory Considerations	There is no Statutory requirement for a set number of outages. The use of live line techniques on the TLC network is difficult, expensive and often not practical in the King Country. The Commerce Commission has set new reliability thresholds. Balancing low cost de-energised renewal work with more expensive live line techniques or use of generator by-pass methods is an on-going topic of discussion between the regulators, TLC and its customers.
Regulatory Considerations	Outages are often necessary for hazard control, renewal, grid emergencies and other requirements under the electricity and HSE regulations.
Stakeholder Considerations	Customer satisfaction and minimal disruption to businesses and individuals in the region is in the best interests of stakeholders as this has a direct effect on the economic and social well-being of the region.
Other Considerations	The targets are a balance between customers' expectations and the practical issues associated with an extensive renewal programme. The targets do force contractors and network operators to carefully plan work and maximise the work done during any one outage. They have been set to allow renewal work to be substantially completed without the use of more expensive live line techniques and generator by pass techniques. The number of outages increases as the remoteness increases due to a reduced number of back feeds being available.

TABLE 5.8: JUSTIFICATION FOR MAXIMUM NUMBER OF PLANNED SHUTDOWN TARGETS

5.1.1.5 Maximum Number of Unplanned Shutdowns per Year by Service Level

The customer agreed maximum numbers of unplanned shutdowns (short and long faults) by service level are listed in Table 5.9. Achieving this in all cases is not possible because of the number of aged hazardous assets in the TLC network, the rugged environment of King Country and extreme events.

TLC sets targets to measure how often this agreed customer performance is achieved. The measuring index of this is based on the percentage of events that complied with the target. Table 5.9 lists these target figures.

TARGETS: MAXIMUM NUMBER OF UNPLANNED SHUTDOWNS						
Service Level Region	**Urban A**	**Rural B**	**Rural C**	**Rural D**	**Remote Rural E**	**Remote Rural F**
Maximum number of long unplanned shutdowns per year (Greater than 1 minute)	5	15	15	15	25	25
Target % of events that achieve this agreed performance	95%	90%	90%	90%	90%	90%
Maximum number of short unplanned shutdowns per year (Less than 1 minute)	20	20	60	60	60	160
Target % of events that achieve this agreed performance	98%	98%	98%	98%	98%	98%

TABLE 5.9 MAXIMUM NUMBER OF SHORT AND LONG FAULTS PER YEAR BY SERVICE LEVEL AND THE TARGETED LEVEL OF EVENTS WHERE THIS IS NOT EXCEEDED

Table 5.10 summarises the justifications for target levels of service related to the maximum number of unplanned shutdowns per year by service level.

JUSTIFICATION FOR MAXIMUM UNPLANNED SHUTDOWN TARGETS	
Item	**Justification**
Consumer Considerations	Customers accept that faults occur but do not enjoy the inconvenience when they do occur. As a consequence TLC has set numerical limits as outlined in Table 5.10. 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 is no Statutory requirement at this time for the number of unplanned short and long duration faults. It is suspected that short duration faults (recloses) may require disclosure in the future.
Regulatory Considerations	There are no Regulatory considerations for the number of unplanned short and long faults. Protective devices must isolate faulty equipment in compliance with the electricity regulations.
Stakeholder Considerations	Customer satisfaction and minimal disruption to businesses and individuals in the region is in the best interests of stakeholders as 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 5.10: JUSTIFICATION FOR MAXIMUM NUMBER OF UNPLANNED SHUTDOWN TARGETS

5.1.2 Customer Oriented Performance Targets – Service Related

The following customer oriented service related targets are used:

- Telephone calls coming into the organisation. TLC is decoupled from retailers and receives all telephone calls locally.
- Unanswered telephone calls coming into the organisation.
- Unresolved complaints to the Electricity and Gas Industry Complaints Commission's complaints resolution processes.
- Number of focus group meetings - TLC has set up several regional focus groups who meet with senior management on a regular basis to discuss service and other outstanding issues.
- Number of customer clinics - TLC schedules meetings in regions where customers come and discuss collectively, or individually, their service concerns.

5.1.2.1 Telephone Calls Coming into the Organisation

The number of telephone calls TLC receives is a measure of the service delivered by the organisation. Experience has shown that customers call when there is a service problem such as incorrect accounts, misadvised planned outages or to report unplanned outages. The target is not to exceed 4500 telephone calls received per month. Incoming calls are recorded by the telephone system and monthly reports detail call statistics.

Table 5.11 summarises the justifications for target levels of service related to the maximum number of calls coming into the organisation on a monthly basis.

JUSTIFICATION FOR TELEPHONE CALLS COMING INTO THE ORGANISATION TARGETS	
Item	**Justification**
Consumer Considerations	Large numbers of customers call when accounts are incorrect, planned outages are incorrectly advertised or when unplanned outages occur. Monitoring call numbers gives an indication of customer issues. The indices can be easily measured and the target has been set based on the numbers of incoming calls that are received during periods when there are no exceptional events. The call numbers double, treble or quadruple when a bill ing run has errors or there is a major outage event.
Statutory Considerations	There is no Statutory requirement regarding the number of calls from customers. Customers calling and being able to talk to someone who can solve their problem or address their need is very important. Complaints to various bodies (EGCC, EC, COMCOM, MED, MPs) have occurred when legacy telephone systems and resources were not adequate to answer billing enquiries or loss of supply calls.
Regulatory Considerations	There is no Regulatory requirement for the number of calls from customers. There is a requirement for TLC to receive information from customers and other stakeholders on hazards and to respond to these hazards in a timely manner.
Stakeholder Considerations	TLC shareholding stakeholders have responded to customers' concerns about out of area telephone call centres. TLC has been instructed to have resources in place to answer calls at a local level using people who have local knowledge of the area. Timely answering of calls and the numbers of calls is important to shareholding stakeholders.
Other Considerations	To improve our customer service, TLC needs to stay in contact with customers, encourage customers to call and needs to be approachable. For quality purposes TLC monitor the number of calls received on a monthly basis.

TABLE 5.11: JUSTIFICATION FOR TARGET LEVELS OF CALLS COMING INTO THE ORGANISATION

5.1.2.2 Unanswered Telephone Calls

Telephone calls that are not answered within a short period indicate problems with service. Customers do not appreciate unanswered calls. The unanswered telephone calls target is not to exceed 3% of telephone calls coming into the organisation per month. Unanswered incoming calls are monitored by the telephone system and the reports are reviewed on a regular basis. The unanswered calls target includes busy signal and short duration calls.

Table 5.12 summarises the justifications for target levels of service related to the maximum number of telephone calls that go unanswered. The target is based on present levels of service.

JUSTIFICATION FOR UNANSWERED TELEPHONE CALL TARGETS	
Item	**Justification**
Consumer Considerations	Unanswered calls indicate a peak customer service issue or not enough resources to answer calls. Customers do not appreciate the lack of response. The target level of 3% per month is based on historic records and performance. From a customer perspective the number of unanswered calls should be as low as possible. Balancing resources can be difficult for short duration peak times.
Statutory Considerations	There is no Statutory requirement for TLC to have a certain level of unanswered calls. Customers do not appreciate unanswered calls. Complaints to various bodies (EGCC, COMCOM, MED, MPs) have occurred when calls go unanswered and customers cannot get issues resolved.
Regulatory Considerations	There is no Regulatory requirement for TLC to have a certain level of unanswered calls. There is a requirement for TLC to answer calls from stakeholders and customers and respond to these, especially when they are associated with an emergency event.
Stakeholder Considerations	TLC shareholding stakeholders have instructed TLC to have resources in place to answer calls at a local level using people who have local knowledge of the area. They accept that it is not economic to employ a large number of resources to answer every call. Monitoring the level of unanswered calls is considered an important target and measurement by stakeholders.
Other Considerations	Call levels are not consistent, there are peaks and troughs. The causes of these are often unforeseeable and in fault situations, for example, some calls may go unanswered. Minimising and controlling this at a level acceptable to customers and stakeholders is important. Customers have to accept that having resources to answer telephone calls adds cost. The 3% target level has resulted in a much lower level of complaints as compared to the use of remote answering centres. The objective looking forward is to improve the service and hold costs. These objectives will most likely be achieved through the application of better telephone technology.

TABLE 5.12: JUSTIFICATION FOR TARGET LEVELS OF UNANSWERED TELEPHONE CALLS

5.1.2.3 Unresolved Complaints Annually Investigated by the Electricity and Gas Industry Complaints Commission or Alternative Complaints Resolution Organisation

Unanswered queries cause frustration and extra costs (staff time and EGCC charges). This can result in dissatisfied customers who may lodge a complaint with the Electricity and Gas Industry Complaints Commission. TLC have set a target to not exceed a total of six complaints per annum that take longer than 3 months for TLC and the Commission to investigate and resolve. The target is measured by recording the numbers of complaints that go to the EGCC and the relevant date. The target has been set based on what is considered a realistic level given TLC's situation. However in recent time the concept of charging based on the place of supply has resulted in an increased number of dead locked complaints. The target has remained unaltered given its intent to resolve this issue in the medium term.

Table 5.13 summarises the justifications for target levels of service related to the unresolved complaints annually investigated by the EGC or alternate complaints organisation.

JUSTICATION FOR UNRESOLVED COMPLAINT TARGETS	
Item	**Justification**
Consumer Considerations	Due to TLC's unique demand and direct billing scheme, a number of customers believe that their line charges are excessive. They have difficulty understanding independent line and energy charges compared with retailers' repackaged charges in other parts of the country. The complaints made to the EGCC have to be funded by charges to TLC. These costs go into the overhead operating charges, which in turn have to be funded by other customers. As a consequence of this, TLC is incentivised to minimise complaints that go to this detailed investigation stage. Most customers understand the issues when they have them explained; however, a number do not and continue with the complaint. This costs TLC in staff time and EGCC charges. A target has therefore been set to limit these complaints to a total of six per annum that take longer than 3 months for TLC and the Commission to investigate and resolve. This level is measurable and has been set based on historical information (it has not been altered due to recent landowner/tenant problems).
Statutory Considerations	There is no Statutory requirement to have a set target of number of complaints to the EGCC. However EGCC costs have to be funded and this displaces other operating costs. This creates indirect Statutory pressure to minimise complaints costs.
Regulatory Considerations	There is no Regulatory requirement to have a set number of complaints to the EGCC. There is a Regulatory requirement to be part of a complaints resolution process.
Stakeholder Considerations	Complaints to the EGCC cost TLC, and other customers, money and results in customer dissatisfaction. Stakeholders require the numbers of customers involved in this process to be minimised.
Other Considerations	The target is easy to measure and gives a further indication of TLC's customer service performance. The better the customer service, the smaller the number of frustrated customers.

TABLE 5.13: JUSTIFICATIONS FOR TARGETS RELATED TO UNRESOLVED COMPLAINTS INVESTIGATED BY EGCC OR ALTERNATE COMPLAINTS ORGANISATION

5.1.2.4 Focus Group Meetings

Focus groups are groups of customers who meet with senior management to discuss the organisation's performance and other issues. Customers bring their local and other issues forward at these meetings. Management usually prepare and present a summary of key current issues at these meetings.

The most recent presentations have focused on price, quality and capacity trade-offs for the Ohakune area. Other recent presentations have centred on the need to complete renewal programmes and to obtain funding for these from revenue. Focus groups normally include various customers and other interested stakeholders from the area. The size of the group varies from 10 customers to over 80. At these meetings discussion is generally around the direct line charging issues that customers have.

Initially the concern of customers attending these meetings was around network reliability but, as this has improved, the focus has moved to charges and capacity. The target is to hold at least 5 meetings per year. This target is measured by logging the meetings in a database. The target has been set based on the number of meetings that TLC can realistically handle given its present staffing levels.

Table 5.14 summarises the justifications for target levels of service related to focus group meetings.

JUSTIFICATION FOR FOCUS GROUP MEETING TARGETS	
Item	**Justification**
Consumer Considerations	The number of annual meetings is regulated by the available time of customers and senior management. Most focus groups presently are requesting an annual meeting. A number of focus groups have been meeting frequently to resolve and keep updated on specific issues such as recent Commerce Commission publications and pricing levels. Focus groups are a mechanism for discussing price quality trade-offs, the AMP, Corporate objectives, pricing and service. Often an independent chairman is used to run the meetings.
Statutory Considerations	There was a Statutory requirement for engagement with customers to discuss price/quality trade-offs. In the current Plan period TLC's prices and quality are set by a Default Price Path. TLC will have to likely apply for a CPP (Customised Price Path) and as part of this will have to demonstrate customer engagement on various issues. The focus group meetings will be a vehicle to achieve this.
Regulatory Considerations	As per above. Focus group meetings have also included discussions on hazard control, related high voltage lines issues and supply quality.
Stakeholder Considerations	Stakeholders require senior management to engage with customers. Focus groups are an essential link in this chain.
Other Considerations	Focus group meetings are very satisfying, particularly when customers endorse and appreciate the hard work staff put into maintaining supply to customers in a rugged difficult environment.

TABLE 5.14: JUSTIFICATION FOR TARGET LEVEL OF FOCUS GROUP MEETINGS

Note: In addition to the focus group a "mayors" working group has recently been established plus a Trust is being set up to help educate customers.

5.1.2.5 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 5.15 summarises the justification for target levels of service related to number of customer clinics.

JUSTIFICATION FOR CUSTOMER CLINIC TARGETS	
Item	**Justification**
Consumer Considerations	Customers appreciate meetings in local areas with staff to discuss specific issues. The target has been set based on present resources and the numbers of customers who use the services.
Statutory Considerations	Commerce Commission will require customer consultation (for CPP applications). Customer clinics are one of the tools TLC uses to achieve this.
Regulatory Considerations	Customer clinics do from time to time involve the discussion of hazard control and power quality issues.
Stakeholder Considerations	Stakeholders request that TLC establishes and maintains direct relationships with its customers. Local Mayors, whose electorate did cover part of the TLC network area, requested that a group be set up to discuss and try to resolve a number of the complaints that have come from customers in the Taumarunui area. This group has been set up and is active.
Other Considerations	Another important link in the interaction with customers. A target has been set to ensure the task is given priority.

TABLE 5.15: JUSTIFICATION FOR TARGET LEVEL OF CUSTOMER CLINICS

5.2 Other Targets Relating to Asset Performance, Asset Efficiency and Effectiveness and the Efficiency of Line Business Activity

5.2.1 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. Where appropriate, historical data are shown to justify targets. Some future targets are also shown.

5.2.1.1 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.

5.2.1.1.1 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. Often customers choose not to fund works/installation upgrades and instead choose to tolerate inadequate supply. These customers are excluded from the performance target. TLC has been investing in equipment that improves network voltage regulation and can predict network performance. 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.

5.2.1.1.2 Voltage Studies: Legacy Issues

Improved network analysis has identified a number of 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.

TLC has included in the AMP a programme to deploy more regulators and other voltage improvement tools, the programme has been levelled and prioritised based on the extent of each violation. The purpose of the programme is to bring the operating voltage back within Regulatory limits [ESR 28] at all sites within the planning period. Details of the programme can be found in Section 7 of the Plan. The target has been set based on the number of additional regulators in the annual plan.

5.2.1.1.3 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. The number has been set based on the typical number of historical complaints.

5.2.1.1.4 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 increasing 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 on the increase of harmonic distortion. This may lead to changes in future connection standards and terms and conditions of supply. The target is to have no sites exceeding the above limits on annual spot measurements throughout the planning period. This target has been set based around information on actual measurements taken.

Table 5.16 summarises the justification for quality asset performance targets.

JUSTIFICATION FOR QUALITY ASSET PERFORMANCE TARGETS	
Item	**Justification of Targets**
Consumer Considerations	Voltage Complaints: The target has been set based on historic complaint levels and takes into account legacy design and connection practices. Voltage Studies: Legacy Issues – Voltage quality will be outside Regulatory limits unless action is taken. Harmonic Levels: Harmonics cause a multitude of problems including interference and other problems in the power system. Voltage Surges: Voltage surges often destroy electronic components. Many of these surges are caused by events such as switching surges and lightning. When appliances are destroyed customers have to claim against their insurance policies for new ones. If they have no insurance then they have to fund these themselves. TLC's objective is to minimise the risk of appliances being destroyed by engineering to minimise surges.
Statutory Considerations	Supply quality is included in electricity requirements.
Regulatory Considerations	Voltage: Voltage levels are covered by regulations. TLC uses these voltage limits as its quality criteria. Harmonics: Harmonic level limits are currently detailed in NZECP36 - this code is somewhat dated by international standards. TLC uses this as its harmonic quality criteria. The target (10% for 3-wire systems and 30% for SWER systems THD) is a TLC performance target. The target set for further investigation (5% change in reading) is all part of TLC's strategy to understand harmonic flows and the implications of these in TLC's network, particularly with the unique multitude of SWER systems. Voltage Surges: There are no Regulatory criteria for voltage surges.
Stakeholder Considerations	Voltage: Stakeholders require voltage levels to comply with regulations. Ideally all parts of the network should comply. The reality is that there are a number of legacy issues that need addressing. Stakeholders need to understand the level of non-compliance and the steps that are in place to address these issues. Harmonic Levels: Stakeholders require network harmonic levels to comply with the regulated code of practice. They wish to be aware of strategies in place to manage this issue to ensure the network continues to be sustainable. The target gives them an assurance that this issue is being monitored. Voltage Surges: Stakeholders wish the number of destroyed appliances to be minimised.

JUSTIFICATION FOR QUALITY ASSET PERFORMANCE TARGETS	
Item	**Justification of Targets**
Other Considerations	Voltage: Many appliances are rated at 240Volts. Regulations state a nominal voltage of 230 Volts. Customers can have problems with equipment because of this mismatch. As a consequence it is important that targets for complaints are reasonably generous. Investigation of complaints often reveals that this mismatch is causing the customers problems. Harmonics: Harmonics is a complex subject. Tests show that electronic compact light bulbs, heat pumps and soft starters produce high levels of harmonics. Hence monitoring the network levels is considered important for long term sustainability. Other Considerations: TLC wishes to manage its assets to minimise the potential of voltage surges. TLC is also encouraging customers to take demand side responsibility by giving away plug-in surge protection devices to customers.

TABLE 5.16: JUSTIFICATION FOR QUALITY ASSET PERFORMANCE TARGETS

5.2.1.2 System Component Performance: Failures

As part of the outage reporting system TLC has monitored system component failures that have caused faults. 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. The targets for the planning period are listed in Table 5.17. This is a simple measure of the impact of and the need for renewal programmes. The target has been set based on historical levels of failure and the expectation these will reduce as the renewal programmes continue.

COMPONENT FAILURE TARGETS	
Year	**Target**
2011/12	244
2012/13	240
2013/14	236
2014/15	232
2015/16	228
2016/17	224
2017/18	220
2018/19	216
2019/20	212
2020/21	208
2021/22	204
2022/23	200
2023/24	196
2024/25	192
2025/26	188
2026/27	184
2027/28	180

TABLE 5.17 COMPONENT FAILURE TARGETS

Table 5.18 summarises the justification for the system component failures performance targets.

JUSTIFICATION FOR THE SYSTEM COMPONENT FAILURES PERFORMANCE TARGETS	
Item	**Justification**
Consumer Considerations	This is a measure of the number of component failures that cause outages. For example, an insulator failure that causes an outage. Counting these items via TLC's asset group based outage reporting system gives a measure of the effectiveness of TLC's maintenance and renewal programmes. Customers are not happy when outages that affect them could have been prevented through better maintenance programmes. The target level has been set based on historically monitored system component failures that have caused faults. It may require adjusting as a consequence of better data coming out of the asset management system. The target was adjusted for the 2010/11 year period forward as compared to 2009/10 year. This was due to data from the new outage reporting system indicating that the previous data collection process was not robust and therefore the level of reporting was not totally consistent
Statutory Considerations	The target and trends with the numbers of component failures will be used in submissions to the Commerce Commission and other regulators. It will be used to highlight the effectiveness of and the need for TLC's renewal programmes.
Regulatory Considerations	In addition to causing outages, faulty equipment creates hazards for both staff and the public. This measure gives impetus to the need for maintenance and renewal programmes.
Stakeholder Considerations	Stakeholders want a sustainable network - they do not want to see increasing number of components failing due to age. This target and measure provides reassurance to stakeholders that maintenance and renewal programmes are working.
Other Considerations	TLC has been measuring these numbers for the last nine years and now has a reasonable amount of data on components that have failed and caused faults. The system component failure target will be reviewed during the planning period and some further adjustment may have to be made as data quality improves.

TABLE 5.18: JUSTIFICATION FOR ASSET PERFORMANCE TARGETS: SYSTEM COMPONENT FAILURES

5.2.1.3 Environmental Performance

The environmental performance is measured using two targets. The first target is not to be prosecuted or receive 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 historical performance and the works included in the Plan.

Table 5.19 lists the environmental performance targets for the planning period.

ENVIRONMENTAL PERFORMANCE TARGETS		
Year	**Prosecution or Abatement Notices**	**Environmental Impact Works Due For Completion**
2011/12	0	0
2012/13	0	3
2013/14	0	0
2014/15	0	0
2015/16	0	1
2016/17	0	1
2017/18	0	0
2018/19	0	0
2019/20	0	0
2020/21	0	1
2021/22	0	1
2022/23	0	1
2023/24	0	0
2024/25	0	0
2025/26	0	0
2026/27	0	0
2027/28	0	0

TABLE 5.19 ENVIRONMENTAL PERFORMANCE TARGETS

Table 5.20 summarises the justification for the environmental performance targets.

JUSTIFICATION FOR THE ENVIRONMENTAL PERFORMANCE TARGETS	
Item	**Justification for Target**
Consumer Considerations	Environmental Control Agencies: No prosecutions or abatement notices. Customers are increasingly becoming aware of and concerned about organisations that breach environmental standards. Completion of Environmental Projects: TLC has a number of sites that have a level of environmental risk. The programme in the AMP includes projects to remove the risks. Customers want environmental risks associated with TLC assets minimised.
Statutory Considerations	Environmental Control Agencies: No prosecutions or abatement notices - environmental prosecutions and abatement notices should be avoided. The costs of prosecution and/or abatement notices is significant and funding these would offsets other, often more productive, operating expenditure. Completion of Environmental Projects: Environmental risk projects are generally high priority and the legislators would have difficulty should TLC to treat such projects with lower priority. Making sure they are completed is likely to be more important to the legislators.
Regulatory Considerations	Environmental Control Agencies: No prosecutions or abatement notices. From a Regulatory consideration, environmental prosecutions and abatement notices should be avoided although no specific targets are set. Completion of Environmental Projects: The reduction in environmental risk will be supported by regulators.
Stakeholder Considerations	Environmental Control Agencies: No prosecutions or abatement notices. From a stakeholder's perspective, abatement notices and prosecutions should be avoided. Completion of Environmental Projects: From a stakeholder's perspective all environmental improvement projects should be completed.
Other Considerations	Environmental Control Agencies: No prosecutions or abatement notices. Abatement notices and prosecutions need to be avoided. Completion of Environmental Projects: Environmental projects need to be completed especially given that many assets are located in sensitive areas.

TABLE 5.20: JUSTIFICATION FOR ASSET PERFORMANCE TARGETS: ENVIRONMENTAL PERFORMANCE

5.2.2 Asset Efficiency Targets

The following targets are used to measure asset efficiency:

- Network losses: Technical and non-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. Where appropriate, historical data are shown to justify targets. Some future targets are also shown.

5.2.2.1 Network Losses: Technical and Non-Technical

Network losses have historically been calculated from the energy coming into and delivered out of the network. Loss calculations became more difficult when the industry was split in 1999 and it is only over the last few year that reports from the Reconciliation Manager have become available and made it possible to calculate meaningful figures. The notion of technical and non-technical losses has also been introduced.

TLC has some control over technical losses but little influence over the retailer functions that lead to non-technical losses. Technical losses are generally I^2R and iron losses. Non-technical losses are metering errors associated with inaccurate or failed metering, meter reading errors and variations caused by the timing of meter reads.

As outlined in other sections, TLC has set up an extensive network analysis model that models right down to distribution transformer level. This model calculates technical losses and was set up as a bench mark in the 2006/07 year.

A result of the 1999 reforms was that network companies were no longer financially responsible for losses and as a consequence it became difficult to use losses in financial calculations to justify expenditure. Losses still exist and are becoming increasingly recognised as a critical long term issue. Tracking the network losses performance and how design decisions impact on these is considered important information.

Distributed generation and power flows (both active and reactive) associated with this 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 5.21 lists the targets that have been set for technical losses for contiguous network regions under heavy and light loads with the generation injecting at expected levels throughout the planning period.

TECHNICAL LOSS TARGETS		
Network Region	**Heavy Load**	**Light Load**
North	7.00%	2.00%
Central	8.00%	5.00%
Ohakune	9.00%	2.00%

TABLE 5.21: TECHNICAL LOSS TARGETS BY REGION

Averaging data in Table 5.21 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.

TLC has not set a non- technical loss factor target due to non-technical losses being mostly outside TLC's control. However it is monitoring the level. A level of concern has been expressed to retailers about the varying level of non-technical issues, including the difficulty in getting accurate information.

Table 5.22 summarises the justification for network loss targets.

JUSTIFICATION FOR NETWORK LOSS TARGETS	
Item	**Justification**
Consumer Considerations	Customers end up paying for losses through energy charges and they are often more concerned about capital related costs than the impact of system losses. Customers tend to be attracted to low cost capital solutions that produce higher losses. Customers are also concerned about long term environmental effects. The loss targets have been set based on present network performance and the objective of the targets is benchmarking. The current levels are known and movement in these targets needs to be understood by customers. The present benchmarking also has the ability to illustrate to customers their retailer's performance with meter reading, metering data and other errors coming out of their metering and billing systems.
Statutory Considerations	The Statutory controllers are indicating in their documents that network companies should be more innovative to promote energy efficiency. Lower loss networks have to be justified. Deployment of distributed generation may or may not reduce losses. Data analysis and network modelling serve to give an accurate picture of losses today so that as Statutory development moves forward TLC can work forward from a position of fact. Accurate submissions and arguments can be formulated as required.
Regulatory Considerations	There is no current Regulatory target for losses. Losses have to be disclosed. The difficulty TLC has is that technical losses can be calculated (subject to assumptions) but non-technical losses have to be sourced from retail data and the market processes. These (based on available data) have a variable level of accuracy. The targets TLC has set segregate these and going forward will clearly show the impact of technical and non-technical losses.
Stakeholder Considerations	Losses are a complex subject for most stakeholders. They are interested in knowing that losses are being monitored and that some form of targets and benchmark is in place.
Other Considerations	There will possibly be much industry development in the future around losses. It is important that TLC has benchmarking targets in place and is aware of what is occurring within the network. The benchmarking targets have been set based on present network configuration and generation injections using an extensive network analysis package. They only relate to technical losses given TLC has no control over non-technical losses that are largely generated by metering error.

TABLE 5.22: JUSTIFICATION FOR NETWORK LOSS TARGETS

5.2.2.2 Network Power Factor

The higher the network power factor the more efficient the transfer of energy. As discussed in other sections 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 5.23 lists the average power factor targets 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.

TARGET POWER FACTOR BY GXP				
Grid Exit Point	**2007/08**	**2008/09**	**2009/10**	**Target Power Factor (Average during RCPD period)**
Hangatiki	0.904	0.905	0.926	0.912
Ongarue	0.916	0.884	0.948	0.916
Tokaanu	0.989	0.993	0.994	0.992
National Park	0.988	0.993	0.989	0.990
Ohakune	0.987	0.994	0.991	0.991

TABLE 5.23 TARGET POWER FACTOR BY GXP DURING RCPD PERIOD

Table 5.24 summarises the justification for power factor performance targets.

JUSTIFICATION FOR POWER FACTOR PERFORMANCE TARGETS	
Item	**Justification**
Consumer Considerations	To encourage demand side reactive power control TLC's demand billing will likely be totally based on kVA demand for all customers once lower cost 2 channel kVA meters become available. Demand side reactive power control is the most efficient location in the power system for power factor correction. The connection of distributed generation reduces grid exit power factor as further detailed in Section 7. Capacity of future DG connections may be limited by their ability to run at unity power factor during RCPD periods. The target is set on the basis that TLC's billing system will encourage demand side power factor improvement. The electricity connection code under the Electricity Governance Rules will mean that customers will likely have to fund more reactive power factor correction in the future.
Statutory Considerations	Reactive power flows reduce network efficiency. All government policy statements focus on improving the efficiency of the electricity supply system. Benchmarking and setting targets to maintain or improve grid exit power factor fits with this objective.
Regulatory Considerations	The electricity connection code under the Electricity Governance Rules place limits on grid exit power factor.
Other Considerations	TLC is committed to ensuring its electricity network is transporting energy as efficiently as possible. Setting a target to maintain or improve grid exit power factor fits with this objective.

TABLE 5.24: JUSTIFICATION FOR NETWORK POWER FACTOR TARGETS AT GXP

5.2.2.3 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 data collected in financial years 2004 to 2010. Historic data gives an average of 62.5% load factor; it is suspected that the financial years 2005-2007 and 2010 had been disclosed inaccurately. The actual average performance was estimated to be around 59%. The target has been set around the assumption that load factor will improve.

Table 5.25 lists the load factor for historic years and the 2010/12 target.

NETWORK LOAD FACTOR: HISTORIC DATA AND TARGET			
Financial Year	**Electricity Volumes Carried (MWhr)**	**Co-incident System Peak (MWhr)**	**Load Factor**
2005/06	317.6	55.7	65.09%
2006/07	329.5	58.4	64.35%
2007/08	327.0	65.0	57.00%
2008/09	319.0	61.0	60.00%
2009/10	354.0	64.0	64.00%
2010/11	323.0	63.0	59.00%
Target			**60.00%**

TABLE 5.25: HISTORIC DATA AND TARGET NETWORK LOAD FACTOR

Table 5.26 summarises the justification for load factor targets.

JUSTIFICATION FOR LOAD FACTOR TARGETS	
Item	**Justification**
Consumer Considerations	The more efficient the operation of the network is the lower the customer charges will be. The target is a benchmark measurement of one of the efficiency indices, demand based billing was introduced to try and improve this performance. The target has been set at the present figure. Over the last few years load factor has been reducing due to demand increasing faster than the energy transported.
Statutory and Regulatory Considerations	Government policy statements require improved network efficiency. As outlined above the reverse trend has been taking place over recent times. The objective of demand billing is to firstly halt this trend and then possibly reverse it.
Stakeholder and Other Considerations	Stakeholders require the best possible returns from the network with the lowest possible charges being passed onto customers. A number of customers are having trouble with the impacts of demand billing and the effects that this has on removing cross subsidies among customers.

TABLE 5.26: JUSTIFICATION FOR NETWORK LOAD FACTOR TARGETS

5.2.3 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.

These targets align with corporate strategic objective to renew, develop and maintain a network that fulfils stakeholders' value expectations including their social and environmental responsibilities. Where appropriate, historical data are shown to justify targets. Some future targets are also shown.

5.2.3.1 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 5.27 lists the performance targets that provide a benchmark for these events.

ACCIDENT/INCIDENT RELATED PERFORMANCE TARGETS	
Event	**Target (maximum events)**
Lost time, injuries with staff and contractor	5
Number of DOL notifiable accidents	0
Number of public injuries on TLC facility	0

TABLE 5.27: ACCIDENT/INCIDENT RELATED PERFORMANCE TARGETS

These targets have been set based on historical data.

Table 5.28 summarises the justification for Accident/Incident targets. These targets are measured by counting the numbers of incidents.

JUSTIFICATION FOR ACCIDENT/INCIDENT TARGETS	
Item	**Justification**
Consumer Consideration	Lost Time; Injuries involving Staff and Contractors: Responsible customers do not support organisations that do not place importance on safety to staff. The target has been set based on previous numbers less a level of improvement. Number of DOL notifiable accidents: DOL notifiable accidents results in an investigation and in the worst case a prosecution; this is a costly and complex process. DOL prosecution costs and fines are substantial and as a result a target of zero has been set. Number of Public injuries involving TLC facility: Responsible customers will not support an organisation that does not have regard for public hazard control. TLC does not want any of its assets to cause public injury and as a consequence a target of zero has been set.
Statutory Considerations	Lost Time; Injuries involving Staff and Contractors: There is no specific legislation that details the lost time injury target. DOL and ACC legislation and the SMS require all significant hazards to be identified and adequately controlled to prevent serious harm. Number of DOL notifiable accidents: Notifying the Department of Labour of accidents results in an investigation and often a prosecution. This is a costly and complex process. Number of Public injuries involving TLC facility: There is comprehensive legislation that focuses on ensuring utilities control, maintain, renew and construct assets that do not cause harm to the public, e.g. safety management system required by the Electricity Act.
Regulatory Considerations	As described under Statutory considerations. Sitting under legislation there are numerous regulations that are focused on ensuring TLC control, maintains, renews and constructs assets that do not cause injury to staff and the public e.g. the Electricity (Safety) Regulations.
Stakeholder Considerations	Responsible and ethical stakeholders want lost time injuries involving staff and contractors, DOL notifiable accidents and injuries involving the public minimised or eliminated.
Other Considerations	TLC wishes to eliminate all accidents/incidents to staff and the public.

TABLE 5.28: JUSTIFICATION FOR ACCIDENT/INCIDENT TARGETS

5.2.3.2 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 architecture; 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 5.29 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	**Service Boxes**	**Two pole Structures**	**GMT**	**Switching Equipment**	**Total Hazards Eliminated/Minimised**
2013/14	40	3	2	4	49
2014/15	37	9	4	7	56
2015/16	30	9	3	7	49
2016/17	10	7	4	5	26
2017/18	3	6	4	6	19
2018/19	0	8	3	5	16
2019/20	0	9	5	3	17
2020/21	0	6	3	5	14
2021/22	0	3	3	5	11
2022/23	0	3	4	2	9
2023/24	0	2	5	3	10
2024/25	0	2	4	5	11
2025/26	0	1	6	1	8
2026/27	0	1	5	2	8
2027/28	0	1	2	3	6

TABLE 5.29: TARGETS FOR REMOVING HAZARDOUS EQUIPMENT SITES DURING THE PLAN PERIOD

Table 5.30 summarises the justification for the number of asset hazards that are eliminated/minimised annually. These targets are the numbers of projects included in Plans.

JUSTIFICATION FOR NUMBER OF HAZARDS ELIMINATED/MINIMISED TARGETS	
Item	**Justification**
Consumer Considerations	Responsible and ethical customers will not support an organisation that fails to rectify known hazards. TLC customers require the network to replace hazardous equipment.
Statutory Considerations	Legislation requires TLC to identify and replace hazardous equipment. Commerce Commission and other regulators accept that hazard renewals take priority and have to be completed. An objective of these targets is to ensure Statutory administrators understand that these needs exist and support programmes to remove hazards.
Regulatory Considerations	There are numerous regulations that require TLC to remove hazardous equipment from service. An objective of these targets is to ensure the programmes are locked in, that TLC has recognised hazards exist and these are being eliminated/minimised.
Stakeholder Considerations	Responsible and ethical stakeholders do not want to be part of an organisation that fails to recognise or rectify known or suspected hazards. The targets TLC has set a clear message to stakeholders that hazardous equipment exists and programmes are locked in place to remove this from service.
Other Considerations	TLC has surveyed the network and evaluated all sites that may contain hazardous equipment or be hazardous by their architecture. This process has produced lists of equipment sites that have been included in long term Plans, the various sites have also been included in cost estimates in other sections of the Plan. The actual numbers of sites have been included in the performance targets to ensure overall integration of the various sections of this Plan.

TABLE 5.30: JUSTIFICATION FOR NUMBER OF HAZARDS ELIMINATED/MINIMISED TARGETS

5.2.3.3 Diversity Factor

Table 5.31 lists the historic diversity factor and 2010/11 target

DIVERSITY FACTOR: HISTORIC DATA AND TARGET			
Year	**Sum of Consumers' maximum demands (KVA)**	**Maximum co-incident demand on system (KVA)**	**Diversity Factor**
2008/09	94217	61300	1.54
2009/10	100838	63500	1.59
2010/11	102481	62980	1.63
Target			**1.56**

TABLE 5.31: DIVERSITY FACTOR HISTORIC DATA AND TARGET

Good work Diversity Factor is the probability that a particular piece of equipment will come on at the time of the facility's peak load. Diversity can be calculated by ratio of the sum of the individual maximum demands to the maximum demand of the whole system. It gives an indication of how diverse it is when the individual maximum demands occur. 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 1.56 which is based on historic performances. Billed demand is used as the substitution figures of maximum demands where ICPs haven't got Demand Meters.

As stated in other sections of the plan, TLC separately bills customers for line charges, the largest component of this charge being based on the demand customers placed on the network during control periods.

The diversity factor is a measure of how effective TLC's demand billing programme has been. It is an indication that customers have spread their load more effectively. Table 5.32 summarises the justification for use of diversity factor as a performance measure.

JUSTIFICATION FOR THE USE OF DIVERSITY FACTOR AS A PERFORMANCE MEASURE	
Item	**Justification**
Consumer Considerations	Diversity factor is an industry indicy that can be researched by customers. A slowly increasing ratio means that TLC's demand charges are spreading the times peaks are occurring and thus indicating an improving asset utilisation.
Statutory Considerations	There are no Statutory requirements for this target. There is a Statutory objective to maximise asset utilisation and operating efficiency.
Regulatory Considerations	There is no Regulatory requirement for this target. There is a Regulatory intent to maximise asset utilisation and operating efficiency.
Stakeholder Considerations	Stakeholders require revenue to be collected in a consistent and equitable manner and assets to be utilised.
Other Considerations	The target has been set based on present performance. Focus on demand side management will possibly see it improve. A review of TLC's pricing structure may see the ratio reviewed.

TABLE 5.32: JUSTIFICATION OF DIVERSITY FACTOR AS A PERFORMANCE MEASURE

5.2.3.4 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. This target is based on historic achievements.

Table 5.33 summarises the justification for use of the ratio of trees felled to trees worked on target.

JUSTIFICATION FOR USE OF THE RATIO OF TREES FELLED TO TREES WORKED ON TARGET	
Item	**Justification**
Consumer Considerations	Tree cutting is TLC's largest controllable operating cost. The more trees felled and removed permanently from line corridors as opposed to trimming, the lower the long term costs for TLC and customers. The lower the long term costs the lower the revenue that has to be sought from customers.
Statutory Considerations	There are no Statutory requirements for a tree fell rate target.
Regulatory Considerations	There are no Regulatory requirements for a tree fell rate target. There is a Regulatory requirement to have a tree programme that complies with the tree regulations.
Other Considerations	Because tree control is TLC's largest controllable operating cost it is important that some form of measure is in place to give an indication of its effectiveness. Data is available for the last seven years that gives fell rate statistics. The target has been set at 70% based on the performance over the last seven years.

TABLE 5.33: JUSTIFICATION FOR THE RATIO OF TREES FELLED TO TREES WORKED ON TARGET

5.2.4 Lines Business Activity Efficiency Targets

The previous lines business activity efficiency targets were based on the 2008 disclosure requirements. These have now been superseded by NZCC22. At the time of writing systems were still being set up for NZCC 12 and we were not in a position to develop an exhaustive list of these indices. The intent is once the reporting systems are part in place to use some of these measurements to assist and support network decision. It is proposed these reporting criteria will be added to future AMP's. In the interim the following criteria are proposed:

The average age of network assets left until they need to be theoretically renewed. This should not become less than the current 21 years; however it will take a little while for the data behind the indices to become firm.

The objective for this measurement is to ratio of depreciate to capital renewal expenditure (inclusive of the Commerce Commission categories Reliability, Safety and Environmental and Asset Replacement and renewal).

The target is to have this one as slightly greater i.e. the assets are being renewed at the depreciation note or slightly more so that the average age network assets is slowly reducing. As the time of writing the changes to the disclosure requirements since the 2012 disclosure under the 2008 rules have not been fully completed and the figures are not totally.

The justification of the target is that it gives a good measure as to whether asset renewals are matching there theoretical aging effects. If the investment in renewal capital expenditure is less than depreciative the average age of the network is increasing; meaning that in the long term there is a risk the network will be sustainable.

5.2.4.1 Capital Expenditure Ratios

All of these ratios are included in the Commerce Commission disclosure comparison tables in NZCC 22. The capital expenditure forecast used is inflation adjusted and does not include non-network fixed assets expenditure.

- Total circuit length.
- Electricity supplied to customers' connection points.
- Connection point.
- Distribution transformer capacity.

They are background comparators that TLC needs to be aware of for comparing performance among lines companies. They are not directly related to issues such as customer service, quality and hazard control. As such, TLC's long term objective is to keep these within a range that conforms to expectations of a network with the issues that TLC is confronted with, (subject to unique legacy geographic and other features/factors associated with the TLC network).

5.2.4.2 Operational Expenditure Ratios

All of ratios are included in the Commerce Commission disclosure comparison tables in NZCC 22. The capital expenditure forecast used is inflation adjusted and is taken from the Commerce Commission expenditure breakdown. The expenditure does not include non-network fixed assets expenditure.

- Total circuit length.
- Electricity supplied to customers' connection points.
- Connection point.
- Distribution transformer capacity.

They again are background comparators that TLC needs to be aware of for comparisons among lines companies. They are not directly related to issues such as customer service, quality and hazard control. As such, TLC's long term objective is to keep these within a range that conforms to expectations of a network with the issues that TLC is confronted with.

5.2.4.3 Interruption Indicators

- Interruption targets Class B (planned)
- Interruption targets Class C (unplanned)

These target forecasts are in disclosure compliance format and reconcile with the earlier customer service focused targets in the earlier parts of this section.

5.2.4.4 Faults per 100km

These target forecasts are in disclosure compliance format and reconcile with the earlier customer service focused targets in the earlier parts of this section.

- 11 kV non SWER annual averages for the forecast 5 years.
- SWER annual average for the forecast 5 years.
- 33 kV annual averages for the forecast 5 years.

Note: Due to the relatively small amount of TLC's network that is underground, only the overhead figures have been included.

5.2.4.5 Reliability

- Overall reliability by SAIDI and SAIFI.
- Class B SAIDI and SAIFI (Planned).
- Class C SAIDI and SAIFI (Unplanned).

5.2.4.6 Operating Cost Per Km and Per ICP

This target is set based on the estimated future operating cost. The line length has been assumed to increase as described in the development plan. The operating costs generally have been assumed to track inflation. Some adjustments have been allowed for changes to Regulatory requirements and expected lower faults costs as the effects of the renewal programmes come through.

The annual increase in the number of ICPs is the average number of new connections over the last 5 years.

5.2.4.7 Faults per Line Lengths

The targets for these have been set based on the expected changes that will occur with the overall SAIDI and SAIFI targets currently advocated by TLC.

5.2.4.8 Total Interruptions

The target for the total interruptions has been set based on the expected changes that will occur with the overall SAIDI and SAIFI targets currently advocated by TLC. The number of unplanned outages is expected to decrease as a result of the renewal programme; planned outages will increase in order to carry out the renewal programme.

Tables 5.34 and 5.35 list the Lines Business Activity Efficiency Targets for the planning period.

LINES BUSINESS ACTIVITY EFFICIENCY TARGETS 2011/12 to 2018/19								
	2013/14	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**
Capital Expenditure per Total Circuit Length	$2,426	$2,262	$3,341	$2,425	$2,677	$2,519	$3,134	$$2,930
Capital Expenditure per Electricity Supplied to Customers Connection Points	$33	$31	$45	$32	$35	$32	$40	$37
Capital Expenditure per ICP	$440	$410	$605	$439	$484	$455	$565	$528
Capital Expenditure per Distribution Transformer Capacity	$43,911	$40,411	$58,928	$42,215	$46,004	$42,727	$52,478	$48,445
Operational Expenditure per Total Circuit Length	$928	$951	$975	$999	$1,049	$1,024	$1,076	$1,103
Operational Expenditure per Electricity Supplied to Customers Connection Points	$13	$13	$13	$13	$14	$13	$14	$14
Operational Expenditure per ICP	$168	$172	$177	$181	$190	$185	$194	$199
Operational Expenditure per Distribution Transformer Capacity	$16,786	$16,985	$17,186	$17,390	$18,035	$17,370	$18,015	$18,228
Interruption Targets Class B (Planned) for planning period.	331	331	331	331	331	331	331	331
Interruption Targets Class C (Unplanned) for planning period	800	800	800	800	800	800	800	800
Faults per 100km for 11 kV non SWER	35	35	35	35	35	35	35	35
Faults per 100km for 11 kV SWER	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Faults per 100km for 33 kV	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Overall Reliability (SAIDI)	300	300	300	300	300	300	300	300
Class B Reliability (SAIDI Planned)	90	90	90	90	90	90	90	90
Class C Reliability (SAIDI Unplanned)	210	210	210	210	210	210	210	210

TABLE 5.34 LINE BUSINESS ACTIVITY EFFICIENCY TARGETS 2013/14 TO 2020/21 (INFLATION ADJUSTED)

LINES BUSINESS ACTIVITY EFFICIENCY TARGETS 2019/20 to 2026/27							
	2021/22	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Capital Expenditure per Total Circuit Length	$3,047	$2,471	$2,524	$3,158	$2,590	$3,122	$2,310
Capital Expenditure per Electricity Supplied to Customers Connection Points	$38	$30	$30	$37	$30	$36	$26
Capital Expenditure per ICP	$549	$444	$454	$567	$465	$559	$414
Capital Expenditure per Distribution Transformer Capacity	$49,727	$39,808	$40,142	$49,585	$40,145	$47,763	$34,892
Operational Expenditure per Total Circuit Length	$1,130	$1,158	$1,187	$1,217	$1,247	$1,279	$1,311
Operational Expenditure per Electricity Supplied to Customers Connection Points	$14	$14	$14	$14	$15	$15	$15
Operational Expenditure per ICP	$204	$208	$213	$218	$224	$229	$235
Operational Expenditure per Distribution Transformer Capacity	$18,444	$18,663	$18,884	$19,107	$19,334	$19,563	$19,795
Interruption Targets Class B (Planned) for planning period.	331	331	331	331	331	331	331
Interruption Targets Class C (Unplanned) for planning period	800	800	800	800	800	800	800
Faults per 100km for 11 kV non SWER	35	35	35	35	35	35	35
Faults per 100km for 11 kV SWER	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Faults per 100km for 33 kV	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Overall Reliability (SAIDI)	300	300	300	300	300	300	300
Class B Reliability (SAIDI Planned)	90	90	90	90	90	90	90
Class C Reliability (SAIDI Unplanned)	210	210	210	210	210	210	210

TABLE 5.35 LINE BUSINESS ACTIVITY EFFICIENCY TARGETS 2021/22 TO 2027/28 (INFLATION ADJUSTED)

The Lines business activity targets are used mostly for industry benchmarking. TLC focuses on the performance targets outlined in earlier sections and the lines business activity efficiency targets give a measure of the effectiveness of these strategies and allow industry benchmarking. Many of these targets are largely not understood by customers. The Lines Company believes that by working towards the performance targets listed earlier in this section, funds will be used in the most efficient way to provide a level of security and level of charges that satisfies customers. The targets have been set based on both historic figures and forward expenditure predictions. (Note the forward expenditure prediction calculator will be expanded to give more accurate predictions of the latest Commerce Commission indices once these have been finalised.

Table 5.36 discusses the justification for lines business activity efficiency targets.

JUSTIFICATION FOR LINES BUSINESS ACTIVITY EFFICIENCY TARGETS		
Target	**Item**	**Justification**
Capital Expenditure and Operational Expenditure per Total Circuit Length	Consumer Consideration	These are disclosure comparison indicators. Can be misleading for people using these as indicators as they do not include privately owned lines. Privately owned line distances can be significant. (In TLC's case, 20% of lines are considered private). The definition of privately owned lines varies among lines companies and as such these indices can be misleading.
	Statutory and Regulatory Consideration	As above. Many Regulatory and Statutory analysts do not understand the complexities of these indicators and may misinterpret the figures. The complexity of the ownership issue has been caused by changes to the Electricity Act and its Regulations over many years.
	Stakeholder Consideration	As above.
Capital Expenditure and Operational Expenditure per Electricity Supplied to Customers' Connection Points	Consumer Consideration	These are disclosure comparison indicators. They can be misleading to customers for two principal reasons. These are: The electricity supplied to consumers throughout the industry has a reasonably high level of inaccuracy caused by misread meters and other errors associated with metering. The energy supplied through a network is not directly related to costs.
	Statutory and Regulatory Consideration	As above.
	Stakeholder Consideration	As above.
Capital and Operating Expenditure per Connection Point	Consumer Consideration	These are disclosure comparison indicators. They are high level indicators that are simpler than some of the others above to understand. Over time they will show trends and give customers a feel of the investments being made per customer.
	Statutory and Regulatory Consideration	High level indicators for intercompany comparisons. They will likely highlight the company's present expenditure strategies and needs.
	Stakeholder Consideration	As above. The indicators give stakeholders and understanding of the investment at an individual customer level.

JUSTIFICATION FOR LINES BUSINESS ACTIVITY EFFICIENCY TARGETS		
Target	**Item**	**Justification**
Capital and Operating Expenditure per Distribution Transformer Capacity	Consumer Consideration	These are disclosure indicators. They are high level indicators that would be difficult for the customer to understand. They also have some distortion effects if they are used to compare urban and rural networks.
	Statutory and Regulatory Consideration	As above.
	Stakeholder Consideration	As above.
Interruption Targets Class B (Planned) and Class C (Unplanned) for the Planning Period	Consumer Consideration	These are disclosure comparison indicators. The numbers of interruptions will go up and down from year to year for a whole host of reasons. They are an indicator indice only. Comparisons among companies are subject to variations caused in definition of interruptions and the like. (The definition in the handbook for example, has a level of misinterpretation variability). Customers may misinterpret this information.
	Statutory and Regulatory Consideration	As above.
	Stakeholder Consideration	As above.
Faults per 100km for 11 kV non-SWER, 11 kV SWER and 33 kV	Consumer Consideration	These are disclosure comparison indicators. Most customers would not understand the difference in voltage or classification, i.e. SWER and non-SWER. These are figures they could use to compare among companies and charges over time. The figures will be influenced by abnormal events when year to year figures are compared.
	Statutory and Regulatory Consideration	As above.
	Stakeholder Consideration	As above.
Reliability: Overall – Planned & Unplanned SAIDI & SAIFI	Consumer Consideration	These are disclosure comparison indicators. SAIDI and SAIFI are international indicators. They are difficult for customers to understand. They are accepted high level indicators, but their downside is well documented in various papers.
	Statutory and Regulatory Consideration	As above. International comparison.
	Stakeholder Consideration	As above.

TABLE 5.36: JUSTIFICATION FOR LINES BUSINESS ACTIVITY EFFICIENCY TARGETS

Section 6

6. Details of Performance Measurement, Evaluation and Improvements

6.1 Review of Progress against Plan, both Physical and Financial

The comparison between planned and actual expenditure, including the reasons for any variances, are discussed in the following sections.

6.1.1 Capital Performance – both Physical and Financial excluding Line Renewals

Table 6.1 lists the approved 2011/12 planned expenditure and the actual expenditure (excluding line renewals). The numbers in the last column relate to the further detail notes that follow the table.

The financial figures in the section below represent the best possible allocations that could be deducted from the available financial information. Improvements in reconciling between the accounts and asset management systems have been made but more are necessary to make the process more accurate and easy to administer going forward.

ACTUAL AND PLANNED CAPITAL EXPENDITURE EXCLUDING LINE RENEWALS			
Project	**2011/12 Actual**	**2011/12 Planned**	**Note**
Equipment Renewals			
New Transformers	154,217	309,000	1
Protection Relay Contingency	3,250	10,300	2
Radio Equipment Contingency	3,976	10,300	3
SCADA Equipment Contingency	4,424	15,450	4
Distribution Equipment Contingency	33,264	51,500	5
SCADA Equipment Specific Renewals	7,155	38,015	6
Radio Equipment Specific Renewals	3,304	30,653	7
Renewals for New Connections Tap-offs etc (including Easements)	3,413	30,900	8
Moving Lines under Electricity Act	-	50,000	9
Hazard Elimination Renewals			
Hazard Elimination Renewals - 2 Pole Structures			
Aria: 2 Pole Structure (T1948)	6,824	5,150	10
Benneydale: 2 Pole Structure (T1454)	10,548	25,750	11
Mokau: 2 Pole Structure (T2193)	-	30,900	12
Mokau: 2 Pole Structure (T2166)	540	5,150	13
Kuratau: 2 Pole Structure (09R02)	10,548	25,750	14
National Park: 2 Pole Structure (15L04)	24,057	20,600	15
Oruatua: 2 Pole Structure (09T03)	90,207	46,350	16
Rangipo Hautu: 2 Pole Structure (11S05)	25,915	82,400	17
Tuhua: 2 Pole Structure (05F14)	-	36,050	18
*National Park: 2 Pole Structure (15L01)	12635	-	19
*Rangipo/Hautu: 2 Pole Structure & Recloser (11S15, 5168)	38030	-	20

ACTUAL AND PLANNED CAPITAL EXPENDITURE EXCLUDING LINE RENEWALS			
Project	**2011/12 Actual**	**2011/12 Planned**	**Note**
Hazard Elimination Renewals - Ground Mounted Transformers			
Tangiwai: Ground Mount Transformer (T4021)	2,712	41,200	21
Kuratau: Ground Mount Transformer (08R17)	31,415	41,200	22
Waihaha: Ground Mount Transformer (08R16)	20,148	41,200	23
Hazard Elimination Renewals - Switchgear			
Chateau: Switchgear Renewal (15N04)	35,233	82,400	24
Kuratau: Omori Road - Till Box	53,884	41,200	25
Ohakune: CBD Switchgear Renewal (20L65 & 20L02)	22,476	41,200	26
Pillar Box Replacements	72,069	92,700	27
*Chateau: Switchgear Renewal (15N01)	8,172	-	28
*Kuratau: Omori Switchgear Renewal (08R18)	15,113	-	29
*Waitete: Substation Switchgear Renewal	74,323	-	30
Te Waireka Substation Project	18,439	257,500	31
*Borough Substation Upgrade	230,026	-	32
*Waitomo Village (T88)	7,394	-	33
Cummulative Capacity (System Growth)			
McDonalds Feeder: Install Regulator	103,093	85,000	34
Ohakune Feeder: Install Switchgear (20L57)	61,712	50,000	35
*Ohakune: Reg 28 (Burns Street)	7,927	-	36
Reliability Projects			
Huirimu: Automate ABS 425	34,341	20,000	37
Maihiihi/Gravel Scoop: Tie Switches (ABS 349 & 373)	60,850	80,000	38
Otorohanga: Automate Switch 317	35,395	20,000	39
Piopio/Mahoenui: Automate Tie Switch 1319	16,818	20,000	40
Tangiwai: Automate Switch 5673	8,904	22,511	41
Tirohanga: Automate ABS 634	31,294	40,000	42
Waitomo: Automate Tie Switch 505	32,705	20,000	43
Mobile Generator & Reactive Power Source (Capacitor Banks)	135,414	250,000	44
*Tawhai: Automate ABS 5663	29,095	-	45
*Tawhai: Substation Automation	-	-	46
*Oparure: Off Take Site Switch 757	14,342	-	47
*Oparure: Upgrade Feeder ABS 243	9,244	-	48
*Rangipo/Hautu Additional Switches	2,906	-	49
*Southern/Raurimu: Automate Switch 5235	8,523	-	50
*Turoa: Automate Feeder Switch 6600	21,011	-	51
*Whakamaru/Mokai: Upgrade Feeder Tie ABS 480	8,426	-	52
*Whakamaru/Mokai: Upgrade Feeder Tie ABS 489	10,531	-	53
*Whakamaru/Tihoi: Inter Tie ABS 428	7,736	-	54
Specific Equipment Renewals			
Borough Substation (T1)	-	82,400	55

ACTUAL AND PLANNED CAPITAL EXPENDITURE EXCLUDING LINE RENEWALS			
Project	**2011/12 Actual**	**2011/12 Planned**	**Note**
Meter Replacement Project (Load Control Relay Changes)	11,081	120,000	56
*Borough Substation RMU	1,149	-	57
*Taharoa Sub Station Building	104,575	-	58
Customer Driven			
General New Connections	447,153	300,000	59
Subdivision New Connections	146,552	105,000	60
Industrial New Connections	120,120	130,000	61
Specific Projects - Taharoa (Industrial Connections)	778	400,000	62
Specific Projects - Miraka Milk Plant Work (Industrial Connections)	1,348,233	2,200,000	63
**Specific Projects Variation - Rangitoto Reg30 (New Connections)	87,825	90,000	64
Total	**3,931,444**	**5,497,729**	

TABLE 6.1: ACTUAL AND PLANNED CAPITAL EXPENDITURE EXCLUDING LINE RENEWALS

Further notes to Table 6.1 Actual and Planned Capital Expenditure excluding Line Renewals.

Equipment Renewals:

1. New Transformers
   Within estimate. Less than anticipated needed to be purchased.
2. Protection Relay Contingency
   Within estimate. There were less failures than anticipated in protection relays.
3. Radio Equipment Contingency
   Within estimate. No significant unexpected events occurred with the radio system.
4. SCADA Equipment Contingency
   Within estimate. No significant unexpected events occurred with the SCADA system..
5. Distribution Equipment Contingency
   Within estimate. Underspend due to less distribution equipment failure during the year.
6. SCADA Equipment Specific Renewals
   Within estimate. Where possible, upgrades have been held back until the new radio communications system is installed as this will allow new data communications and RTU's to be utilised.
7. Radio Equipment Specific Renewals
   Within estimate. Radio purchases were deliberately held back due to the upgrades scheduled to start in the 2012/13 financial year. This investment is on the repeater sites for voice and data.
8. Renewals for New Connections tap-offs and Easements
   Within estimate. Costs were below estimate due to reduced economic activity.
9. Moving lines under Electricity Act
   There were no requests from councils or Transport Authorities received this financial year.

Hazard Elimination Renewals:

10. Aria: 2 Pole Structure (T1948)
    Project completed slightly above estimate.
11. Benneydale: 2 Pole Structure (T1454)
    Roll forward project. Held up due to delays in obtaining technical resources.

12. Mokau: 2 Pole Structure (T2193)
    Roll forward project. Delays in obtaining technical resources rolled the project forward into 2012/13
13. Mokau: 2 Pole Structure (T2166)
    Roll forward project. Delays in obtaining technical resources rolled the project forward into 2012/13
14. Kuratau: 2 Pole Structure (09R02)
    Roll forward project. Cost to date are for design and materials. Due to resourcing issues, project execution was pushed out to 2012/13.
15. National Park: 2 Pole Structure (15L04)
    Project completed slightly above estimate.
16. Oruatua: 2 Pole Structure (09T03)
    Project completed over estimate. Additional costs incurred to install new ground mount transformer.
17. Rangipo Hautu: 2 Pole Structure (11S05)
    Roll forward project. Cost to date is for design and materials. Due to resourcing issues, project execution was pushed out to 2012/13.
18. Tuhua: 2 Pole Structure (05F14)
    Roll forward project. Lack of suitable resources resulted in this project being delayed until the 2012/13 financial year.
19. *National Park: 2 Pole Structure (15L01)
    2010/11 project completed within estimate. A reworked design and reused transformer enabled a significant saving on this project.
20. *Rangipo/Hautu: 2 Pole Structure & Recloser (11S15, 5168)
    2010/11 project completed. Expenditure reported last year did not include replacing the recloser.
21. Tangiwai: Ground Mount Transformer (T4021)
    Roll forward project. Lack of suitable resources resulted in this project being primarily delayed until the 2012/13 financial year.
22. Kuratau: Ground Mount Transformer (08R17)
    Roll forward project. Costs to date are for design and materials. Due to resourcing issues, project execution was pushed out to 2012/13.
23. Waihaha: Ground Mount Transformer (08R16)
    Project completed within estimate. Reassessment of design enabled resolution by replacing switches rather than the transformer, resulting in significant savings.
24. Chateau: Switchgear Renewal (15N04)
    Roll forward project. Costs to date are for materials only. Due to other network issues and seasonal timing restrictions, the timeframe for completing this project has been pushed out.
25. Kuratau: Omori Road - Till Box
    Roll forward project. Final cost expected to be above estimate due to higher than anticipated asset cost, job complexity and location remoteness.
26. Ohakune: CBD Switchgear Renewal (20L65 & 20L02)
    Roll forward project. Final cost expected to be above estimate due to additional cabling work required, job complexity and location.
27. Pillar Box Replacements
    Pillar box changes have become reasonably routine with the techniques and work processes arrived at and the average cost has come down slightly. There were fewer difficult pillar box change outs than anticipated.

28. *Chateau: Switchgear Renewal (15N01)
    2010/11 project completed within estimate. The project was planned for an estimated $40k and equipment was purchased. Due to the lack of technical resources to complete the project, some costs have carried into the 2011/12 financial year.

29. *Kuratau: Omori Switchgear Renewal (08R18)
    2010/11 project completed within estimate. A lack of technical resources resulted in the job not being completed until 2011/12.

30. *Waitete: Substation Switchgear Renewal
    2010/11 project completed above estimate. Costs increased as complexity necessitated installing a voltage sensing and control cables.

31. Te Waireka Substation Project
    Project delayed because the switchgear failed its pre-installation hazard control tests and had to be returned to the offshore supplier.

32. *Borough Substation Upgrade
    2010/11 project completed over estimate. The project was delayed due to faults being detected in the new switchgear and relays during testing and equipment having to be returned to the offshore supplier.

33. *Waitomo Village (T88)
    2010/11 project completed within estimate. A reworked design and reused transformer enabled a significant saving on this project.

Cumulative Capacity (System Growth):

34. McDonalds Feeder: Install Regulator
    Project completed over estimate. Additional costs incurred due to the need to add additional seismic strengthening.

35. Ohakune Feeder: Install Switchgear (20L57)
    Project completed over estimate. Additional costs incurred with extended travel requirements and associated difficulties with getting both live line and limited technical resources to site at the same time.

36. *Ohakune: Reg 28 (Burns Street)
    Carry forward expenditure associated with completing earlier project. (There were difficulties associated with communication signal strength to the site and various bits of equipment had to be moved to accommodate this.)

Reliability Projects

37. Huirimu: Automate ABS 425
    The estimate was exceeded mostly due to the additional travel times to the site and the difficulty with coordinating technical and live line resources.

38. Maihiihi/Gravel Scoop: Tie Switches (ABS 349 & 373)
    Within estimate. Project was executed according to plan.

39. Otorohanga: Automate Switch 317
    Exceeded estimate due to difficulties encountered in coordinating technical and live line resources.

40. Piopio/Mahoenui: Automate Tie Switch 1319
    Project completed within estimate. Work execution was straightforward and without complication.

41. Tangiwai: Automate Switch 5673
    Included in the 2012/13 year plan. Materials were available and for efficiency it was bought forward to be completed in conjunction with other work in the area.

42. Tirohanga: Automate ABS 634
    Project completed within estimate. Work execution was straightforward and without complication.

43. Waitomo: Automate Tie Switch 505
    Exceeded estimate due to difficulties encountered in coordinating technical and live line resources.

44. Mobile Generator & Reactive Power Source (Capacitor Banks)
    Mobile capacitor banks were developed instated of more expensive generators.

45. *Tawhai: Automate ABS 5663
    2010/11 project completed within estimate. Roll forward was due to difficulty in getting outages that affected the ski fields and the Chateau.

46. *Tawhai: Substation Automation
    2010/11 project completed within estimate however expenditure entry has carried over to the 2012/13 year. The project roll forward was due to difficulty in getting outages that affected the ski fields and the Chateau.

47. *Oparure: Off Take Site Switch 757
    2010/11 project completed within estimate. There were no undue complications on the project however a relocation of assets under emergency conditions resulted in a delayed completion date.

48. *Oparure: Upgrade Feeder ABS 243
    2010/11 project completed within estimate. Straightforward job with no complications using existing pole and previously installed ABS.

49. *Rangipo/Hautu Additional Switches
    2010/11 project completed close to estimate. Residual expenditure has carried into the 2011/12 financial year.

50. *Southern/Raurimu: Automate Switch 5235
    2010/11 project completed within estimate. There were no undue complications on the project however a lack of technical resources delayed completion.

51. *Turoa: Automate Feeder Switch 6600
    2010/11 project completed slight above estimate. Execution of work was delayed due to a lack of technical resources.

52. *Whakamaru/Mokai: Upgrade Feeder Tie ABS 480
    2010/11 project completed within estimate. There were no undue complications on the project however a lack of technical resources delayed completion.

53. *Whakamaru/Mokai: Upgrade Feeder Tie ABS 489
    2010/11 project completed within estimate. There were no undue complications on the project however a lack of technical resources delayed completion.

54. *Whakamaru/Tihoi: Inter Tie ABS 428
    2010/11 project completed within estimate. The project was planned for 2010/11 and design and equipment costs incurred. Remaining work carried into 2011/12 financial year with delays in obtaining technical resources.

Specific Equipment Renewals:

55. Borough Substation (T1)
    Project completed within estimate. $60,477 should have been recorded as capital expenditure against this project but was incorrectly coded to maintenance in the accounting system.

56. Meter Replacement Project (Load Control Relay Changes)
    With the impeding introduction of the Smart meters that will have the load control relay built into the meter the number of relays needing to be installed is somewhat reduced. Installs to date have been on streetlight circuits and areas where signal levels have traditionally been low.

57. *Borough Substation RMU
    2010/11 project commenced previous year and is now complete. The delay was caused as a result of switchgear earthing not working as expected on delivery.

58. *Taharoa Sub Station Building
    The expectation last year was that this would be completed within the estimate however carry forward costs were subsequently found in the accounting system. Final expenditure exceeds estimate.

Customer Driven:

59. General New Connections
    New Connections - The new connections estimate was reduced in 2010/11 to take into account the effects of the economic downturn; however, there has been a higher than expected upsurge in new connections that resulted in expenditure being greater than the reduced estimate. Many of these were associated with the diary and other upgrades that required improvements to local 11kV fuse protection and earthing.

60. Subdivision New Connections
    New Subdivisions - The estimate was exceeded due to a greater than expected number of transformers and related switchgear having to be purchased.

61. Industrial New Connections
    Estimate and actual align.

62. Specific Projects - Taharoa (Industrial Connections)
    Roll over project. The NZ Steel Taharoa Iron Sands development was delayed until the customer clarified what they required. (There was uncertainty around the detail of the mining processes.)

63. Specific Projects - Miraka Milk Plant Work (Industrial Connections)
    The costs were split over 2 years.

64. **Specific Projects Variation- Rangitoto Regulator 2011 (Reg30) (New Connections)
    This project was included by a variation of proposed expenditure put to the Board in June 2011 and completed within estimate. The project had been scheduled for the 2016/17 year however increased load from dairy conversions necessitated it being bought forward.

6.1.2 Line Renewal (Capital) Performance – both Physical and Financial

Table 6.2 lists the actual planned line renewal expenditure and the approved 2011/12 expenditure. The numbers in the last column relate to the further detail notes that follow the table.

LINE RENEWAL CAPITAL EXPENDITURE			
Line Renewal Projects	**2011/12 Actual**	**2011/12 Planned**	**Note**
33kV Lines			
Kiko Road 33kV (01) Line Renewal	10,655	67,798	1
Taharoa A 33kV (02) Line Renewal	102,345	104,000	1
*Turangi 33kV (01) Line Renewal	87,121	-	1
11kV Lines			
Benneydale 11kV (04) Line Renewal	-	391,211	3
Coast 11kV (03) Line Renewal	-	181,891	3
Maihiihi 11kV (07) Line Renewal	-	190,912	3
Mokau 11kV (04) Line Renewal	127,319	78,618	2
Mokauiti 11kV (03) Line Renewal	193,413	259,405	1
Ohura 11kV (06) Line Renewal	11,545	171,866	3
Ongarue 11kV (01) Line Renewal	129,046	201,845	1
Oparure 11kV (01) Line Renewal	21,491	70,892	1
Oparure 11kV (02) Line Renewal	140,062	100,000	3
Otorohanga 11kV (04) Line Renewal	90,614	92,252	1
Pureora 11kV (01) Line Renewal	-	423,306	3
Rangipo/Hautu 11kV (03) Line Renewal	-	118,427	3
Rangitoto 11kV (03) Line Renewal	-	174,938	3
Raurimu 11kV (01) Line Renewal	197,875	222,924	1
Rural 11kV (02) Line Renewal	22,428	11,251	2
Southern 11kV (06) Line Renewal	40,760	66,508	1
Tangiwai 11kV (04) Line Renewal	86,173	140,434	1
Tirohanga 11kV (02) Line Renewal	315,200	166,982	2
Turoa 11kV (02) Line Renewal	17,936	40,685	1
Wharepapa 11kV (05) Line Renewal	-	341,094	3
*Maihiihi 11kV (09) Line Renewal	1,483	-	4
*National Park 11kV (03) Line Renewal	1,399	-	4
*Rangipo/Hautu 11kV (01)	441,209	-	5
*Rangitoto 11kV (06) Line Renewal	2,305	-	4
*Tangiwai 11kV (04) Line Renewal	142,083	-	5
*Turoa 11kV (01) Line Renewal	353,941	-	5
*Waitomo 11kV (01 & 02) Line Renewal	6,845	-	4
LV Lines			
Oparure LV (02) Line Renewal	-	150,000	3
Coast LV (03) Line Renewal	2,060	12,500	3

LINE RENEWAL CAPITAL EXPENDITURE			
Line Renewal Projects	**2011/12 Actual**	**2011/12 Planned**	**Note**
Emergent			
Line Emergent Renewals	1,131,922	1,200,000	6
Total	**3,677,230**	**4,979,739**	

TABLE 6.2: PLANNED AND ACTUAL LINE RENEWAL CAPITAL EXPENDITURE

Further notes to Table 6.2 Planned and Actual Line Renewal Capital Expenditure.

1 Detailed line inspection and analysis revealed less work was needed than originally anticipated. This combined with improved operational efficiency resulted in line renewal work being completed below estimate. Some of these line renewals may incur costs carried over into the next financial year.

2 Line renewal work exceeded estimate. This was primarily due to detailed line inspections and analysis revealing more complex work was required than originally estimated. Other cost-adding factors included difficulty accessing land and reaching customer acceptance of the outages necessary.

3 The expenditure for work on these lines has not been incurred in the 2011/12 financial year. The projects have subsequently been completed.

4 Residual expenditure associated with 2010/11 completed projects.

5 Projects planned for the 2010/11 year that due to scheduling and resource constraints, were not commenced during that period. The Rangipo/Hautu (01) renewal exceeded estimate due to the extent of work required. Tangiwai (04) and Turoa (01) projects were completed close to estimate and within estimate respectively.

6 Emergent line renewals - expenditure necessary to carry out urgent capital repairs to maintain supply and remove hazards - was less than estimated.

The biggest contributor to the non-completion and subsequent roll forward of a number of the technically related capital renewal programs were caused by key technical staffing difficulties. Specifically, the team leader had to return to his overseas home for personal reasons for a period. He has subsequently returned and progress has been made since this time. TLC did try to fill the gaps caused by his absence and other resourcing issues with external contractors, however this was found to be problematic due to the amount of travel involved, the complexity and uniqueness of the TLC network and their existing workloads.

6.1.3 Direct Maintenance Expenditure

The comparison between estimated and actual expenditure and the reasons for this are discussed in the following sections on a category by category basis. Table 6.3 lists the estimates from the 2011/12 plan and the actual amounts spent. The note numbers in Column 4 relate to the further detail documented below the table. The figures shown are the best possible representation available at this point.

DIRECT MAINTENANCE EXPENDITURE			
Description	**2011/12 Actual**	**2011/12 Planned**	**Note**
Cable Maintenance	55,643	54,590	1
33/11kV Cable Repairs and Terminations	3,621	32,754	2
LV Cable Maintenance	21,490	32,754	3
Ground Pillar Box Repairs	-	1,092	4
Cable Location Costs	3,691	-	5
Sub Total	**84,446**	**121,190**	
Line Maintenance			
33kV Line Maintenance	24,041	65,508	6
11kV Line Maintenance	67,578	174,688	7
Low Voltage Line Maintenance (including Permanent Disconnections)	36,379	32,754	8
Street Light Network Maintenance	1,199	8,734	9
Line Disconnections for Safety	62,331	30,570	10
Sub Total	**191,528**	**312,254**	
Tree Maintenance			
Tree Trimming - Planned (maintenance of existing)	491,089	473,892	11
Tree Trimming - Emergent/Faults (initial work)	167,708	195,738	12
Tree Recoveries	-50,757	-30,906	13
Sub Total	**608,040**	**638,724**	
Line Faults			
33 kV Faults	24,336	27,295	14
11 kV Faults	562,737	455,800	15
LV Line Faults	392,178	327,540	16
Substation Faults	29,139	32,754	17
Standby Faults	165,270	201,983	18
Sub Total	**1,173,660**	**1,045,372**	

DIRECT MAINTENANCE EXPENDITURE			
Description	**2011/12 Actual**	**2011/12 Planned**	**Note**
Zone Substation Maintenance			
Ground Maintenance at Zone Subs and Voltage Regulators	4,643	16,377	19
Building Maintenance at Zone Subs	21,908	21,836	20
Zone Substation Planned Maintenance	131,582	21,836	21
Zone Substation Unplanned Maintenance	23,261	10,918	22
Zone Transformer Planned Maintenance	75,927	87,344	23
Zone Transformer Unplanned Maintenance	16,785	5,459	24
Protection & Control Equipment Maintenance	14,400	16,377	25
Batteries/Chargers Replacement & Maintenance	18,310	21,836	26
Substation Energy Costs	13,651	10,918	27
Substation Rates	2,364	7,298	28
Substation Rents	1,918	8,735	29
Sub Total	**324,749**	**228,934**	
Distribution Transformer Maintenance			
Ground Mounted Transformer Maintenance	29,877	76,300	30
SWER Earthing Maintenance	1,263	74,200	31
Pole and Ground Mounted Transformer Workshop Maintenance	65,965	59,950	32
Transformer Changes Due to Corrosion etc	3,822	5,450	33
Other Distribution Transformer Site Maintenance	15,514	5,450	34
Sub Total	**116,441**	**221,350**	
Technical Equipment Maintenance			
Northern Load Plant Maintenance	11,158	22,928	35
Southern Load Plant Maintenance	22,818	10,918	36
Repeater Site Maintenance	8,952	21,836	37
Repeater Site Rentals	13,105	5,459	38
Radio Maintenance	191	5,459	39
Radio Licences	9,111	27,295	40
SCADA Maintenance	15,930	32,754	41
Line Circuit Breaker Maintenance	16,614	27,295	42
Line Regulator Maintenance	1,924	5,459	43
Fuse Switches/Till Boxes Maintenance	1,155	3,275	44
Strategic Spares Storage	-	21,836	45
Mobile Generators	-	10,918	46
Generator / Transformer & Equipment	177	10,918	47
Sub Total	**101,136**	**206,350**	
Total	**2,599,999**	**2,774,174**	

TABLE 6.3: DIRECT MAINTENANCE EXPENDITURE

Further notes to Table 6.3 Direct Maintenance Expenditure

Cable Maintenance:

1 33/11kV cable maintenance was slightly above estimate, due mostly to two occasions where inspection necessitated cable replacement.

2 LV cable maintenance had a smaller number of cable problems than anticipated.

3 Ground pillar box repairs were minimised. The renewal programme and modified pillar box design assisted in achieving this.

4 Cable location costs were not incurred during this period.

5 Ski field cable maintenance was not distinguished in planning estimates however some direct maintenance costs were incurred.

Line Maintenance:

6 33kV line maintenance was under estimate due mostly to the reduced number of abnormal events occurring during the year that required follow up maintenance.

7 11kV line maintenance was under estimate due mostly to the reduced number of abnormal events occurring during the year that required follow up maintenance.

8 Low voltage line maintenance was above estimate due mostly to the costs associated with the transfer of conductor onto Telecom poles.

9 Street light maintenance was within estimate.

10 Line disconnections for safety expenditure is above estimate. The expenditure includes permanent disconnections – which had been reported separately in earlier years. Expenditure estimates for future years have taken this into consideration. Safety disconnections primarily include customer requests, property fires and lines down.

Tree Maintenance:

11 Planned tree trimming involves maintaining vegetation that has been previously trimmed. This expenditure was increased above estimate due to the additional amounts able to be recovered and the need for maintenance work to be performed.

12 Emergent tree trimming includes vegetation being cut for the first time or as the result of faults. This expenditure was under estimate.

13 Tree recovery income was higher than estimated with more chargeable works being undertaken.

Line Faults:

14 33kV line faults were below estimate.

15 11kV line faults exceeded estimate. This was mainly due to the extreme weather in March 2012.

16 LV line faults were above estimate. This was largely attributable to the March 2012 storms.

17 Substation fault expenditure was less than estimate, with fewer incidents occurring than anticipated.

18 Standby fault expenditure was below estimate.

Zone Substation Maintenance:

19 Ground maintenance at zone substations and voltage regulators was below that estimated with less work being required than envisaged.

20 Building maintenance at zone substations was close to expectations.

21 Zone substation planned maintenance exceeded estimates. A significant portion of this was the increased labour and transport costs associated with completing the work. Technical resources had to be brought in from outside the district and there were also additional costs associated with the need to familiarise new staff.

22 Zone substation unplanned maintenance exceeded estimates due to more unexpected failures than anticipated.

23 Zone substation transformer planned maintenance costs were below estimate. A portion of the expenditure recorded was incorrectly coded and should have been allocated to a capital expenditure project.

24 Zone substation transformer unplanned maintenance exceeded estimate. Several of oil samples needed to be taken from a transformer to investigate the presence of high levels of gas detected during routine diagnostic testing (DGA testing). A number of tap changers were also found to be leaking, resulting in oil top-ups being required.

25 Protection and control equipment maintenance expenditure was less than expected.

26 Batteries and charger replacements and maintenance expenditure was within expectations.

27 Substation energy costs exceeded estimate. Analysis of expenditure indicates the allowance was underestimated. This has been revised for future years.

28 Substation rates are lower than anticipated. This appears to be the result of incorrect posting of some costs.

29 Substation rents were lower than anticipated. This appears to be the result of incorrect posting of some costs.

Distribution Transformer Maintenance:

30 Ground mounted transformer maintenance expenditure was less than estimate. In part, this was due to insufficient suitable resources to carry out all of the planned works.

31 SWER earthing maintenance was less than anticipated due to the annual testing identifying less repairs required than in previous years.

32 Pole and ground mounted transformer maintenance was above estimate with more transformer repairs than anticipated.

33 Transformer changes due to corrosion are within estimate. As replacement and maintenance schedules improve, the costs being incurred in this category are significantly reducing.

34 Other distribution transformer site maintenance was above estimate. This is largely due to the incorrect posting of a transformer refurbishment to this code.

Technical Equipment Maintenance:

35 Northern load plant maintenance was within estimate with no unforeseen issues occurring.

36 Southern load plant maintenance exceeded estimate. The main expenditure items were service connection agreements and annual inspections, the cost of which was underestimated. The estimate has been reviewed for future years.

37 Repeater site maintenance was within estimate with less work being required than anticipated.

38 Repeater site rentals were above estimate. This is due in part to the estimate for the year being below par and partly to incorrect coding of expenditure in the accounting system.

39 Radio maintenance was minimal due to the impending upgrade.

40 Radio licence costs were within estimate.

41 SCADA maintenance was below estimate with the system remaining stable throughout the year.

42 Line circuit breaker maintenance tracked below estimate. Due to limited technical resource availability, not all work could be done and, as a consequence, a level of prioritisation took place. The work that was not completed has been rescheduled.

43 Line regulator maintenance is under budget as planned maintenance work has not been completed due to a lack of suitable resources. These works have been rescheduled into the next financial year.

44 Fuse switches and Till box maintenance expenditure was within estimate.

45 Strategic spares storage costs were not incurred.

46 Generator truck costs were not incurred.

47 Generator/transformer and equipment was minimal due to a lack of resources.

Overall, the direct maintenance expenditure was about 6% less than estimated.

The above notes outline the expenditure variances and the reasons for them and general progress against maintenance initiatives and maintenance.

6.1.3.1 Effectiveness of Direct Maintenance Programmes

The effectiveness of these programmes is summarised in Table 6.3a below. More detail is also included in subsequent sections where a gap analysis and identification of improvement initiatives is completed. (Refer to Section 7, table 7-1 for initiatives and programmes).

EFFECTIVENESS OF DIRECT MAINTENANCE PROGRAMMES	
Maintenance Initiative and Programme	**Effectiveness**
Overhead lines and cables (including poles).	Patrols, inspections and follow-ups have contributed to controlling hazards and improving reliability. Emergent work has been necessary to rectify unplanned events and overcome legacy problems. The first 15 year inspection cycle is due for completion in 2020.
Vegetation	28,842 trees have been worked on during the financial year. The fell rate is relatively high (77%) and being maintained. Customers and most plantation owners are becoming increasingly aware of tree issues.
Zone substations	The programme has been effective in maintaining zone substations and ensuring components operate to industry life expectancies. Different maintenance schedules for new equipment versus legacy technology have been allowed for.
Pole mounted transformers	Effective in maintaining transformer stock and ensuring hazard control equipment such as earthing were inspected and tested.
Ground mounted transformers	Effective in maintaining ground mounted stock and ensuring hazard control equipment such as earthing is inspected and tested. Hazard elimination (both worker and public) is being addressed in the programme by introducing double locking and covering exposed terminals in the transformer cubicles.
Service boxes	Effective in ensuring service boxes are secure, labelled and hazards are controlled.
SCADA	Effective in ensuring the SCADA system is robust and operates reliably, particularly when the network is under stress.
Communication	Effective in ensuring the communication system operates reliably, particularly when the network is under stress.
Load control	Effective in ensuring the northern system operates until the remaining ripple relays are changed out. Effective in ensuring the newer electronic equipment is maintained to manufacturer's expectations.
Three phase reclosers and automated switches	Effective in ensuring that these devices operate reliably and to correct protective settings.
Voltage regulators	Effective in ensuring that the equipment operates reliably and voltage is maintained within statutory limits.
SWER systems	Effective in ensuring earthing systems are being maintained. There are a number of new initiatives currently being investigated to improve this further in conjunction with the development of the network analysis programme.
Fault inspections	Effective in identifying hazards and stopping repeat tripping and unexplained faults.
Other inspections	Effective in continually monitoring the network and developing an understanding of issues such as harmonic current flows.
Overall network reliability and security	The maintenance programmes have been effective in ensuring network reliability is meeting forecasts.
Overall network operating costs	The maintenance programmes have been effective in ensuring TLC's network operating costs are within the industry bands (refer to PWC industry comparisons of operation costs).

TABLE 6.3A: SUMMARY OF THE EFFECTIVENESS OF MAINTENANCE PROGRAMMES

6.1.4 Indirect Maintenance Expenditure on System Management and Operations

Table 6.4 lists the actual spends and the estimates from the 2011/12 plan.

INDIRECT MAINTENANCE EXPENDITURE			
Description	**2011/12 Actual**	**2011/12 Planned**	**Note**
Recoveries	-290,338	-274,860	1
Vehicles and Equipment	96,161	92,340	2
Staff Costs	1,493,817	1,429,697	3
Consultants and Inspections	318,491	511,220	4
Corporate Allocations	154,045	118,169	5
Sundry/Equipment Maintenance	109,988	66,069	6
Other Expenditure	49,504	29,160	7
Total	**1,931,669**	**1,972,345**	8

TABLE 6.4: INDIRECT MAINTENANCE EXPENDITURE ON SYSTEM MANAGEMENT AND OPERATIONS

Further notes to Table 6.4 Indirect Maintenance Expenditure.

1 Total recoveries from capital works to cover the cost of engineering time associated with capital works were slightly higher than estimated.

2 Vehicle costs were slightly greater than estimates due mostly to fuel costs.

3 Staffing costs were close to estimate. There have been some increases due to a review of TLC pay rates to ensure they are competitive with the current market. The Engineering and Design wage component is also increasing to target a sustainable succession staffing plan and resources capable of returning design cost savings.

4 Consultants and Inspections (external consultants) expenditure was less than estimated due to initiatives to minimise the use of these services.

5 Corporate allocation was higher than anticipated. Insurance and ACC Levy form the bulk of this expenditure.

6 Sundry/Equipment Maintenance costs were above estimate. The bulk of this expenditure is for software license fees.

7 Other expenditure (eg subscriptions and radio transmission charges) tracked higher than estimate.

8 Overall, Asset Management and Engineering indirect expenditure was as estimated.

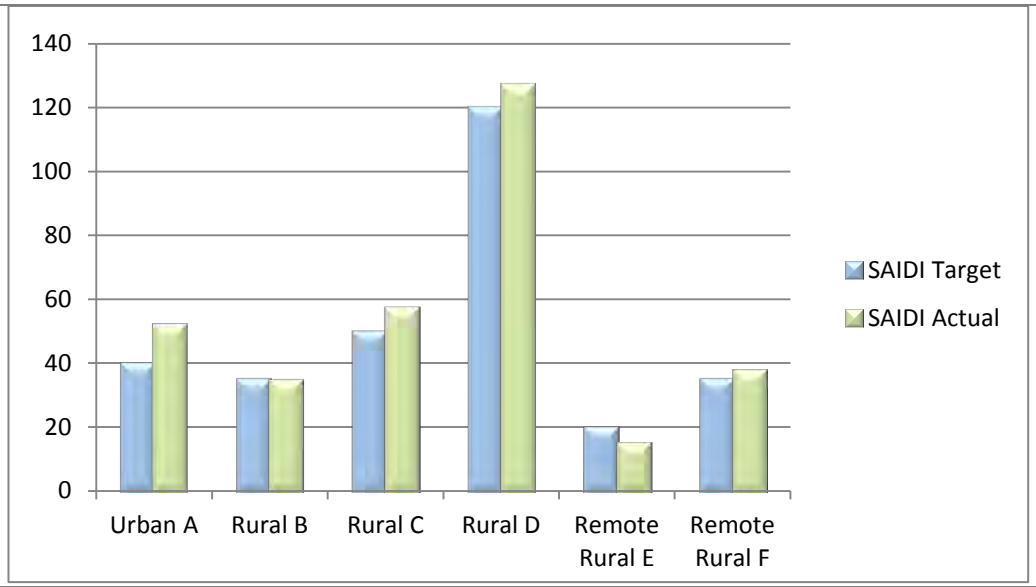
Allocation of operational expenditure for AMP reporting requires does not smoothly integrate with the organisation accounting system and some variance may occur. The figures shown are accurate as possible.

6.2 Evaluation and comparison of actual performance against targeted performance objectives

6.2.1 Consumer Oriented Performance Targets – Asset Related

6.2.1.1 SAIDI Performance

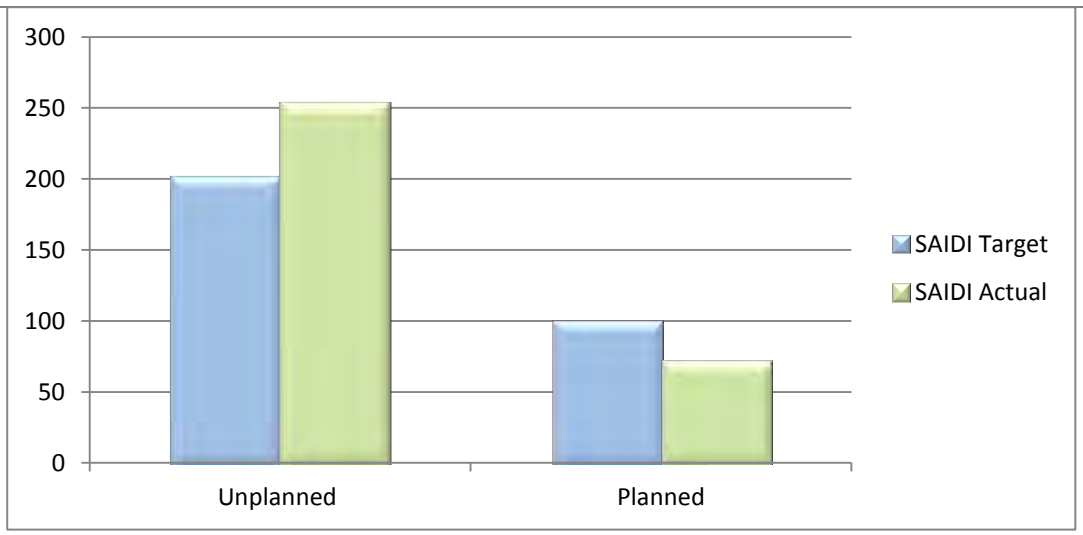
Table 6.5 lists the SAIDI performance by service level areas (refer to section 5 for service level area explanation) for the year 2011/12. Row 3 lists the variance for the 2011/12 year.



SAIDI Target	40	35	50	120	20	35	**TOTAL**	**300**
SAIDI Actual	52.12	34.73	57.48	127.21	15.12	37.86	**TOTAL**	**324.52**
Variance	30% (U)	1% (F)	15% (U)	6% (U)	24% (F)	8% (U)	**TOTAL**	**8.17% (U)**

TABLE 6.5: SAIDI PERFORMANCE 2011/12 AGAINST TARGET BY SERVICE LEVEL

The split between unplanned and planned SAIDI was 252.82 and 71.70 respectively. This compares against a target of 200.6 unplanned and 99.4 planned. Table 6.5A illustrates this.



SAIDI Target	200.6	99.4	**TOTAL**	**300**
SAIDI Actual	252.82	71.70	**TOTAL**	**324.52**
Variance	26.03% (U)	27.87% (F)	**TOTAL**	**8.17% (U)**

TABLE 6.5A: SAIDI PERFORMANCE 2011/12 AGAINST TARGET BY PLANNED/UNPLANNED

6.2.1.1.1 Explanation of Significant Variances

The main driver in the variances was the extreme storm events in March, April, July and August months. Approximately 139 SAIDI minutes were a result of the extreme storm events. Urban A, Rural B, Rural C and Rural D service levels all had above 20 SAIDI minutes due to weather conditions. Specifically the problem was caused by crown owned plantation trees on Treaty settlement land that were in the vicinity of the Sir Edmund Hillary Outdoor Pursuits Centre. They destroyed lines and no alternative supplies were able to be put in place until the weather condition improves. The extreme 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 was working on rural line renewals, in cases like this it takes time for them to mobilise back into urban areas.

6.2.1.1.2 Actions Being Taken to Address the Variances

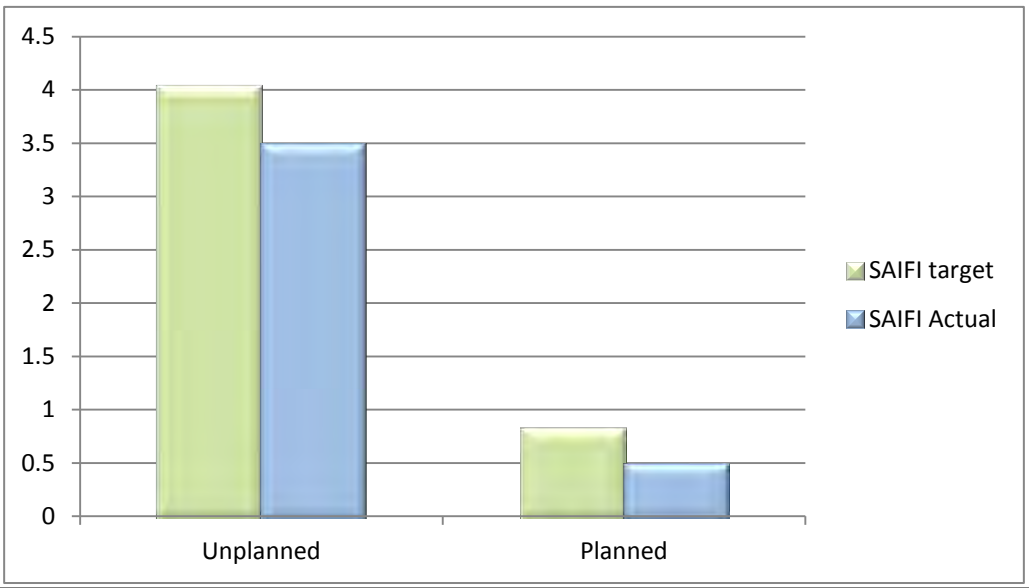
TLC's on-going objective is to continue to target the rural service level regions through the planning period. A number of urban and rural areas are also being targeted for switch automation. A number of events that have affected CBDs occurred when staffs were all away from the urban areas working on rural lines. It can take an extended time to mobilise back into the urban areas and, as a consequence, CBD areas were without supply for some time. This had an effect on the time to restore supply criteria discussed in Section 6.2.1.3 below.

TLC is currently in the process of preparing a Commerce Commission Customised Price Path (CPP). In the future, it is likely that this target will have to be varied due to the CPP application.

Cutting of trees in the vicinity of the Sir Edmund Hillary Outdoor Pursuits Centre has been completed. Legal opinions have been sought and negotiations with the Trusts holding ownership of much of the land have been scheduled.

6.2.1.2 SAIFI Performance

Table 6.6 lists the total SAIFI performance for the 2011/12 year. Column 3 lists the variance for the 2011/12 year.



SAIFI Target	4.03	0.83	**TOTAL 4.86**
SAIFI Actual	3.48	0.50	**TOTAL 3.98**
Variance	14% (F)	40% (F)	**TOTAL 18.0%** (F)

TABLE 6.6: SAIFI PERFORMANCE FOR 2011/12 AND COMPARISON OF 2011/12 TO TARGET

6.2.1.2.1 Explanation of Significant Variances

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 unplanned interruption during extreme storm events in March, April, July and August months (the reasons for this are discussed in section 6.2.1.1.1)

6.2.1.2.2 Actions Being Taken to Address Variances

TLC's on-going renewal programme will continue to improve SAIFI performance at the individual service level regions and overall levels.

SAIFI values will be affected by the renewal programme in that outages will be needed for renewals to occur. The use of generators to reduce SAIDI often does not have a significant effect on SAIFI given that a short outage is often needed to disconnect and reconnect from the existing line.

It is also more difficult to reduce SAIFI than SAIDI in urban and rural areas when switching and back feeds that cannot be paralleled are used to restore supply. The key to the long-term control of the indices is an effective renewal and maintenance programme.

TLC is currently in the process of preparing a Commerce Commission Customised Price Path (CPP). In the future, it is likely that this target will have to be varied due to the CPP application.

6.2.1.3 Time to Restore Supply

The customer agreed time to restore supply and the performance targets for achieving this, the actual performance and the variances from targets are listed in table 6.7 (See Section 5 for details on the service level areas.)

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 Were Not Met**	**Target %**	**Actual Performance**
Urban A	91	3	177	36	95.0%	79.7% (U)
Rural B	17	6	42	0	90.0%	100% (F)
Rural C	57	6	250	26	90.0%	89.6% (U)
Rural D	130	6	461	48	90.0%	89.6% (U)
Remote Rural E	22	12	128	2	90.0%	98.4% (F)
Remote Rural F	16	12	115	19	90.0%	83.5% (U)

TABLE 6.7: PERFORMANCE TARGETS AND VARIANCES TO RESTORE SUPPLY AFTER AN UNPLANNED OUTAGE

6.2.1.3.1 Explanation of Significant Variances

The main driver in the variances is the extreme storm events in March, April, July and August months. The extreme wind and lightning strikes in these months significantly delayed the restoration of supply to both remote and rural areas. Faults occurred in urban areas when staff were working on rural line renewals, it took time for them to mobilise back into urban areas.

Rural B and Remote Rural E service level performance was better than the target and they have improved compared to the previous financial year (In the previous year Rural B was 97.8% and Remote Rural was 94.5%).

6.2.1.3.2 Actions Being Taken to Address Variances

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 staff are being trained in cable jointing and cabling systems.
- Additional training is taking place on the use of generator by-pass.
- Further automation is being deployed into areas, i.e. automation of a number of key ring main sites in urban areas.
- 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.

6.2.1.4 Number of Planned Shutdowns per Year

The customer agreed number of planned shutdowns and the performance targets for achieving this, the actual performance and the variances from targets are listed in Table 6.8 (See section 5 for details on service level areas.)

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	5	95%	94.5% (U)
Rural B	17	4	0	90%	100.0% (F)
Rural C	57	6	4	90%	93.0% (F)
Rural D	130	6	6	90%	95.4% (F)
Remote Rural E	22	8	0	90%	100% (F)
Remote Rural F	16	10	0	90%	100% (F)

TABLE 6.8: PERFORMANCE TARGETS AND VARIANCES OF THE NUMBER OF PLANNED SHUTDOWNS PER YEAR

6.2.1.4.1 Explanation of Significant Variances

The variances were within expected levels. Only the Urban A region was marginally below target; 5 out of 91 asset groups had more than 2 planned shutdowns.

The reasons for these were:

- The replacement of a transformer than was hit by lightning in the Otorohanga Town area (Otorohanga Feeder). Due to the complexity of this job a short shutdown was required to disconnect the generator truck off the network.
- The replacement of two low voltage poles; one of which was a red tagged pole, in the Otorohanga town area (Otorohanga Feeder). Two shutdowns were required to complete this work.
- An extensive line renewal project in the Te Kuiti area (Oparure Feeder). Due to the complexity of this job three shutdowns were required to complete this work.
- The installation of a new magnafix was carried out in the Ohakune town (Ohakune Feeder). Due to the nature of the work three shutdowns were required to complete this work.
- The installation of new regulators was carried out in the Ohakune area (Ohakune Feeder). Due to the nature of the work two shutdowns were required to complete this work.

In the future, it is likely that this target will have to be varied to accommodate more de-energised renewal work; given that need to complete renewal work at the lowest possible cost.

6.2.1.4.2 Actions Being Taken to Address Variances

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.
- Ensuring contractors and controllers co-ordinate work and planned outages.
- Proposed CPP application and the related public consultation that goes with this has meant that customers may understand the issues better and be more receptive to varying this target.

6.2.1.5 Number of Short and Long Faults per Year

The customer agreed number of short and long faults and the performance targets for achieving this, the actual performance and the variances from target are listed in table 6.9 (See Section 5 for details on service level areas and how these relate to asset groups.)

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	57	130	22	17
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	10	0	2	0	0	0
Target	**95%**	**90%**	**90%**	**90%**	**90%**	**90%**
Actual Performance	89% (U)	100% (F)	96% (F)	98% (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 6.9: PERFORMANCE TARGETS AND VARIANCES OF THE NUMBER OF SHORT AND LONG FAULTS PER YEAR

6.2.1.5.1 Explanation of Significant Variances

Urban A service levels long fault performance is below the target. The main driver in the variance is the extreme storm events in March, April, July and August months. Of the ten asset groups that did not meet the criteria seven were in the Northern area, these were mainly affected by lightning. The remaining three asset groups were located in the Southern area and were mainly affected by extreme weather particularly wind. The performance of the remaining service levels is above the target.

In the above performance the effect on downstream network has not been included.

6.2.1.5.2 Action Being Taken to Address the Variances

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.
- The Service Provider has restructured and additional faults staff has been added to rosters.
- Feeder open points have been adjusted, and automated, in a few locations.

6.2.2 Consumer Oriented Performance Targets – Service Related

6.2.2.1 Telephone Calls Coming In to the Organisation and Unanswered Calls

Table 6.10 lists the targeted numbers of telephone calls coming into the organisation and the number of unanswered calls (averaged per month). These are compared to the actual.

COMPARISON OF ACTUAL TELEPHONE CALLS AND UNANSWERED CALLS AGAINST TARGETS (Averaged Per Month)							
Item	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**Target**	**Variation**
Number of Incoming calls	5260	3119	3785	4098	3932	**4500**	12.62% (F)
Number of Unanswered calls	534	67	336	238	130	**135**	3.70% (F)
Note : The numbers represent average per month							

TABLE 6.10: COMPARISON OF ACTUAL TELEPHONE CALLS AND UNANSWERED CALLS AGAINST TARGETS

6.2.2.1.1 Explanation of Significant Variances

The monthly average calls overall were below the target of 4500. The number of unanswered calls was below the target of 135. More detailed analysis is shown in Table 6.10a.

FURTHER DETAIL ON INCOMING TELEPHONE CALLS						
Month	**Total number of Calls**	**No Answer**	**Busy Signal**	**Short Duration**	**Total Unanswered Calls**	**Percentage of Unanswered**
April	4256	16	0	22	38	0.9%
May	3958	12	7	16	35	0.9%
June	4097	14	0	17	31	0.8%
July	3925	22	21	16	59	1.5%
August	4724	128	26	62	216	4.6%
September	3970	120	2	13	135	3.4%
October	3243	210	14	14	238	7.3%
November	4303	64	28	11	103	2.4%
December	3177	100	8	12	120	3.8%
January	2815	33	17	2	52	1.8%
February	3238	29	1	11	41	1.3%
March	5474	176	293	26	495	9.0%

TABLE 6.10A: FURTHER DETAIL ON INCOMING TELEPHONE CALLS

The October 2011 price rise notification prompted an increase in the number of calls. While total calls were below target the timing of the calls centred around the October price increase and the combination of storm conditions in March 2011 and the load reset notification in March 2011.

6.2.2.1.2 Action Being Taken to Address the Variances

We have now established a new team to answer customer pricing queries to take the pressure off the accounts and faults department. This should result in customers being directed to the correct person to talk to more quickly and free up the main lines for more calls to be answered promptly.

6.2.2.2 Unresolved Complaints: Focus Group Meetings: Customer Clinics

Table 6.11 lists the targets and numbers of maximum unresolved complaints annually investigated by the Electricity and Gas Complaints Commission (EGCC), the industry's complaints resolution organisation, focus groups and customer clinics. Targets are compared to actual.

COMPARISON OF UNRESOLVED COMPLAINTS, FOCUS GROUP MEETINGS AND CUSTOMER CLINICS AGAINST TARGETS							
Item	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**Target**	**Variance**
Unresolved Complaints	9	2	33	40	9	**5**	80% (U)
Focus Group Meetings	4	4	5	11	6	**5**	20% (U)
Customer Clinics	25	36	30	26	19	**12**	58% (F)

TABLE 6.11: COMPARISON OF UNRESOLVED COMPLAINTS, FOCUS GROUP MEETINGS AND CUSTOMER CLINICS

6.2.2.2.1 Explanation of Variances

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 negative public relations campaign run by a group of customers.

Focus 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.

Customer Clinics – There were more customer clinics than targeted.

6.2.2.2.2 Action Being Taken to Address the Variances

Since TLC has now established a complaint tracking and recording system the number of unresolved complaints has dropped. It is, however, still above target. It is anticipated that 2012/13 results will increase again due to the changes in the pricing in 2012 and the introduction of a new customer profile.

Other initiatives included the formation of a "Mayors" working group, this regulates discussion with the key people in lobby groups and other internal changes of the governance level. A judicial review of the decisions being made by the EGCC is also being considered.

6.2.3 Other Targets Relating to Asset Performance, Asset Efficiency and Effectiveness and the Efficiency of Line Business Activity

6.2.3.1 Asset Performance Targets

6.2.3.1.1 Asset Performance Targets: Quality: Voltages

Table 6.12a lists the quality performance targets and compares them to actual performance.

COMPARISON OF VOLTAGE PERFORMANCE ACTUALS AND TARGETS							
Item	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**Target**	**Variance**
Voltage Complaints	1	2	4	10	1	**10**	90% (F)
Resolved Legacy Voltage Issues	1	3	1	1	3	**2**	200% (F)

TABLE 6.12A: ASSET PERFORMANCE: COMPARISON OF QUALITY TARGETS VERSUS ACTUALS

6.2.3.1.1.1 Explanation of Significant Variances

The voltage complaints were lower than the previous year and three legacy voltage issues were resolved.

Three voltage regulators were installed in 2011/12 to overcome legacy voltage problems. Two of the three regulators were part of the 2011/12 programme, the third regulator was a carryover from the 2010/11 programme. The need to target legacy voltage issues is on-going and one of the drivers behind network constraints and load controller settings.

6.2.3.1.1.2 Actions Being Taken to Address the Variances

The voltage levels within the network are constantly monitored and short and long term issues are followed up. Short term issues tend to be addressed by adjustments to equipment including regulators and tap settings. The long term issues tend to be identified by network analysis and improved strategies that are included in this plan. Monitoring of voltage equipment via SCADA has also been increased as part of improvements to customer service and compliance. (The voltage complaint numbers include those originating in customer owned assets).

6.2.3.1.2 Asset Performance: Harmonic Levels

Table 6.12b lists the quality performance targets and compares them to actual performance.

HARMONIC DISTORTION: ACTUALS AND TARGETS					
System	**Description**	**2008/09**	**2009/10**	**2010/11**	**2011/12**
Harmonic Levels 3-Wire Systems **Target is 10%**	Measured Sites	143	143	171	87
	Instance where target exceeded	11.19% (U)	11.19% (U)	8.19% (F)	6.89% (F)
Harmonic Levels SWER Systems **Target is 30%**	Measured Sites	66	66	21	60
	Instance where target exceeded	3.03% (F)	3.03% (F)	9.25% (F)	0% (F)

TABLE 6.12B: ASSET PERFORMANCE: HARMONIC DISTORTION TARGETS AND ACTUAL

Table 6.12b 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.

6.2.3.1.2.1 Explanation of Variances

The harmonic levels were better than previous years

a) The Southern 33 kV system variances were caused by light loading, downstream SWER feeders, ski field operations and long cable lengths.

b) Southern 11 kV system variances were caused by industrial loads with high numbers of variable speed drives.

c) All SWER system had below the targeted 30% harmonic distortion

6.2.3.1.2.2 Action Being Taken to Address Variances

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.

6.2.3.1.3 Asset Performance: Surges That Cause Destruction of Electronic Equipment

Table 6.13 lists the voltage surge performance targets and compares them to actual 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)	55	**80**	31% (F)

TABLE 6.13: VOLTAGE SURGE PERFORMANCE

6.2.3.1.3.1 Explanation of Variances

There were fewer incidents and complaints from customers than the target.

6.2.3.1.3.2 Actions being taken to address variances and voltage surges

TLC is taking the following actions to reduce the impact of surges:

a) Surge suppression devices are being fitted throughout the network at a relatively low break-over voltage.
b) TLC is encouraging customers to install surge protection in their installations. This includes free giveaways to promote a demand site management approach.
c) 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.

6.2.3.1.4 System Component Performance: Failures

Table 6.14 lists the system component performance failure targets and compares these to actual performance.

COMPONENT PERFORMANCE FAILURE ACTUALS AND TARGET							
Item	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**Target**	**Variance**
Component Failures	219	271	295	290	269	**244**	10.25% (U)

TABLE 6.14: COMPARISON OF SYSTEM COMPONENT PERFORMANCE: FAILURES VERSUS TARGETS

6.2.3.1.4.1 Explanation of Variances

The system component failure performance was higher than the target by 10.25%. Weather conditions in March, April, June and October caused a number of component failures. 79% of the total component failures were due to HV asset failure, 40% of the HV asset failures were mainly overhead HV lines and old deteriorating HV fuse problems. 21% of the total component failures were due to LV asset failures, 37% of the LV asset failures were due to overhead LV lines. The overall system component failure performance was marginally better than last year.

6.2.3.1.4.2 Actions Being Taken to Address the Variances

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 very focused on the quality of components that are used on the network.

6.2.3.1.5 Environmental Performance

Table 6.15 lists the environmental targets and compares these with the performance.

COMPARISON OF ACTUAL VERSUS TARGET ENVIRONMENTAL PERFORMANCE			
2011/12	**Actual**	**Target**	**Variance**
Prosecution or Abatement Notices	0	**0**	0%
Environmental Improvement Works Completed	0	**0**	0%

TABLE 6.15: COMPARISON OF ACTUAL VERSUS TARGET ENVIRONMENTAL PERFORMANCE

6.2.3.1.5.1 Explanation of Variances

There are no variances in the targeted performance. Environmental work is prioritised and completed within planned schedules.

6.2.3.1.5.2 Actions Being Taken to Address the Variances

A review of environmental compliance also took place. This review identified the need to continue with the strategies within this Plan to mitigate environmental risks. TLC has assets that do need environmental enhancements and these are included in forward Plans.

6.2.3.2 Asset Efficiency Targets

6.2.3.2.1 Network Losses

Table 6.16 lists the technical loss targets by regions and the actual losses as confirmed by network studies based on system loads. (Heavy and light load).

COMPARISON OF TECHNICAL LOSS STUDIES BASED ON NETWORK REGION										
Region	**2009/10**		**2010/11**		**2011/12**		**Target**		**Variance**	
	Heavy	*Light*	*Heavy*	*Light*	*Heavy*	*Light*	***Heavy***	***Light***	*Heavy*	*Light*
North	6.65%	1.74%	5.13%	1.29%	5.08%	1.60%	**7.00%**	**2.00%**	1.92% (F)	0.40% (F)
Central	6.20%	5.00%	10.39%	1.84%	11.41%	1.90%	**8.00%**	**5.00%**	3.41% (U)	3.10% (F)
Ohakune	4.70%	1.10%	13.37%	1.57%	11.74%	0.81%	**9.00%**	**2.00%**	2.74% (U)	1.19% (F)

TABLE 6.16: COMPARISON OF TECHNICAL LOSS STUDIES BASED ON NETWORK REGION

6.2.3.2.1.1 Explanation of Significant Variances

The technical losses at light loads are below the target and technical losses at heavy loads are above the target in the Central and Ohakune 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.

6.2.3.2.1.2 Action Being Taken to Address the Variances

Setting loss targets is difficult due to the variability that comes about with run of river hydro distributed generation connections. Rain can make a significant difference to the operation of the plant. Overall loss targets (not included in Table 6.16) are also significantly affected by non-technical losses caused by metering, meter reading and data processing errors.

Long term, TLC is focusing on reducing losses by:

- Demand site management initiatives by the use of load control systems and charges.
- Reducing retailer errors by making them aware of the issues and upgrading the metering technology to be able to produce demand data.
- 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. (Our preference however would be for this to be done by demand side initiatives).
- In the case of Ohakune; upgrading of the network and the use of mobile capacitors during ski weekend times.

  Note: TLC has one mobile capacitor unit that has been proved to be successful. The use of the device is becoming greater as the intellectual understanding grows within the organisation. Not included in the present AMP but likely in future reviews will be either more of these units of varying sizes or a unit that can be varied.

6.2.3.3 Network Power Factor

Table 6.17 lists the target power factor average by Grid Exit Point (GXP) during RCPD periods and the actual performance as calculated from the national dataset that is available from the Electricity Commission.

COMPARISON OF GRID EXIT POWER FACTOR TARGETS AND ACTUAL			
Grid Exit	**Actual Power Factor**	**Power Factor Target**	**Variance**
Hangatiki	0.922	0.912	1.10% (F)
Ongarue	0.794	0.916	-13.32% (U)
Tokaanu	0.996	0.992	0.40% (F)
National Park	0.998	0.990	0.81% (F)
Ohakune	0.990	0.991	-0.10% (U)

TABLE 6.17: COMPARISON OF GRID EXIT POWER FACTOR TARGETS AND ACTUAL

Note: The Ohakune grid exit is shared with Powerco as discussed in other sections.

6.2.3.3.1 Explanation of Significant Variances

The target is to hold power factors at present levels. The distributed generation injection at Ongarue GXP is lowering the power factor at the site. The Ongarue power factor appears to have been lowered by a combination of events associated with both the generation and load. (See Section 7 for further explanation on effects of distributed generation on power factor). Ohakune power factor is also slightly lower than its target. Hangatiki GXP has improved compared to previous year.

6.2.3.3.2 Actions Being Taken to Address Variances

As outlined in Section 7, distributed generation reduces grid exit power factor unless plant is injecting reasonably large amounts of reactive power during RCPD periods. This is often not possible due to network voltage levels and the types of machines being used.

It is possible to also show that it is not the RCPD power factor figure the connection code should be focused on but rather the amount of reactive power during RCPD periods. As a consequence of this, TLC has applied to Transpower, and has been granted, 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. (Improved generator power factor has a flow on effect in that network voltages can become excessively high during light load periods).

6.2.3.4 Network Load Factor

Table 6.18 lists the target load factor and compares this with the actual for the 2010/11 year.

COMPARISON OF LOAD FACTOR TARGETS AND ACTUAL			
	Actual	Target	Variance
Overall Network Load Factor	53.00%	60.00%	11.67% (F)

TABLE 6.18: COMPARISON OF LOAD FACTOR TARGETS AND ACTUAL

NETWORK LOAD FACTOR ACTUAL			
Financial Year	Electricity Volumes Carried (MWhr)	Co-incident System Peak (MW)	Load Factor
2005/2006	317.6	55.7	65.09%
2006/2007	329.5	58.4	64.35%
2007/2008	327.0	65.0	57.00%
2008/2009	319.0	61.0	60.00%
2009/2010	354.0	64.0	64.00%
2010/2011	323.0	63.0	59.00%
2011/2012	318.0	68.0	53.00%

TABLE 6.18B: NETWORK LOAD FACTOR ACTUAL

6.2.3.4.1 Explanation of Variances

The load factor is lower than the target. The total energy and maximum co-incident demand is also lower than the previous year.

The variance between the 2010/11 and 2011/12 figures and the target are due to an error in the 2010/11 generation half hourly data. In the 2010/11 data the Electricity supplied to other EDBs (Tangiwai) was assumed to be 13GWhrs due to not having an operational meter at Tangiwai. In 2011/12 TLC obtained accurate reading from a newly installed meter at Tangiwai. The metered readings showed the Electricity supplied for the year was 4GWhrs.

6.2.3.4.2 Actions Being Taken to Address Variances

A high load factor means that assets are being well utilised. There can be some conflict between this and the loss target depending on network dynamics. 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. It does vary from year to year and there are many factors that cause this.

6.2.3.5 Diversity Factor

Table 6.19 compares the target to the actual.

Diversity Factor						
2007/08	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**Target**	**Variation**
1.48	1.42	1.51	1.36	1.32	1.44	-0.08 (U)

TABLE 6.19: DIVERSITY FACTOR: ACTUAL COMPARED TO TARGET

6.2.3.5.1.1 Explanation of Variances

The performance is slightly lower than the target.

Load factor and Diversity are two related indices that TLC sees as measures of the effectiveness of its demand charging initiatives. Looking forward a more reliable breakdown of these figures into the various segment of the network will take place.

6.2.3.5.1.2 Action Being Taken to Address the Variances

This is a benchmark target that has been set to measure the level of asset utilisation. Analysis and reporting work is being established to ensure that this ratio is consistent at both individual transformer level, and by segments, asset groups and billing density. Transformers that are incorrectly sized, i.e. customers who are not being fairly charged for their network capacity and demands, are identified. This work will create a stable ratio and target.

Note: The target ratio will have to be adjusted if the spread of the demands averaged for individual customers is changed in any review of the billing system.

6.2.3.6 Asset Effectiveness Targets

6.2.3.6.1 Accidents/Incidents Involving TLC Network Assets

Table 6.20 compares the targets to the actual.

ACCIDENT/INCIDENT PERFORMANCE: ACTUAL COMPARED TO TARGET					
Event	**Actual 2009/10**	**Actual 2010/11**	**Actual 2011/12**	**Target**	**Variance**
Lost time - injuries involving Staff or Contractors	18	6	5	**5**	0% (F)
Average hours lost (per employee)	1.42	1.32	0.04	**<2.5**	98% (F)
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 6.20: ACCIDENT/INCIDENT PERFORMANCE: ACTUAL COMPARED TO TARGET

6.2.3.6.1.1 Explanation of Significant Variances

The number of lost time injuries, average hours lost at or employee, OSH notifiable accidents and the numbers of public injuries involving a TLC facility were at or below the target. 2011/12 performance has improved significantly compared to the previous year due to better hazard control.

6.2.3.6.1.2 Actions Being Taken to Address the Variances

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

- Hazard control is 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 feed back.
- On-going asset patrol and inspection programmes in place.
- Formal staff hazard awareness programme put in place.

6.2.3.6.2 Number of Asset Hazards that are Eliminated /Minimised Annually

Table 6.21 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 2011/12**	**Target 2011/12**	**Variance**
Pillar Boxes	46	**50**	8.00% (U)
Two Pole Structures	5	**9**	44.44% (U)
Ground Mount Transformer	2	**3**	33.33% (U)
Switching equipment	0	**3**	100.00% (U)
Total Hazard Control	53	**66**	18.46% (U)

TABLE 6.21: ASSET HAZARDS ELIMINATED/MINIMISED: ACTUAL COMPARED TO TARGET

6.2.3.6.2.1 Explanation of Significant Variances

Hazard elimination/minimisation projects were 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.

6.2.3.6.2.2 Actions Being Taken to Address the Variances

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).

The intellectual experience of the contracting team is gaining a greater understanding of the need to resource for the amount of work they have in front of them.

6.2.3.6.3 Ratio of Total Number of Trees Felled to Trees Worked on Annually

Table 6.22 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							
	2007/08	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**Target**	**Variance**
Ratio of the Number of Trees Felled to Number Of Trees Worked On	75.00%	73.00%	79%	80%	77%	**70.00%**	10% (F)

TABLE 6.22: COMPARISON OF THE RATIO OF TREES FELLED TO TREES WORKED ON

6.2.3.6.3.1 Explanation of Variances

The variation was within expectations. The 2011/12 fell rate was above target due to a number of trees being removed from plantation areas. Customers' understanding of the importance of allowing trees close to power lines to be removed to improve reliability and minimise costs is increasing.

6.2.3.6.3.2 Actions Being Taken to Address the Variances

TLC is constantly striving to increase the fell rate to try and minimise its long term vegetation control costs and improve reliability.

6.2.3.7 Line Business Activity Efficiency Targets

The line business activity efficiency targets are based on the Electricity Distribution Information Disclosure Requirements 2012, Decision NZCC 22. The data and information requirements needed to establish these targets and measure against them have taken a little time to understand and develop.

Table 6.23 lists the 2011/12 lines business activity efficiency targets and the actual performance achieved against them.

DISCLOSED PERFORMANCE INDICES ACTUAL VERSUS TARGET		
Description	**2011/12 Actual**	**2011/12 Target**
Capital Expenditure per Total Circuit Length	$1,463	$2,170
Capital Expenditure per Electricity Supplied to Customers Connection Points	$20	$31
Capital Expenditure per ICP	$266	$395
Capital Expenditure per Distribution Transformer Capacity	$26,817	$40,797
Operational Expenditure per Total Circuit Length	$679	$884
Operational Expenditure per Electricity Supplied to Customers Connection Points	$9	$12
Operational Expenditure per ICP	$123	$161
Operational Expenditure per Distribution Transformer Capacity	$12,456	$16,613
Interruption Targets Class B (Planned) for planning period.	341	331
Interruption Targets Class C (Unplanned) for planning period.	1,173	800
Faults per 100km for 11 kV non SWER	22.18	35
Faults per 100km for 11 kV SWER	3.46	0.7
Faults per 100km for 33 kV	1.09	3.3
Overall Reliability (SAIDI)	324.52	300
Class B Reliability (SAIDI Planned)	71.70	97
Class C Reliability (SAIDI Unplanned)	252.83	203

TABLE 6.23: 2011/12 DISCLOSED PERFORMANCE INDICES ACTUAL VERSUS TARGET

6.2.3.7.1 Explanation of Significant Variances

The following operational business activity efficiencies were within target. The capital business activity efficiencies were lower than targeted. The principal reason for this was that the 2011/12 target was set based on data that were not as robust as current data and errors in allocation were found once the new outage reporting system was put in place. Another major variance between 2011/12 target and actual performance was number of unplanned faults that occurred during extreme storm events.

There is also some confusion industry wide on the definitions of the indices behind the criteria. A key aspect of this is the interface between the accounting and asset management systems. Development of the interface is on-going. The Commerce Commission has also recognised this indices comparison difficulty and has just released a draft consultation paper to give further clarity on the measurements.

6.2.3.7.1.1 Actions Being Taken to Address the Variances

Data System

A new data system has been put in and greater focus has been put on procedures and policies to improve the accuracy of entered data. The actions being taken to address this include the on-going investment in the system to continually develop and expand the data held. The work includes making the system more user friendly. Also in parallel with this development the intellectual understanding of staff is continually being progressed.

The Number of Faults on 11 kV Lines

The renewal programme is focused on bringing all lines, including 11 kV lines, up to a performance level that aligns with the criteria in Section 7.

6.3 Gap Analysis and Identification of Improvement Initiatives

6.3.1 Significant Gaps between Targeted and Actual Performance

6.3.1.1 Financial CAPEX Expenditure Performance

Capex performance overall, on a project by project basis, was within estimate expectations. Variations occurred on specific projects due to a host of factors; these varied from issues revealed once more detailed design was done through to landowner and access issues. Many of these factors are difficult to control given the realities of the remote, rugged rural environment and TLC's limited resources; things have to change from time to time and TLC does not have large numbers of people to put into exhaustive planning.

The most significant controllable factors that are causing a gap in performance are:

i. Data for the reported spends were of higher accuracy than in previous years. Further work is required to improve the process and make compiling the plan less labour intense. This gap in performance is being worked on by researching and looking at ways to better integrate the job costing system and Basix. This will probably see more of the job costing functions transferred to Basix over time.
ii. A number of projects have had a delayed starting time due to lack of resources, which includes both labour and material. This results in some of the projects rolling between years. TLC is continually balancing costs against resources. The way forward to control this gap in performance is to automate as much of the planning as possible through the use of tools such as Basix. Planning tools are available in Basix and an individual with the knowledge to develop this has recently been employed. It will take time to develop this further using a continuous improvement approach.
iii. Line renewal expenditure is difficult to predict until the specific line detail is captured. This is done as part of the 15 yearly inspection process and until the cycle is completed there will be a variation between the forward estimates and the actual needs once a detailed inspection has taken place. Performance to date, however, has shown that the bottom line has remained relatively constant and as estimated.
iv. TLC's network capacity is being pushed to allowable equipment ratings in some places. Any perturbation in customer development can quickly cause a need for further cumulative upstream network investment. This causes a gap in performance, and the need to modify the network rapidly to provide capacity is being managed through the use of the network analysis tool and work in developing load predictions. Demand billing is also seen as a way forward to minimise this gap.

The capital expenditure is a significant driver of forward revenue requirements. Research and evaluation to date provides evidence that the work is needed. The major challenge for TLC is to complete this work at a lower cost. Analysis of capital expenditure shows that about 30% of the cost is materials and the remaining 60% is labour and plant. Live line and generator by-pass work are more expensive than de-energised work methods in terms of labour and plant.

Customers often complain about prices and shutdowns for maintenance and renewal. A key part of TLC's forward strategy is to make customers aware of this issue trade-off as detailed in a CPP application currently being proposed. This includes things such as public relations, customer consultation and development of the asset management systems to provide customised customer information, for example the outage notification will need to be tailored for customer notification letters, texts and emails.

6.3.1.2 Maintenance Expenditure Performance

Maintenance expenditure overall was about 6% lower than estimates. The subcategories (see Table 6.3) all tracked relatively close to estimates. There were some gaps in individual items, however, as discussed in 6.3.1 above where it is thought that many of these gaps in the performance have come about due to reporting problems in the job costing systems. Overall, the direct maintenance activities followed the plans and policies in Section 8.

Indirect maintenance work followed a similar pattern with all but the allowances for consultants tracking close to estimates. Savings were made by employing less external advice than estimated.

6.3.1.3 SAIDI Performance by Service Levels

Overall SAIDI performance was slightly above target. The major variance was between the planed target and performance. The on-going renewal programme is designed, over time, to minimise the gaps between performance and targets.

6.3.1.4 SAIFI Performance: Overall and by Service Levels

Overall SAIFI performance was slightly below target. TLC is concerned that SAIFI may become more difficult to control in rural areas. SAIFI going forward will need to be monitored carefully as its effects on customers can be more significant than SAIDI. TLC's on-going renewal programme will continue to improve SAIFI performance at the individual service level regions and overall levels.

6.3.1.5 Time to Restore Supply

The gap to restore urban areas was greater than expected. Strategies are included in this Plan to address this (see section 7 and the discussion earlier part of this section). The significant gains are expected to come from automation particularly in urban areas. Other innovative initiatives such as the use of mobile capacitor banks to increase the capacity of alternative supplies are also being developed.

6.3.1.6 Number of Planned Shutdowns per Year

The variances were within expected levels. In the future, it is likely that this target will have to be varied to accommodate more de-energised renewal work; given that need to complete renewal work at the lowest possible cost.

6.3.1.7 Number of Short and Long Faults per Year

Overall performance for the number of short and long faults has improved. Performance for long faults was below target for Urban A service level. The main cause was the time to mobilise staff and carry out repairs during the extreme storm event. Automation improvements in recent plans have been targeting improvements in these areas.

6.3.1.8 Telephone Calls Coming Into Organisation

While total calls were below target the timing of the calls centred around the October price increase and the combination of storm conditions in March 2011 and the load reset notification in March 2011. TLC have now established a new team to answer customer pricing queries to take the pressure off the accounts and faults department. On-going PR, continuous improvements of the billing system, improved telephone systems and other customer service initiatives are key to ensure this gap is controlled.

6.3.1.9 Unresolved Complaints: Focus Group Meetings: Customer Clinics

Gaps in the unresolved complaints were significant, a high number of complaints were associated with landowner and tenant issues. These indices will have to be monitored carefully going forward, given the amendments to the electricity legislation making landlords responsible for line charges. Since TLC has now established a complaint tracking and recording system the number of unresolved complaints has dropped. Future initiatives will be focused on focus group meetings, customer clinics, and various public relations initiatives. These should help to reduce misunderstandings and dissatisfaction.

6.3.1.10 Quality Voltage and Harmonics

Voltage complaints have reduced considerably and did not exceed the target. Voltage levels are constantly monitored and analysed. TLC on-going objective is to increase the understanding of voltage levels on some of the remote SWER systems where loadings are higher. SWER systems have different characteristic impedances than 2 and 3 wire systems and this effect can cause greater voltage attenuation than the more conventional systems; understanding these, and how they relate to the actual TLC operating considerations, needs further research.

The Electricity (Safety) Regulations 2010 fine structure places more significance on gaps between statutory limits and operating voltage levels outside of these limits.

6.3.1.11 System Component Performance: Failures – Gap Analysis

The system component failure performance was higher than the target by 10.25%. Extreme weather conditions in March, April, June and October caused a number of component failures. The gap between target and actual of system component failures is an on-going point of focus. The gap between target and performance means:

- Continuing focus and recognition of the importance of the renewal programme.
- Continuing research and improvement on the quality of materials, components and work methods used on the network.
- On-going focus on the quality of data being put into the Basix system to ensure that the performance can be consistently measured between years.

The gap reinforces the need for renewal programmes.

6.3.1.12 Environmental Performance

There were no incidents and there is no gap between target and performance.

6.3.1.13 Network Losses

The discrepancies in the network losses are an on-going point of focus. There is a problem with getting consistent information on energy sold to customers from the market. This is beyond TLC's control and is a gap that the industry and market have recognised and are attempting to address through improved registry and other systems.

The winter loads and the need to 'sweat' the Ohakune networks and Central area networks in the ski seasons pushed the losses in these areas higher than expectations. The building of additional capacity and reactive power flow control will likely ease this increase in future years.

6.3.1.14 Network Power Factor

The overall network power factors have remained aligned to targets with the exception of Ongarue GXP. The low power factor at the Ongarue GXP is due to number of distributed generation injections. Hangatiki GXP also has distributed generations but TLC has been granted an exemption from the codes for Hangatiki and other applications will be forwarded when resource is available to prepare and submit these.

6.3.1.15 Network Load Factor

There was a 7% decrease in network load factor as compared to target. The variance between the 2010/11 and 2011/12 figures and the target are due to an error in the 2010/11 generation half hourly data. In the 2010/11 data the Electricity supplied to other EDBs (Tangiwai) was assumed to be 13GWhrs due to not having an operational meter at Tangiwai. In 2011/12 TLC obtained accurate reading from a newly installed meter at Tangiwai. The metered readings showed the Electricity supplied for the year was 4GWhrs.

6.3.1.16 Diversity Factor

Diversity factor is the ratio of sum of individual maximum demand of every feeder to maximum demand of the network. There was a slight performance gap in the Diversity Factor. This is a measure that will be monitored closely as time goes on to ensure TLC is recovering appropriate revenue from various network areas. This index is part of the on-going research and development of understanding on the impact of demand billing.

6.3.1.17 Accidents/Incidents Involving TLC Assets

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 all below the target. 2011/12 performance has improved significantly compared to the previous year due to better hazard control.

6.3.1.18 Number of Hazards that are Eliminated/Minimised Annually

Hazard elimination/minimisation projects were below target. This was due to a number of tasks being more complex and technical than anticipated. Continuous improvement of the work management systems is taking place to ensure focus throughout the year is maintained on priority hazard renewals. Rate of Total Number of Trees Felled to Trees Worked On Annually

There was no performance gap with the ratio of the total number of trees felled to trees worked on annually. TLC is constantly striving to increase the fell rate to try and minimise its long term vegetation control costs and improve reliability.

6.3.1.19 Line Business Activity Efficiency Targets

The line business activity efficiency targets are aligned to the Commerce Commission disclosure requirements. They are designed for intercompany comparisons. There will be variations among companies for a whole host of reasons including the architecture of the individual networks and how this came about.

The targets have been set based on the expected results, given TLC's current plans. Variances will result when changes to these plans have to be made due to changes in customers, legislations, environmental

The principal reason for the variances was that the 2011/12 targets were set based on data that were not as robust as current data and errors in allocation were found once the new outage reporting system was put in place. Another major variance between 2011/12 target and actual performance was number of unplanned faults that occurred during extreme storm events.

TLC has been developing an automated database to record this data and has also been developing its intellectual understanding of these needs to ensure that the data are correct.

There is still some way to go and some of the reasons for this are to do with the underlying definitions of the indices behind these data. As outlined earlier in this section work is underway at all industry levels to better define these so that intercompany comparisons can be improved.

6.3.2 Overall Quality of Asset Management and Planning Processes

6.3.2.1 Overview

TLC has been continually striving to improve its AMP. The principal objective of the AMP is to meet the requirements of stakeholders as reflected in the Statement of Corporate Intent, the agreement between TLC and its owners. This agreement obliges TLC to continue to invest in its network to undertake a sustainable renewal programme to minimise/eliminate hazards and meet reliability targets.

The 2013/14 review has been changed to align as best as possible with the requirements of NZCC22 in the time frames available. The review has changed the way that data was presented on planned renewal and development works in an effort to better present these details to stakeholders.

The focus of the 2011/12 Plan was to further review future workloads and smooth this to give more stable funding and resource requirements. The focus of the 2013/14 Plan is to

- Continue to refine the work completed in previous years.
- Improve outage reporting and quantifying the accuracy of data and the development of reporting.
- Further improve the network models and further load prediction modelling to be able to track as accurately as possible the impacts of demand billing.
- Align the AMP requirements of NZCC22 (This is a significant task and the reality is that the organisation will take a period to gain an understanding of NZCC22 requirements).

The network performance objectives are generally being met with few gaps between actual and the details included in the terms and conditions of supply. The renewal, development and maintenance plans will continue to unfold to produce this performance through the planning period. Customers will not tolerate a network that does not meet quality reliability and hazard control expectations. TLC has to focus on renewal of remote rural lines and removal of hazards from the network lines. The 15 year renewal cycle has been accepted by landowners.

At an overview level, managing the TLC assets which are old and have hazard control deficiencies, is relatively complex given that the majority of them were constructed to supply electricity to the remote and rugged areas of the King Country. These assets were constructed with government subsidies using low cost methods such as SWER and recycled railway iron poles. Today, customer expectations are much greater than those for which the assets were designed. The government subsidy is no longer available for renewal and the customers have limited ability to pay. The Plan recognises this background and is designed to give the best value for money in a sustainable way whilst meeting a myriad of legislative requirements.

To meet this objective, the Plan will continue to evolve, pushed along by advances in equipment, technology, customers'/stakeholders' expectations, legislative development and the organisation's intellectual knowledge.

As explained in earlier sections, a big focus for TLC in the next period will be to complete capital works in a more effective way that minimises the costs and on-going increase in RAB. The increase in RAB drives the need for more revenue as the value of assets increases.

A whole host of initiatives are planned to address this issue, including some external assistance in reviewing this Plan, a likely Customised Price Path (CPP) application for quality, customer consultation and extensive modelling of the implications for the impact of changes to engineering overheads and work effectiveness.

As demand billing has filtered out to customers many have become increasingly aware of load control and the associated control times. In the future, it is likely that an increased focus will be needed on control times and the impacts of these on customers.

Areas that need further improvement include financial reconciliation, delivery of the projects listed in this Plan in a more effective manner, and the development of further advanced network strategies. Further work is also proposed on the overall identification of works and individual activity strategies. This will be aligned with the evolution of Commerce Commission, Safety Management System, Electricity Legislation and downstream requirements.

TLC believes that, overall, the quality of the asset management and processes are in line with industry best practice.

6.3.2.2 Evaluation of the Asset Management Maturity Assessment

All EDB's are required to complete an Asset Management Maturity Assessment Tool (AMMAT) which has been developed to assess the maturity of EBD asset management systems. The AMMAT has highlighted key area in the asset management system that TLC will need to improve in, this means that engineering resources will be consumed when updating the asset management system.

Going forward TLC's focus is on improving their assets as well as on improving the asset management, planning and information systems that support the assets. This includes planning and documenting the asset management systems in more detail. The conclusion is that to meet or surpass the standard (PAS 55:2008) in the most effective way the following items need to be achieved.

6.3.2.3 Background and Objectives

The overall quality of the asset management and planning within the business is summarised in the following sections:

6.3.2.3.1 The purpose of the Plan

The purpose is understood, and is described in Section 2. The quality of this understanding will continue to develop.

6.3.2.3.2 The interaction between those objectives and other corporate goals, business planning processes and plans

The Asset Management Plan interacts with corporate goals, business planning processes and plans. As the quality of the AMP has improved and will continue to improve, so has the quality of the interaction and business planning processes. Improvements in the quality of the AMP have added clarity to the business planning options available.

A long term objective/concept is to improve integration between engineering, reliability, quality, development, hazard control and prices. This detail will see continuous improvement in the understanding of the different costs for regions and customer groups. These will possibly in the long term result in different changing structures.

It is recognised that the asset management systems need further development to be able to translate these costs into more detailed levels of pricing.

6.3.2.3.3 The period covered by the Plan, and the date the Plan was approved by the Board of Directors of the EDB

The focus has been to take the Plan out as far as possible to give stakeholders a clear picture of the network needs into the future. It is recognised that the planning process requires a long term focus. The Directors put considerable thought into the implications and quality of the AMP before approving it. They recognise that considerable effort has to go into the development of the Plan and have to balance this against other organisational needs.

6.3.2.3.4 Stakeholder interests

TLC's stakeholders' interests are considered in the asset management and planning processes. The overall quality of these interests in the asset management and planning processes is considered best industry

practice. For example, based on feedback from stakeholders, the separate section listing our future planned works has been modified and reintegrated into section 7 and 8.

6.3.2.3.5 Accountabilities and responsibilities for asset management

The quality of staff accountable and responsible for asset management and planning aligns with industry best practice. The staff who are accountable and responsible are qualified and have many years of industry experience. Directors also pay considerable attention to performance and demand a high level of accountability and responsibility.

6.3.2.3.6 Asset management systems and processes

Some years ago TLC recognised that it needed to improve its asset management systems and processes. It has invested in intellectual knowledge and technology to improve systems. This is an on-going process and includes the integration of information. TLC believes the current quality of these systems aligns with industry best practice. Looking forward, TLC is well down the track via its demand side management and other initiatives to setting up the "next generation" of systems and will, in the near future, have quality that might be considered to set a higher level of capability than industry best practice.

Specifically, the database and system framework will allow more complex and smarter control systems to extend network capability. Plans are in place, and progress will be made in the next few years, to establish a full connectivity model, including all assets utilised down to individual ICP level. The connections from transformers to the low voltage systems are where TLC's database is currently incomplete.

In parallel with this the pricing calculators will also have to become more complex and they will have to be integrated back into the asset management systems.

6.3.3 Overview of Asset Management Plan

6.3.3.1 Assets Covered

6.3.3.1.1 High level description of distribution area

The asset management and planning process covers the entire network and includes details of the area covered, large customers, load characteristics and peak demand. The quality of this information is as accurate as possible and comprehensive.

6.3.3.1.2 Network Configuration

The asset management and planning process includes the full description of assets. This description includes a comprehensive amount of key data including general asset types, capacity and physical location. The quality of information has significantly improved and is based on network knowledge, technical information and linked data from TLC's asset systems.

TLC is continuing to develop its asset analysis and databases to better model the network to determine the optimal network configuration. During the 2012/13 year, further modules will be added to the network module to better model 2 phase systems and wind turbines.

6.3.3.1.3 Justification for assets

The asset management and planning process includes consideration of the justification for assets. TLC's pricing and billing strategies sharpen the quality of asset justification considerations. Because TLC has a vast rural area, with a limited amount of customers, funding of assets has to be transparent. Assets have to be justified.

6.3.3.2 Network Assets by Category

6.3.3.2.1 Network assets by category, including age profiles and condition assessment

The asset management and planning process includes the use of information on assets by category, including age profiles and condition assessment. The quality of this information has significantly improved and is extensively linked to data in TLC's asset systems. TLC believes the quality of this now aligns with industry best practice. The last two areas of data uncertainty are now being worked on. These are a connectivity model through the low voltage network i.e. the connection between transformers and individual ICPs and a further breakdown of technical equipment.

6.3.3.3 Service Levels

6.3.3.3.1 Consumer oriented performance targets

TLC has developed consumer oriented performance targets that use industry indices as a base but expand on these. The objective of these is to make them more focused on what the customer understands and requires. The quality of the data behind these targets has significantly improved and the targets are used in planning and asset management processes.

As time goes on, the levels of these targets will be reviewed and adjusted to ensure they align with customers' expectations. The quality of this process is considered to be industry best practice. TLC will continue to base asset development and renewal on customer related performance. (This will also include integration with other requirements such as the SMS system).

6.3.3.3.2 Targets relating to asset performance, asset efficiency and effectiveness and the efficiency of the line business activity

TLC has developed asset performance efficiency and effectiveness targets. The objectives of these targets are to focus on asset performance and not get side tracked onto specific technical issues. These targets will be reviewed as time progresses. The quality of this process is considered to be continually improving and aligned to industry best practice. It is likely that load control performance targets will be introduced during the next review of the AMP.

6.3.3.3.3 Justification for target levels of service based on customer, legislature, regulatory, stakeholder and other considerations

TLC has developed targets based on performance delivered to the customer and maintained industry comparison targets for regulatory and legislation purposes. The quality of targets and justification for these targets, the quality of data, and related systems is considered to be continually improving and reflective of industry best practice.

6.3.3.4 Evaluation of Performance

6.3.3.4.1 Progress against plan; both physical and financial

The review of the 2010 plan has included an extensive review of performance criteria and systems were developed during 2010 to give improved consistent reporting on these. It is considered that this review has significantly improved the quality of the asset management and planning focus.

The difficulties encountered with the change in accounting systems have attenuated the quality of some of the financial information. Work underway will reverse this with improved financial information becoming available for future years from the new system.

6.3.3.4.2 Evaluation and comparison of actual performance against targeted performance objectives

The review of the 2010 plan included an extensive review of performance criteria and systems were developed during 2010 to give improved, consistent reporting on these. It is considered that this review has significantly improved the quality of the asset management and planning focus. The 2011 and 2012 reviews included work on the development of accurate data input and measurement of these indices.

6.3.3.4.3 Gap analysis and identification of important initiatives

This section completes this review. It is believed that this review has contributed overall quality of the asset management and planning process.

6.3.3.5 Network Development Planning

6.3.3.5.1 Planning Criteria and Assumption

The planning criteria and assumptions align with corporate objectives. These will continue to evolve as time goes on and it is believed the overall quality of these fits with TLC's asset management and planning.

6.3.3.5.2 Prioritisation Methodology adopted for development projects

TLC's prioritisation methodology is focused on doing high consequence, high risk development projects first. Many of these relate to hazard control. It is believed that the overall quality of asset management and planning that results from this meets customer, legislative, regulatory and stakeholders' expectations.

6.3.3.5.3 Demand Forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast load increases

TLC forecasting data has become more detailed in recent times. The impact of distributed generation and demand side management has been considered in more detail since the 2010/11 review.

TLC now has load flow models for the entire network set up for each year in the planning period. Initial data are also available from the effects of demand billing and the upgrades that will be required if demand side strategies are effective listed down to zone substation transformer level.

A future work stream is to:

- Review models as further effects of demand side management become available.
- Put together detailed cost benefit models outlining the financial impact of demand side management strategies.

Investments by distributed generators during 2013/14 will also see the need for the model to be extended to include power electronic type wind turbines. Refinements are also planned for improved modelling of single phase lines.

TLC believes that the quality of work it has done in this area aligns with advanced industry best practice.

6.3.3.5.4 Identification of the network development programme and actions to be taken including associated expenditure predictions

TLC has put a large investment into detailing the future development programme in Section 7. Programmes assume the savings that distributed generation and demand side management will bring about. Models and initial data are now becoming available to demonstrate the savings this is bringing about. The quality of future Plans will be improved by continually developing this research and analysis. TLC has used external parties to provide advice on these strategies.

Additional work is planned to verify the identification of development and renewal work during the coming planning period, this will also include external advice.

The details included in this section drive TLC's comprehensive pricing models. The quality of these will be continually enhanced as data improve. TLC pricing models in the medium future will be able to give accurate costs and margins of supplying customers connected to individual distribution transformers throughout the network.

6.3.3.5.5 Policies on Distributed Generation

TLC has distributed generation policies in place. These policies have been reviewed and tested by external legal and engineering organisations. Recent substantial reductions in the cost of photovoltaic cells may trigger the need for a review of standards associated with latest inverter technology. Power electronic based wind turbines may also cause the requirement to review the standard going forward. We believe the quality of present policies is consistent with legislative, regulatory and technical best industry practice.

6.3.3.5.6 Policies on non-network solutions

TLC has introduced changes that ensure non-network solutions for both customers and network development are considered throughout the asset management and planning processes. TLC and its customers have learnt a lot from the introduction of these innovative and advanced industry best practice strategies. The quality of these strategies is continually improving.

6.3.3.6 Lifecycle Asset Management Planning (Maintenance and Renewal)

6.3.3.6.1 Maintain planning criteria and assumptions

TLC has maintenance planning criteria and assumptions and believes the quality is satisfactory given the best information that is currently available. Recent staff changes have slowed the development of financial and asset data developed in this area. Further work including closer links between specific individual maintenance tasks, the SMS system, the financial system and the data systems are planned. The basic framework for many of these improvements has been set up.

6.3.3.6.2 Routine and preventative inspection and maintenance policies, programmes, and actions to be taken for each asset category; including associated expenditure projections

TLC has in place practically focused inspection and maintenance policies and programmes. These are being followed and actions being taken are in compliance with this Plan. The difficulties experienced with the accounting system have made accurate tracking of expenditure difficult in recent times; however, on-going

improvements are being made. Quality will also be further improved by building more detailed cost models of planned maintenance activities.

This initiative will improve the overall quality of the asset management and planning process associated with routine and preventative maintenance.

6.3.3.6.3 Asset Renewal and Refurbishment Policies

The asset renewal and refurbishment policies are detailed to what is considered a good level of quality. These policies will undergo a detailed review as part of future Plan preparation to ensure they continue to be relevant.

TLC has put considerable thought into these policies over the last eight years and this has aligned them with customer performance expectations. The organisational intellectual understanding of the policies is continuing to develop and improve. This is closely integrated with improving hazard control, (SMS and other systems), and development of the asset database.

6.3.3.6.4 Renewal or Refurbishment Programmes or Actions to be taken for each asset category including associated expenditure productions

TLC has put significant effort into data collection and using these in renewal and refurbishment programmes to produce high quality expenditure predictions. The review worked through each project, checked its priority and ensured it was correctly linked and described in this plan and future expenditure predictions.

The quality of the programmes will be further enhanced as they are adjusted as a result of improved asset performance information coming from the recently installed data systems. Forward expenditure predictions will also be enhanced by better quality data coming from the financial systems. Detailed cost proposal renewal programmes are available out until 2027/28. It is believed this level of planning and detail aligns with industry best practice.

6.3.3.7 Non-Network Development, Maintenance and Renewal

6.3.3.7.1 Description of Non-Network Development, Maintenance and Renewal Plans

TLC's non-network assets include the Basix asset management system, fleet vehicles, TLC's main offices, equipment associated with line inspections and information systems associated with network design and analysis.

Annual maintenance and renewal budgets for these items are included in the plan. Purchase of non-network assets are approved by the Engineering Manager or by an appointed delegate.

6.3.3.8 Risk Management

6.3.3.8.1 Methods, Details and Conclusions of Risk Policies

TLC has developed the quality of the Methods, Details and Conclusions of Risk Policies section as part of the 2010 review to improve quality. Quality will be further enhanced as better performance data become available from the new asset systems and further information becomes available from the impact of TLC's demand management strategies.

The risk section has been expanded and a number of concepts from the asset management standard PAS55 – 1:2008 included. This included a section estimating the cost of risks associated with not doing particular functions. Quality of the risk section will be further enhanced when the work discussed in the forecasting section is further advanced. For example, it is hoped the risks associated with focusing on renewal, and delaying network reinforcement through demand management strategies will be better understood. In future Plans we need to ensure that the need for renewals is not resulting in loss of focus on development and that TLC will not end up with a capacity crisis. It is believed that the development of this section ensures it aligns with best industry practice.

6.3.3.8.2 Emergency response and contingency plans

TLC believes the overall quality of the asset management and planning contingency plans is adequate. It is recognised that if resources were available further work could be done in this area. Recent staff changes have caused disruption to plans in this area.

6.3.3.9 Capability to Deliver

6.3.3.9.1 Process used by the EDB to Ensure the AMP is Realistic and Objectives in the Plan are Achievable

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.

A review of the financial performance at all levels of network operations, including income and costs on a monthly basis is undertaken. Consumer oriented performance targets are reviewed. Area's that are underperforming are analysed further, rectification for these areas are then included in the plan.

6.3.3.9.2 The Organisational Structure and Process used to Support the Implementation of the AMP

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.

6.3.3.10 Expenditure Forecasts and Reconciliation

6.3.3.10.1 Forecasts of capital and operating expenditure for the minimum ten year asset management planning period

The capital and maintenance forecasts extend out until 2028 and the models that feed into the expenditure predictions are extensive. Significant improvements were made to these systems as part of the 2012 review with the transfer of this data to the Basix system. Many of the multiple spread sheet errors have been eliminated.

Systems to reconcile the financial information to the actual activity detailed in the asset system have been further developed and enhanced.

6.3.3.10.2 Reconciliations of actual expenditure against forecasts for the most recent financial year

The process is of good quality. The data available from the accounting system for the reconciliation is of improving quality. Reconciliations are done to the best accuracy possible. Looking forward, better accounting information is becoming available as systems are developed.

6.3.3.11 Further Disclosed Information

6.3.3.11.1 All significant assumptions, clearly identified in a manner that makes their significance understandable to electricity consumers and qualified where possible

Key significant assumptions are stated and explained. Improvements to this section will come with continuous development and a better understanding of the Commerce Commission's and stakeholders' requirements for this section.

6.3.3.11.2 The basis on which significant assumptions have been prepared, including principal sources of information from which they have been derived

These have been stated. Improvements to this section will come with continuous development and a better understanding of the Commerce Commissions and stakeholder's requirements for this section.

6.3.3.11.3 The assumptions made in relation to these sources of uncertainty and the potential effects of the uncertainty on the prospective information.

These have been stated. As above, improvements to this section will come with continuous development and a better understanding of the Commerce Commission's and stakeholders' requirements for this section.

Section 7

7. Network Development Planning

7.1 Description of Planning Criteria and Assumptions

7.1.1 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 15 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 15 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 ten years, out to the years 2027/28.

7.1.2 Planning Assumptions

7.1.2.1 Performance Assumptions

- Customers will require reliability to the service level targets in Section 5.
- Customers will require service to the levels in Section 5 i.e. restoration times etc.
- Customers will require quality to levels in Section 5.
- 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.

These assumptions are compiled from customer feedback. Customers will be consulted in compliance with Commerce Commission Customised Price Path (CPP) requirements to determine the quality standards they are prepared to accept and fund.

7.1.2.2 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. (Note: For cumulative capacity projects, additional revenue must come from charges in line with Commerce Commission guidelines. In some cases rates may have to be adjusted in a regional charging density area, or for specific customers, to achieve required returns to make investment bankable.)
- 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.

7.1.2.3 Customer Load Growth Assumptions

- Customers are increasing the average household energy load, with the availably of heat pumps, spa pools and numerous electronic devices.
- 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.

7.1.2.4 Business Environment Assumptions

- Low growth in urban areas. The focus is on renewal and hazard control.
- Some development around urban centres with lifestyle blocks.
- Growth in numbers of holiday homes in the National Park, Taupo Lake surrounds and Ohakune area. (Since 2009 this development has slowed down.)
- Underground conversion in urban centres is customer funded.
- Dairy farming growth will continue but at a slower rate than during the boom years of 2008-2009.
- 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. Generally customer expansions are customer funded projects.
- Small business growth has a low growth rate. If any investment is made this will generally be customer funded and planning horizons are short.
- Continued growth of distributed generation. Some proposed hydro generation has been included in this plan and the proposals for wind farm development have been partially included. (Wind farm projects have a high level of uncertainty).

7.1.2.5 Asset Assumptions

- Assets are being run to their upper capacity limits to defer development investment as long as possible. Renewals are 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. (Two mobile units however, have been set up to provide emergency network support).
- 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.
- Development reliability improvement should be designed to give the maximum improvement to lower or potentially 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.

7.1.2.6 Data and Network Analysis Assumptions

- Develop data systems to provide accurate regulatory reporting.
- 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 load flow program to model future network requirements, harmonic and capacitor models, wind farm models 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.

7.1.2.7 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. (See discussions on distributed generation for more detail on the reasons for this.)

7.1.2.8 Equipment End of Life Assumptions

Equipment end of life disposal is considered when selecting equipment. It is assumed that issues such as SF6 disposal and other toxic substances should be considered when selecting equipment.

7.1.3 Planning Criteria

The planning criteria are focused on ensuring network performance will meet or exceed performance targets as detailed in Section 5. 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.

7.1.3.1 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.

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.

7.1.3.2 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 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.

7.1.3.3 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)

7.1.3.4 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.

7.1.3.5 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.

7.1.3.6 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)

7.1.3.7 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.

7.1.3.8 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.

7.1.3.9 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.

7.1.3.10 Planning Criteria: Quality of Supply

7.1.3.10.1 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.

7.1.3.10.2 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.

7.1.3.10.3 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. (See Section 5)

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.

The photograph in Figure 7-1 illustrates an 11 kV switch installed in a relatively polluted environment at a lime processing works. The switch is inside a shed with a dust cover designed to fit over the switch to minimise the dust contaminating the equipment. (Dust cover bunched up on top of equipment in this photo).

FIGURE 7-1: 11 KV SWITCH WITH DUSTCOVERS INSTALLED AT A LIME WORKS

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.

7.1.3.11 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 5.

7.1.3.12 Planning Criteria: Asset Replacement and Renewal

Asset replacement and renewal means the capital expenditure associated with the physical deterioration of existing Network assets. Section 8 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;

7.1.4 Description of strategies or processes that promote cost efficiency

7.1.4.1 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;

TLC has considered the use of standardised assets and designs to promote cost efficiency. Listed below are the initiatives used:

- The use of electronic sectionalisers verses the cost of refurbishing and redeploying older oil sectionalisers. Advantages of using electronic sectionalises include less man hours to install, no refurbishment costs, no oil disposal costs and little to no modification required on existing hardware.

- The use of post insulators verses double crossarms and pin insulators. Historically when spans were uneven or lines not straight TLC used a single crossarm with pin insulator; this created a problem of excessive wear and tear on the crossarms due to the pin insulator moving. TLC then implemented the use of double crossarms and pin insulators instead of a single crossarm, this has proved to be successful in alleviating the problem, however it is quite costly. TLC has now implemented the use of post insulator with a wider footprint on a single crossarm. This reduces the wear and tear on the crossarm, resulting in longer life and reducing the cost of using double crossarms.

- The use of the existing earth mat verses installing an additional earth mat when retrofitting surge arrestors onto existing transformers. Historically a new earth mat was installed when retrofitting surge arrestors to existing transformers. However given that the purpose of the surge arrestor is to protect the transformer and not to connect the surge to earth, TLC has decided to connect the arrestors to the existing earth mat. This will significantly reduce earthing cost.

- As mentioned in previous sections TLC uses CATAN software for line design. When poles require replacement, structural load calculations are completed to determine the requirements of the new pole. This process promotes cost efficiency in that it avoids over engineering and designing.

- TLC liaises with Transpower to ensure that planned works that affect the network are done in the most cost effective way available.

7.1.4.2 The use of standardised designs may lead to improved cost efficiencies. This section should discuss-

7.1.4.2.1 The categories of assets and designs that are standardised;

To decrease design time and associated “teething issues” TLC uses standardised designs. These designs cover:

- Overhead Lines,
- Distribution Transformers,
- Earthing,
- Underground Reticulation,
- Earthing Systems Specific to Single Wire Earth Return Lines and
- Substation Fencing.

7.1.4.2.2 The approach used to identify standard designs

TLC's existing design standards are reviewed annually, and are updated to include design issues and equipment concerns that have been identified during the past year. Where existing standards do not cover new requirements additional standards are created to ensure effective and efficient design.

When standards require revision or a new standard is developed, the standard is assigned to the relevant Engineer for preparation. They are then checked and authorised by the Engineering Manager for issue and application.

TLC's standards are designed to comply where applicable with current Regulations, AS/NZS standards, Codes of Practice, Guides produced by the EEA and local requirements.

7.1.5 Description of strategies or processes that promote the energy efficient operation of the network.

7.1.5.1 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network.

The energy efficient operation of the network could be promoted, for example, though network design strategies, demand side management strategies and asset purchasing strategies.

TLC has considered strategies to promote energy efficiency of the network. One of the strategies is demand side management. TLC encourages consumer to use less energy during peak demand hours, or to move the time of energy use to off-peak times such as night time and weekends. TLC has also developed an in home display unit to show consumers when the network in load controlling as well as to show consumers their energy usage and demand, the in home displays are still at a trial stage.

7.1.6 Capacity Criteria for Selecting New Equipment for Different Types of Assets or Different Parts of the Network

The capacity of components and sections of the network is considered when planning developments. Each project has to be designed on a case by case basis to verify that the capacity requirements are achieved and that TLC's design standards and AS/NZS 7000:2010 Overhead Line Design – Detail Procedure are adhered to in order to ensure asset performance, efficiency and effectiveness targets are met. (Note: TLC design standards are based on Acts, Regulations, Codes and industry best practice.)

TLC network analysis program, ETAP, is configured to represent the predicted growths as illustrated in the demand forecast tables in Section 5.4. Network models are run with the predicted loadings; this allows TLC's planners to factor future capacity requirements into their equipment selection for the growth anticipated.

For design purposes TLC considers the end of the planning period forecast capacity requirements in normal operation and contingent operation; the rating or size selected generally is one size greater than normal operation, which allows for contingent operation.

In technical terms this means:

7.1.6.1 33 kV Lines

7.1.6.1.1 Conductor

New conductor is sized taking into account the end of the planning period load and common industry sizes. Unless information exists that indicates a different approach is justified, one size up from that which will meet the end of planning period load is chosen. The conductor size is selected for both electrical load and mechanical strength. Typically, the conductors used are Ferret, Mink, Dog, and Jaguar. (Smaller conductors cannot be used in some locations because of their inability to withstand fault currents.)

Future power-flows are modelled using the network analysis program to ensure that predicted growth is catered for by the selected conductor size. (This includes any likely network layout changes).

7.1.6.1.2 Poles

Poles are selected that have the mechanical strength to withstand wind and ice loadings as detailed in codes and modified when necessary to meet local conditions. Both concrete and wooden poles are used.

Wooden poles have better dynamic loading capabilities and are lighter, allowing smaller helicopters to be used to carry them to remote sites. They do twist, however, on drying. Concrete poles do not twist and are better for static loadings but are more expensive and heavier than wooden poles.

The line design software package, "Pole-n-Wires" is used to analyse forces and loadings to ensure the correct pole and stay options are selected.

7.1.6.1.3 Insulators

Insulators rated for high pollution environments are selected. In practical terms, this means 44 kV rated insulators with long creepage distances, and of such a height that magpies have about 100 to 150 mm clearance to the conductor when standing on top of a cross arm. (This includes any likely network layout changes).

7.1.6.2 33 kV Cables

7.1.6.2.1 Conductor size

The next regularly used conductor size up from that required to meet the end of the planning period load. The conductor and screen size is selected for both load and fault current rating. Cabling generally is installed in ducting to allow future replacement and, accordingly, must be de-rated in carrying capacity.

Future power flows are modelled using the network analysis program to ensure that predicted growth is catered for by the selected conductor size. (This includes any likely network layout changes).

7.1.6.2.2 Terminations

Terminations must have high impulse withstand voltages and be of a design that minimises the risk of discharge between cores that cross each other in the termination area.

7.1.6.2.3 Surge Arrestors

All 33 kV cables must be protected by riser, or better, class of arrestor. They should be rated at 27 kV to minimise network surge levels. This criterion is required to meet network quality targets.

7.1.6.3 Zone Substations

7.1.6.3.1 Structures and Enclosures

All equipment that is not security fenced and is below 5.5 metres above ground must be insulated or bonded to earth.

All structures should be built robustly and be capable of handling fault currents and mechanical loadings.

The structure must be arranged so that modular extensions can take place and transformers can be easily swapped between sites.

7.1.6.3.2 Transformers

Transformers should be sized to provide supply to the present load and be arranged to restrict the fault current in the 11 kV network. (Experience has shown that the TLC 11 kV network cannot withstand fault levels of typically greater than 80 to 100 MVA.) Where it can be justified, transformers are sized to provide back-up for adjacent loads.

Transformers and their associated equipment must be arranged so that they can be moved from site to site.

7.1.6.3.3 Switchgear

Switchgear must be simple and able to carry the load and predicted fault currents until the end of the planning period at the least. Typically, most commonly available switchgear is rated above the loadings on the TLC network. Industry standard equipment is purchased.

Preference is given to equipment that is oil and gas free and is made of materials that can be recycled.

7.1.6.4 Distribution Lines

7.1.6.4.1 Conductor

The conductor capacity shall be the next preferred size above that currently required to carry the load and provide adequate voltage. The typical conductor sizes used are Magpie, Flounder, Ferret, Mink, Dog, and Dingo. (Fault currents often restrict the use of smaller size conductors.)

Forecast loadings on the feeders are checked using the network analysis program to ensure that predicted growth is catered for when selecting conductor size.

7.1.6.4.2 Insulators

Short creepage distance insulators have proved unsuccessful due to fertiliser pollution. Replacement with longer creepage distance 11 kV insulators is being undertaken as part of line renewal programmes or as a result of faults. The insulator chosen must be rated for high pollution levels.

On SWER systems, 22 kV insulators (13 kV to earth rating) as a minimum are being used as renewal/replacement is progressed.

7.1.6.4.3 Poles

Poles of adequate strength should be used to comply with codes and be capable of withstanding the area ice loading. A mixture of wood and concrete is used. Wooden poles are selected for their dynamic loading and weight attributes. Weight is important as it allows smaller, lower cost helicopters to be used to place poles in rugged country.

The line design software package, “Pole-n-Wires” is used to analyse forces and loadings to ensure the correct pole and stay options are selected.

7.1.6.5 Distribution Cables

Distribution cables should be sized adequately for their intended purpose e.g. subdivision strength, feeder strength, heavy feeder strength. Cables must also be suitable for carrying the available fault current and industry standard sizes should be used.

Forecast loadings on the feeders are checked using the network analysis program to ensure that predicted growth is catered for when selecting the conductor size.

Termination design should ensure that an earthed screen is under all cross points in cable termination areas.

Where possible all 11 kV cables should have a back feed option. It is recognised that this is sometimes not achievable or cannot be justified as customers are not willing to pay for it.

Arrestors should be installed on cable terminations. These should be riser class or better, and rated for 9 kV for 11 kV single phase and three phase, and 18 kV for 11 kV SWER lines. The objective of these arrestors is to stop equipment damage and control network surge levels.

7.1.6.6 Distribution Transformers

Transformer capacity is based on the preferred size to meet present needs. The use of ground-mounted transformers should be minimised due to the high maintenance costs and the on-going security risk they create. However pole mounted transformer structures for 100 kVA and 200 kVA transformers require extra strengthening and staying to withstand earthquakes. Pole mounted transformers should be protected with distribution class 9 kV surge arrestors to minimise damage and control network surge levels.

7.1.6.7 Distribution Switchgear

Distribution switchgear shall have a capacity and fault current rating suitable for the expected lifecycle. The planning policy for new subdivisions requires the use of ground mounted switchgear and oil RTE switches at alternate sites. This is to minimise costs while ensuring that cables can be easily isolated and earthed.

Reclosers should have synch check and automatic opening during under or over frequency events. (The synchronise function ensures compatibility with future distributed generation connections in the network.)

Pole mounted equipment requires distribution class surge protection to minimise damage and control network surge levels.

7.1.6.8 Low Voltage

Low voltage systems are generally rated at 2 kVA to 6 kVA (typically 5 kVA) per domestic connection. TLC policy is to avoid over-dimensioning installations so as to minimise the risks of stranded assets or excessive asset values that must be funded by customers.

Low voltage renewal work is in the plan, but only work to remedy hazardous installations or work incorporated into the 11 kV line renewals can be justified unless there is a significant customer contribution.

7.2 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 7-2 illustrates the process for prioritising risk driven needs.

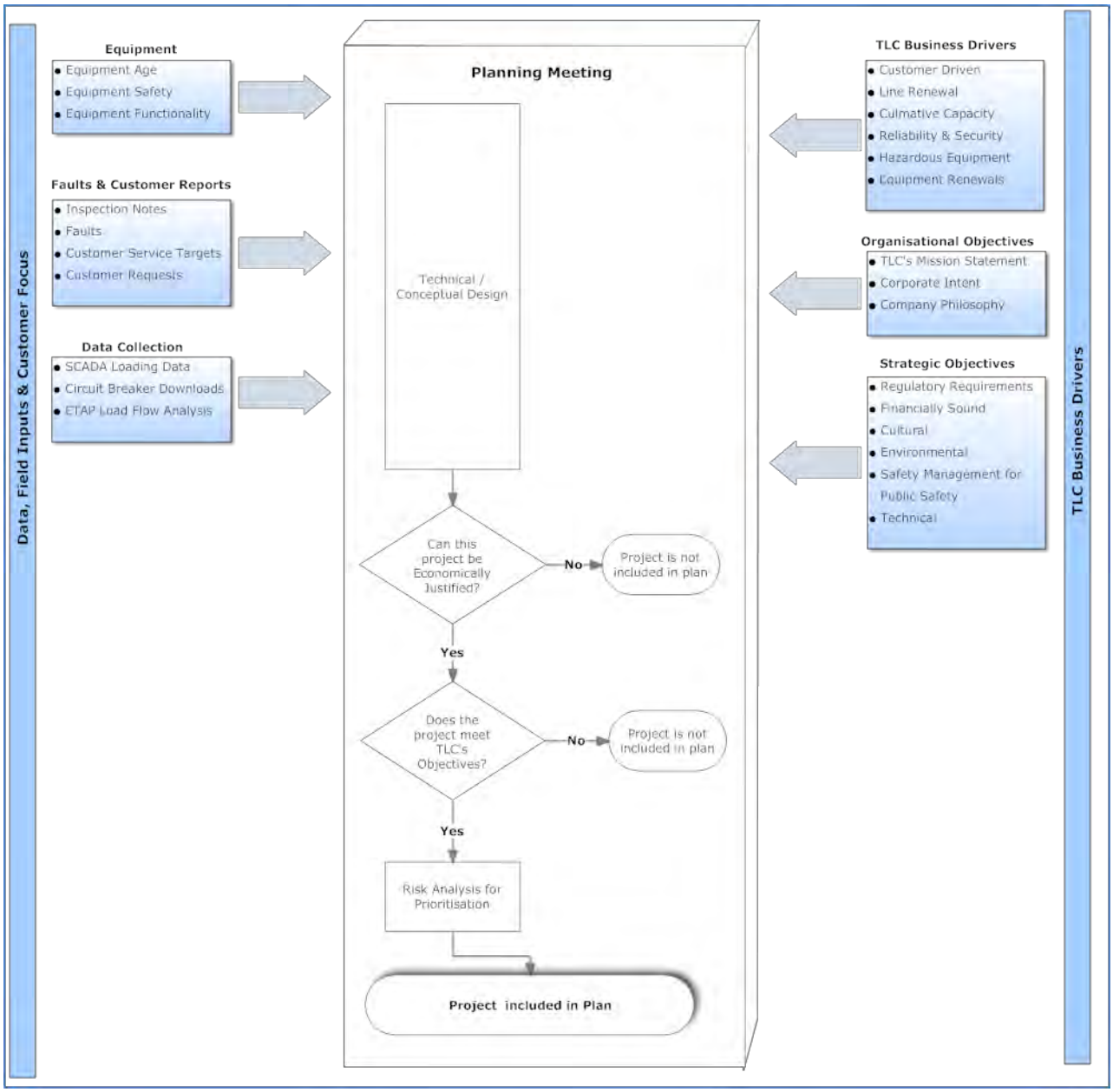


FIGURE 7-2: PLANNING METHODOLOGY

Figure 7-3 illustrates the process for prioritising risk driven needs, and Table 7-1 provides more details/guidelines on how the risk assessment across the project sets is undertaken.

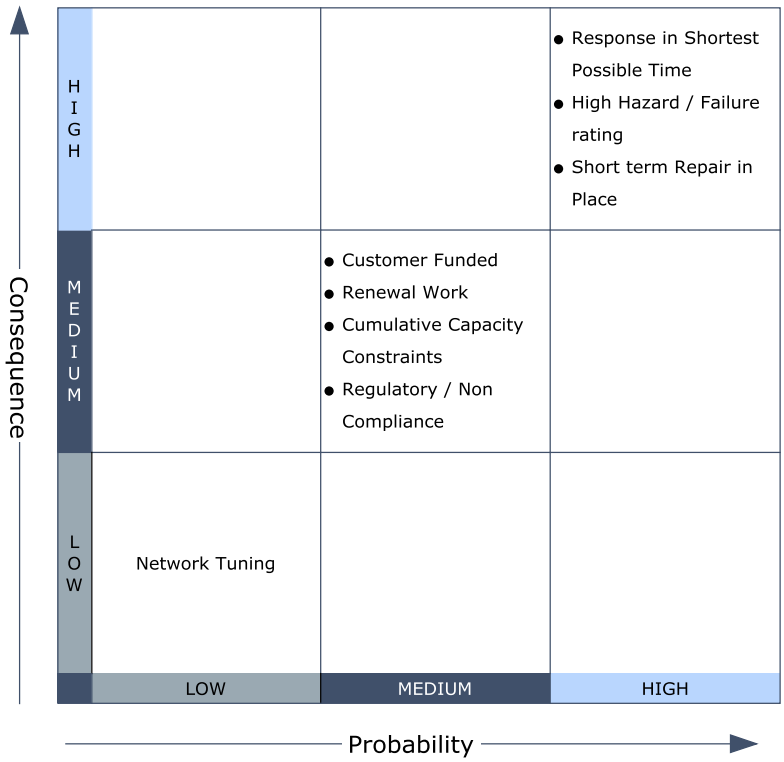


FIGURE 7-3: PRIORITISATION MATRIX FOR RISK DRIVEN NEEDS

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 15 year plan. This database also enables the network planner's easy adjustment of the time scale as required.

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 300 SAIDI minutes or 4.86 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 slips). » 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 7-1: SUBJECTIVE/OBJECTIVE ANALYSIS GUIDELINE FOR PRIORITY SETTING

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

7.2.1.1 Customer connections

The organisation will borrow to meet the cost of customer work. 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 expect service, 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.

7.2.1.2 System growth

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

These include:

- 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.

These objective data are used in growth forecasting and the resulting figures used in TLC's load flow programme to anticipate capacity constraints on the network. The data are subjectively checked and from time to time and figures have to be adjusted based on local knowledge.

The background of the subjective forward loading estimates is outlined in the forecasting section. Quality of supply is closely related to system growth and projects are prioritised in a similar manner. Projects are objectively prioritised based on data. For example, data are collected using SCADA figures, switch history data, a live line power quality meter and other instruments. These data are 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. These are considered to have the greatest risk.

There is an element of subjective analysis included in predictions and designs based on engineering knowledge of harmonic and voltage flicker implications. Specifically it is known that lightly loaded distribution SWER systems will resonate in the 400 to 700 Hz range and that industrial equipment is often affected by sudden voltage variations of greater than 10%.

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. A number of other inherited problems have been identified by load flow analysis and will have to be funded from standard revenue.

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.

7.2.1.3 Reliability, Safety (Hazard Control) and Environment

7.2.1.3.1 Reliability

The reliability improvement strategy approved in 2003 analysed and produced a list of reliability options based on costs per customer minute. These have been reviewed each year and where necessary updated.

The list forms the basis for the objective review of reliability improvement projects, and is included in Table 7-2.

Item	Cost per Customer Minute
Substation Automation	0.01 to 0.07
Down line Breaker and Switch Automation	0.04 to 0.06
Automation Associated with Grid Exit Restoration	0.04
Tree Trimming	0.08
Additional Ties Between Feeders	0.15
Low Voltage Back Feeds	0.11

TABLE 7-2: SUMMARY OF IMPROVEMENTS COST ANALYSIS

Data from previous outages, customer numbers, network architecture and asset condition are used to make both subjective and objective predictions on the reliability and economic impact projects will make.

The objective and subjective work has been used to set priority for automation reliability improvement projects through to 2027. The majority of the discretionary network development projects included in the planning period are focused on reliability improvement work. 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.

For example: Automation projects in the plan are included that target urban and rural areas. The urban projects have become necessary because the renewal programmes are moving further out into the rural areas. There will be extended periods of time when staff will not be available, i.e. they will all be working out in the remote areas. If a fault occurs in an urban area it will take some time for staff to relocate. The solution to this is to increase urban area automation.

Reliability improvement has been capped at levels that will cement the corporate objective to renew, develop and maintain a network that does not exceed the targets of 300 SAIDI minutes and 4.86 SAIFI interruptions.

7.2.1.3.2 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.)

An example of a high consequence, high probability risk SMS minimisation project would be the upgrading of energised equipment that can be accessed, without undue force or effort, by members of the public. A number of these have been addressed over the last few years; however, getting the outages needed to upgrade equipment is often dependent on parallel projects.

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 objective 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.

7.2.1.3.3 Environmental

Substation inspection data highlight pending environmental risks and concerns. The objective of priority setting includes analysing these data. An example is that the existence of bunding, oil separation and earthquake constraints is identified.

The subjective analysis is associated with the impact of the likelihood of an oil leak or a transformer falling over in an earthquake. When 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 or 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.

At this time, system losses are not a direct commercial consideration in direct network cost benefit studies. (The benefit of this flows onto the retailers, while the extra cost of more extensive upgrades cannot be recovered from customers.) It is however recognised that retailers and TLC source income from the same customers that are connected to the TLC network. The regulatory bodies are also increasingly encouraging to networks to control losses even though in TLC's case they are commercially decoupled. (The only coupling is that losses add to demand charges.) As a consequence TLC has invested in understanding the loss implications and is considering the implications in planning decisions. (See earlier sections.)

The objective analysis of losses includes the use of network data, power flow analysis and reconciliation data. The subjective element of analysis includes the estimates for missing data and the varying generation/load assumption used in power flow studies.

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 7-4 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 7-4: LINES THROUGH MIDDLE OF TREE

7.2.1.4 Asset replacement and renewal

Section 6 describes the more general renewal programme and the way the work is prioritised. The subjective element of replacement and renewal is associated with the knowledge and experience to know how long a piece of equipment can continue to give reliable service. The objective elements are things like test results, calculations, measurements, data on failures and economic analysis of the cost of renewal as opposed to continuing to maintain.

TLC tests pole and carries out other tests such as corona discharge and oil tests to maximise the objective component.

The subjective component is also made as consistent as possible by always trying to use the same staff to make calls. Various reviews also take place before and after jobs to determine how accurate any subjective calls made were. For example, old poles are checked after removal to confirm earlier inspection and test results. Renewal work aligns with the objective to meet customers' quality and reliability expectations.

7.3 Demand Forecasts

7.3.1 Introduction

To operate TLC's Network efficiently, and to ensure maximum security and network stability, TLC needs to forecast:

- Loadings on TLC's Network with sufficient accuracy and for a sufficiently long forward period to enable it to plan the development of the 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.

7.3.2 Forecasting Methodology

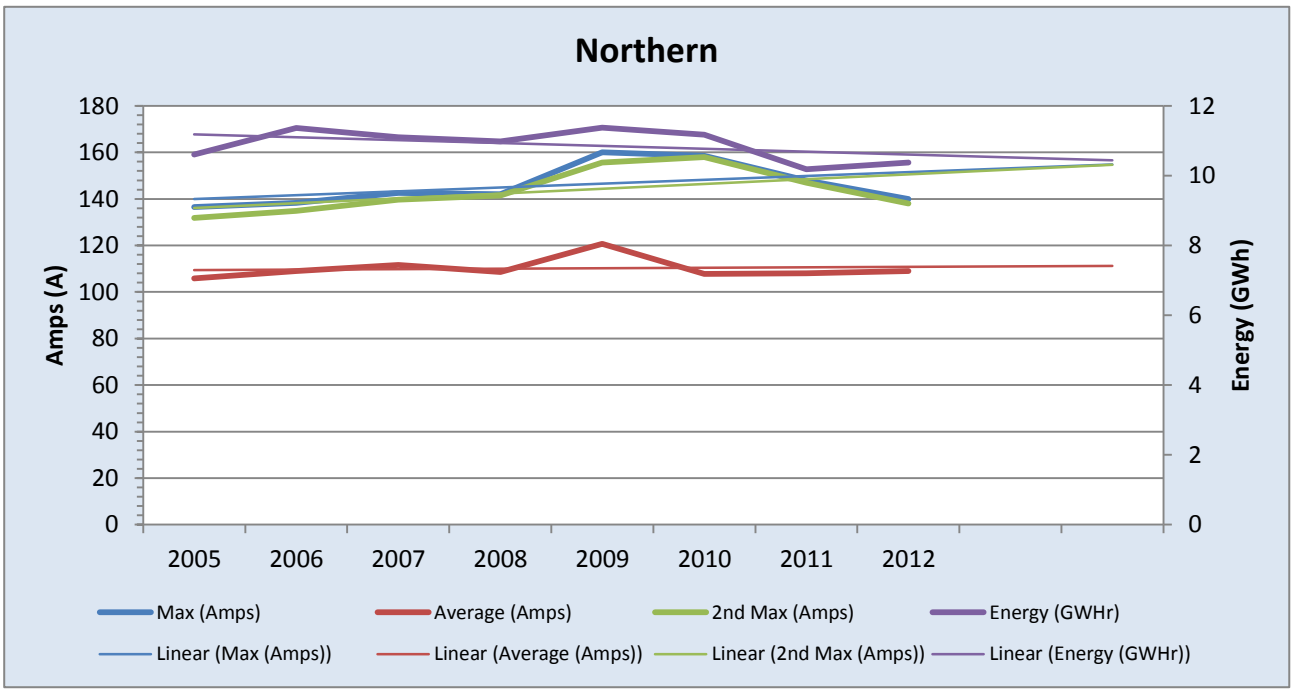
Load forecasts gives an estimate on the amount of electricity required in different parts of geographical area served by TLC.

TLC uses an internally developed spread sheet model to forecast the future energy demand on the network for the planning period of next 15 years. The spread sheet consists of historic data collected from SCADA loading figures. The data is graphed and a trend line used for the predicted growth or percentage growth per year. Adjustments are made to the percentage growth figure to allow for known system growth and feeder development projects. Adjustments are also made for spikes in the trend line that give unrealistic percentage growth factors. Table 7-3 indicates the factors considered when adjusting the percentage growth rate.

Feeder	Northern (Supplies Northern area of Taumarunui)	Gravel Scoop (Supplies South West area of Otorohanga)
GXP	**Ongarue**	**Hangatiki**
Class	Res/Rural/Lifestyle	Res/Rural/Industrial
Length (km)	130.22	109.9
Used to back-feed adjacent feeders	Yes	Yes
Installed kVA	8473.50	5369.50
Max Loading (Amps)	140	104
Approx. MVA	2.67	1.98
Trend:		
Max Increase (includes back-feeds)	2.14%	-85.57
Average Max Increase	0.92%	1.08%
Energy Increase	1.93%	0.259%
Previous year's Increase	-9.72%	3.64%
2010/11 Increase setting	0.1%	0.2%
Proposed Generation	No	No
Proposed Modular Substations	Yes	Yes
Other e.g. Pivotal industrial loads	No	No

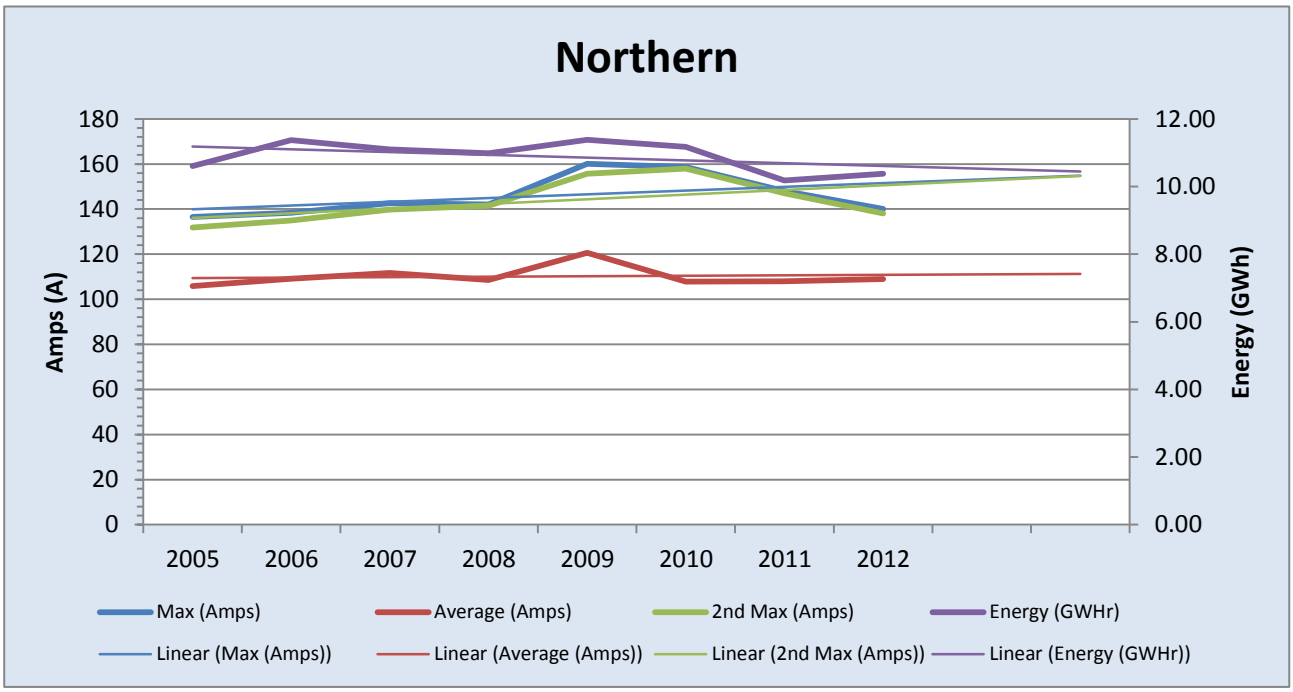
TABLE 7-3: FACTORS CONSIDERED WHEN ADJUSTING % LOAD GROWTH FOR FEEDERS

Graphs 7-1 and 7-2 illustrate a sample of data collected and the graphs used to ascertain the straight line growth trends.



GRAPH 7-1: FEEDER DATA GROWTH TRENDS - LOAD, AMPS AND ENERGY CONSUMPTION

(Gravel Scoop feeder from Te Waireka Zone Substation Otorohanga)



GRAPH 7-2: FEEDER DATA GROWTH TRENDS - LOAD, AMPS AND ENERGY CONSUMPTION

(Turangi Town Feeder)

With reference to the data shown in Graph 7-1, Gravel Scoop Feeder, which is supplied from Hangatiki grid exit point, indicates the trend is an increase in energy consumption, as well as a sharp increase in the maximum current transported at one time. This may be due to back-feeding support for adjoining feeders

during maintenance or fault conditions throughout the year. The Network Planner needs to factor this increase into the 15 year plan to ensure that back-feeding is still possible to reduce SAIDI and SAIFI minutes

Graph 7-2 indicates that the Turangi Town Feeder, that is supplied from the Tokaanu grid exit point, has a trend line indicates a large decrease in energy consumption. (The thinking is that this large decrease is due to demand billing) The trend line also shows an increase in the maximum current transport at one time.

The information is then fed into a power flow analysis program, where load forecasting is programmed up to 15 years ahead. The voltage levels, expected current levels and the effects of power factor can all be modelled and planning upgrades can be programmed accordingly. The feeder loading data is broken down into high load, average load and low load.

When using the power flow program to analyse the data, typically the high load is used when considering worst case feeder restraints situations, the average load when planning shutdown back-feeds and the low load is used when considering worst case distributed generation applications.

TLC uses GIS Arc-Map for all topographical data. Data from Statistics NZ can be overlaid into TLC's mapping data to monitor population growth trends.

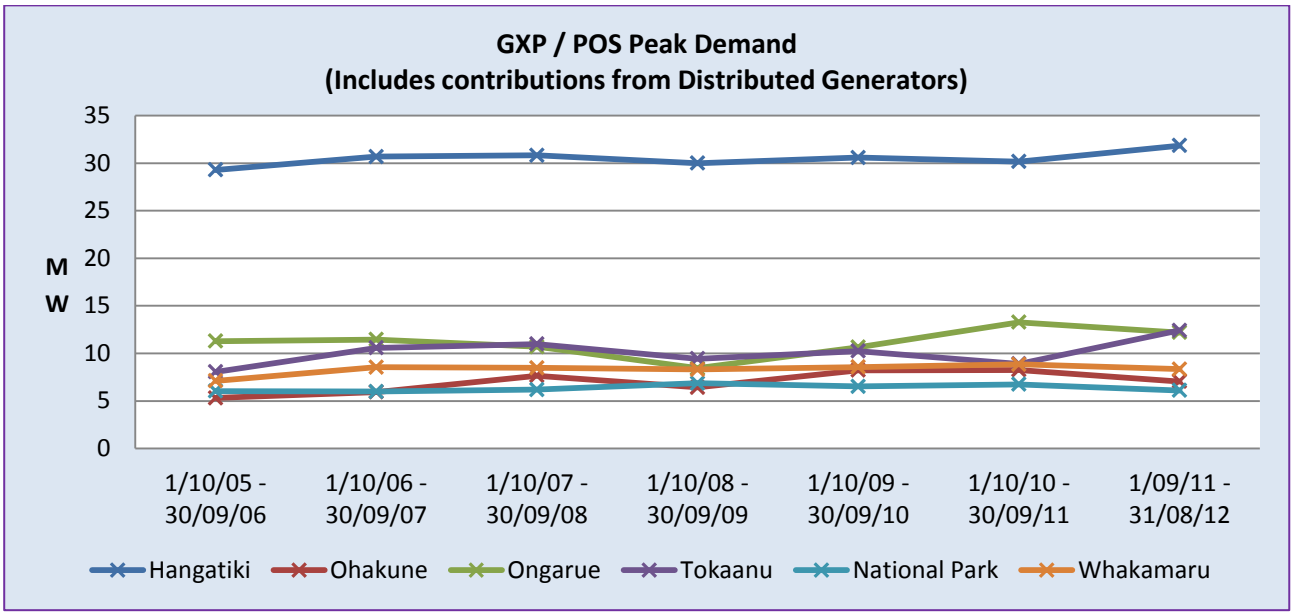
7.3.2.1 Typical factors considered when adjusting the straight line growth principle are:

7.3.2.1.1 Energy Transported and Peak Demands

Refer to Graph 7-3 "Instantaneous Peak demand trends from 2005/06 to 2010/11" and Table 7-4 "Peak Demand in MW". These figures are based on the most recent winter so are taken from October to September.

The overall base data used for load forecasts include the energy transported and peak demand figures as listed in Section 3 of this AMP plan. (These figures are based on TLC's financial year from April to March and include the winter before last). If the figures from the Tables in Section 3 are averaged over five years, the energy units transported have been increasing at 1.61 % and the system peaks at 1.84 % per annum.

Demand based billing was introduced in 2007 and, possibly as a consequence of this, the demand for the 2008/09 year actually reduced while the energy transported remained approximately constant. Demands do fluctuate from year to year and Graph 7-3 indicates the trends over the last 5 years. Table 7-4 lists the figures illustrated in Graph 7-3. The table lists the supply points with the actual and average changes over the last 7 years. These are the instantaneous peaks in MW.



GRAPH 7-3: INSTANTANEOUS PEAK DEMAND TRENDS FROM 2005/06 TO 2011/12

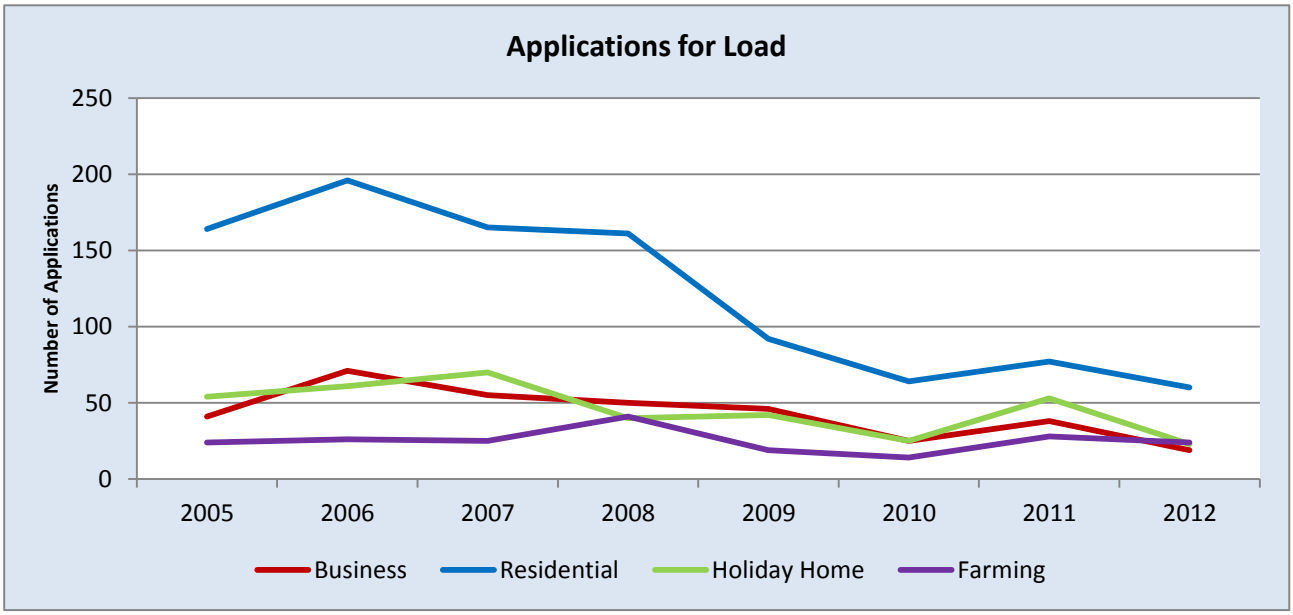
GXP/Supply Points	1/10/05 - 30/09/06	1/10/06 - 30/09/07	1/10/07 - 30/09/08	1/10/08 - 30/09/09	1/10/09 - 30/09/10	1/10/10 - 30/09/11	1/09/11 - 31/08/12	Average change
	MW	MW	MW	MW	MW	MW	MW	% p.a
Hangatiki	29.3	30.69	30.84	30	30.6	30.18	31.86	1.25
Ohakune	5.32	5.94	7.66	6.42	8.22	8.26	7.04	4.62
Ongarue	11.28	11.46	10.7	8.44	10.64	13.28	12.2	1.17
Tokaanu	8.06	10.58	10.98	9.44	10.24	8.9	12.42	7.73
National Park	6.03	5.98	6.18	6.86	6.52	6.74	6.1	0.17
Whakamaru	7.12	8.54	8.48	8.3	8.56	8.84	8.34	2.45

TABLE 7-4: PEAK DEMAND IN MW

(DEMAND FIGURES INCLUDE CONTRIBUTIONS FROM DISTRIBUTED GENERATORS)

7.3.2.1.2 Applications for Load

Graph 7-4 (Applications for Connecting Load onto TLC's Network) illustrates the trend in applications for load development. Residential housing, businesses and holiday homes have shown a great downturn over the past few years. However 2011 had an increase in the trend but declined again in the current year.



GRAPH 7-4: APPLICATIONS FOR CONNECTING LOAD ONTO TLC'S NETWORK.

Further information that gives the Planning Engineer 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.

7.3.2.1.3 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.

7.3.2.1.4 Effect of Construction of a New Zone Substation

Forward estimates have included the effects of additional modular zone substations and the resulting feeder breakup. For example: with reference to Table 7-6 in Section 7.3.3.4. "Northern Area Distribution Feeders Load Forecasts" the forecast feeder loading, in year 20-21 includes a modular substation that is proposed for Ranganui Road. This will reduce load on the Pureora Feeder. These changes are built into the modelling of the network.

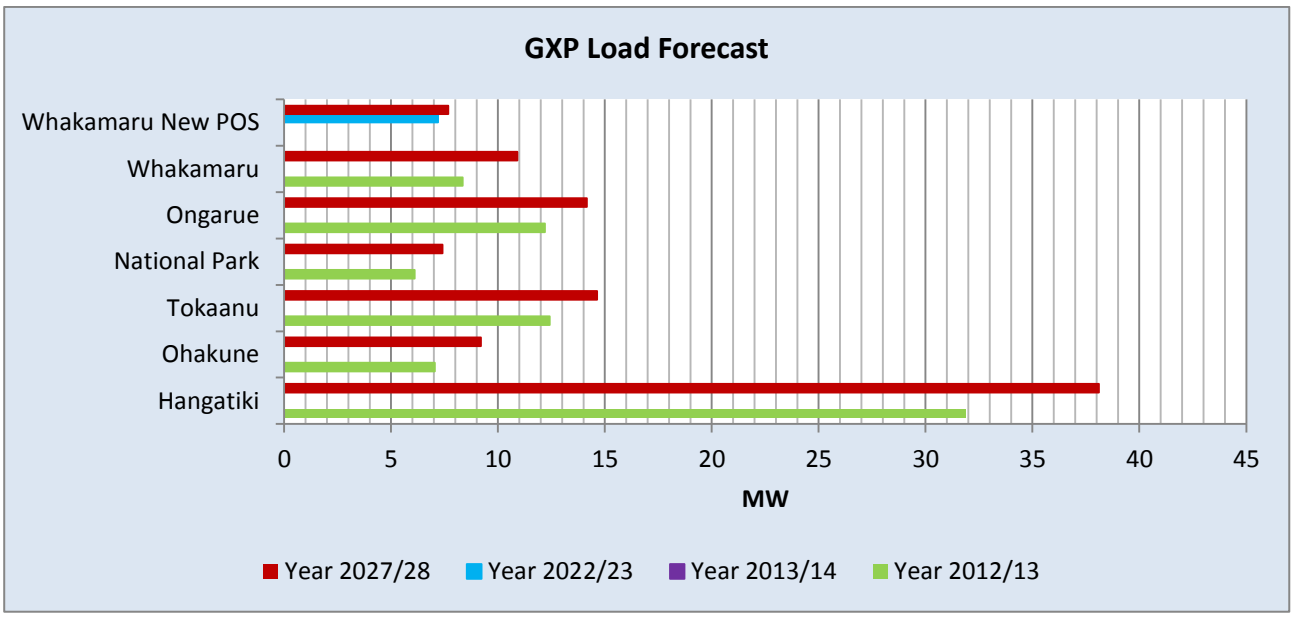
7.3.3 Load Forecasting Broken down to Feeder Level over the 15 Year Planning Period

Detailed below are the specific load forecasts down to 11 kV feeder level and the associated reasons for the forecast, based on the methodologies and data included in Section 7.3 that details how TLC prioritises projects.

7.3.3.1 Supply Area Projected Demands

Refer to Graph 7-5 "Projected Supply Point Current & 15 Year Forecasted Loads"

Graph 7-5 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 graph is in MW and shows the 2012/13 maximum load against the forecast load for years 2027/28. The figures take into account the poor power factor at grid exits due to the effects of distributed generation.



GRAPH 7-5: PROJECTED SUPPLY POINT CURRENT & 15 YEAR FORECASTED LOADS

Uncertainties associated with these projections:

- Hangatiki has seen a slump in growth over the past couple of years; the figures assume that there will be continuing development of farming and primary products processors and this trend will reverse.
- If the proposed wind farm generation goes ahead than there would be significant impact on Hangatiki GXP.
- 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. The need for a new investment contract for a supply point transformer upgrade will be able to be further delayed.
- Ohakune estimates assume no stepped changes to ski fields or holiday home developments. The grid exit transformer has reached 95% of its capacity initially but with demand billing and demand side management, load changed significantly in the current year. It is assumed that Transpower will upgrade the GXP transformer to avoid further overloading.
- During plan outages at Ohakune, Transpower is planning to provide a mobile substation. However, this is not confirmed yet.
- 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. (See network description section for details on this capacity.)
- 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 Whakamaru in year 2022/23 to accommodate increasing growth of local dairy farming and irrigation pumps along Waikato River. Furthermore, Atiamuri Zone transformer is on the verge of constraining at the end of the planning period (refer Table 7-5: Sub Transmission) and a new substation will remove this constraint.

7.3.3.2 33 kV Lines Projected Demands

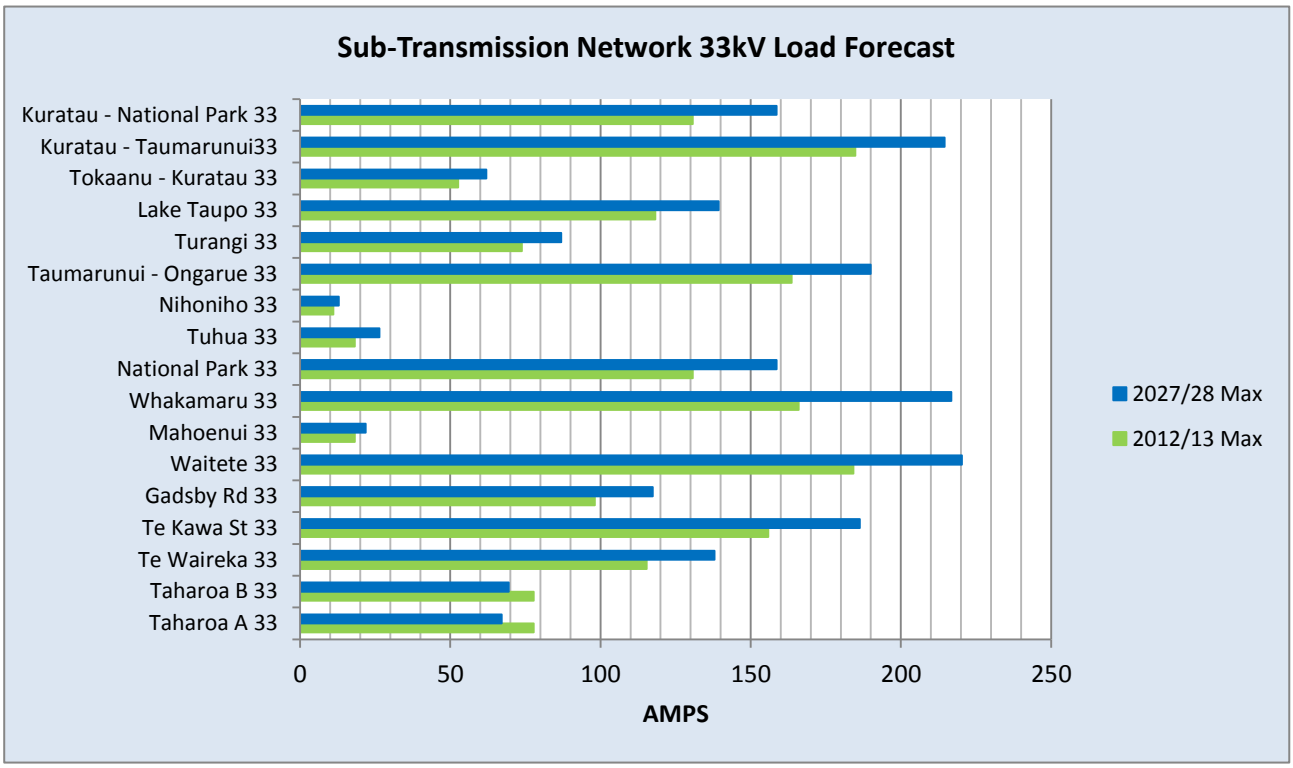
Graph 7-6 illustrates the load for 2012/13 year and the forecast loadings for the 15 year planning period for each of TLC's sub-transmission lines.

Where 33 kV data is not available; the estimates are back calculated based on 11 kV recordings. Some assumptions have to be made including:

- Lines that operate in parallel share the load evenly.
- It is assumed that distributed generation is not available. (Worst case)
- Substations connected to a particular circuit have concurrent peaks.

The currents on the Taharoa lines do not include the effects of the wind farm distributed generation effects. If these applications go ahead, the Taharoa A line will have to be converted to 110 kV.

It has been assumed the existing network configuration will be maintained in the Taumarunui and Kuratau areas and that the Kuratau generators will fund more of the cost of the Manunui to Kuratau 33 kV line. (This will make it uneconomic to take supply out of Transpower Taumarunui)



GRAPH 7-6 33 KV LINE FORECASTS

7.3.3.3 Zone Substation Projected Demands

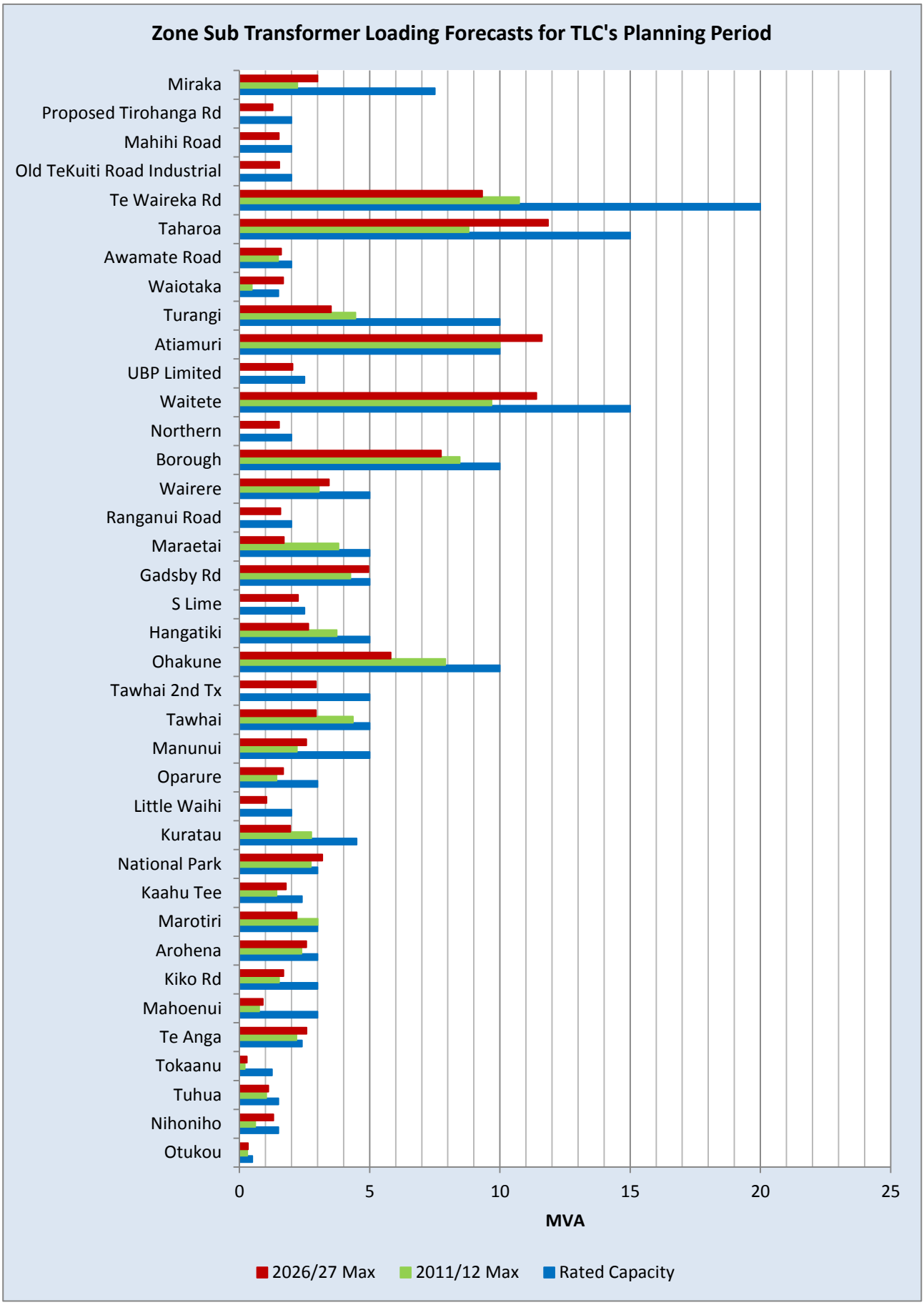
These forecasts assume the adoption of the development plan included in later sections of the plan and the upstream projects described in earlier sections taking place.

Specific assumptions include:

- Removal of Piripiri zone substation transformer sees increase in load at Te Anga zone substation. Continuous growth would cause Te Anga constraint in year 2021/22.
- Tatu mine opening in 2021, hence the increased loading at Nihoniho zone substation. If this does not eventuate there will be little impact on sub transmission assets. Due to many years of dry stock farm rationalisation there is capacity in this area.
- 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.)
- Establishment of a modular substation at Waihi to backup Kuratau and holiday home developments in 2021/22. It is expected that the Waihi distributed generation will be re-commissioned around this time. This will be needed to export Waihi generation and reduce the loading on the Kuratau transformer. If the Waihi generation is not re-commissioned (this is an abandoned site dating back to the 1920's) then it is likely that the project will still be needed due to holiday home development and increasing customer reliability expectations in the Kuratau area.
- 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.) There is a proposed hydro scheme in the area that is a small and run of the river scheme. The greatest demand is from the dairying in the area and from the meat processing plant whose peak time is through the lamb kill in the summer months. This is when the river is normally at its lowest and generation nil, therefore the zone substation will be required to boost the voltage whether or not the distribution generation project goes ahead. 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 to be built from Waitete substation to proposed substation on Ranginui Road or closer to Crusader Meats yard with a new 33kV substation.
- Lime processors in Te Kuiti/Otorohanga area opting for a modular substation in 2021/22 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.
- Continued lifestyle and residential development at the north end of Otorohanga resulting in the need for a 33 kV extension, and a substation to support the load, in the Maihiihi area. This is programmed for 2026/27 and is dependent on how quickly the lifestyle blocks are sold and built on. If this happens faster the project will need to be brought forward; if not the status quo configuration will continue. This will reduce the load supplied by Te Waireka zone substation.

- 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.
- An additional container sub is installed in the Mangarino Road area in 2021/22 to pick up industrial load creep associated with dairying and lime processing. This will reduce the load from Te Waireka zone substation. This project will not be needed if plants close or dairying load does not continue to expand. The timing is dependent on a combination of industrial and dairying 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.
- An additional container sub north of Taumarunui in 2022/22. 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. (This is being encouraged by the environmental agencies due to air pollution problems in the area.)
- Transformer replacement as proposed in the forward plan does occur.
- It is assumed that the Ohakune load will be supplemented by some additional supply out of Tangiwai.

Graph 7-7 "11 kV Zone Transformer Loading Forecasts" illustrate the zone substation transformer load of 2012/13 year against the 2027/28 year at the end of the planning cycle. Table 7-5 shows the figures used for the forecast and pink highlights are when zone transformers are forecast to overload. The green cells indicate when a development project is programmed and the anticipated changes in loading.



GRAPH 7-7: 11 KV ZONE TRANSFORMER LOADING FORECASTS

Site	Rating (MVA)	Number of Transformers (MVA)	Forecast MD's (MW) for year ending March 31														
			2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Otukou	0.5	1 x 0.5	0.31	0.31	0.31	0.31	0.31	0.31	0.32	0.32	0.32	0.32	0.32	0.32	0.33	0.33	0.33
Nihoniho	1.5	1 x 1.5	0.62	0.63	0.64	0.65	0.66	0.67	0.68	0.69	1.20	1.22	1.23	1.25	1.27	1.29	1.31
Tuhua	1.5	1 x 1.5	1.03	1.04	1.04	1.05	1.05	1.06	1.07	1.07	1.08	1.08	1.09	1.09	1.10	1.10	1.11
Tokaanu	1.25	1 x 1.25	0.21	0.22	0.22	0.23	0.23	0.24	0.24	0.25	0.25	0.26	0.26	0.27	0.27	0.28	0.28
Te Anga (Piripiri)	2.4	1 x 2.4	2.22	2.24	2.26	2.29	2.31	2.34	2.37	2.39	2.42	2.44	2.47	2.50	2.53	2.55	2.58
Mahoenui	3	1 x 3.0	0.77	0.78	0.79	0.80	0.80	0.81	0.82	0.83	0.84	0.85	0.86	0.87	0.88	0.89	0.90
Kiko Rd	3	1 x 3.0	1.53	1.55	1.56	1.57	1.58	1.59	1.60	1.61	1.62	1.63	1.65	1.66	1.67	1.68	1.69
Arohena	3	1 x 3.0	2.39	2.41	2.42	2.43	2.44	2.45	2.47	2.48	2.49	2.50	2.52	2.53	2.54	2.55	2.57
Marotiri	3	1 x 3.0	3.04	1.91	1.93	1.95	1.97	2.00	2.02	2.04	2.06	2.08	2.11	2.13	2.15	2.18	2.20
Kaahu Tee	2.4	1 x 2.4	1.45	1.47	1.49	1.52	1.54	1.56	1.59	1.61	1.63	1.66	1.68	1.71	1.73	1.76	1.79
National Park	3	1 x 3.0	2.77	2.80	2.83	2.85	2.88	2.91	2.94	2.97	3.00	3.03	3.06	3.09	3.12	3.15	3.19
Kuratau	3	1 x 3.0	2.78	2.79	2.80	2.82	2.83	2.85	2.86	2.88	2.89	2.90	1.92	1.93	1.94	1.95	1.96
Kuratau Backup	1.5	1 x1.5															
Little Waihi	2	1 x 2.0											1.00	1.01	1.02	1.03	1.04
Oparure	3	1 x 3.0	1.44	1.46	1.48	1.49	1.51	1.53	1.54	1.56	1.58	1.59	1.61	1.63	1.65	1.67	1.68
Manunui	5	1 x 5.0	2.23	2.25	2.28	2.30	2.32	2.35	2.37	2.39	2.42	2.44	2.47	2.49	2.52	2.54	2.57
Tawhai	5	1 x 5.0	4.45	4.54	4.63	4.72	4.82	4.91	2.51	2.56	2.61	2.66	2.71	2.77	2.82	2.88	2.94
	5	1 x 5.0 (2018)							2.51	2.56	2.61	2.66	2.71	2.77	2.82	2.88	2.94
Ohakune	10	1 x 10.0	8.01	4.91	4.98	5.04	5.11	5.17	5.24	5.31	5.38	5.45	5.52	5.59	5.66	5.74	5.81
Hangatiki	5	1 x 5.0	3.77	3.81	2.35	2.37	2.39	2.42	2.44	2.47	2.49	2.52	2.54	2.57	2.59	2.62	2.65
S Lime	2.5	1x 2.5			2.00	2.02	2.04	2.06	2.08	2.10	2.12	2.14	2.17	2.19	2.21	2.23	2.25
Gadsby Rd	5	1 x 5.0	4.31	4.35	4.40	4.44	4.49	4.53	4.58	4.62	4.67	4.71	4.76	4.81	4.86	4.91	4.95
Maraetai	5	1 x 5.0	3.85	3.89	2.93	2.96	2.98	3.01	3.04	3.08	1.61	1.62	1.64	1.65	1.67	1.69	1.70
Ranganui Road	2	1 x 2.0										1.50	1.51	1.53	1.54	1.56	1.58
Wairere	5	2 x 2.5	3.07	3.10	3.12	3.15	3.17	3.20	3.22	3.25	3.28	3.30	3.33	3.35	3.38	3.41	3.44
Borough	10	2 x 5.0	8.54	8.63	8.72	8.80	8.89	8.98	9.07	9.16	9.25	9.34	7.44	7.51	7.59	7.66	7.74
Northern	2	1 x 2.0												1.50	1.51	1.51	1.52
Waitete	15	3 x 5.0	9.79	9.89	10.00	10.11	10.22	10.34	10.45	10.56	10.68	10.80	10.92	11.04	11.16	11.28	11.40
UBP Limited	2.5	1 x 2.5							2.00	2.01	2.01	2.02	2.02	2.03	2.03	2.04	2.04
Atiamuri	10	1 x 10.0	10.10	10.20	10.30	10.41	10.51	10.62	10.72	10.83	10.94	11.05	11.16	11.27	11.38	11.49	11.61
Turangi	10	2 x 5.0	4.46	4.47	3.47	3.48	3.48	3.48	3.49	3.49	3.49	3.50	3.50	3.50	3.51	3.51	3.51
		One unit southern back up unit 2018 and then taken to Tawhai.															
Waiotaka	1.5	1 x 1.5	0.48	0.49	1.49	1.51	1.52	1.54	1.55	1.57	1.58	1.60	1.61	1.63	1.65	1.66	1.68
Awamate Road	2	1 x 2.0	1.49	1.50	1.51	1.52	1.52	1.53	1.54	1.55	1.55	1.56	1.57	1.58	1.59	1.59	1.60
Taharoa	15	3 x 5.0	8.98	9.16	9.34	9.53	9.72	9.91	10.11	10.31	10.52	10.73	10.94	11.16	11.39	11.61	11.85
Te Waireka Rd	20	2 x 10.0	10.87	11.01	11.14	11.27	11.41	11.54	11.68	11.82	11.96	12.11	12.25	12.40	12.55	11.20	9.32
Old TeKuiti Road Industrial	2	1 x 2.0													1.50	1.51	1.53
Mahihi Road	2	1 x 2.0														1.50	1.51
Proposed Tirohanga Rd	2	1 x 2.0		1.20	1.21	1.21	1.22	1.22	1.23	1.24	1.24	1.25	1.26	1.26	1.27	1.27	1.28
Miraka	7.5	1 x 7.5	2.27	2.32	2.37	2.41	2.46	2.51	2.56	2.61	2.66	2.72	2.77	2.83	2.88	2.94	3.00

Pink Boxes indicate an overloading on the transformers

Green Boxes Indicate a change in system conditions

TABLE 7-5: SUB-TRANSMISSION: ZONE SUBSTATION TRANSFORMER FORECAST LOADS

7.3.3.4 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.
- Establishment of an additional 11 kV feeder out of a new substation to supply Maihiihi. This assumes continuing growth north of Otorohanga. If this does not take place the status quo would remain.
- 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. This could be brought about in the area caused by a surge in the uptake of heat pumps. 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 Taumarunui railway 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.
- If expansion occurs, additional connections to the sub transmission network will be required. If not, the existing network configuration will remain.
- Continued growth in Ohakune area for current year. Few subdivisions and holiday homes transpired; however, TLC expects this to grow in coming years. Since the Ohakune transformer has reached its 95% capacity, much of the existing Tangiwai feeder will be supplied from a new POS at Transpower Tangiwai substation. This will avoid Ohakune Transformer overloading.
- Continued dairying and irrigation expansion in the Mangakino area.

Tables 7-6 “Northern Area Distribution Feeder Load Forecasts” and Table 7-7 “Southern Area Distribution Feeder Load Forecasts” show the forecast for the northern and southern areas of TLC’s Network. The green boxes indicate forecast developments that will change the feeder loadings if they go ahead.

The estimated forward loadings on distribution feeders are included in Tables 7-6 & Tables 7-7.

Northern Area Feeder Name	Feeder Number	Forecast MD's (A) for year ending March 31														
		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
McDonalds	110	167	169	172	174	176	178	181	183	185	188	190	193	195	198	200
McDonalds Lime Industrial	130	116	118	120	122	124	125	127	129	131	133	135	137	139	141	143
Gravel Scoop	109	103	104	104	104	104	104	105	105	105	105	105	106	106	18	18
Otorohanga	112	190	192	194	196	199	201	203	205	208	210	212	214	217	219	222
Maihiihi	111	236	239	243	247	250	254	258	262	266	270	274	278	282	286	203
Coast \ Te Anga	125	118	119	120	121	123	124	126	127	128	130	131	133	134	136	137
Mokauiti	115	54	54	54	54	54	54	54	54	55	55	55	55	55	55	55
Mahoenui	113	51	51	51	51	51	51	51	51	52	52	52	52	52	52	52
Piopio	116	67	68	69	70	70	71	72	73	74	74	75	76	77	78	79
Te Mapara	117	34	34	34	35	35	36	36	36	37	37	38	38	38	39	39
Aria	114	27	28	28	28	28	29	29	29	29	29	30	30	30	30	31
Benneydale	103	264	267	270	273	276	199	201	203	205	207	210	212	214	217	219
Te Kuiti Town	105	52	53	53	54	54	55	56	56	57	58	58	59	59	60	61
Te Kuiti South	104	92	93	94	95	96	97	98	99	100	102	103	104	105	106	107
Rangitoto	106	140	141	142	143	144	145	146	147	148	149	150	151	152	153	154
Hangatiki East	102	159	161	163	165	167	168	170	172	174	110	111	112	114	115	116
Caves	101	66	67	68	69	69	70	71	72	73	73	74	75	76	77	77
Oparure	107	139	141	142	144	145	147	148	150	152	153	155	157	159	160	162
Waitomo	108	136	137	139	140	142	144	145	147	148	150	152	153	155	157	158
Wharepapa	122	101	102	104	106	107	109	110	112	114	115	117	119	121	123	124
Mangakino	118	39	39	40	40	41	41	41	42	42	43	43	44	44	45	45
Huirimu	121	43	43	43	43	43	43	43	43	43	43	44	44	44	44	44
Pureora	119	120	121	123	125	127	129	131	133	26	26	27	27	28	28	28
Whakamaru	120	93	93	93	93	94	94	94	94	94	94	94	94	94	94	43
Tirohanga	129	77	78	80	81	82	83	84	86	87	88	90	91	92	94	95
Mokai	123	115	87	88	90	91	92	94	95	97	98	99	101	102	104	106
Tihoi	124	54	55	55	56	57	57	58	58	59	60	60	61	62	62	63
Rural	126	128	129	129	130	130	131	132	132	133	134	134	135	136	136	137
Mokau	128	51	52	52	53	53	54	55	55	56	56	57	58	58	59	60
Proposed Limestone industrial		0	0	0	0	0	0	0	0	0	104	105	105	106	106	107
Proposed Mangaoronga		0	0	0	0	0	0	0	0	0	0	0	0	0	0	90
Proposed Meat Processing Industrial		0	0	0	0	0	80	80	81	81	82	82	82	83	83	84
Proposed Mangaoronga Rd		0	0	0	0	0	0	0	0	0	0	0	0	90	91	93
Proposed Ranginui Road		0	0	0	0	0	0	0	0	100	102	103	105	106	108	109
Sandel Road		0	0	0	0	0	0	0	0	0	0	0	0	0	0	60
Proposed Tirohanga Rd			63	64	64	65	66	67	67	68	69	70	70	71		

Green Highlighting denotes a step change caused by a power system development

TABLE 7-6: NORTHERN AREA DISTRIBUTION FEEDER LOAD FORECASTS

Southern Area Feeder Name	Feeder Number	Forecast MD's (A) for year ending March 31														
		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Hakiaha	401	98	98	98	98	99	99	99	99	99	99	99	99	99	99	100
Northern	402	155	156	157	158	160	161	162	163	164	165	166	168	97	97	98
Western	403	69	70	71	72	73	74	75	77	78	79	80	81	83	84	85
Matapuna	404	196	199	202	205	208	211	214	217	221	224	227	231	234	238	241
Motuoapa	425	35	36	36	36	36	37	37	37	38	38	38	38	39	39	39
Oruatua	417	426	429	432	435	438	441	444	447	450	453	457	460	463	466	470
Hirangi	405	79	79	80	80	80	81	81	82	82	82	83	83	84	84	84
Turangi	423	114	114	114	115	115	115	115	115	115	115	115	115	116	116	116
Rangipo-Hautu	424	133	133	134	134	134	134	134	134	134	134	135	135	135	135	135
Waiotaka	427	26	26	26	26	27	27	27	28	28	28	29	29	29	29	30
Manunui	408	64	65	66	67	67	68	69	70	70	71	72	73	73	74	75
Southern	409	51	52	52	53	53	54	54	55	55	56	56	57	57	58	59
Ongarue	421	35	36	36	36	36	36	36	37	37	37	37	37	38	38	38
Tuhua	422	42	43	43	43	43	43	44	44	44	44	45	45	45	45	45
National Park	411	78	79	79	80	81	82	83	84	85	86	87	88	89	90	91
Raurimu	410	102	103	104	105	106	107	108	109	110	112	113	114	115	116	117
Otukou	418	16	16	16	16	16	17	17	17	17	17	17	17	17	17	17
Turoa	415	220	224	227	231	234	238	241	245	248	252	256	260	264	268	272
Tangiwai	416	99	42	43	43	44	44	45	45	46	46	47	47	48	48	49
Ohakune	414	156	123	124	126	127	129	130	131	133	134	136	137	139	140	142
Waihaha	426	41	42	42	42	42	42	43	43	43	43	44	44	44	44	44
Kuratau	406	117	118	118	119	120	120	121	121	122	75	75	75	76	76	76
Chateau	419	238	243	248	253	258	263	268	274	279	285	290	296	302	308	314
Tokaanu	420	11	12	12	12	12	13	13	13	13	14	14	14	15	15	15
Nihoniho	412	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Ohura	413	26	26	27	27	27	27	27	27	27	27	28	28	28	28	28
Proposed Okahukaru		0	0	0	0	0	0	0	0	0	0	0	0	75	76	77
Proposed Little Waihi		0	0	0	0	0	0	0	0	0	50	51	51	52	52	53
Proposed Pulp Mill		0	60	61	61	62	63	63	64	65	65	66	67	68	68	69

Green Highlighting denotes a step change caused by a power system development

TABLE 7-7: SOUTHERN AREA DISTRIBUTION FEEDER LOAD FORECASTS

7.3.4 The Impact of Uncertain but Substantial Individual Projects on Load Forecasts

7.3.4.1 Wind Farm Projects

There are two large wind farm projects for which TLC has applications to connect to the network. The impact of these two projects going ahead will mean that one of the two existing 33 kV lines to Taharoa will need to be converted to 110 kV to transport the energy produced into the national grid.

The load for the Taharoa iron sands operation will consume some of the generation produced in the area, therefore the importance on the existing lines for that particular industry will change. This will be a significant impact on Hangatiki GXP as Taharoa requires increase in capacity.

The effects of the generation have not been included in the forecasts as the purpose and configuration of the network will change considerably to accommodate the generation. The modular nature of the upgrades if the sites do go ahead at the full capacity will have minimal impact in planning decisions for the remainder of the network.

7.3.4.2 Hydro Generation

Distributed generation (as discussed later in this section) 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. (There are many future potential distributed generation sites and where and when these will be consented and developed is uncertain.)

TLC at the time of writing has five applications but these projects are still uncertain as to when they will proceed.

The Plan includes a voltage regulator for the Gadsby – Wairere 33 kV line to pull the voltage down if a distributed generator does connect. This project is dependent on that development.

The Plan also includes a modular substation for the Ranganui Road area; if the proposed distributed generation does go ahead that this may defer this development project. This decision would depend on the generator's output and seasonal variability.

7.3.4.3 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 a 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

If these industrial developments do not occur the modular substations proposed for the industrial site will be removed from the plan.

7.3.4.4 Dairy Farming & Irrigation

A large irrigation project was commissioned in 2012/13 year. The project took place in Whakamaru area. There is a possibility that there may be a ripple effect once farmers see the benefits of this project.

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.

7.3.4.5 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.

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 will have a combination of petrol/diesel and electric motors with some battery storage. Toyota is understood to be developing a version of their Prius vehicle with this technology that will only have a fully electric range of 30 km.

For the purposes of the 2013/14 plan, the effects of electric vehicle penetration on the network have not been included.

7.3.5 Equipment or Network Constraints Anticipated due to the Forecast Loadings for 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.

Table 7-8 and Table 7-9 are samples of the reports and notes that can be added for planning purposes.

ETAP REPORT			PLANNERS NOTES
Bus ID	**Nominal kV**	**Voltage (%)**	**Comments Voltage & Asset Group**
106 Bus86	11	97.96	
106 Bus87	11	97.88	
106 Bus89	11	97.13	
106 Bus848	11	99.42	
106 Bus851	11	99.18	
106 Bus852	11	98.97	
106 Bus856	11	98.86	
106 Bus860	11	97.22	
106 Esplanade	11	98.65	
210 Waitomo/ Te Kuiti Town Tie	11	97.05	
242 Oparure/Te Kuiti South Tie	11	98.19	
269 Oparure/Piopio Tie	11	96.38	
269 Piopio Oparure tie	11	93.93	Piopio regulator in 2019/20
489 Whakamaru Pureora tie	11	98.84	
505 Waitomo Hangatiki East Tie	11	98.42	
507 Spur	11	97.16	
531 Huirimu Pureora Tie	11	95.38	
Bus288	11	94.11	Wharepapa regulator 2013/14
Bus298	11	93.12	Wharepapa regulator 2013/14

TABLE 7-8: ETAP VOLTAGE CONSTRAINT REPORT & PLANNERS NOTES

Note: ETAP can be pre-set with a colour coding for voltage levels that are outside set limits and close to limits to be highlight; in this case pink for close to 95% of the rated voltage and red for over 95% of the rated voltage.

The report highlights the section of the network that is below or close to 95% of the rated voltage. Sections that indicate voltage level below 95% has voltage regulator proposed in the planning epoch.

ETAP REPORT				PLANNERS NOTE			
ID	Max Amp Flow 2012	Forecast Amps 2018/19	Forecast Amps 2027/28	Conductor	Conductor Rating	Asset Group Location	Location
Cable 282	1.46	1.46	1.46				
Cable 283	0.80	0.80	0.80				
Cable 284	180.30	184.60	191.80	1-3/C Al 95	234	404-01	Matapuna. CB6063
Cable 285	165.90	170.10	176.40	3-1/C Cu 7/083	165	404-01	Matapuna. Sw 1.3
Cable 286	158.70	162.80	168.80	3-1/C Cu 7/083	165	404-01	Matapuna. Sw B.2
Cable 287	140.70	144.30	149.70	1-3/C Cu 50	207	404-01	Matapuna. Sw 5031
Cable 288	112.80	115.70	119.90	1-3/C Cu 50	207	404-01	Before Victory bridge
Cable 289	105.70	108.40	112.40	3-1/C Cu 7/064	120	404-01	Sunshine settlement
Cable 290	105.70	108.40	112.40	3-1/C Cu 7/064	120	404-01	Sunshine settlement
Cable 291	91.39	93.74	97.21				
Cable 292	91.39	93.74	97.21				
Cable 293	59.66	61.19	63.46				
Cable 294	43.83	44.95	46.62				
Cable 295	19.23	19.72	20.46				

TABLE 7-9: SAMPLE OF ETAP REPORT FOR CURRENT CONSTRAINTS WITH PLANNERS NOTES ADDED

Note: Exporting the ETAP reports into Excel allows the planner to use conditional formatting to highlight information, in this case any cable or line carrying over 100 amps (TLC has loaded the information into ETAP to use cables for all conductors, both cable and overhead lines.).

The above sample table illustrates the currents expected through the conductors if the projected load growth occurs. Using conditional formatting in Excel the spread sheet can be used to highlight any conductor expected to carry over 100 Amps. This is then checked against the actual conductor's current rating to ensure the conductor is capable of carrying the normal and contingent loads forecast.

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.

7.3.5.1 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 (see Section 3). The 2013 and 2028 estimates for off-take from this site are approximately 30 and 43.45 MVA respectively. 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 wind farm generation comes online than this would ease the problem alternatively if the distributed generators who have applied for connection would also reduce the overloading of the transformer. This is however dependent on the generators producing output through the periods when the transformer load is high. Unfortunately, this is often during summer when there is little wind or rain to power the distributed generation schemes.

Transpower is planning to renew the two transformers at Hangatiki in years 2014/15, including a redesign.

A new ripple injection plant has been installed at Hangatiki. However, it is expected that the change out of all the relays will take about 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.

The 725 Hz signals series resonate at some industrial sites that have power factor correction and on SWER systems. In addition to the signal attenuation effect this series resonance causes, it also can interfere with electronic equipment and has done so.

Ohakune - The capacity of the shared Ohakune GXP transformer (shared with PowerCo) was reached in 2007. (Grid emergency declared.) This was the first season of the upgraded ski field and its demand side management generation was not available.
During the 2008 year the ski field snow making needs were not co-incident with the town's accommodation peak. Things were different in 2009 and 2010. During each of these years two peaks occurred that resulted in Transpower issuing loading warnings. (The grid exit transformer was at 95% capacity.) A possible solution for the ski field operators is to run their generators but they are reluctant to do this, given the difficulty of getting large quantities of fuel to sites high up on the ski field.

However, in establishing of demand management, the load for year 2011/12 went down to 75% of rated grid exit transformer.

Due to increased capacity previously, the option is to bring an additional supply out of the neighbouring Tangiwai grid exit has been included in the plan for 2013/14 year. A Tangiwai supply point will enable backup for the Ohakune site for planned and unplanned outage events. Alternatively, the Ohakune GXP transformer will be upgraded if customers fund the project.

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 continue to 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. Transpower has proposed work at National Park in the 2013/14 year. TLC has programmed work to coincide with Transpower's work to reduce the number of circuit breakers, reduce hazards, improve reliability and solve environmental issues.

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.

Whakamaru / Atiamuri - It is likely the capacity of the 10 MVA backup supply out of Atiamuri will be at its upper limit towards the end of the planning period. (Our load predictions are indicating this and it will be very dependent on the developments that take place around the Tuaropaki energy park).

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 after a relay rollout in 2015 (approximately; subject to advanced metering rollouts). In addition to historic load control, signals are essential for customer demand side management under TLC's charging structures.

TLC has included in its Plan load control for the new point of supply at Mokai to allow peak demand load controlling and demand side management initiatives.

7.3.5.2 33 kV Line Constraints

Taharoa A & B - These lines have capacity to supply the iron sands complex at Taharoa. At present, final applications have been received for the connection of more distributed generation than the capacity of the lines.
The iron sands extraction company is also proposing to expand the present operation. A consequence of their expansion will be the continued funding of the 33 kV lines and substation. If they leave before the end of the lifecycle of the generators, then the generators will have to fund the lines.

To get the capacity the generators wish to transmit back to Hangatiki, TLC will have to apportion outputs, only accept one application or upgrade the lines. The amounts of these outputs will be heavily dependent on the control systems the generators put in place. Parts of the lines currently have an age and reliability constraint. Funding to improve these will come from the connected parties. Apart from the lines, the biggest liabilities facing the generators will be costs associated with power factor correction at the Hangatiki grid exit and protection. The generators may also decide to fund the option of upgrading one line to 110 kV.

Te Waireka & Te Kawa - These two lines operate in a closed ring supplying Otorohanga. Loadings shown in the forecast are the amounts expected for each of these lines individually to supply the load. Present (n-1) security to Otorohanga with these two lines will become marginal by the end of the planning period.

Gadsby Road - The capacity of this line will not be exceeded at the end of the planning period unless there is an extreme level of distributed generation activity beyond load estimates.

Waitete - The capacity of this line will not be exceeded at the end of the planning period unless there is an extreme level of distributed generation activity beyond load estimates.

Gadsby / Waitete 33 including Wairere Tee - The capacity of this line will not be exceeded at the end of the planning period unless resource consents are granted for the Mokau generation scheme. If this occurs then regulators will be required to pull down the voltage. This has been programmed for 2024/25 but will depend on the timing of the proposed generation connection.

Mahoenui 33 - This line has sufficient capacity for the planning period.

Whakamaru 33 - This line will be reaching full capacity by the middle of the planning period. It is likely that ability to retain 11 kV voltages at zone substations fed from this line within desired limits will be lost towards end of the planning period. Plans are in progress for installing a regulator at Atiamuri and an additional regulator in 2016/17 if required. Beyond this it is likely that an additional 33 kV supply will have to be taken out of Transpower or Mokai at Whakamaru.

National Park 33 - It is not likely that this line will have reached full capacity by the end of the planning period.

Tuhua 33 - This line will not have reached full capacity by the end of the planning period.

Nihoniho 33 - This line will not have reached full capacity by the end of the planning period. If the Tatu or other coalmines in the Ohura area reopened then it is likely this line will have to be extended. The line has a reliability and hazard constraint caused by its age and inherent low strength design.

Taumarunui to Ongarue 33 - This line is currently operating at close to full capacity if generation is not available. There will be no need to alter the configuration during the planning period provided the generation continues to be available. The line has a reliability and low risk hazard constraint caused by its age and inherent low strength design.

Tokaanu / Kuratau - The capacity of this line will not be exceeded at the end of the planning period unless there is an extreme level of distributed generation activity beyond load estimates. The line has a reliability and hazard constraint caused by its age and inherent low strength design.

Kuratau / Taumarunui 33 - The capacity of this line will not be exceeded at the end of the planning period unless there is an extreme level of distributed generation activity beyond load estimates. The line has a reliability and hazard constraint caused by its age and inherent low strength design.

Kuratau / National Park - The capacity of this line will not be exceeded at the end of the planning period unless there is an extreme level of distributed generation activity beyond load estimates. The line has a reliability and hazard constraint caused by its age and inherent low strength design.

Turangi 33 - The capacity of this line will not be exceeded at the end of the planning period.

Lake Taupo 33 - This line will not have reached its full capacity by the end of the planning period. The line was originally totally constructed of a small diameter conductor that was inadequate for the fault capacity of the Tokaanu grid exit. Most of the line has been reconstructed using mink conductor; however, there is one section left still that has hazard constraints at the crossing of the Tongariro River. Work is planned to install taller poles and cover the conductors across the river to help alleviate the hazard of the bare live wires to people trout fishing.

7.3.5.3 33 kV Zone Substations and Transformer Constraints

Taharoa - Increased industrial load for iron sands extraction will mean it will be necessary to reinstall fans on the Taharoa units. Other modifications to switchgear and metering will be needed at the site to accommodate the customers' expansion requests in the planning period.

Te Waireka - The existing transformers will have adequate capacity to the end of the planning period. Present (n-1) capacity is lost during the planning period. There is a part light load back up from the 11 kV network. The site has indoor switchgear with a single 11 kV bus bar without bus sectioning. Fault currents are also too high for close-in downstream equipment.
Modifications for the site are included in the planning period estimates. Additional backup will likely come from modular substations installed at industrial installations. Increased capacity to relieve one feeder's loading in particular will come through the installation of a modular substation and a 33 kV extension during the latter half of the planning period.

Te Anga - The load on this transformer will slowly grow as the seaside settlements at Marokopa and Te Waitere develop. The summer load at the beach settlements are at a time when the connected distributed generation is at its lowest output.

Mahoenui - The existing transformer will be able to supply adequate capacity throughout the planning period. Part backup only is available if the transformer fails. Beyond this planning period, it is likely that the loading on this transformer site will reduce if the 33 kV line is extended past Mahoenui towards Mokau to supply an additional coastal development.

Oparure - The existing transformer will be able to supply adequate capacity throughout the planning period. This transformer principally supplies one large industrial customer in a quarry. If the site is expanded, the transformer will possibly need upgrading.

Hangatiki - The existing transformer will not have adequate capacity to the end of the planning period. Limited backup is available from the 11 kV network. An additional modular substation at a lime processing plant has been included in the plan to provide adequate capacity.

Gadsby Road - The capacity of the existing transformer will be adequate for the planning period.

Wairere - The existing transformers will have adequate capacity to the end of the planning period. Very light load backup is available. This site is integrated with a distributed generation connection. An (n-1) capacity is only available at light load times.

Waitete - The site has adequate transformer capacity. It has ageing single bus bar 11 kV switchgear without any bus sectioning. The switchgear is backed up with a low cost ring-main unit arrangement. To take the industrial pressure off the site, large users are being encouraged to install modular substations at their plant sites. Fault current levels are also a constraint. Light load back up is available. Modular substations at industrial sites have been included in planning estimates.

Maraetai - The capacity of the existing transformer will be exceeded in the earlier part of the planning period. This is due increase capacity at Crusader Meats and installation of irrigation pumps at Whakamaru area. It will have to be upgraded or else additional modular substations will have to be installed in the area. Light load backup is available and the area also has a growing dairying load. A modular substation closer to the major load has been included in planning estimates. This may be alleviated partly if the proposed generation into the Pureora feeder goes ahead within the planning period.

Atiamuri - The existing transformer is predicted to be up to capacity midway through the planning period. It is likely that options for backing up this transformer and its unique connections will be developed by the end of the planning period.

The exact detail for this requirement is very difficult to predict at this time given the uncertainty of development at the Tuaropaki energy park, but will likely involve taking more capacity from the internal network. If this occurs it is unlikely that the Atiamuri transformer would be upgraded as a consequence. An allowance for upgrading has not been included in estimate other than putting fans on the existing unit.

Arohena - The existing transformer will be able to supply adequate capacity throughout the planning period. Light load backup only is available to this dairying area. The site may not meet dairy customers' security expectations and will be subject to discussion with stakeholders.

Marotiri - Some of the load on this substation has been shifted to a new substation at Kaahu Road. This extends the existing transformer capacity to supply to the end of the planning period, though a significant upsurge in dairying could change this.
The Marotiri load will further be affected by load at the Miraka Milk plant. The transformer will be called on to back-up the energy park when the Mokai geothermal plant output is not available. At the time of writing further discussions are underway with Tuaropaki re the future development that will be needed in this area.

Kaahu Tee - A modular substation of 2 MVA was installed in 2009 that will carry the load until the end of the planning period.
The unit will also be used to back-up the Miraka milk plant in parallel with the Marotiri transformer when the Mokai geothermal generation is not available.

Borough - The existing transformers will have marginally adequate capacity to the end of the planning period. Very light load backup is available. Further improved reliability and backup has been provided for in the latter half of the planning period with an additional modular substation to the north of the site and to re-conductor a section of line at Manunui. This reduces capacity requirement on the transformers to the end of the planning period and improves supply to the area. It also improves an environmental constraint as Borough has the potential to flood.

Manunui - The existing transformer will be able to supply adequate capacity throughout the planning period. Light load backup is available.

Nihoniho - The event that will cause a load increase will be the re-establishment of a coalmine at Tatu. If this coalmine is not re-established the Nihoniho capacity needs will decline with no other industrial or commercial operations in the area. Load estimates include an allowance for the coalmine and, as such, the site will need upgrading during the planning period. The site has a hazard constraint caused by its enclosure design. The site also has a landowner constraint and at some stage TLC will possibly be evicted from the site. (Site is in a DOC scenic reserve.)

Tuhua - As per Nihoniho except that the demand on this site will remain close to the present. The site has a medium to low risk hazard constraint caused by its design and closeness to the neighbouring houses. (This risk has reduced as fences have been moved by the adjacent landowners in recent times.)

National Park - The existing transformer will be able to supply adequate capacity through to the end of the planning period. The switchgear configuration at this substation is not ideal and the site has a reliability and medium risk hazard constraint. (Hazard constraint associated with fence and load control plant.) Work at this site will be co-ordinated with Transpower as the site is located at the GXP.

Otukou - The load will not exceed capacity during the planning period. The site has a medium risk hazard constraint caused by its design and age.

Tawhai - The existing transformer will be fully loaded by the end of the planning period. Light load backup is available. Expansion at the ski field and mountain village area beyond 5 MVA will mean the transformer has to be upgraded or additional units have to be brought in. An additional unit has been included in planning estimates.

Kuratau - The existing 3 MVA transformer will not be able to provide adequate capacity throughout the planning period. The oil tests are indicating that there is a condition constraint with this transformer. A backup has been installed in 2009 with a capacity of 1.5 MVA. It will be necessary for this to stay in place until 2022 when it is planned to install an additional modular substation at Waihi to provide an improved supply arrangement for the area and supplement capacity.

Turangi - The existing transformers will have adequate capacity to the end of the planning period. The site has hazard and reliability constraints. Two modular substations have been commissioned during the recent planning period to provide back up to the site at all but heavy load times. It is planned to increase load on the modular substations and relocate one of the existing transformers to Tawhai during the planning period.

Kiko Road - The existing transformer will be able to supply adequate capacity throughout the planning period. No backup is available if the transformer fails other than by-passing the site and operating the 33 kV system at 11 kV. The site has a low risk hazard constraint due to the fence design. (Area was in a forest but it has been subsequently developed as a housing subdivision. The fence and site was not designed to be part of a residential development.)

7.3.5.4 Distribution Feeder Constraints

Table 7-10 to Table 7-15 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 rural spurs.	Distributed generation. Very long feeder with some large industrial and rural customers. Recent line renewal has strengthened the feeder. 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 year 2024/25.
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 2025/26.
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	Regulator installed 2011/12 year.	Rural feeder with lime works connected. High fault currents near zone substation.

HANGATIKI POINT OF SUPPLY						
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. Voltage starts to decline at Taumatamarie area. Regulators proposed for 2015/16 and 2018/19 and upgrade existing 750kVA regulator.	Significant amount of overhead line in exposed coastal environment. A number of coastal towns with proposed subdivisions on hold. 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.
Oparure	OK	3	4	2	None within this planning period.	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 2019/20.
Rangitoto	OK	4	3	2	Regulator installed in 2011/12 year.	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. Has a metering constraint.
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 7-10: 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	Regulator installed in 2012/13 year.	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 Karangahape Road to dairy farms on Kawakawa Road. Regulator on other leg of feeder.	Rural feeder with dairying, subdivision and industrial load growth. Regulator proposed in 2016/17 year.
Pureora	OK	5	3	2	Two regulators on this feeder. Load increase in year 2012/13 for Crusader Meats and irrigation pump constraints the feeder.	Long rural feeder with meat processor on end. Two regulators proposed for year 2017/18 and year 2023/24.
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 one regulator. However, continued dairy growth in the year has seen the need to program additional regulators for 2013/14 year.	Long rural feeder supplying dairy load.
Tirohanga	OK	3	3	2	None within this planning period.	Rural feeder with many trees along route.

TABLE 7-11: CONSTRAINTS ON FEEDERS SUPPLIED BY WHAKAMARU & MOKAI POS'S

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 at its upper limits.	Mostly urban feeder in Taumarunui. Small cable. Regulator is proposed for year 2026/27.
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 but will depend on Tatu mine.	Old feeder into very remote rugged country. Five separate SWER systems. Regulators are proposed if mining goes ahead.
Ongarue	5 (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 2021/22.
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 in the next 4 - 5 years.	Long rural feeder with high current SWER systems.

TABLE 7-12: 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. River crossing over popular trout stream. 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. Number of GMT enclosures upgraded in 2012/13 to eliminate hazard.
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 7-13: 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, constraints at heavy loads.	Hazard concerns include National park switchgear and 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	Three phase voltage is starting to drop away at Kaitieke just before SWER isolating transformers. SWER transformers are overloaded at peak loading times.	Feeder with three very long SWER systems into remote rugged country. These systems have high current loadings.

TABLE 7-14: 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	4	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	Three regulators installed on this feeder.	Supply to ski fields. Has old switchgear and requires more 11 kV switches for safe operation.

TABLE 7-15: 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 7-16 to 7-19 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 15 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 7-16: 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 7-17: 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 7-18.

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 7-18: RELIABILITY CONSTRAINT

Note: TLC has recently introduced better software to calculate line strengths when data come back from line inspections. Assessments are becoming more accurate as better data flow through.

Extreme Weather Constraints

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 7-19: EXTREME WEATHER CONSTRAINTS

Constraints due to extreme weather conditions rise as wind speed accelerates. 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.

7.3.6 Impact of Distributed Generation on Forecasts

7.3.6.1 The Impact of Distributed Generation on Supply Area Projected Demand Forecasts

Refer to Graph 7-8 "Projected Supply Point Injections and Loads Showing the Effect of Proposed Distributed Generation" and Table 7-20 "Existing & Projected Supply Point Injections with Demand Side Management against the Possible Impact of Distributed Generation"

The graph details the impact of existing and planned distributed generation on forecast demands at supply points. Distributed generation has the potential to save the need for supply point transformer upgrades at Hangatiki. It will however complicate the grid exit power factor compliance with connection codes at these sites.

Hangatiki "In Injections", either coming on sooner or later are dependent on the construction of Taharoa wind farms. The plan has these projects programmed for years 2013/14 and 2014/15 but these dates are based on the time it has taken developers to get to the stages they are currently at. The actual investment amounts that will be required by TLC are also unknown until designs are finalised.

If the proposed wind-farms connect to Hangatiki in years 13/14 and 14/15 with 20 MVA each year and in year 18/19 with 16 MVA, then the generation will support TLC's expected load and the remainder will be exported through Hangatiki GXP. This table includes the anticipated effect of demand side management initiatives.

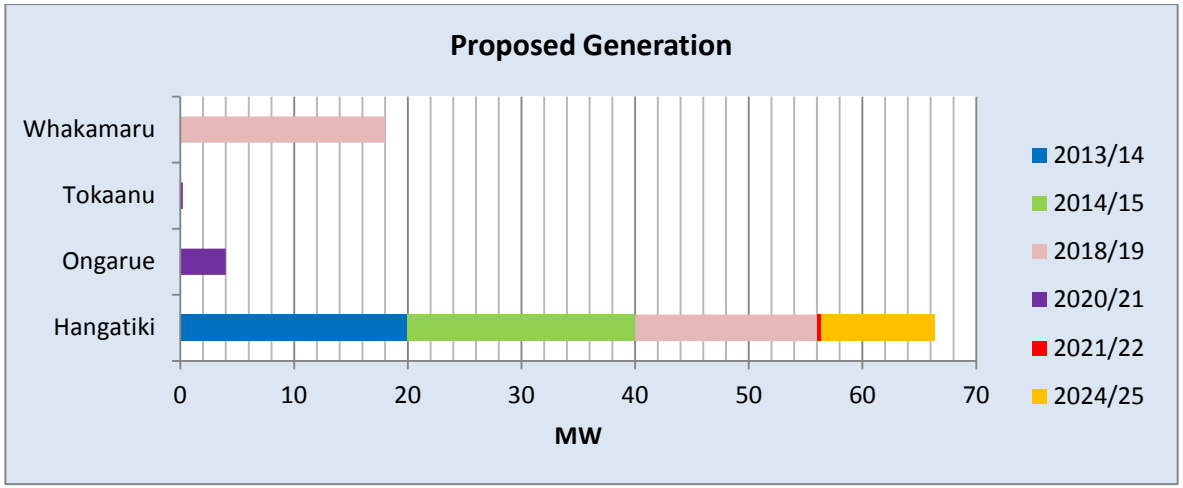
The hydro generation that is proposed for connection to Hangatiki GXP that will be transported through the Gadsby 33 kV will result in the need for regulators to pull the voltage down and the additional generation will constrain the capacity of the existing line. These are included in the plan.

The need to upgrade the transformer at Atiamuri can be delayed if distributed generation is connected on the Pureora Feeder. This will alleviate the supply constraints when supply from Whakamaru is unavailable.

The distributed generation at Kuratau and Piriaka currently allows extended Transpower maintenance outages at Ongarue. The proposed generation connected to the Ongarue GXP will support the load and the excess will be exported.

The impact of the generation on the Pureora feeder will lighten the load on the Maraetai transformer and the generated capacity will be consumed within the feeder. The generation will also assist with voltage levels when Whakamaru supply point is out of service and supply is taken from Atiamuri.

There is no proposed generation that would connect to the grid through the National Park or Ohakune GXP's in this planning period.



GRAPH 7-8: PROJECTED SUPPLY POINT INJECTIONS AND LOADS SHOWING THE EFFECT OF PROPOSED DISTRIBUTED GENERATION

		Point of Supply Off Take verses Generation (MVA)														
		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Hangatiki	Generation	20.00	40.00	40.00	40.00	40.00	56.00	56.00	56.00	56.32	56.32	56.32	66.32	66.32	66.32	66.32
	Off Take	32.24	32.63	33.02	33.42	33.82	34.22	34.63	35.05	35.47	35.90	36.33	36.76	37.20	37.65	38.10
Ohakune	Off Take	7.17	7.30	7.43	7.56	7.70	7.84	7.98	8.12	8.27	8.41	8.57	8.72	8.88	9.04	9.20
Tangiwai	Off Take	2.00	2.02	2.04	2.06	2.08	2.10	2.12	2.14	2.17	2.19	2.21	2.23	2.25	2.28	2.30
Tokaanu	Generation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
	Off Take	12.56	12.69	12.83	12.98	13.12	13.26	13.41	13.56	13.71	13.86	14.01	14.16	14.32	14.48	14.63
National Park	Generation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Off Take	6.18	6.26	6.34	6.42	6.51	6.59	6.68	6.76	6.85	6.94	7.03	7.12	7.22	7.31	7.40
Ongarue	Generation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
	Off Take	12.32	12.45	12.57	12.70	12.82	12.95	13.08	13.21	13.34	13.48	13.61	13.75	13.88	14.02	14.16
Whakamaru	Generation	0.00	0.00	0.00	0.00	0.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00
	Off Take	8.49	8.64	8.80	8.96	9.12	9.28	9.45	9.62	9.79	9.97	10.15	10.33	10.52	10.71	10.90
	Off Take										7.20	7.32	7.43	7.55	7.67	7.67
Mokai	Off Take	5.62	5.68	5.75	5.81	5.98	6.16	6.35	6.54	6.73	6.94	7.14	7.36	7.58	7.81	8.04

TABLE 7-20: EXISTING & PROJECTED SUPPLY POINT INJECTIONS WITH DEMAND SIDE MANAGEMENT AGAINST THE POSSIBLE IMPACT OF DISTRIBUTED GENERATION

7.3.6.2 The Impact of Distributed Generation on the Sub-transmission Network Forecasts

Refer to Table 7-21 "Forecast loads on sub-transmission lines"

Analysis of the network loading forecasts given the asset details, this table indicates that without the effects of distributed generation. The load has declined slightly compared to previous year and is unlikely to have any overloading and voltage issues.

The connection of wind farms at Taharoa will require the Taharoa A line to be converted to 110 kV. The distributed generation at Wairere and Mokauiti currently allows the Gadsby to Waitete 33 kV to be maintained without outages that will potentially affect large numbers of customers.

There have been several applications for consent to build further generation in this region.

33kV Estimated Loadings (Amps) based on 11kV CB SCADA																
	Feeder No	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Taharoa A 33	**301**	79	59	60	60	61	61	62	63	63	64	65	65	66	66	67
Taharoa B 33	**302**	79	61	62	62	63	63	64	65	65	66	67	67	68	69	69
Te Waireka 33	**303**	117	118	120	121	122	124	125	127	128	130	132	133	135	136	138
Te Kawa St 33	**304**	158	160	162	163	165	167	169	171	174	176	178	180	182	184	186
Gadsby Rd 33	**305**	99	101	102	103	104	105	107	108	109	111	112	113	115	116	117
Waitete 33	**306**	186	189	191	193	196	198	200	203	205	208	210	213	215	218	220
Mahoenui 33	**309**	18	19	19	19	19	20	20	20	20	21	21	21	21	22	22
Whakamaru 33	**310**	169	172	175	178	181	185	188	191	195	198	202	206	209	213	217
National Park 33	**601**	132	134	136	138	139	141	143	145	147	149	151	153	155	157	159
Tuhua 33	**602**	18	19	19	19	19	19	19	20	25	25	25	26	26	26	26
Nihoniho 33	**603**	11	11	11	12	12	12	12	12	12	12	12	13	13	13	13
Taumarunui - Ongarue 33	**604**	165	167	169	170	172	174	175	177	179	181	183	184	186	188	190
Turangi 33	**605**	75	75	76	77	78	79	80	81	81	82	83	84	85	86	87
Lake Taupo 33	**606**	120	121	122	124	125	126	128	129	131	132	133	135	136	138	139
Tokaanu - Kuratau 33	**607**	53	54	54	55	56	56	57	57	58	59	59	60	61	61	62
Kuratau - Taumarunui33	**608**	187	189	190	192	194	196	198	200	202	204	206	208	210	212	215
Kuratau - National Park 33	**609**	132	134	136	138	139	141	143	145	147	149	151	153	155	157	159

TABLE 7-21: FORECAST LOADS ON SUB-TRANSMISSION LINES

7.3.6.3 The Impact of Distributed Generation on Zone Substation Transformers Forecasts

Analysis of the loading forecasts in Table 7-5 "Sub-transmission: Zone Substation Transformer Forecast Loads" (Section 7.3.3.3) and tables in Section 3 giving asset details shows that without the effects of distributed generation there will be no significant changes to loading and voltage issues on zone substation transformers by the end of the planning period. Injection into the 11 kV beyond this period will ease the situation out into future planning periods.

Distributed generation connections will require the following zone substations to be upgraded during the planning period.

- Waihi : Additional 1.5 MVA
- Taharoa Interconnection : 40 MVA 33 kV to 110 kV transformer

These have been allowed for in forecasts. Auxiliary generation over peak periods on the ski fields has been assumed to delay the need to upgrade the Tawhai transformer as included in the Plan.

7.3.6.4 The Impact of Distributed Generation Distribution on Feeders on Forecasts

Analysis of the loading forecasts in Table 7-6 and Table 7-7 Northern and Southern Area Distribution Feeder Load Forecasts (Section 7.3.3.4) and tables in Section 3 giving asset details shows that without the effects of distributed generation there will be forecast loading issues on the following feeders:

- Benneydale – Distributed generation is currently being used to support voltage and reduce load current. If it did not exist, the 33 kV would have to be extended out of Maraetai sooner than the dates included in the plans. (Ranganui Road Modular substation would have to be established.)
- Pureora – Forecast proposed generation will support voltage.

7.3.7 Impact of Demand Management Initiatives on Forecasts

7.3.7.1 Effect of Auxiliary Generation on Peak Demand Reduction

7.3.7.1.1 The Ski Fields

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.

7.3.7.1.2 Coastal Holiday Area

Mokau, during peak holiday times, with the anticipated growth is expected to constrain the existing lines midway through the planning period. This loading is seasonal and based around the holiday times.

Mobile distributed peak generation at holiday periods have been included in forecasts to support voltage.

Without this proposed auxiliary generation, the 33 kV would have to be advanced from Mahoenui during the early part in the planning period; at this stage, the expansion is programmed for year 13. Demand side management has given an additional 6-10 years' headroom.

7.3.7.2 Effect of Load Control on Peak Demand Reduction

TLC uses a load control system to reduce loading at peak periods. The load control targets are set, as best can be achieved with existing equipment, to align with Transpower's regional peaks and network constraints.

Customers have a ripple relay that controls hot water and other assigned loaded. 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. This includes the Nihoniho transformer, which is forecast to reach full capacity near the end of the planning period and, without load shedding, this capacity would be reached earlier in the planning period. 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.

7.3.7.3 Effect of Peak Demand Billing on Peak Demand Reduction

In 2007 TLC introduced Demand Billing. 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 plans to roll out advanced meters to all customers over

time; however, the initial focus will be on areas where there is no signal and Ohakune where there are difficulties with the profiling methodologies due to the high proportion of holiday load. The roll out will be staged over time to ensure all difficulties with meters are identified and rectified.

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 loads.

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.

7.3.7.4 The Implications of Demand Side Management Initiatives

7.3.7.4.1 On Supply Points

7.3.7.4.1.1 General Discussion on Demand Side Management Effects on Substations

Refer to Table 7-22 "Forecast Grid Exit Loads Connected But Without Demand Side Management or Distributed Generation "and Graph 7-9 "Network Load Forecast with and without DSM"

Hangatiki - Forecasts as shown in Table 7-22 indicates that by the end of the planning period Hangatiki power off-take will be 46 MVA compared to an estimate of a predicted 38 MVA with demand side management; see Table 7 -20 "Existing & Projected Supply Point Injections With Demand Side Management Against The Possible Impact Of Distributed Generation".

The principal implication of this is that the load will be reaching the combined full capacity of 47 MVA sooner than if demand side management had not been put in place. (See Section 4 for further details of ratings) 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. The upgrade cost will increase typical annual customer charges by substantial amounts.

Ohakune - At present when TLC's off take of about 8.3 MVA is added to Powerco's load, the grid transformers are fully loaded. Taking supply out of Tangiwai buys time, or up to 2 MVA of load. Calculations show that if a demand growth reduction of 0.5% were achieved from next year onwards, i.e. reducing growth from 1.8% to 1.3%, an additional four years would be gained in terms of the capacity of the Ohakune transformer.

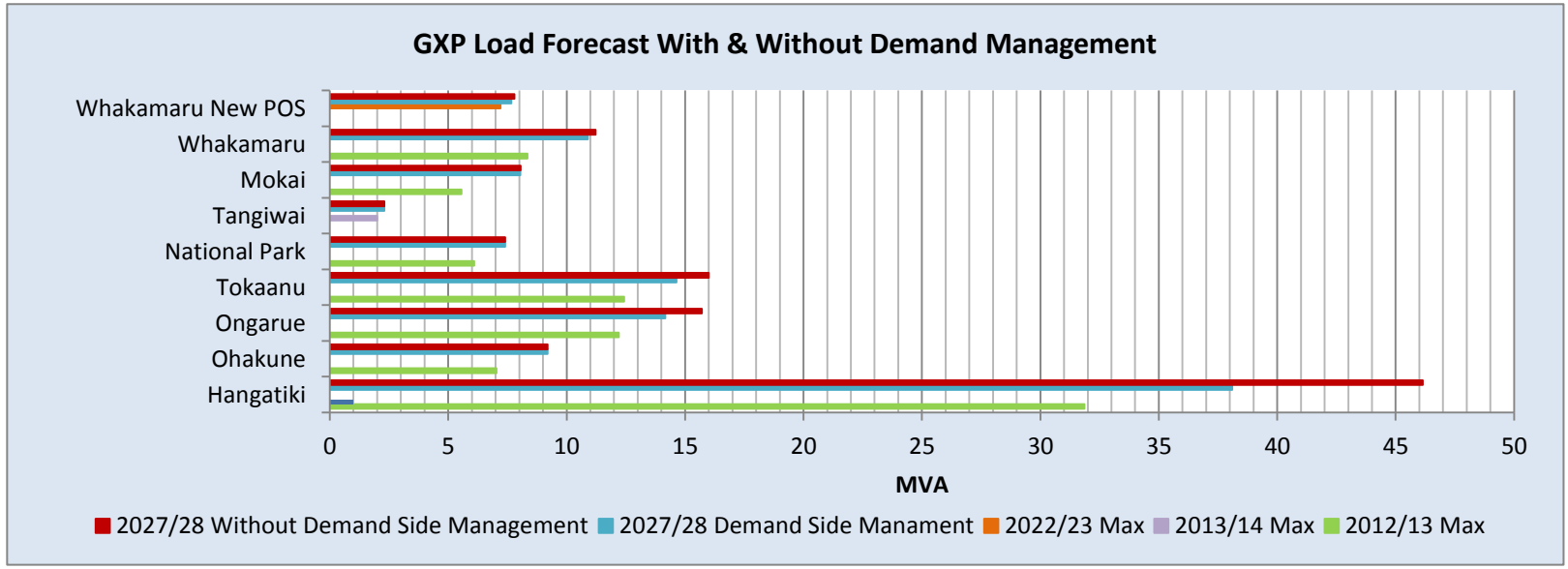
Tokaanu and Ongarue - It is predicted that if present growth in demand figures continue, then growth will be delayed by six and seven years respectively at these two sites. There are no supply point constraints on the planning horizon for either of these two sites.

National Park - Demand growth is being driven by the ski field and demand charging does not appear to have any significant effect in securing additional supply point headroom. 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. (This however has been offset by expansions on the ski field).

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 than without.

Forecast Grid Loads without Demand Side Management in MVA																
		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Hangatiki	Off Take	32.66	33.47	34.31	35.17	36.05	36.95	37.87	38.82	39.79	40.78	41.80	42.85	43.92	45.02	46.14
Ohakune	Off Take	7.17	7.30	7.43	7.56	7.70	7.84	7.98	8.12	8.27	8.41	8.57	8.72	8.88	9.04	9.20
Tangiwai	Off Take	2.00	2.02	2.04	2.06	2.08	2.10	2.12	2.14	2.17	2.19	2.21	2.23	2.25	2.28	2.30
Tokaanu	Off Take	12.63	12.85	13.06	13.29	13.51	13.74	13.98	14.21	14.45	14.70	14.95	15.20	15.46	15.73	15.99
National Park	Off Take	6.18	6.26	6.34	6.42	6.51	6.59	6.68	6.76	6.85	6.94	7.03	7.12	7.22	7.31	7.40
Ongarue	Off Take	12.41	12.62	12.83	13.05	13.27	13.50	13.73	13.96	14.20	14.44	14.69	14.94	15.19	15.45	15.71
Whakamaru	Off Take	8.51	8.68	8.85	9.03	9.21	9.39	9.58	9.77	9.97	10.17	10.37	10.58	10.79	11.00	11.22
	Off Take										7.20	7.34	7.49	7.64	7.79	7.79
Mokai	Off Take	5.62	5.68	5.75	5.81	5.87	6.06	6.25	6.45	6.66	6.87	7.09	7.32	7.56	7.80	8.05

TABLE 7-22: FORECAST GRID EXIT LOADS CONNECTED BUT WITHOUT DEMAND SIDE MANAGEMENT OR DISTRIBUTED GENERATION



GRAPH 7-9: NETWORK LOAD FORECAST WITH AND WITHOUT DSM

7.3.7.4.1.2 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:

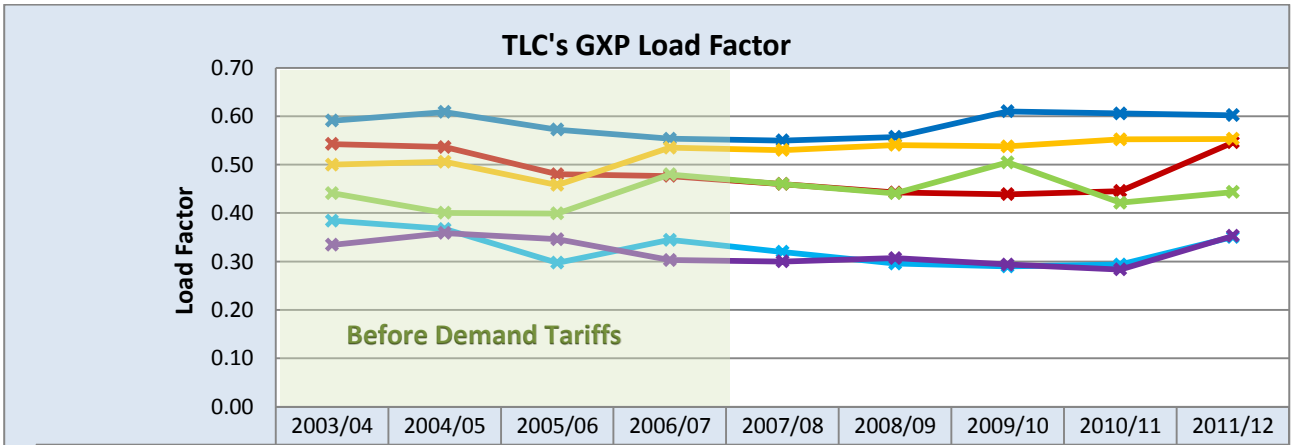
- A reduction in Transpower charges. TLC is able to reduce its loading during the nation's electricity peaks thus reducing the transmission charges imposed on it. In 2010 TLC system load was lower than in 2009 during a regional energy peak known as Regional Coincident Peak Demand (RCPD). As a result of this, TLC lowered its proportion of the nation's transmission charges.
- 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 assets 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 that were introduced in 2007.

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.

$$\text{Load Factor} = \frac{\text{Actual Energy Consumed}}{\text{Maximum Demand x Time in hours of period}}$$

See Graph 7-10 "Load Factor at each Supply Point for the TLC Network". Load Factor is on the Y axis. The figures used are from 1st October to the 30th September for every year and includes the most recent winter. (This load factor figure varies slightly from the load factor figure in Section 4, which is based on the financial year 1st April 2010 to 31st March 2011.)

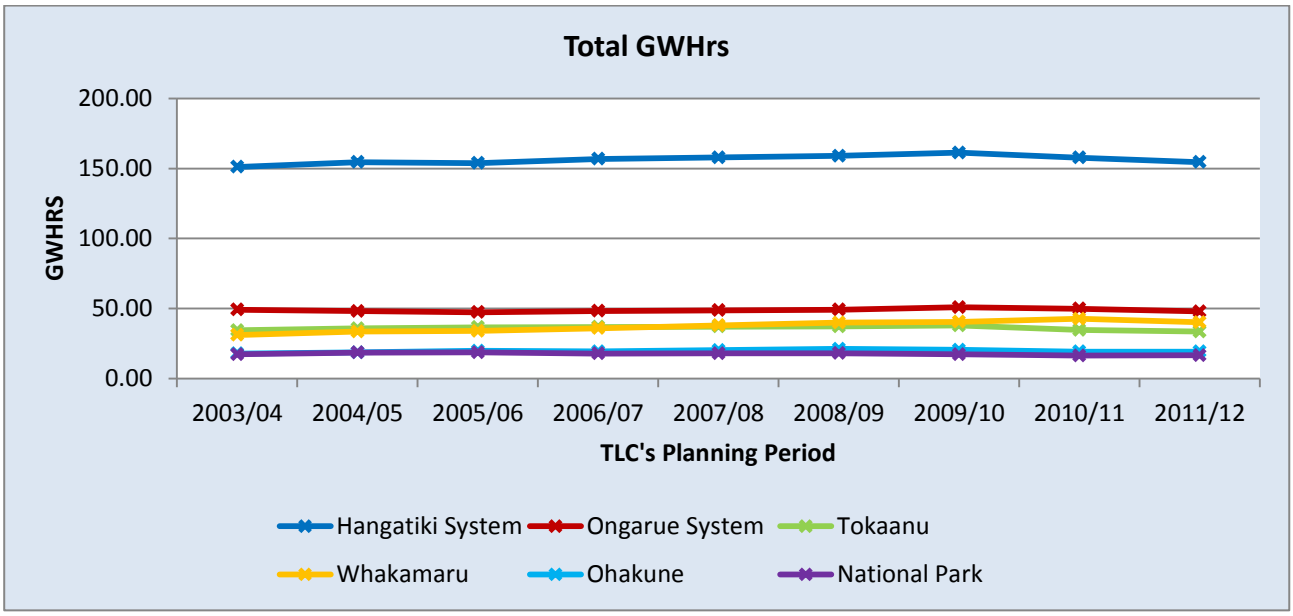


	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Hangatiki System	0.59	0.61	0.57	0.55	0.55	0.56	0.61	0.61	0.60
Ongarue System	0.54	0.54	0.48	0.48	0.46	0.44	0.44	0.45	0.55
Tokaanu	0.44	0.40	0.40	0.48	0.46	0.44	0.50	0.42	0.44
Whakamaru	0.50	0.51	0.46	0.53	0.53	0.54	0.54	0.55	0.55
Ohakune	0.38	0.37	0.30	0.34	0.32	0.30	0.29	0.29	0.35
National Park	0.33	0.36	0.35	0.30	0.30	0.31	0.29	0.28	0.35

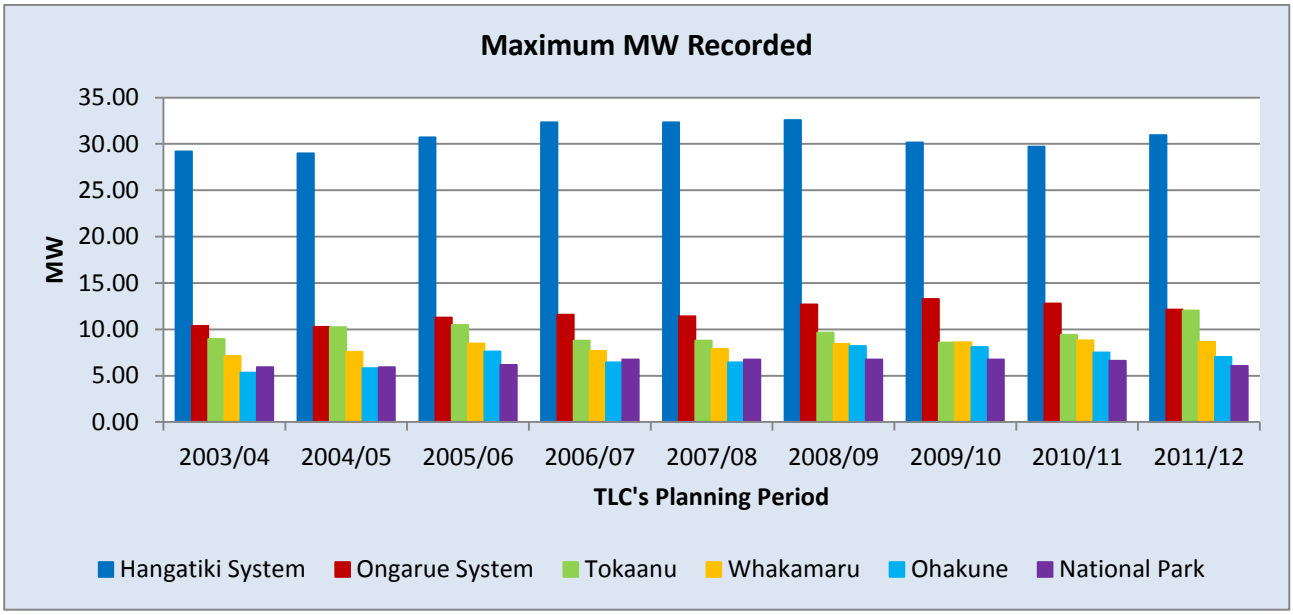
GRAPH 7-10: LOAD FACTOR AT EACH SUPPLY POINT FOR THE TLC NETWORK

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.

Assumptions from this data need to be reconciled with the energy used as in Graph 7-11 "Energy Consumed per POS" and the demand as per Graph 7-12 "Demand per POS" as there may be factors such as people converting to gas and not using energy as compared to a shift in the peak demand load.



GRAPH 7-11: ENERGY CONSUMED PER POS



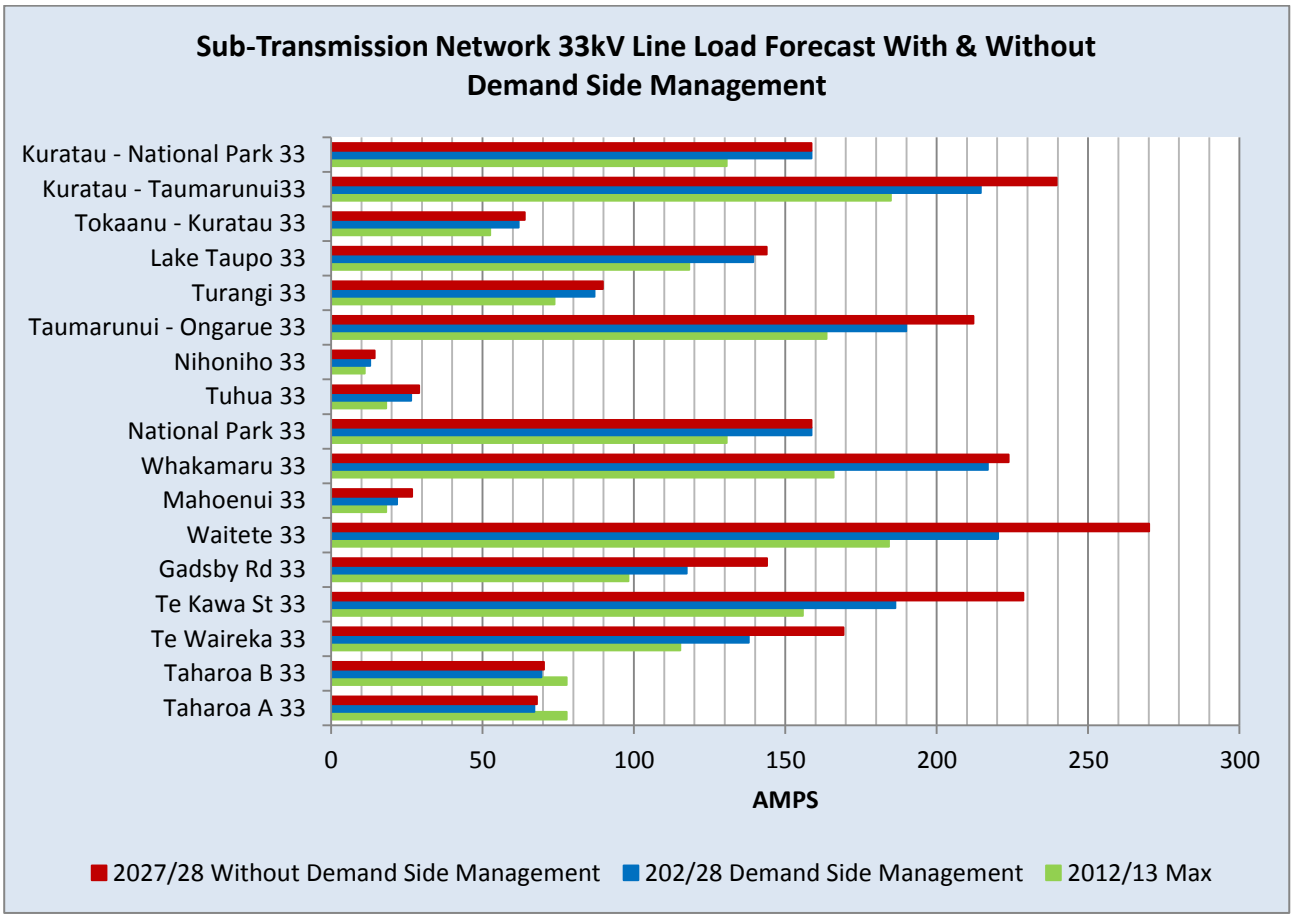
GRAPH 7-12: DEMAND PER POS

7.3.7.4.2 On 33 kV Lines

The network analysis program indicates that:

- Without demand side management, the conductor rating would exceed its rated capacity. However all the conductors as predicted are below its rated capacity for the planning period.

Refer to Graph 7-13 "Sub Transmission Network Forecast with and without DSM".



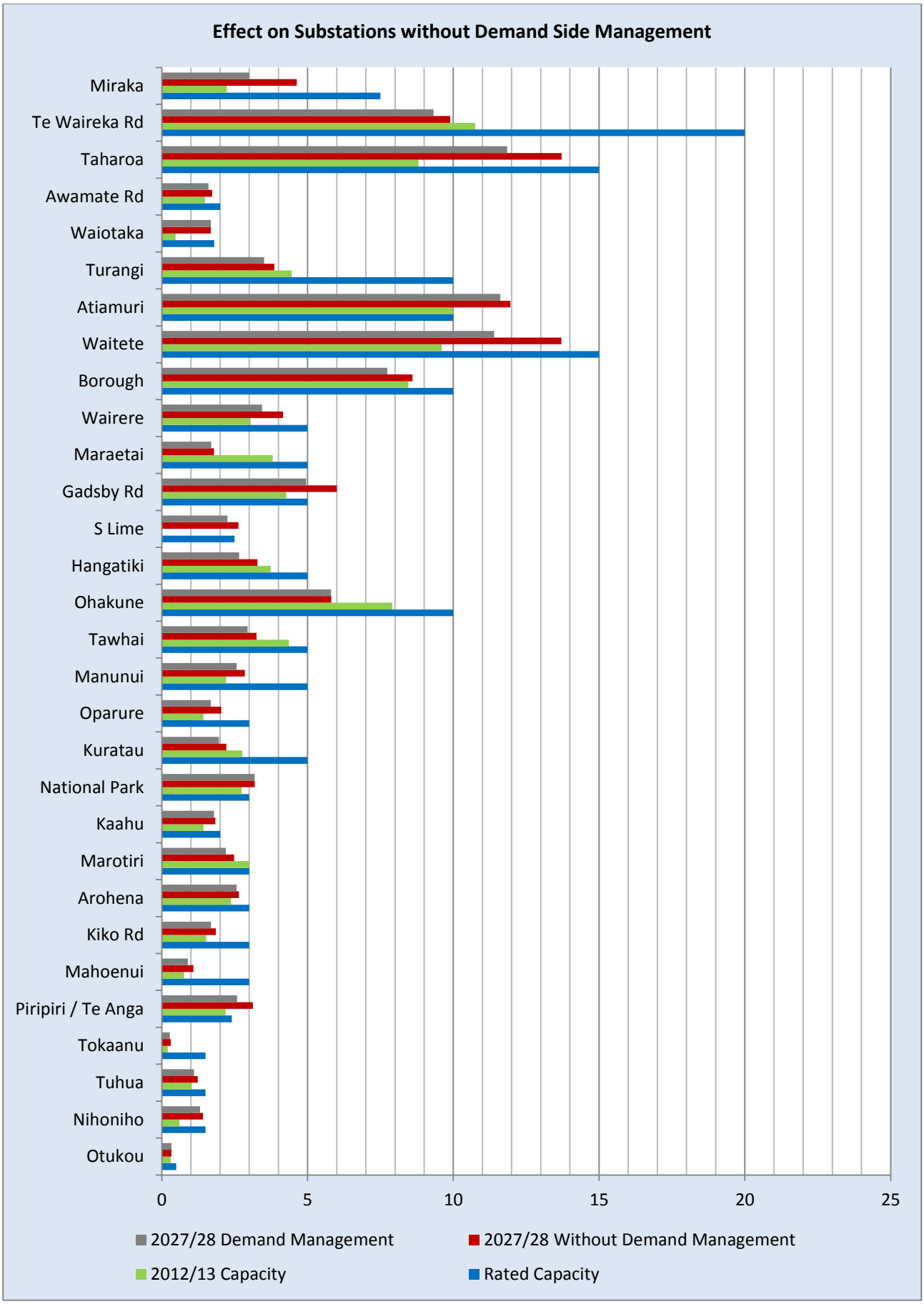
GRAPH 7-13: SUB TRANSMISSION NETWORK FORECAST WITH AND WITHOUT DSM

7.3.7.4.3 On Zone Substations

Refer to Graph 7-14 "Zone Substation Forecasts With And Without DSM".

Graph 7-14 compares the projected forecasts, with and without the effects of demand side management on the capacity of zone substations. The following assumptions can be made about the impact of demand side management initiatives:

- The Marotiri transformer has reached its full load but with demand side management capacity is still available.
- 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 2022/23 which will alleviate this constraint.
- The Tawhai transformer will be at maximum loading, but demand side management off sets the urgency of the transformer upgrade.
- Gadsby Road transformer will reach its capacity at the end of planning year. With demand side management, the predicted capacity is just under its rated capacity.
- The Borough transformer is well under the rated capacity however the installation of a modular substation to the north of Taumarunui will also affect loading.
- National Park transformer is forecast to reach full load end of the planning year.



GRAPH 7-14: ZONE SUBSTATION FORECASTS WITH AND WITHOUT DSM

7.4 Analysis of Network Development Options Available and Details of the Decisions made to satisfy and meet Target Levels of Service.

The solutions listed below are after consideration of non-asset solutions including the gains made by demand billing and distributed generation.

7.4.1 Network Development Options Available and Details of Decisions Made For Solving the Issues

Earlier sections details the constraints experienced on TLC's Network. The following tables summarise the development option decisions, cost estimates and timing of the projects selected for the next 15 year planning period. Notes:

- The highlighted row indicates the selected option.
- 11 kV Development tables only show option chosen due to the large amount of data.
- The values are at today's value without inflation.
- Voltage regulators are listed as a separate table for development work for voltage constraints Table 7-44 as are conductor upgrades Table 7-45
- Substation Asset replacements and renewals are included in this section for ease of presenting the information in one place to make it easier for project managers to understand. The renewals have been coded to the appropriate Commerce Commission code categories.
- Line Asset replacements and renewals are listed in Section 8.

7.4.1.1 The Whole Network

Table 7-23 lists the development work planned that will be advantageous to TLC's whole network by mitigating the constraints listed earlier. The table lists the options considered, the final decision made, the planning year and cost estimate.

WHOLE NETWORK (Common Mobile Assets)			
Constraint	**Option**	**Description**	**Year and Cost Estimate**
Reliability and Security	Network Option	Build a network that has n-1 security throughout.	
	Non Network Option	Semi- Mobile containerised 2.5 MVA substation.	290k in year 3
	Do Nothing	Do nothing and increase the length of customer outages or hire in generators to support the load which increases the overall cost of work.	
Reliability and Security	Network Option	Install n-1 at all substations.	
	Non Network Option	Have a mobile generator to support loads. Upgrade existing generator.	174k in year 13
	Do Nothing	Do nothing and increase the length of customer outages.	
Reliability and Security	Network Option	Construct a backup injection plant at each site.	
	Non Network Option	Have a semi mobile injection plant that can be relocated. Reuse the load control plant that is removed from National Park.	70k in year 2
	Do Nothing	Unable to control the load in times of constraint.	

TABLE 7-23: PROPOSED DEVELOPMENT WORK THAT BENEFITS THE WHOLE NETWORK

7.4.1.2 Assets Connected to Hangatiki Point of Supply

Figure 7-5 indicates the area supplied from the Hangatiki Point of supply and the Feeders' geographical location. Figure 7-6 and Figure 7-7 indicates the Supply Point's relationship to the Zone Substations and downstream Feeders.

Table 7-24 to Table 7-26 lists the development work planned for assets connected to the Hangatiki point of supply to eliminate the constraints listed earlier. The table lists the options considered, the final decision made, the planning year and cost estimate.

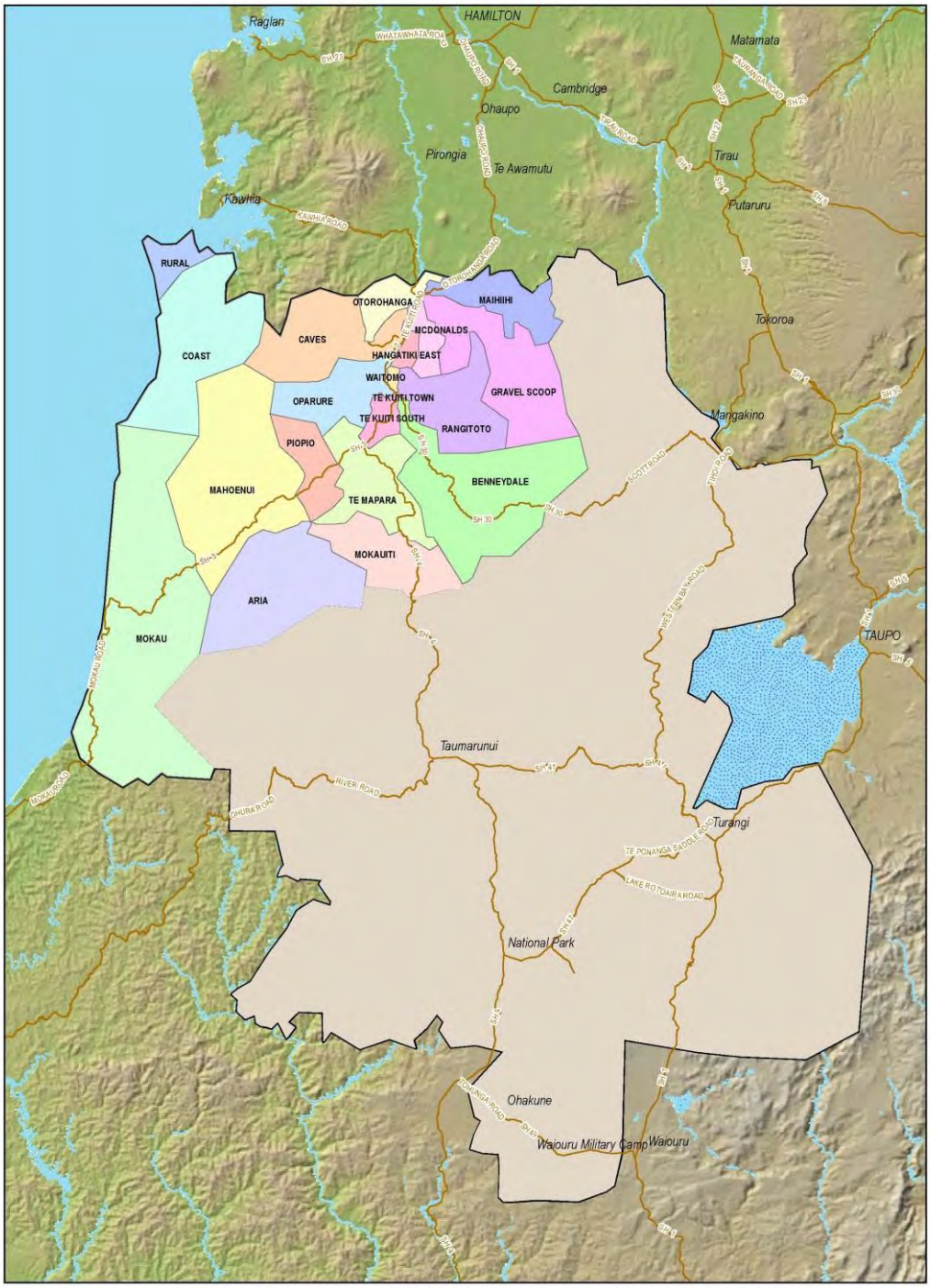


FIGURE 7-5: HANGATIKI SUPPLY AREA AND FEEDER LOCATIONS

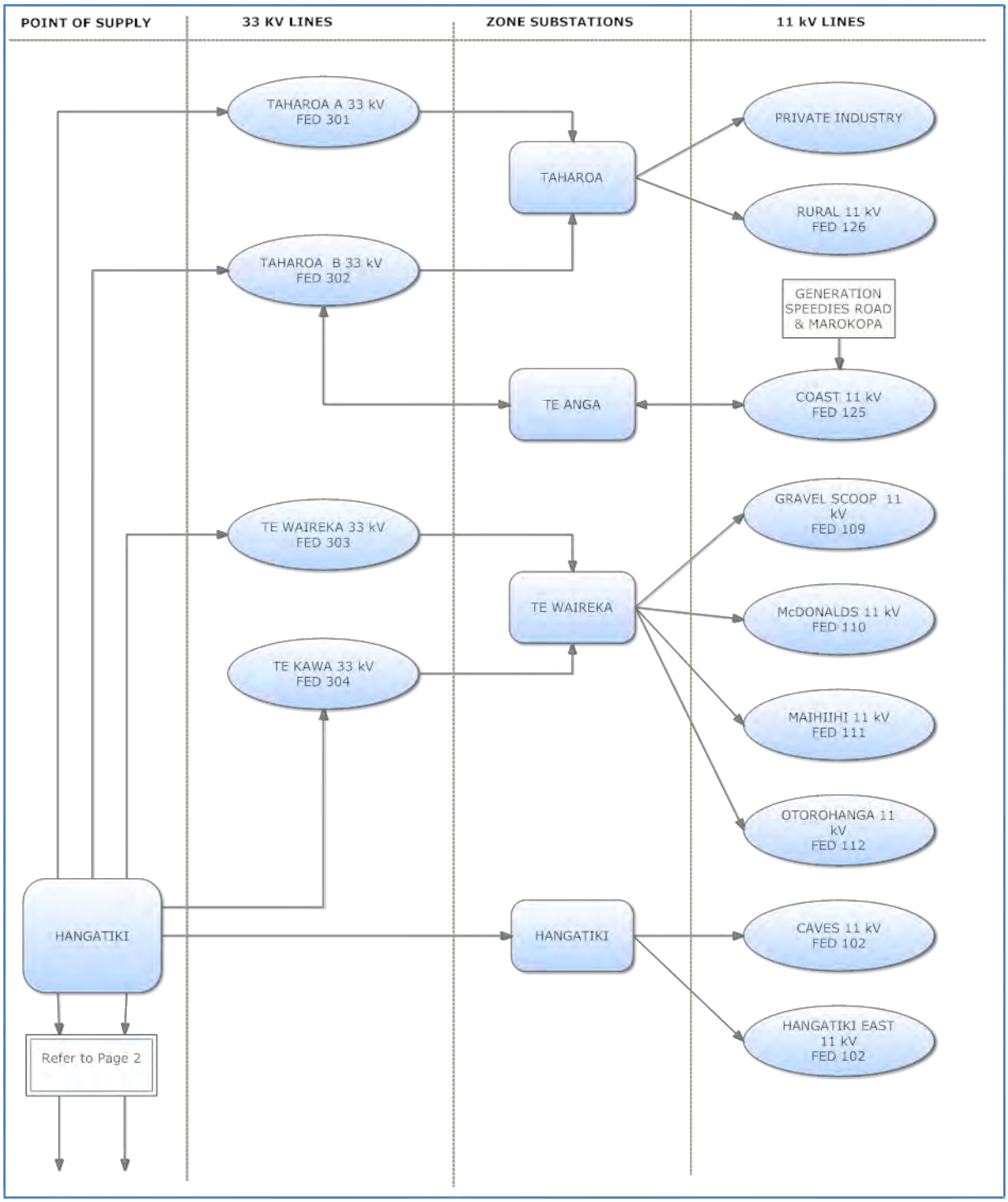


FIGURE 7-6: CONNECTION DIAGRAM OF ASSETS CONNECTED TO HANGATIKI POS (PAGE 1)

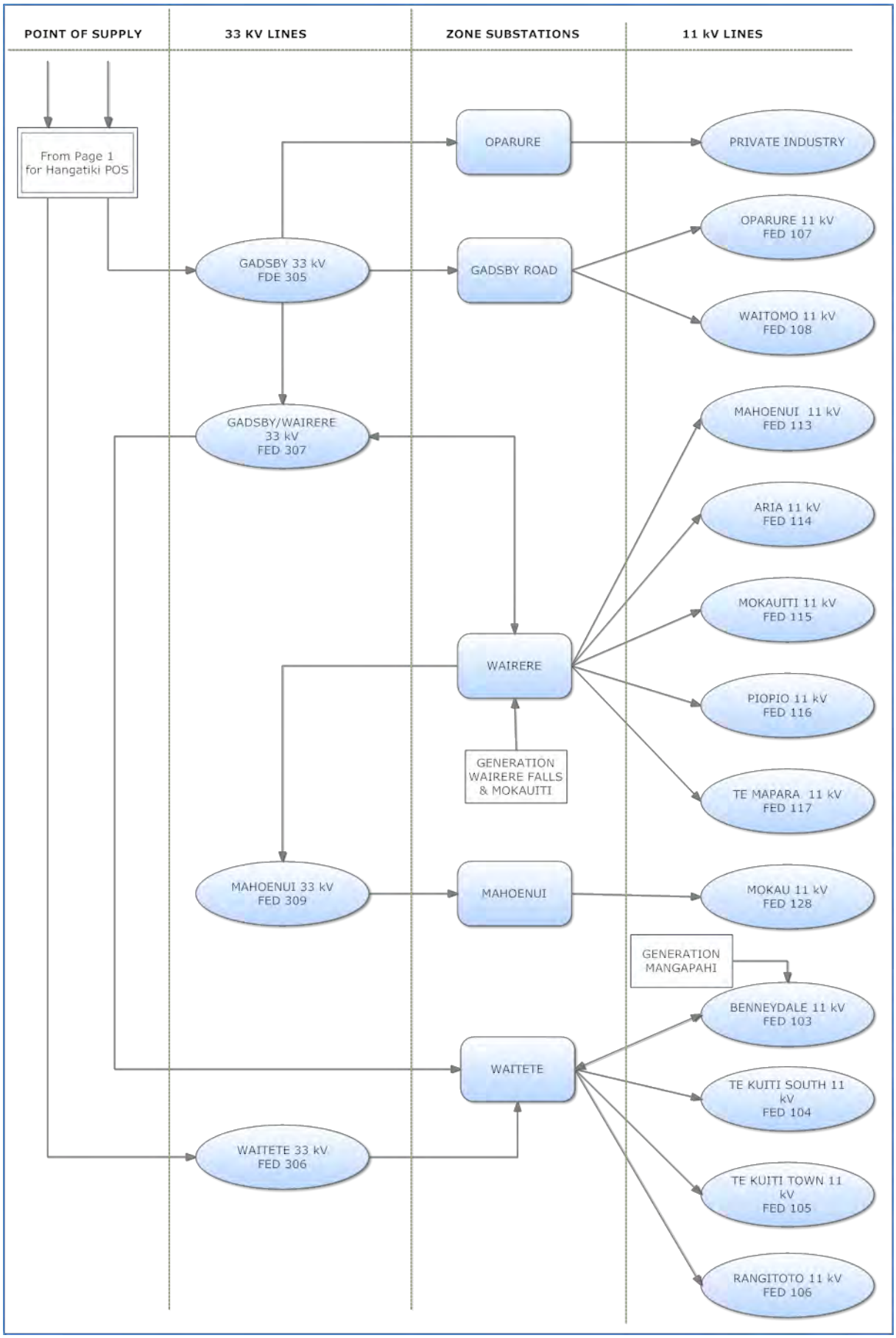


FIGURE 7-7: CONNECTION DIAGRAM OF ASSETS CONNECTED TO HANGATIKI POS (PAGE 2)

HANGATIKI POS: 33 kV LINES (excluding Line Renewals)					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
TAHAROA B	Hazardous Asset Renewals	Network Option	Renew and remove hazardous equipment. Customer has not made a decision: Coincides with confirmed upgrading of site. Cost to bring reliability to expectations of large 24/7 plant.	116k in yr3	Hazard and Reliability control of existing equipment.
		Non Network Option	Industrial customer to install generators for reliability and TLC customers would experience longer outage times. Wait for DG (distributed generation).		
		Do Nothing	Down grade reliability and only complete emergency repairs		
TAHAROA A	Customer Connection	Network Option	Upgrade line to higher transmission voltage and capacity (for distributed generation connection).	349k in yr6	Customer will require a line upgrade to a higher voltage and landowner access requirements. (This expenditure may be directly funded by the customer.)
		Non Network Option	Connect to line with reduced capacity. (Customers have selected capacity greater than the lines capacity).		
		Do Nothing	Connect to line and affect other customers. Operate assets beyond their maximum limits.		
GADSBY/WAIRERE	Customer Connection	Network Option	Allow for full output of proposed schemes. Install additional Regulators at Wairere to pull down voltage.	281k in yr12	If generator gets resource consent they will not want to restrict output.
		Non Network Option	Restrict generation injection with proposed schemes.		
		Do Nothing	If the proposed generation goes ahead then the current on these lines will be over the current capacity of the existing lines.		
WAIRERE/MAHOENUI	Cumulative Capacity	Network Option	Built out 33 kV line as load grows in Mokau area.	699k in yr13	Best long term solution
		Non Network Option	Install further capacitors and generators to hold load in busy periods i.e. the holiday season.		
		Do Nothing	11 kV voltages will be below regulation.		

TABLE 7-24: PLANNED WORK FOR 33 KV LINES CONNECTED TO HANGATIKI POS

HANGATIKI POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
TAHAROA	Customer Connection	Network Option	Upgrade to customers' requirements and specifications. Funded through on-going charges to industrial customers.	1628k in yr3 58k in yr4	To meet customer expectations.
		Non Network Option	None available.		
		Do Nothing	Industrial customers will not be able to expand.		
TE WAIREKA	Asset Renewal	Network Option 1	Replace 11kV bulk oil breakers With vacuum truck breakers.	53k in yr8	Parts for existing equipment are no longer available.
		Non Network Option	None available.		
		Do Nothing	If breaker fails there are no available parts for repairs.		
TE WAIREKA	Cumulative Capacity	Network Option 1	Build out along Rangiatea Road with 33 kV extension and install modular substation near Mangaoronga Road.	1,463k in yr14	Lowest cost solution and does not increase the already high fault levels at Te Waireka Road.
		Network Option 2	Upgrade lines from Te Waireka substation.		
		Non Network Option	Install generators or capacitors to lift the voltage. Will not achieve the required capacity.		
		Do Nothing	Restrict loading and experience possible voltage level breaches. Unacceptable to customers.		
HANGATIKI	Asset Renewal	Network Option 1	Replace 11kV bulk oil breakers With vacuum truck breakers.	53k in yr10	Parts for existing equipment are no longer available.
		Non Network Option	None available.		
		Do Nothing	If breaker fails there are no available parts for repairs.		
HANGATIKI	Environmental	Network Option 1	Rebuild site.		
		Network Option 2	Install oil separation.	17k in yr4	Only realistic option.
		Non Network Option	None available.		
		Do Nothing	Possible environmental contamination due to oil leakages.		
HANGATIKI	Customer Connection	Network Option	Install more capacity.		
		Non Network Option 1	Diversify and encourage industrials downstream to install 33/11kV modular substations on their sites. Oyma container sub. Customer funds costs through on-going charges.	408k in yr9	Cost, reliability improvements and fault current control.
		Non Network Option 2	Transfer load to another site. However this is not possible at this site.		

HANGATIKI POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
		Do Nothing	Industrial customers will not be able to expand. Customer choice.		
GADSBY ROAD	Environmental	Network Option 1	Rebuild site		
		Network Option 2	Modify existing site by installing better earthquake restraints.	35k in yr10	Only realistic option.
		Non Network Option	None available.		
		Do Nothing	Possible environmental contamination due to oil leakages during an earthquake.		
WAITETE	Asset Renewal	Network Option 1	Replace 11kV bulk oil breakers With vacuum truck breakers.	53k in yr6	Parts for existing equipment are no longer available.
		Non Network Option	None available.		
		Do Nothing	If breaker fails there are no available parts for repairs.		
WAITETE	Customer Connection	Network Option	Install another transformer at Waitete.		
		Non Network Option	Install modular substation at industrial sites, Funded through on-going charges to industrial customers.	408k in yr5	More modular and cost is Customer focused.
		Do Nothing	Industrial customers will not be able to expand.		
WAITETE	Hazardous Asset Renewals	Network Option 1	Move or alter substation.		
		Network Option 2	Replace fence.	70k in yr3	Need a secure area for substation. Most cost effective.
		Non Network Option	None available.		
		Do Nothing	Fence deterioration could cause a security breach.		
WAIRERE	Asset Renewal	Network Option 1	Replace transformer.		
		Network Option 2	Refurbish transformers (T2).	93k in yr8	Oil tests indicate transformer life can be extended with refurbishment. Cost and network security
		Non Network Option	None available.		
		Do Nothing	Leave as it is at present. Transformer could fail if not refurbished.		

HANGATIKI POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
WAIRERE	Asset Renewal	Network Option 1	Replace transformer.		
		Network Option 2	Refurbish transformers (T1).	93k in yr6	Oil tests indicate transformer life can be extended with refurbishment. Cost and network security.
		Non Network Option	None available.		
		Do Nothing	Transformer could fail if not refurbished.		
WAIRERE	Environmental	Network Option 1	Rebuild site.		
		Network Option 2	Install oil separation.	17k in yr6	Only realistic option.
		Non Network Option	None available.		
		Do Nothing	Possible environmental contamination due to oil leakages.		
WAIRERE	Hazardous Asset Renewals	Network Option	Renew switchgear and improve protection schemes (33 kV).	350k in yr8	Protection schemes need updating due to the separate owners of the generation.
		Non Network Option	None available.		
		Do Nothing	Leave site as is and risk network security.		
WAIRERE	Reliability	Network Option	Install 5MVAR capacitors on the 11kV bus to support voltage during heavy load times.	210k in yr7	Most cost effective way of increasing capacity and achieving improvement
		Non Network Option	Support voltage with generator and get customers to improve power factor		
		Do Nothing	Restrict loading and experience possible voltage level breaches		

HANGATIKI POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
OPARURE	Environmental	Network Option 1	Rebuild site.		
		Network Option 2	Install bunding, oil separation and earthquake restraints.	47k in yr5	Only realistic option.
		Non Network Option	None available.		
		Do Nothing	Possible contamination due to oil leakages.		
MAHOENUI	Environmental	Network Option 1	Rebuild site.		
		Network Option 2	Increase the height of the oil bund and install oil separation.	17k in yr11	Required for environment protection.
		Non Network Option	None available.		
		Do Nothing	Possible environmental contamination due to oil leakages.		
MAHOENUI	Asset Renewal	Network Option 1	Replace transformer.		
		Network Option 2	Refurbish transformer.	58k in yr11	Oil tests indicate transformer life can be extended with refurbishment. Cost and network security.
		Non Network Option	None available.		
		Do Nothing	Transformer could fail if not refurbished.		
MAHOENUI	Hazardous Asset Renewals	Network Option	Replace fault thrower with CB 33 kV.	70k in yr13	Fault throwers are unreliable and cause damage to other equipment. They have to be manually reset.
		Non Network Option	None available.		
		Do Nothing	Could decrease reliability.		

TABLE 7-25: PLANNED WORK FOR SUBSTATIONS CONNECTED TO HANGATIKI POS

HANGATIKI POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
BENNEYDALE	Hazardous Asset Renewals	Switches (Hazard Improvement)	REG 04 REG 07 REG 14	Install bypass protection on Regulator Install bypass protection on Regulator Install bypass protection on Regulator	5K in yr5 5K in yr15 5K in yr1
		Low and Hazardous Two Pole Structures	T2506	Rebuild with a standard single pole structure.	28k in yr5
		Ground Mount Transformers: Condition & Hazards	T2598	3-Phase 500kVA.	45k in yr11
COAST	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	T547 T640	3-Phase 300kVA. 3-Phase 200kVA.	47k in yr5 47k in yr7
CAVES	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	T1185	Construct to TLC's current Network Standards.	30k in yr9
GRAVEL SCOOP	Reliability	Switches (Reliability Improvement)	304	Automate to TLC's current Network Standards.	45k in yr10
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	T1007	3-Phase 300kVA.	45k in yr8
HANGATIKI EAST	Reliability	Switches (Reliability Improvement)	361 336	Automate to TLC's current Network Standards.	35k in yr7 40k in yr6
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	T381	Replace the I tank or front access transformer. Use refurbished transformer if available.	47k in yr3
MAHOENUI	Reliability	Switches (Reliability Improvement)	1343 1512	Automate to TLC's current Network Standards.	35k in yr7 20k in yr8
	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	T1453 T1692 T1865 T2520	Construct to TLC's current Network Standards.	41k in yr3 41k in yr6 6k in yr3 41k in yr3
MAIHIIHI	Hazardous Asset Renewals	Switches (Hazard Improvement)	REG 06 REG 01	Install bypass protection on Regulator	5k in yr10 5k in yr3

HANGATIKI POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
MCDONALDS	Reliability	Switches (Reliability Improvement)	320 387 328	Automate to TLC's current Network Standards.	23k in yr5 35k in yr4 23k in yr4
	Hazardous Asset Renewals	Switches (Hazard Improvement)	REG 11	Install bypass protection on Regulator	5k in yr13
MOKAU	Reliability	Switches (Reliability Improvement)	1626	Automate to TLC's current Network Standards.	47k in yr13
	Cumulative Capacity	Feeder Development	FED 128	Mokau Generator: Add remotely controlled diesel or gas injection for holiday periods and during shutdown interruptions.	350k in yr7
	Hazardous Asset Renewals	Switches (Hazard Improvement)	REG 03 REG 02	Install bypass protection on Regulator	5k in yr7 5k in yr8
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	T2140 T2154 T2155	T2140 3-Phase 100kVA. T2154 to change 11kV cable and DDO's. T2155 3-Phase 500kVA.	47k in yr7 47k in yr7 47k in yr7
		Low and Hazardous Two Pole Structures	T2153 T2177 T2194 T2208	T2153- Rebuild restructure with standard single pole design. T2177 Construct to TLC's current Network Standards. T2194 Construct to TLC's current Network Standards. T2208- Rebuilt structure with standard single pole design.	28k in yr2 47k in yr5 6k in yr6 47k in yr6
OPARURE	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	T1043 T457 T663 T9	T1043 3-Phase 500kVA. T457 Install a front access transformer 300kVA with I blade RTE switch. T663 Replace with refurbished I tank transformer. T9 3-Phase 250kVA.	58k in yr9 45k in yr4 36k in yr2 40k in yr6
	Reliability	Switches (Reliability Improvement)	242	Automate to TLC's current Network Standards.	23k in yr13

HANGATIKI POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
OTOROHANGA	Reliability	Switches (Reliability Improvement)	316 288 645 308	Automate to TLC's current Network Standards.	47k in yr11 34k in yr3 23k in yr2 23k in yr2
		Feeder Development	FED 112	LV Link T554 toilet block link to adjacent Transformers.	117k in yr5
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	T557 T1174 T1552 T170 T699 T557 T2417	T557 RTE T1174 3-Phase 200kVA. T1552 3-Phase 300kVA. T170 3-Phase 200kVA. T699 3-Phase 300kVA. T557 Install TX T2417 3 Phase 200kVA	47k in yr7 47k in yr14 45k in yr11 47k in yr9 47k in yr5 53k in yr15 47k in yr15
RANGITOTO	Reliability	Switches (Reliability Improvement)	224	Automate to TLC's current Network Standards.	47k in yr12
	Hazardous Asset Renewals	Switches (Hazard Improvement)	REG 30	Install bypass protection on Regulator	5k in yr12
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	T464	Replace with a refurbished I tank. Check loading and size of transformer.	47k in yr4
RURAL	Reliability	Ground Mount Transformers: Condition & Hazards	T1367 T1390 T1559	T1367 3-Phase 100kVA. T1390 3-Phase 200kVA. T1559 3-Phase 100kVA.	47k in yr9 47k in yr8 47k in yr10
TE KUITI SOUTH	Reliability	Switches (Reliability Improvement)	730	Automate to TLC's current Network Standards.	52k in yr1
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	T10	T10 3-Phase 300KkVA.	45k in yr8
		Low and Hazardous Two Pole Structures	T478 T559	Construct to TLC's current Network Standards.	45k in yr5 48k in yr2
TE MAPARA	Reliability	Switches (Reliability Improvement)	1316	Automate to TLC's current Network Standards.	23k in yr1
	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	T1777 T1829	Construct to TLC's current Network Standards.	47k in yr3 20k in yr4

HANGATIKI POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
WAITOMO	Reliability	Switches (Reliability Improvement)	182	Automate to TLC's current Network Standards.	23k in yr9
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	T1003 T406	T1003 3-Phase 200kVA. T406 3-Phase 200kVA.	47k in yr14 47k in yr3

TABLE 7-26: PLANNED DEVELOPMENT WORK FOR 11 KV FEEDERS CONNECTED TO HANGATIKI POS

7.4.1.3 Assets connected to Whakamaru & Mokai Geothermal Points of Supply

Figure 7-8 indicates the area supplied from the Whakamaru and Mokai Geothermal Points of supply and the connected feeders geographical location. Figure 7-9 indicates the Supply Point's relationship to the Zone Substations and Feeders downstream.

Table 7-27 to Table 7-30 list the development work planned for assets connected to the points of supply in the Whakamaru / Mokai areas to eliminate the constraints listed earlier. The table lists the options considered, the final decision made, the planning year and cost estimate.

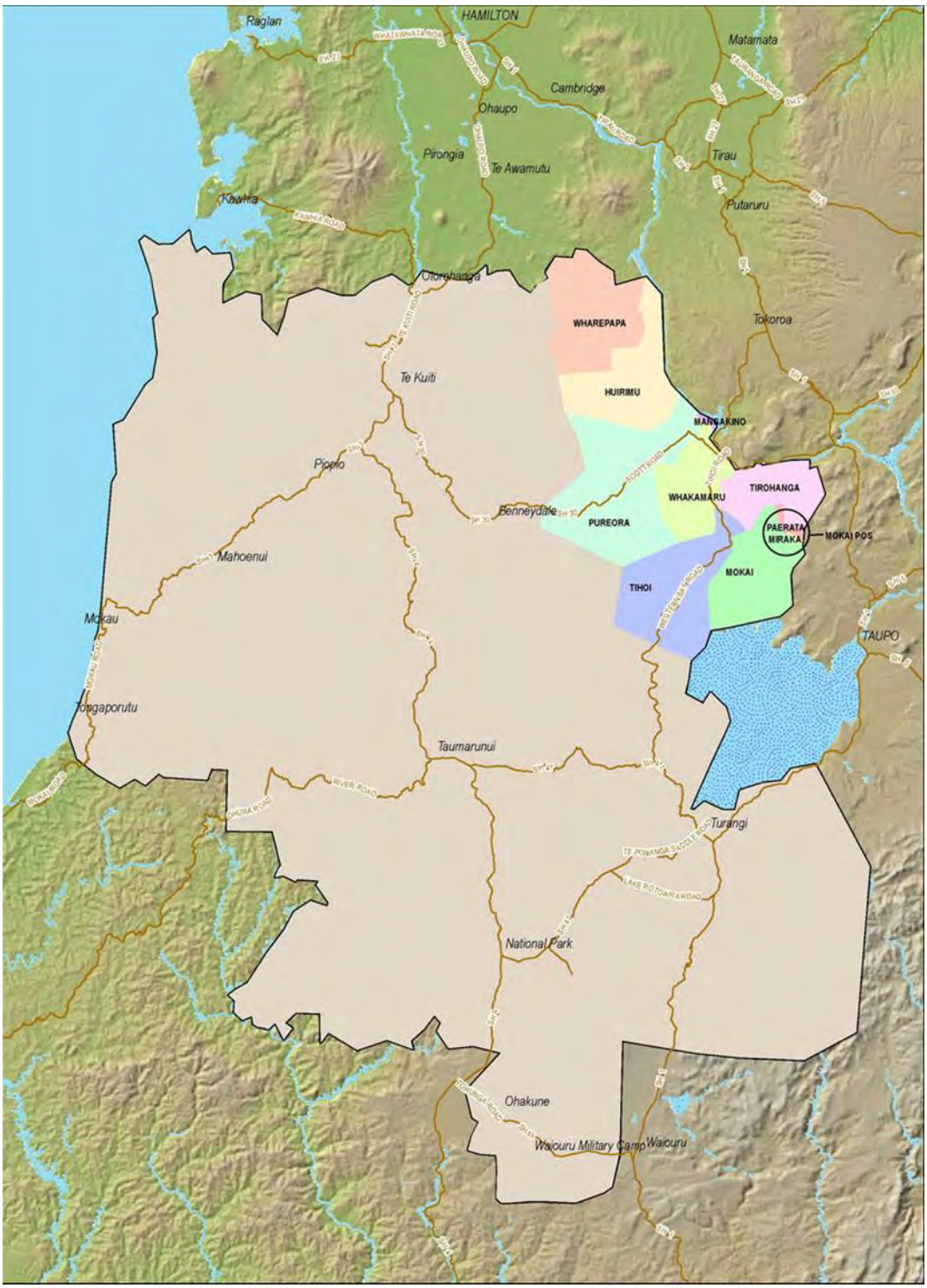


FIGURE 7-8: WHAKAMARU & MOKAI GEOTHERMAL SUPPLY AREAS AND FEEDER LOCATIONS

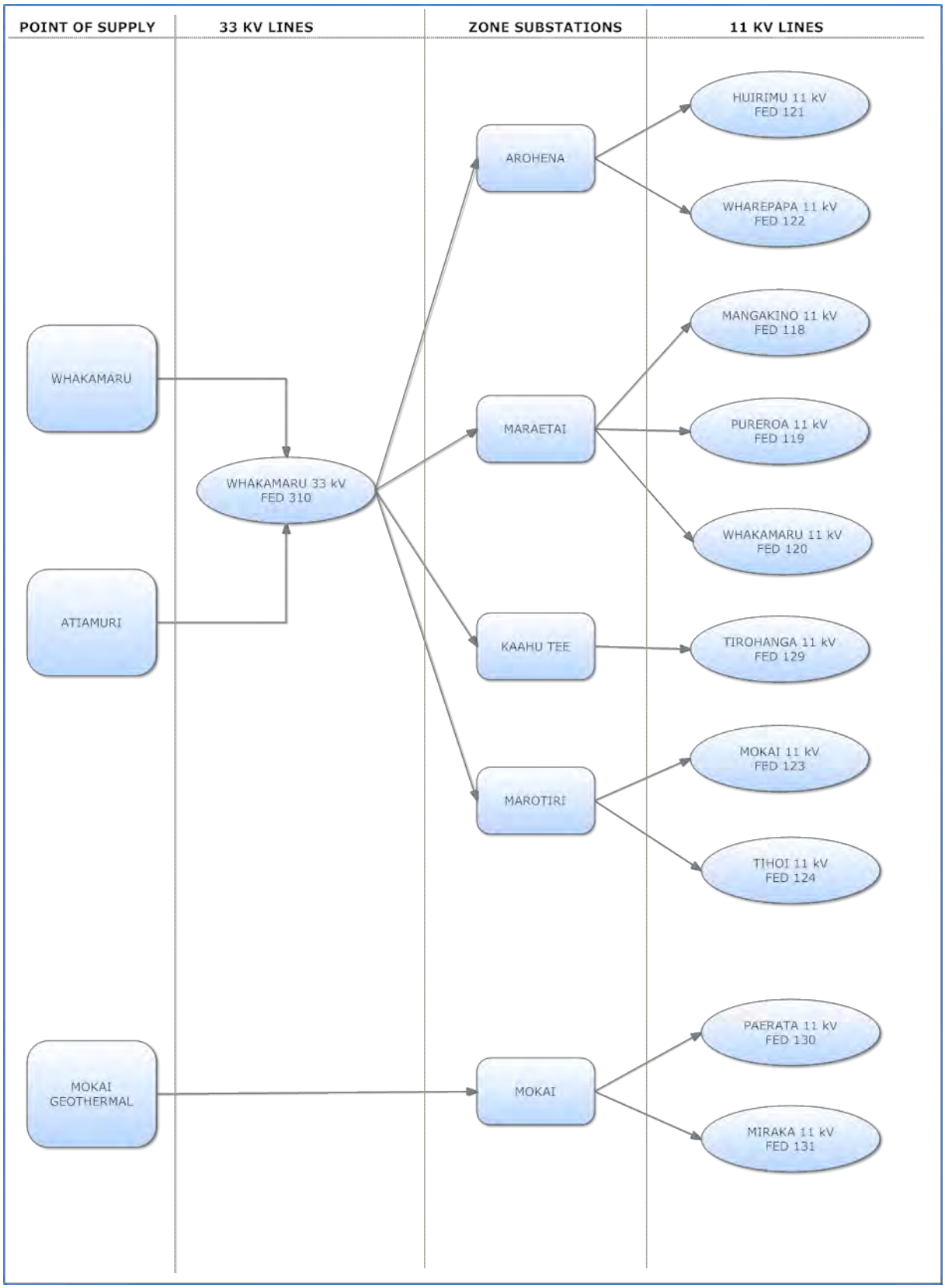


FIGURE 7-9: CONNECTION DIAGRAM OF ASSETS CONNECTED TO WHAKAMARU & MOKAI GEOTHERMAL SUPPLY AREAS AND FEEDER LOCATIONS

WHAKAMARU & MOKAI POS: SUPPLY POINTS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
ATIAMURI	Cumulative Capacity	Network Option 1	Increase transformer capacity		
		Network Option 2	Install cooling fans and include SCADA upgrade to include information regarding the transformer temperature. Year one do SCADA information Year 2 revisit the need for fans.	35k in yr1	Will delay higher cost options.
		Non Network Option	None available.		
		Do Nothing	Overheat transformer and reduce its life. Limited ability to meet customer's capacity expectations.		
ATIAMURI	Cumulative Capacity	Network Option 1	Upgrade transformer at POS. If the transformer at Atiamuri is upgraded the conductor size is not great enough to transport the capacity so a line upgrade would be required.		
		Network Option 2	Supply from Transpower at Whakamaru on the 220 kV or Mokai 110 kV supply connection at Whakamaru.	1,500k in yr3	This is the most cost effective solution.
		Non Network Option	Uses generators and capacitors to back up load at peak loading times.		
		Do Nothing	Restrict loading and experience possible voltage level breaches.		
MOKAI	Cumulative Capacity	Network Option 1	Take a supply from Transpower proposed substation near Mokai. This will be expensive.		
		Network Option 2	Increase capacity taken from Mokai Geothermal.	394k in yr14	Most cost effective.
		Non Network Option	None available.		
		Do Nothing	Restrict loading and experience possible voltage level breaches.		
MOKAI	Reliability and Security	Network Option 1	Add additional back up transformer off Mokai 1 bus to supply Mokai Energy Park	500k in yr2	This is the most reliable and cost effective long term solution.
		Non Network Option	Use of generators to support Mokai Energy Park during outages		
		Do Nothing	No power to large customer (Miraka milk plant) in the area during outages.		
MOKAI	Cumulative Capacity	Network Option	Install a load control plant at Mokai. Install ripple signal which generates at 317 Hz signal.	408k in yr6	This is the most cost effective.
		Non Network Option	Run without load control, use some other technology.		
		Do Nothing	Unable to control load in area.		

TABLE 7-27: PLANNED WORK FOR SUPPLY POINTS CONNECTED TO WHAKAMARU & MOKAI GEOTHERMAL POS

WHAKAMARU & MOKAI POS: 33 kV LINES (excluding Line Renewals)					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
WHAKAMARU	Cumulative Capacity	Network Option	Install second regulator at Maraetai substation site on the 33 kV line.	291k in yr4	This is the most cost effective solution providing voltage support throughout the year.
		Non Network Option	Provide voltage support with generators at times of know network constraint.		

TABLE 7-28: PLANNED WORK FOR 33 KV LINES CONNECTED TO WHAKAMARU & MOKAI GEOTHERMAL POS

WHAKAMARU & MOKAI POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
MARAETAI	Asset Renewal	Network Option	Replace breaker due to age, reliability and condition.	68k in yr13	Parts for existing equipment are no longer available.
		Non Network Option	None available.		
		Do Nothing	If breaker fails there are no available parts for repairs. Risk of protection failure.		
MARAETAI	Cumulative Capacity	Network Option	Diversify off site with a modular substation near Ranganui Road.	466k in yr8	Cost, reliability improvements, fault current control and landowner issues. Will depend on Crusader Meats growth.
		Non Network Option	Install capacitors to support voltage.		
		Do Nothing	Restrict loading and experience possible voltage level breaches.		
MARAETAI	Cumulative Capacity	Network Option	Install modular substation on Sandel Road in Whakamaru.	466k in yr3	Most cost effective solution.
		Non Network Option	Install capacitors or generation to support voltage during heavy load times.		
		Do Nothing	Restrict loading and experience possible voltage level breaches.		
ATIAMURI	Asset Renewal	Network Option 1	Replace breaker due to age, reliability and condition.	87k in yr8	Parts for existing equipment are no longer available.
		Network Option 2	Maintain existing.		
		Non Network Option	None available.		
		Do Nothing	If breaker fails there are no available parts for repairs. Risk of protection failure.		

WHAKAMARU & MOKAI POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
AROHENA	Reliability	Network Option	Install 1MVAR of capacitors on both Wharepapa and Hurimu feeder	105K in yr1	Most cost effective way of increasing capacity and achieving improvement
		Non Network Option	Support Voltage with generator and get customers to improve power factor		
		Do Nothing	Restrict loading and experience possible voltage level breaches		

TABLE 7-29: PLANNED WORK FOR ZONE SUBSTATIONS CONNECTED TO WHAKAMARU & MOKAI GEOTHERMAL POS

WHAKAMARU & MOKAI POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
MANGAKINO	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	T700 T701	T700 3-Phase 300Kva. T701 Check loading and replace with a refurbished I tank of suitable size. Install RMU with 2 fuses and one for T2316.	30k in yr2 47k in yr1
	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	T1081	Check loading; rebuild structure with 100 kVA if loading light enough, otherwise use refurbished ground mount 200 kVA. 11 kV below regulation height.	58k in yr4
MOKAI	Hazardous Asset Renewals	Switches (Safety Improvement)	REG 24	Install bypass protection on regulator	5k in yr1
	Reliability	Switches (Reliability Improvement)	474 446	474 Check sites. 446 Check sites.	47k in yr12 47k in yr12
	Cumulative Capacity	Development Feeder	FED123	Upgrade conductor to Mink on Tirohanga Road,	747k in yr5
PUREORA	Reliability	Switches (Reliability Improvement)	423	Automate to TLC's current Network Standards.	23k in yr3
	Hazardous Asset Renewals	Switches (Safety Improvement)	REG 26 REG 09	Install bypass protection on regulator	5k in yr2 5k in yr9
TIHOI	Reliability	Switches (Reliability Improvement)	454	Automate to TLC's current Network Standards.	45k in yr1
	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	T1618	Construct to TLC's current Network Standards.	7k in yr7
TIROHANGA	Reliability	Switches (Reliability Improvement)	434	Automate to TLC's current Network Standards.	40k in yr1
	Hazardous Asset Renewals	Switches (Safety Improvement)	REG 23	Install bypass protection on regulator	5k in yr14
	Cumulative Capacity	Development Feeder	FED129	More Feeder ties and a new modular substation at Mine road. Will depend on forest conversion to dairying.	524k in yr11
WHAKAMARU	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	463	Automate to TLC's current Network Standards.	45k in yr5
	Hazardous Asset Renewals	Switches (Safety Improvement)	REG 25	Install bypass protection on regulator	5k in yr6
		Hazardous Underground Refurbishment	FED120	RMU and 300 kVA TX for T2523 and remove T2524 and T2521. Through-joint at T2523 to T2525. Replace LV cable around village with 4c Cable, new 16mm^2 N/S street light cable and TUDs pillar boxes. May need to include replacement of service main to boxes on side of houses.	500k in yr4

WHAKAMARU & MOKAI POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
WHAREPAPA	Hazardous Asset Renewals	Switches (Safety Improvement)	REG 25	Install bypass protection on regulator	5k in yr6
MOKAI POS	Hazardous Asset Renewals	Switches (Safety Improvement)	REG 29	Install bypass protection on regulator	29k in yr15

TABLE 7-30: PLANNED DEVELOPMENT WORK FOR 11 KV FEEDERS CONNECTED TO WHAKAMARU & MOKAI GEOTHERMAL POS

7.4.1.4 Assets connected to Ongarue Point of Supply

Figure 7-10 indicates the area supplied from the Ongarue Point of supply and the connected feeders geographical location. Figure 7-11 indicates the Supply Point's relationship to the Zone Substations and Feeders downstream.

Table 7-31 to Table 7-34 list the development work planned for assets connected to the Ongarue point of supply to eliminate the constraints listed earlier. The table lists the options considered, the final decision made, the planning year and cost estimate.

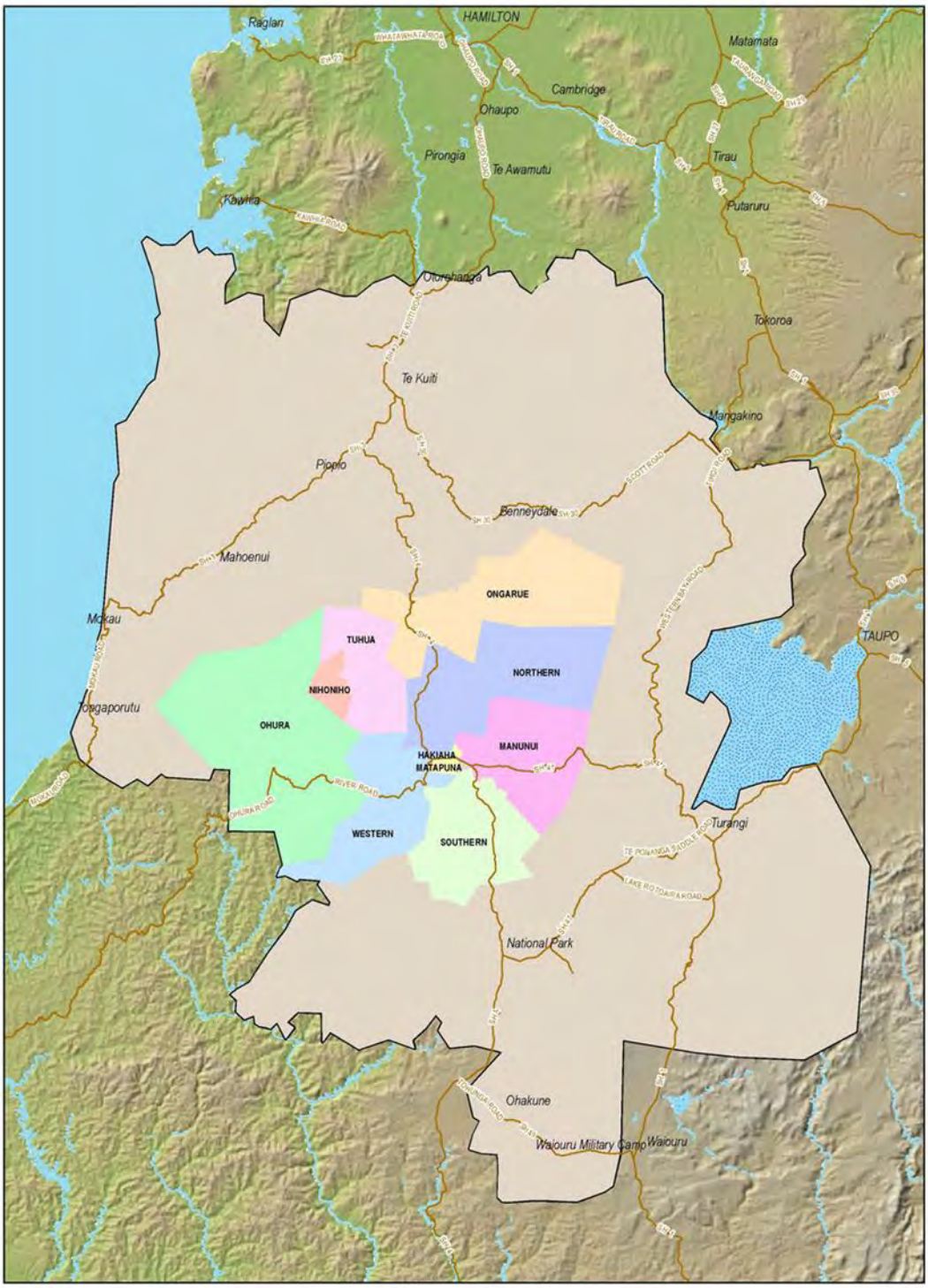


FIGURE 7-10: ONGARUE SUPPLY AREA AND FEEDER LOCATIONS

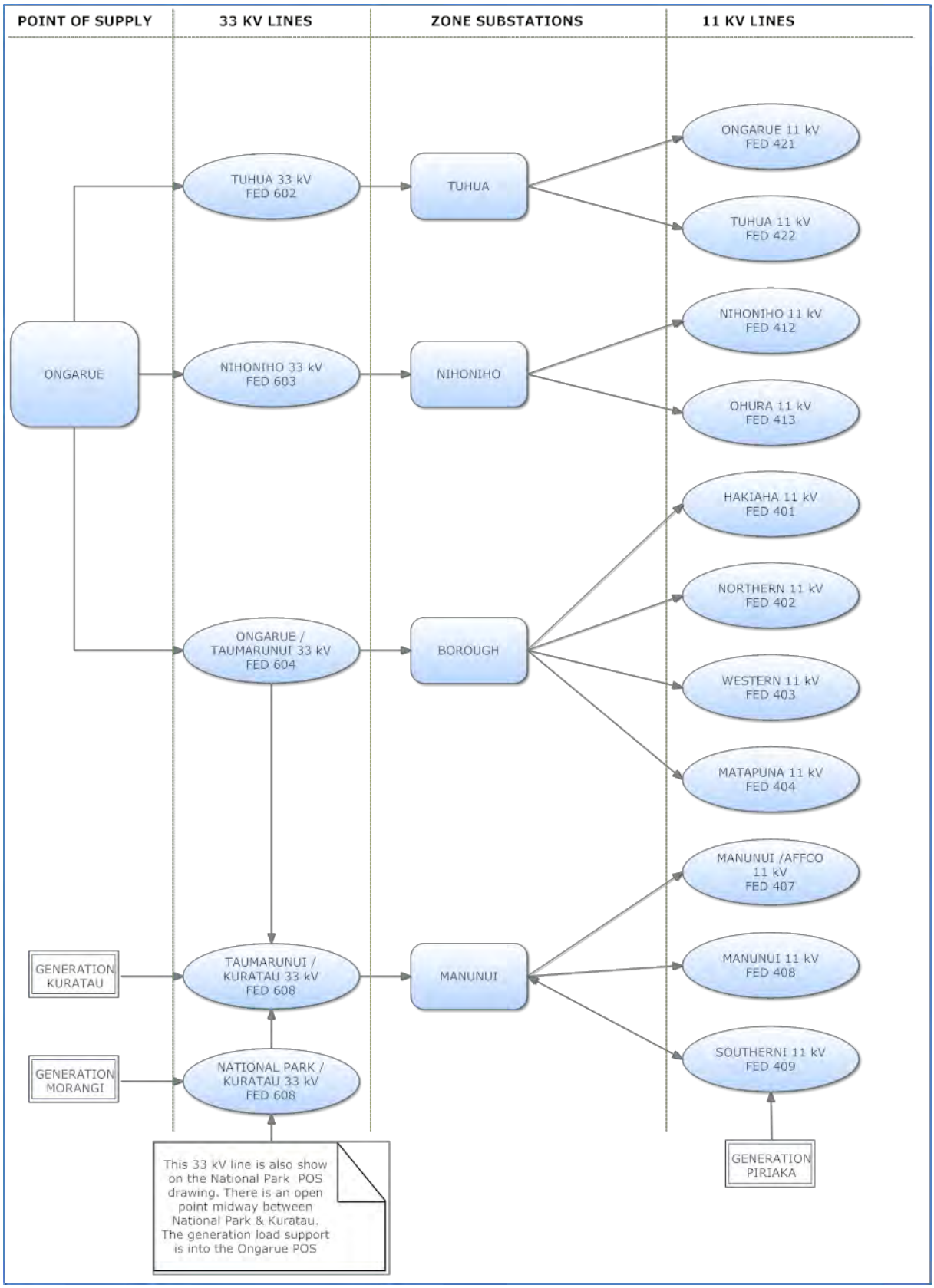


FIGURE 7-11: CONNECTION DIAGRAM OF ASSETS CONNECTED TO ONGARUE POS

ONGARUE POS: SUPPLY POINTS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
ONGARUE	Asset Renewal	Network Option	Rationalise the number of outgoing feeder circuit breakers. Put breaker on Taumarunui and Nihoniho lines. Remove old Nihoniho breaker. Needs 4 line reclosers and one or two automated 33kV switches. Allows splitting of feeders and isolation of Transpower supply. Some 33kV cabling will be necessary. Reduce the number of circuit breakers from 3 to two and upgrade the bypass option.	699k in yr4	It is more cost effective for TLC to have its own 33kV bus system, than pay the high annual connection charges associated with circuit breakers to Transpower. Typically, Transpower's annual charges are 1.5 times the capital cost of a circuit breaker. There is a potential to remove 3 Transpower owned circuit breakers and reduce site hazards and improve operational ease. Reliability and security will also benefit.
		Non Network Option	By-pass the site.		
		Do Nothing	Increases in customer charges.		

TABLE 7-31: PLANNED WORK FOR SUPPLY POINTS CONNECTED TO ONGARUE POS

ONGARUE POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
TUHUA	Cumulative Capacity	Network Option 1	Install 1MVAR capacitor bank that can be remotely switched with controllers at Tuhua Substation for 11 kV voltage support.	105k in yr1	Lowest cost given low growth of area, the assets that are in place and the income available from the area.
		Network Option 2	Negotiate contract with Transpower to take supply from Taumarunui railway supply. This is a more expensive option.		
		Non Network Option	Install large generators. More expensive option.		
		Do Nothing	Restrict capacity to customers.		
TUHUA	Hazardous Asset Renewals	Network Option 1	Replace with modular substation.	382k in yr12	The present site has had some barriers put up but it does not achieve an acceptable long-term solution. Solves hazard control, equipment age, environmental and other site. Given the safety constraint, the modular substation is the best option.
		Network Option 2	Modify existing site by installing bunding, oil separation and earthquake restraints. Discounted due to age of equipment on site.		
		Non Network Option	None available.		
		Do Nothing	Possible environmental contamination due to oil leakages. Hazards due to access and incorrect equipment operation (protection).		
NIHONIHO	Hazardous Asset Renewals	Network Option	Replace with modular substation.		
		Network Option	Replace fence and upgrade transformer.	225k in yr12	Landowner issues associated with present site and need to move site if mine reopens. (DOC is landowner)
		Non Network Option	None available.		
		Do Nothing	Leave as is, possible security breaches due to deteriorating fence condition.		

ONGARUE POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
BOROUGH	Asset Renewal	Network Option 1	Replace 11kV bulk oil breakers With vacuum truck breakers.	53k in yr12	Parts for existing equipment are no longer available.
		Non Network Option	None available.		
		Do Nothing	If breaker fails there are no available parts for repairs.		
BOROUGH	Environmental (River flooding)	Network Option 1	Diversify with modular substations. Located above slip on main road.	390k in yr9	Diversity increases reliability.
		Network Option 2	Construct further 11kV links to Manunui Substation. More costly than option 1.		
		Non Network Option	Install generators in a separate location to support back feed supplies from Manunui substation.		
		Do Nothing	Leave site as is and risk the site flooding.		
BOROUGH	Environmental	Network Option 1	Rebuild site.		
		Network Option 2	Install oil separation.	17k in yr4	Only realistic option.
		Non Network Option	None available.		
		Do Nothing	Possible environmental contamination due to oil leakages.		
BOROUGH	Cumulative Capacity	Network Option 1	Install 3MVAR capacitor bank that can be remotely switched with controllers at Borough Substation for 11 kV voltage support.	124k in yr1	Lowest cost given low growth of area, the assets that are in place and the income available from the area.
		Network Option 2	Negotiate contract with Transpower to take supply from Taumarunui railway supply. This is a more expensive option.		
		Non Network Option	Install large generators. More expensive option		
		Do Nothing	Restrict capacity to customers.		
MANUNUI	Asset Renewal	Network Option 1	Replace transformer.		
		Network Option 2	Refurbish transformer.	93k in yr1	Cost and network security
		Non Network Option	None available.		
		Do Nothing	Transformer could fail is left.		
MANUNUI	Hazardous Asset	Network Option 1	Rebuild site.	175k in yr1	Most cost effective option.

ONGARUE POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
	Renewals	Network Option 2	Modify site for bunding and earthquake restraints		
		Non Network Option	None available.		
		Do Nothing	Possible environmental contamination due to oil leakages.		
MANUNUI	Environmental	Network Option 1	Rebuild site.		
		Network Option 2	Install oil separation.	29k in yr1	Manual bund draining has to be done after rain. Costly and not robust.
		Non Network Option	None available.		
		Do Nothing	Possible environmental contamination due to oil leakages.		

TABLE 7-32: PLANNED WORK FOR ZONE SUBSTATIONS CONNECTED TO ONGARUE POS

ONGARUE POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
HAKIAHA	Reliability	Switches (Reliability Improvement)	5.19 5.3 5831 5.4 5.23	Automate to TLC's current Network Standards.	47k in yr9 20k in yr14 41k in yr2 20k in yr14 20k in yr14
		Back feed Reliability Improvements	FED401	Low voltage ties between transformers in CBD. Do in conjunction with switch gear for 01A38 and 01A82. Add an 11 kV tie between Matapuna and Hakiaha adjacent to rail bridge where the feeder come within a few metre of one another.	117k in yr11 131k in yr11
	Hazardous Asset Renewals	Switches (Hazard)	FED401	Add 11 kV switch gear for 01A38 and 01A82.	58k in yr1
		Low and Hazardous Two Pole Structures	01A31 01B11	01A31 Construct to TLC's current Network Standards. 01B11- Rebuild structure with safer LV wiring, Raise the height of the transformer.	47k in yr6 47k in yr3
MANUNUI	Reliability	Switches (Reliability Improvement)	5912 5914	Automate to TLC's current Network Standards.	35k in yr3 41k in yr1
	Hazardous Asset	Low and Hazardous	07K11	07K11- Replace two pole structure with standard single pole SWER isolating	46k in yr2

ONGARUE POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
	Renewals	Two Pole Structures		structure.	
			08J04	08J04- Replace with standard single pole structure.	50k in yr8
			08J07	08J07 Construct to TLC's current Network Standards.	25k in yr6
			08J10	08J10 Maintenance.	7k in yr7
			08K14	08K14 Replace pole mounted transformer with refurbished ground mounted transformers.	51k in yr2
			08L17	08L17 Lift equipment on poles so all equipment is above regulation height. Recloser bushings are 3.75 m from ground level.	30k in yr4
MATAPUNA	Reliability	Switches (Reliability Improvement)	1.7 1.5 5357 5838 1.6	Automate to TLC's current Network Standards.	27k in yr15 27k in yr15 36k in yr5 47k in yr3 27k in yr15
	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	01A75	Construct to TLC's current Network Standards.	47k in yr7
		Ground Mount Transformers: Condition & Hazards	01A36 01A70 01B20 01B21 01B24 01B25	Check sites and improve site hazards and transformer condition as required.	20k in yr11 47 in yr6 35k in yr13 35k in yr13 47k in yr5 35k in yr13
NORTHERN	Reliability	Switches (Reliability Improvement)	5119 6127 5164 5984	Automate to TLC's current Network Standards.	45k in yr11 30k in yr2 47k in yr11 41k in yr2
	Hazardous Asset Renewals	Switches (Hazard)	01A52 07I14 08I19 08I03	Install Switchgear.	15k in yr8 47k in yr11 47k in yr12 47k in yr9
		Low and Hazardous Two Pole Structures	01A46	01A46- Replace structure and install a refurbished ground mounted transformer.	47k in yr3
			08I02	08I02- Replace with a ground mounted refurbished transformer. Check loadings.	45k in yr7
			T4055	T4055- Raise equipment on structure to over regulation height and maintain	23k in yr7

ONGARUE POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
				clearances.	
		Ground Mount Transformers: Condition & Hazards	01A48 07I12 T4025	Check sites and improve site hazards and transformer condition as required.	34k in yr13 20k in yr11 47k in yr10
NIHONIHO	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	06E01	Construct to TLC's current Network Standards.	30k in yr8
OHURA	Reliability	Switches (Reliability Improvement)	5758	Automate to TLC's current Network Standards.	47k in yr10
	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	10E09	10E09 Rebuild site, two SWER transformers, on site visit needed for design. Cost split between T4130 and 10E09.	41k in yr10
			07D03	07D03 Construct to TLC's current Network Standards.	47k in yr8
			07D08	07D08 Construct to TLC's current Network Standards.	30k in yr5
			07D11	07D11 Rebuild structure with standard single pole isolating SWER transformer structure.	41k in yr12
			07D16	07D16 Replace with standard single pole isolating SWER structure.	41k in yr10
			09C05	09C05 Construct to TLC's current Network Standards.	30k in yr11
			T4130	T4130 Rebuild site, two SWER transformers, on site visit needed for design. Cost split between T4130 and 10E09.	41k in yr12
		Ground Mount Transformers: Condition & Hazards	07D24	Industrial on roadside exposed drywell fuses, was installed for the prison. Check loading and replace with I tank ground mounted transformer.	31k in yr4
ONGARUE	Reliability	Switches (Reliability Improvement)	5462	Automate to TLC's current Network Standards.	47k in yr13
	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	01K02	01K02 Check loading on this transformer. Mill is now closed and structure changed to a standard structure single pole with a 30 kVA TX.	58k in yr4
			02K08	02K08 Equipment is under regulation height on structure. Rebuild structure with single pole standard structure, if possible, or rebuild one pole away.	56k in yr5
			02K16	02K16 Rebuild structure 11 kV bushing area below regulation height.	58k in yr5

ONGARUE POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
SOUTHERN	Reliability	Switches (Reliability Improvement)	5136	Automate to TLC's current Network Standards.	47k in yr5
	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	09K02	09K02 Construct to TLC's current Network Standards.	20k in yr8
			09K25	09K25 Rebuild structure with standard single pole Isolating SWER structure.	44k in yr4
			09K50	09K50 Check loading on transformer. Either 100 kVA standard single pole or 200 kVA refurbished ground Mount.	44k in yr3
			10K14	10K14 Construct to TLC's current Network Standards.	40k in yr7
			11K11	11K11 Construct to TLC's current Network Standards.	47k in yr6
			12K08	12K08 Construct to TLC's current Network Standards.	41k in yr10
TUHUA	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	05G03	Lift equipment over regulation height and maintain clearances.	28k in yr2
WESTERN	Reliability	Switches (Reliability Improvement)	5795 5404	Automate to TLC's current Network Standards.	29k in yr1 29k in yr1
	Hazardous Asset Renewals	Switches (Hazard)	08I31 08I55	Install RMU's.	47k in yr12 47k in yr2
		Low and Hazardous Two Pole Structures	08H03	08H03 Construct to TLC's current Network Standards.	47k in yr5
			08I21	08I21 Raise equipment on structure to above regulation height for 11 kV from ground level. Maintain clearances.	58k in yr4
		Ground Mount Transformers: Condition & Hazards	T4012	Check sites and improve site hazards and transformer condition as required.	47k in yr14

TABLE 7-33: PLANNED DEVELOPMENT WORK FOR 11 KV FEEDERS CONNECTED TO ONGARUE POS

7.4.1.5 Assets connected to Tokaanu Point of Supply

Figure 7-12 indicates the area supplied from the Tokaanu Point of supply and the connected feeders geographical location. Figure 7-13 indicates the Supply Point's relationship to the Zone Substations and Feeders downstream.

Table 7-34 to Table 7-36 lists the development work planned for assets connected to the Tokaanu point of supply to eliminate the constraints listed earlier. The table lists the options considered, the final decision made, the planning year and cost estimate.

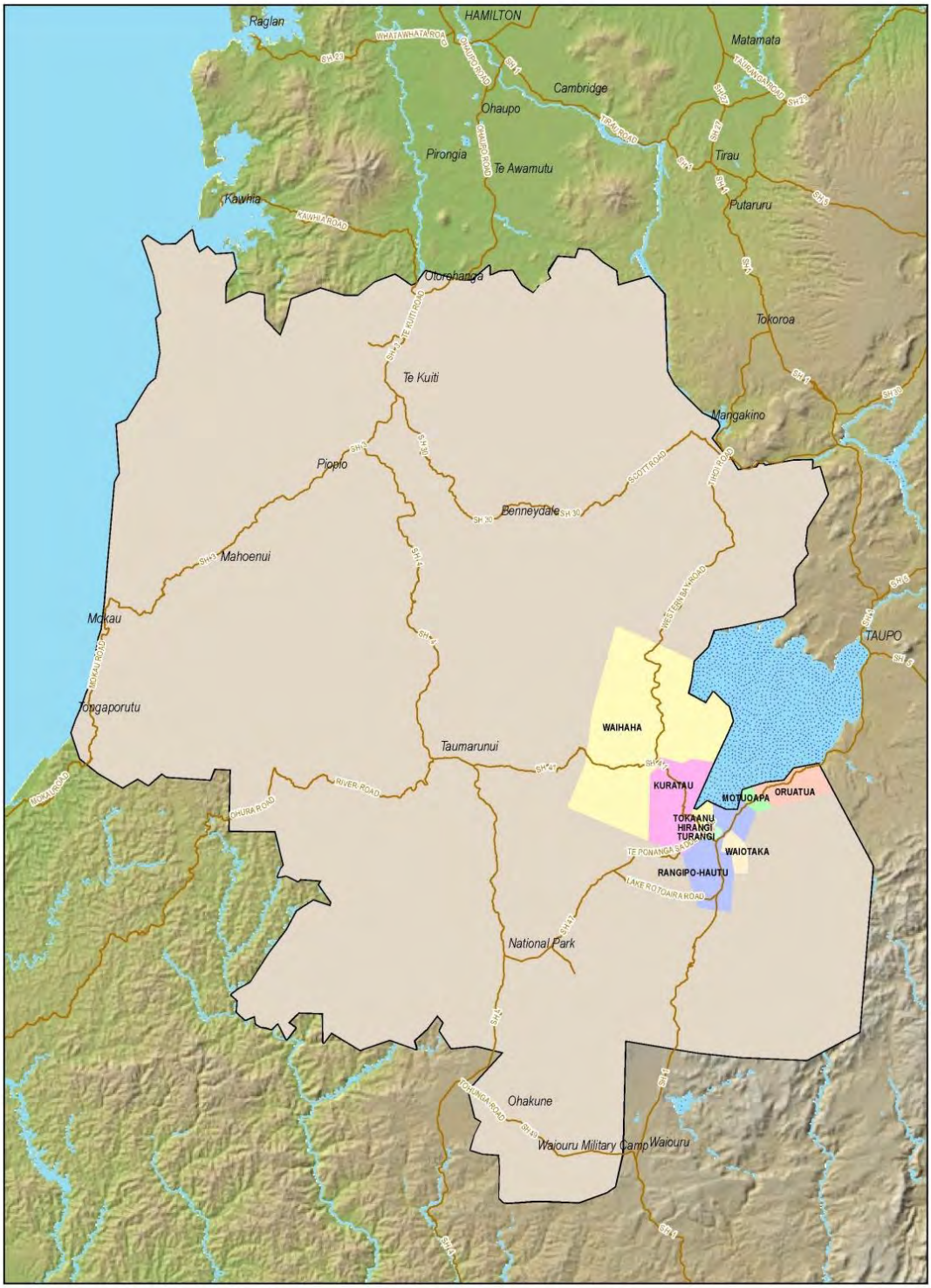


FIGURE 7-12: TOKAANU SUPPLY AREA AND FEEDER LOCATIONS

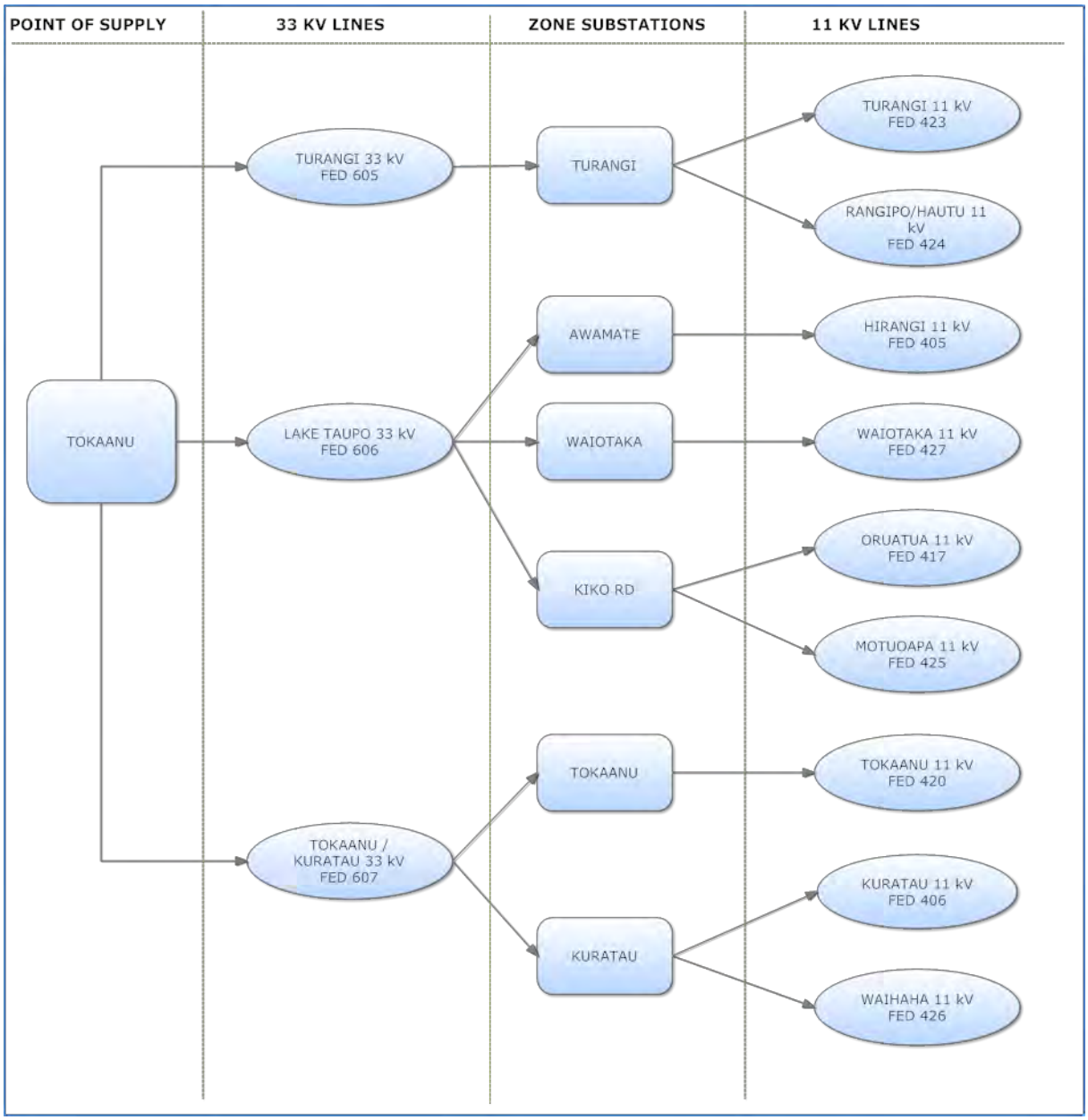


FIGURE 7-13: CONNECTION DIAGRAM OF ASSETS CONNECTED TO TOKAANU POS

TOKAANU POS: 33 kV LINES (excluding Line Renewals)					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
LAKE TAUPO 33	Hazardous Asset Renewals	Network Option 1	Put up insulated conductors and raise height of line if possible. Rebuild overhead using insulated conductor and taller poles. Complex job both technically and in terms of landowner issues.	350k in yr11	Crossing of Tongariro River where fishing is extensive. Maori landowner issues. Lower cost than cable.
		Network Option 2	Rebuild with cable.		
		Non Network Option	Use generators to back up supply.		
		Do Nothing	More prone to faults and customer increase in customer minutes. SMS hazards associated with river crossing.		
TOKAANU / KURATAU 33 kV	Reliability	Network Option	Switches (Reliability Improvement)	41k in yr2	5984 - Automate to TLC's current Network Standards.

TABLE 7-3204: PLANNED WORK FOR 33 KV LINES CONNECTED TO THE TOKAANU POS

TOKAANU POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
TURANGI	Hazardous Asset Renewals	Network Option	Add additional 33 kV switchgear. New 33 kV in year 12/13. Underground and remove double circuit to be done at same time as far as 5673 tap-off. (See 11kV line renewals.) 11 kV breakers in year 15/16 to split heavily loaded feeder.	160k in yr3	Present arrangement is complex, non-standard and consists of old components not designed for the job they are doing. Hazards and reliability / security is improved.
		Non Network Option	None available.		
		Do Nothing	Confusing set up for staff to work on.		
KURATAU	Cumulative Capacity	Network Option 1	Put in a modular substation at end of network close to an existing 33kV line.	466k in yr9	Most cost effective way of increasing capacity and achieving improvements.
		Network Option 2	Put in a second transformer at present site.		
		Non Network Option	Install capacitors or generation to support voltage during heavy load times.		
		Do Nothing	Restrict loading and experience possible voltage level breaches.		

TABLE 7-35: PLANNED WORK FOR ZONE SUBSTATIONS CONNECTED TO TOKAANU POS

TOKAANU POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
HIRANGI	Reliability	Switches (Reliability Improvement)	6186	Install 2 Bay Xiria Unit	56 in yr7
KURATAU	Reliability	Switches (Reliability Improvement)	5921 6557 6355 6353	Automate to TLC's current Network Standards.	23k in yr5 34k in yr6 35k in yr4 35k in yr3
	Cumulative Capacity	Feeder Development	FED406	Line rebuilds: SWER replacement associated with Kuratau development. Line rebuilds i.e. SWER to 3 phase rebuilds associated with Kuratau development.	58k in yr10 58k in yr8
		Switches (Hazard)	08R20 09R14 09R16	08R20 Install transformer with RTE switch. 09R14 Install a Xiria in association with Transformer 09R14 & work on 09R16. 09R16 Install RTE switch.	47k in yr2 47k in yr3 47k in yr3
		Low and Hazardous Two Pole Structures	08R09 09R27 09R28	08R09 Ground mount transformer. Check loading and use a refurbished transformer if available. 09R27 Lift equipment on pole to above regulation height and maintain clearances. 09R28 Construct to TLC's current Network Standards.	45k in yr15 41k in yr3 47k in yr9
MOTUOAPA	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	09T04	Replace with ground mounted 300 kVA; use a refurbished transformer.	48k in yr2

TOKAANU POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
ORUATUA	Hazardous Asset Renewals	Hazardous River Crossing	FED417	Remove dangerous overhead river crossing where trout fishing occurs and lines tangle with overhead conductors, underground cable across bridge. Work in association with 09U11.	163k in yr2
		Switches (Hazard)	09U11	Install switch gear near or associated with 09U11.	51k in yr2
		Low and Hazardous Two Pole Structures	09U12	09U12 Construct to TLC's current Network Standards.	45k in yr8
RANGIPO/HAUTU	Reliability	Switches (Reliability Improvement)	5207 5963	Automate to TLC's current Network Standards.	50k in yr2 52k in yr10
		Developed Feeder	FED424	Add LV links through the town.	117k in yr14
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	10S47 11S18	10S47 3-Phase 300kVA. 11S18 3-Phase 300kVA.	20k in yr12 47k in yr10
		Switches (Hazard)	10S03 10S13 10S49 FED424	10S03 Install switchgear. 10S13 Install switchgear. 10S49 11 kV Cable hard on to 11 kV line, replace pole fit DDO's or Vertical ABS and fuses. FED424 Hazard from Genesis 33 kV Line crossing.	47k in yr4 47k in yr10 23k in yr12 58k in yr8
		Low and Hazardous Two Pole Structures	11S04	Check loading on transformer, downsize TX as required. Rebuild with standard single pole structure.	33k in yr1
TOKAANU	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	10R20	3-Phase 200kVA.	47k in yr14

TOKAANU POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
TURANGI	Reliability	Feeder Development	FED423	Add LV links through the town. Develop an 11 kV link for the Turangi Town Feeder through to Rangipo Hautu 11 kV by bridge on SH 1. This will include changing switchgear at 10S40.	117k in yr12 281k in yr7
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	10S26 10S29 10S30 10S39 10S42 10S44	10S26 Tin shed with Magnefix. Tape up leads. Open LV rack. 10S29 Open LV rack in tin shed. 10S30 Open LV rack in tin shed. 10S39 3-Phase 200kVA. 10S42 Install front access TX with 11kV internal fusing. Do in conjunction with 10S41. 10S44 Open LV rack in tin shed. Replace with GMT.	30k in yr3 31k in yr4 20k in yr12 30k in yr5 45k in yr2
		Switches (Hazard)	10S38 10S41	Install Switch Gear	20k in yr9 47k in yr6
WAIHAHA	Reliability	Switches (Reliability Improvement)	5150	Automate to TLC's current Network Standards.	47k in yr1
	Cumulative Capacity	Feeder Development	FED426	Build out adjacent 11 kV feeders as development takes place. This will include breaking up existing SWER systems.	233k in yr7 175k in yr10
	Hazardous Asset Renewals	Switches (Hazard)	07R13	Install RMU.	47k in yr5
		Low and Hazardous Two Pole Structures	04Q06 07Q14	04Q06 Construct to TLC's current Network Standards. 07Q14 Rebuild structure next to State Highway. Existing equipment is below regulation height.	20k in yr8 32k in yr1

TABLE 7-36: PLANNED DEVELOPMENT WORK FOR 11 KV FEEDERS CONNECTED TO TOKAANU POS

7.4.1.6 Assets connected to National Park Point of Supply

Figure 7-14 indicates the area supplied from the National Park POS and the connected feeders geographical location. Figure 7-15 indicates the Supply Point's relationship to the Zone Substations and Feeders downstream.

Table 7-37 to Table 7-40 lists the development work planned for assets connected to the National Park point of supply to eliminate the constraints listed earlier. The table lists the options considered, the final decision made, the planning year and cost estimate.

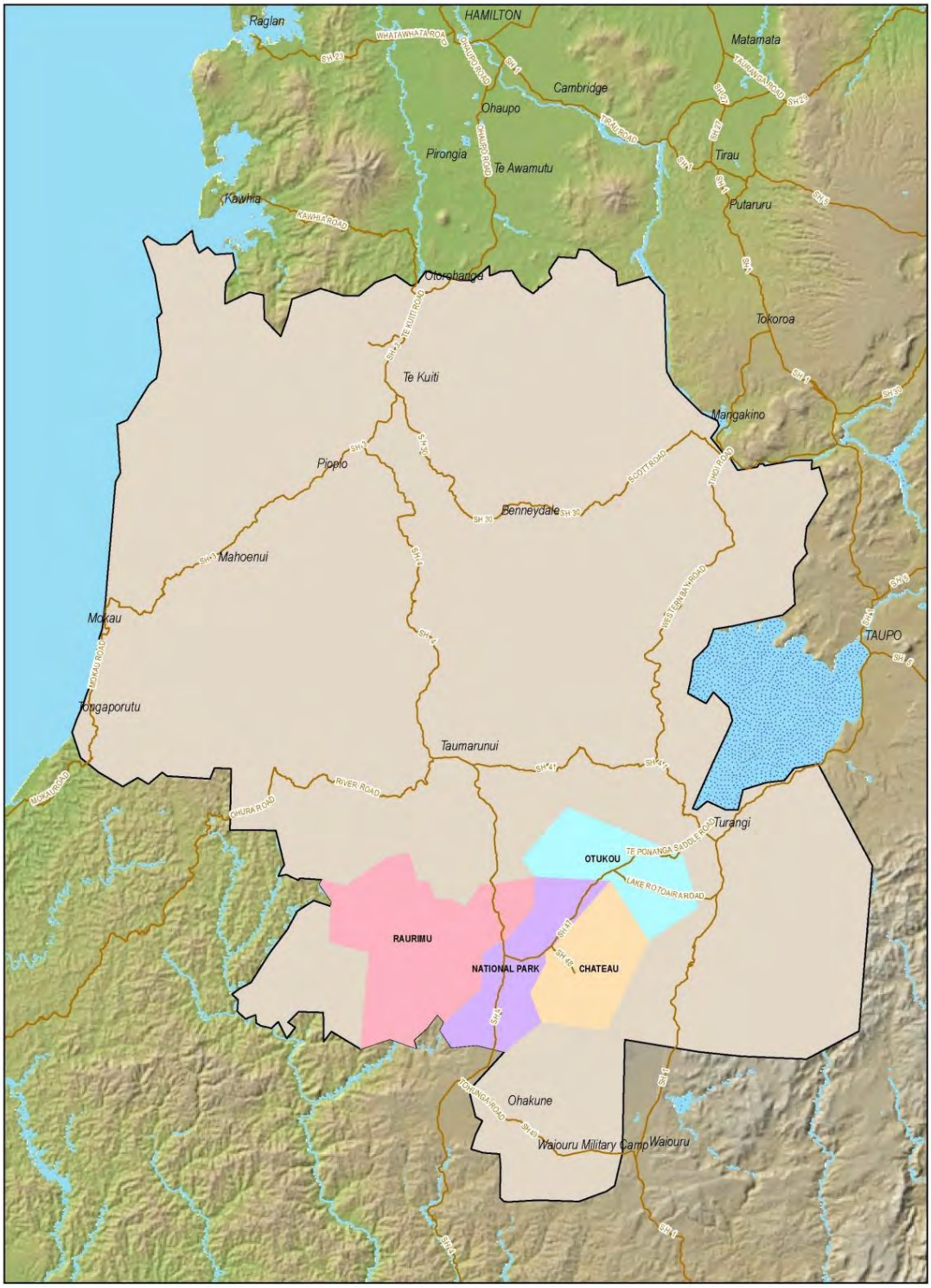


FIGURE 7-14: NATIONAL PARK SUPPLY AREA AND FEEDER LOCATIONS

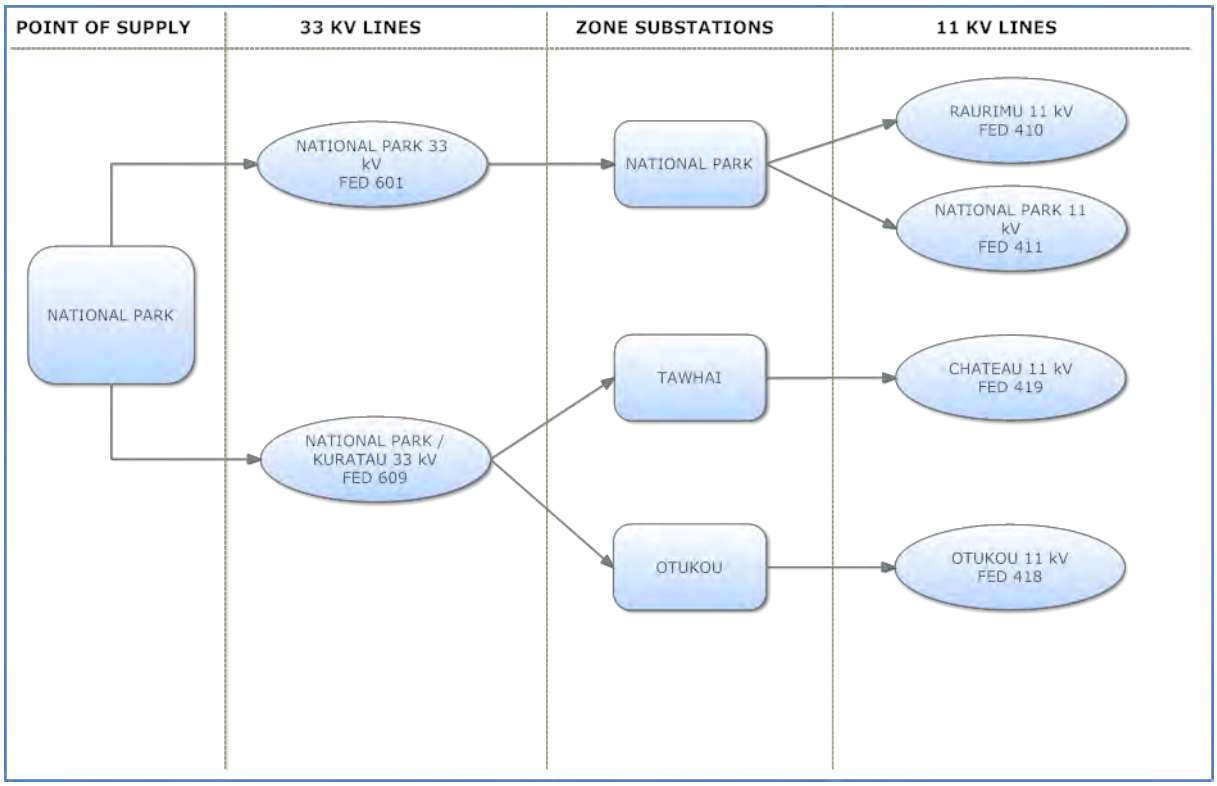


FIGURE 7-15: CONNECTION DIAGRAM OF ASSETS CONNECTED TO NATIONAL PARK POS

NATIONAL PARK POS: SUPPLY POINTS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
NATIONAL PARK	Hazard Asset Renewals	Network Option	ZSub516 Install ripple plant in a container. Rationalise the number of outgoing feeder circuit breakers and containerise the switch gear for the 11 kV Feeders. This work aligns with the installation of a new modular substation with the switch gear in a container (see Zone Substations).	699k in yr1	The principal driver of this project is to remove the hazards associated with the existing load control plant and outgoing 11 kV protection. A by product will be lower Transpower connection charges achieved through rationalising the number of outgoing 33 kV circuits. The most cost effective solution is to rebuild the site using a modular approach.
		Non Network Option	Bypass site.		
		Do Nothing	Increases in customer charges.		

TABLE 7-37: PLANNED WORK FOR SUPPLY POINTS CONNECTED TO NATIONAL PARK POS

NATIONAL PARK POS: 33 kV LINES (excluding Line Renewals)					
Asset	**Constraint**	**Asset**	**Description**	**Year & Cost Estimate**	**Principle Reason for this Option Choice**
NATIONAL PARK / KURATAU 33 KV	Hazardous Asset Renewals	Network Option	Low and Hazardous Two Pole Structures.	45k in yr7	12N05 Investigate installing a ground mounted transformer, or rebuild 33 kV / 400 V transformer structure to make safer. Investigate a refurbished 33 kV / 400 v transformer. A lot of children visit this area; structure needs to be hazard controlled.

TABLE 7-38: PLANNED WORK OF 33 KV LINES

NATIONAL PARK POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year & Cost Estimate**	**Principal Reason for this Option Choice**
NATIONAL PARK	Environmental	Network Option 1	Rebuild Site. Rebuild with a modular substation and rationalise CB in conjunction with grid exit work.	330k in yr1	Cost and landowner consideration given equipment is sited on Transpower land. This solution gives the best overall solution. The site is next to a major State highway, and in a high tourist area with DOC land adjacent to the TP site; therefore a tidy, environmentally sound and secure solution is required.
		Network Option 2	Rebuild fence and include bunding, oil separation and earthquake restraints. This will not be practical given the site restrictions.		
		Non Network Option	None available.		
		Do Nothing	Leave as existing. Fence is deteriorating and possible environmental contamination due to oil leakages during an earthquake.		
OTUKOU	Environmental	Network Option 1	Replace with modular substation		
		Network Option 2	ZSub512. Modify existing site by installing bunding, oil separation and earthquake restraints.	40k in yr11	Cost of restraints, bunding and separation is less than a modular substation.
		Non Network Option	None available.		
		Do Nothing	Possible environmental contamination due to oil leakages.		
TAWHAI	Asset Renewal	Network Option 1	Replace transformer		
		Network Option 2	Refurbish transformer	90k in yr1	Oil test results are showing that provided it is serviced, transformer will likely give further reliable service.
		Non Network Option	None available		
		Do Nothing	Transformer could fail if not refurbished.		

NATIONAL PARK POS: ZONE SUBSTATIONS					
Asset	**Constraint**	**Options**	**Description**	**Year & Cost Estimate**	**Principal Reason for this Option Choice**
TAWHAI	Hazardous Asset Renewals	Network Option 1	Rebuild site.		
		Network Option 2	ZSub513. Renew fence.	58k in yr2	Adequate fencing is important.
		Non Network Option	None available.		
		Do Nothing	Leave as is, possible security breaches due to deteriorating fence condition.		
TAWHAI	Cumulative Capacity	Network Option	ZSub513. Install a second transformer. Use a transformer out of Turangi.	699k in yr7	It is likely that customers on mountain will want both options pursued. RAL generation will also increase the reliability of supply to the ski fields. A second cable to mountain will also have to be installed when capacity of existing transformer is reached.
		Non Network Option	Install capacitors or generation to support voltage during heavy load times.		
		Do Nothing	Ski field at Whakapapa will not be able to expand.		

TABLE 7-3921: PLANNED WORK FOR ZONE SUBSTATIONS CONNECTED TO NATIONAL PARK POS

NATIONAL PARK POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
CHATEAU	Cumulative Capacity	Feeder Development	FED419	Cable from Tavern to Water Tower, 2nd Cable. Add second cable from Tawhai to Tavern.	350 in yr09 583k in yr12
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	16N04 16N05 16N06 16N07	16N04 1-Phase 15kVA. 16N05 3-Phase 50kVA. 16N06 3-Phase 200kVA. 16N07 3-Phase 200kVA.	28k in yr11 35k in yr6 52k in yr12 52k in yr12
		Switches (Hazard)	15N02 15N09 15N11 15N12 16N01 16N02 16N09 16N17 16N21 16N28 16N29	15N02 Add 11 kV switchgear to transformer. 15N09 Add 11 kV switchgear to transformer. 15N11 Add 11 kV switchgear to transformer. 15N12 Add 11 kV switchgear to transformer. 16N01 Add 11 kV switchgear to transformer. 16N02 Add 11 kV switchgear to transformer. 16N28 Add 11 kV switchgear to transformer. 16N29 Add 11 kV switchgear to transformer. 16N09 Install switchgear. 16N17 Add switchgear to this site. 16N21 Add 11 kV switchgear to transformer.	47k in yr11 47k in yr12 47k in yr8 47k in yr14 47k in yr5 47k in yr6 47k in yr4 45k in yr1 47k in yr2 47k in yr7 47k in yr7
NATIONAL PARK	Reliability	Switches (Reliability Improvement)	5151 5146	Automate to TLC's current Network Standards.	47k in yr7 47k in yr8
	Hazardous Asset Renewals	Ground Mount Transformers: Condition & Hazards	14L05 14L12	14L05 3-Phase 500kVA. 14L12 Install transformer with RTE switch.	47k in yr14 40 in yr2
		Switches (Hazard)	15L07	Install Switch Gear.	47k in yr5
		Low and Hazardous Two Pole Structures	15K06 15L05 16L02	15K06 Construct to TLC's current Network Standards. 15L05 Transformer is close to motel balcony. Ground mount transformer, check loadings for transformer size. 16L02 Construct to TLC's current Network Standards.	58k in yr11 47k in yr1 47k in yr6
OTUKOU	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	12O01	Renew Structure. (This transformer needs to be checked for loading.)	41k in yr8
	Reliability	Ground Mount Transformers: Condition & Hazards	12N08	Renew with modern equivalent.	47k in yr11

NATIONAL PARK POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
RAURIMU	Hazardous Asset Renewals	Low and Hazardous Two Pole Structures	13I10	13I10 Renew Structure. Check the loading on this transformer ETAP load flows indicate that it may be overloaded. Rebuild site. Costs slipped over 13I10 and T4132 as there are two SWER isolating transformers on the one structure.	35k in yr2
			T4077	T4077 Construct to TLC's current Network Standards.	47k in yr9
			T4132	T4132 Renew Structure. Check the loading on this transformer ETAP load flows indicate that it may be overloaded. Rebuild site. Costs split over 13I10 and T4132 as there are two SWER isolating transformers on the one structure.	35k in yr2

TABLE 7-40: PLANNED DEVELOPMENT WORK FOR 11 KV FEEDERS CONNECTED TO NATIONAL PARK POS

7.4.1.7 Assets connected to Ohakune Point of Supply

Figure 7-16 indicates the area supplied from the Ohakune POS and the connected feeders geographical location. Figure 7-17 indicates the Supply Point's relationship to the Zone Substations and Feeders downstream.

Table 7-41 to Table 7-42 lists the development work planned for assets connected to the Ohakune point of supply to eliminate the constraints listed earlier. The table lists the options considered, the final decision made, the planning year and cost estimate.

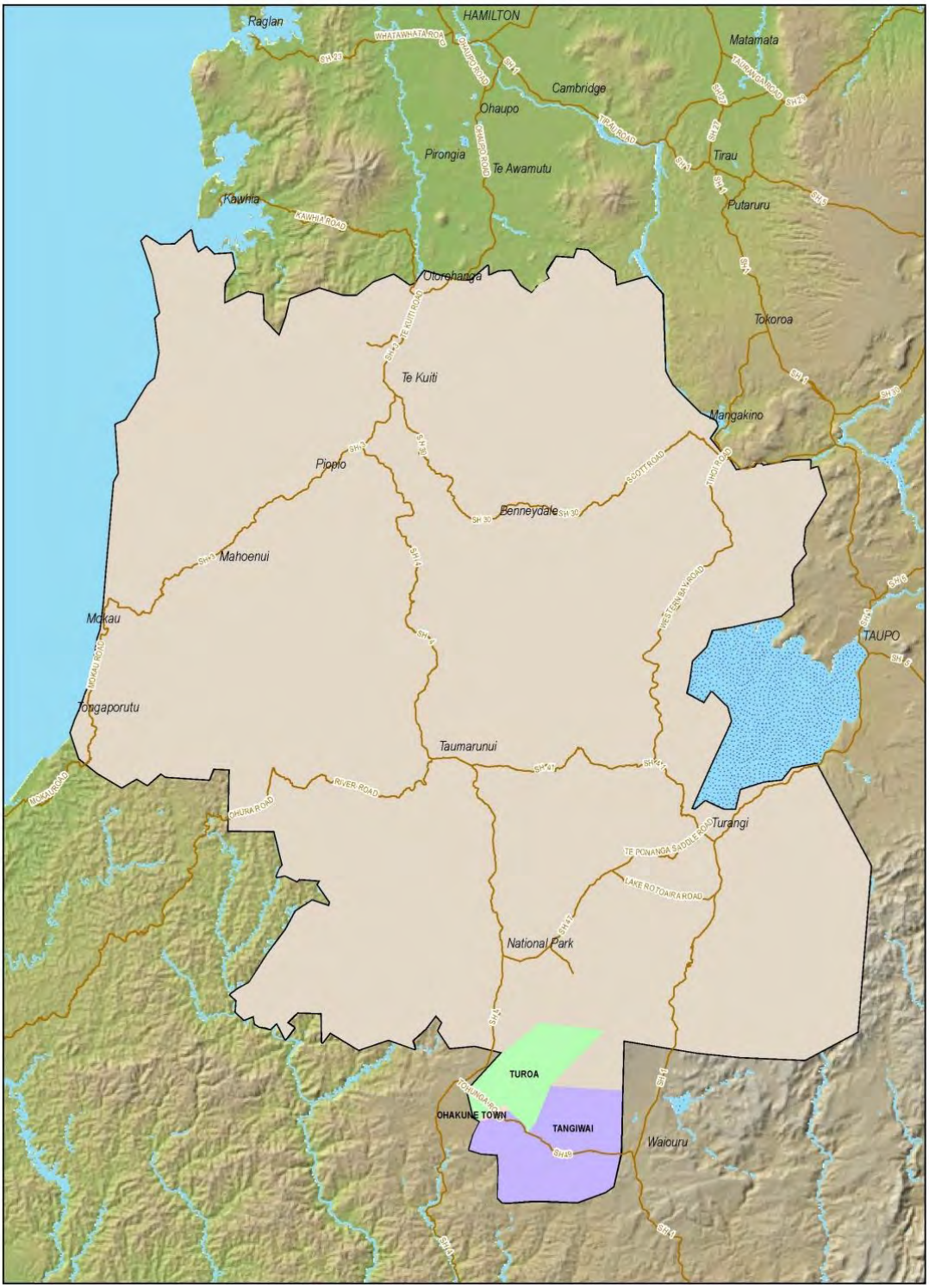


FIGURE 7-16: OHAKUNE SUPPLY AREA AND FEEDER LOCATIONS

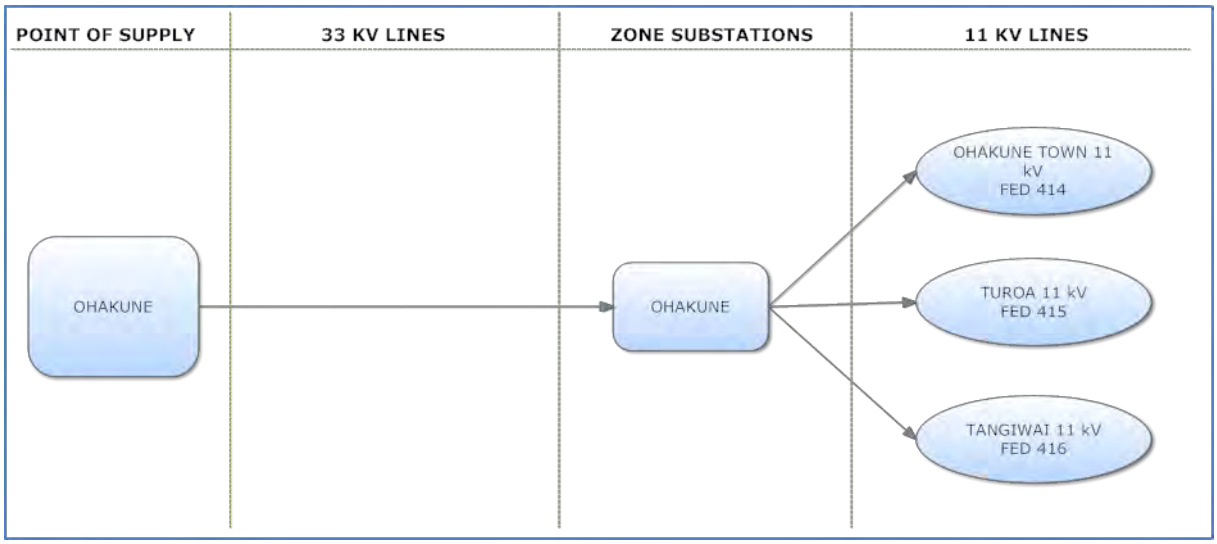


FIGURE 7-17: CONNECTION DIAGRAM OF ASSETS CONNECTED TO OHAKUNE POS

OHAKUNE POS: SUPPLY POINTS					
Asset	**Constraint**	**Options**	**Description**	**Year and Cost Estimate**	**Principal Reason for this Option Choice**
OHAKUNE	Cumulative Capacity	Network Option 1	ZSub517. The size of the conductor connecting switchgear at Ohakune substation is too small for the present loadings. Install Xiria on incomer. Break into the circuit before the cross bus. Split one feeder off. Have capacity for a spare feeder. Transpower planning includes a new 20 MVA transformer planned for 13/14 years.	175k in yr9	Most cost effective solution.
		Network Option 1	Install expensive indoor switchgear.		
		Non Network Option	Transfer loads to proposed Tangiwai supply in times of constraint.		
		Do Nothing	Possible faults due to conductor stress through overheating.		

TABLE 7-41: PLANNED WORK FOR SUPPLY POINTS CONNECTED TO OHAKUNE POS

OHAKUNE POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
OHAKUNE TOWN	Cumulative Capacity	Feeder Development	FED414	Install underground cable down Shannon Street to link Ohakune Town and Tangiwai feeders. Cable size 95 mm^2 Al XLPE Re-conductor from ferret to dog between 5925 and 6011 on Goldfinch Street Re-conductor from ferret to dog between 6644 and 6444 on Goldfinch Street	107k in yr8 210k in yr15 79k in yr4
	Hazardous Asset Renewals	Switches (Hazard)	20L15 20L18 20L59 20L68	20L15 Upgrade transformer to transformer with RTE. 20L18 Install switchgear. 20L59 Install transformer with RTE switch. 20L68 Install additional switchgear.	47k in yr1 47k in yr4 47k in yr3 80k in yr3
TANGIWAI	Reliability	Switches (Reliability Improvement)	6118	6118 Automate to TLC's current Network Standards.	26k in yr4
	Hazardous Asset Renewals	Switches (Hazard)	20L43 20L44 20L45 20L46	Install switchgear.	47k in yr3 47k in yr5 40k in yr4 35k in yr6
		Low and Hazardous Two Pole Structures	20L06 20L21	20L06 Replace structure with ground mounted transformer. 20L21 Ground mount 100 kVA transformer, use a refurbished transformer.	45k in yr3 45k in yr13

OHAKUNE POS: 11 kV ACTIVITIES (excluding Regulators and Line Renewals)					
Feeder	**Constraint**	**Allocation**	**Asset Details**	**Planned Work**	**Year and Cost Estimate**
TUROA	Reliability	Switches (Reliability Improvement)	5680 5695	5680 Automate to TLC's current Network Standards. 5695 Automate to TLC's current Network Standards.	26k in yr4 47k in yr8
	Cumulative Capacity	Feeder Development	415-01 415-04 415-04	415-01 Upgrade Cu 16mm^2 Cu XLPE cable between Magnefix switch 6420 and transformer 20L18 to a feeder strength sized cable. Check on loadings and determine cable size from predicted future loadings. 415-04 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. Wire upgrade 20/21 along Miro Street to strengthen feeder tie – conductor strength needs increasing to accommodate snow loading.	55k in yr4 87k in yr4 587k in yr8
	Hazardous Asset Renewals	Hazardous Underground Refurbishment	FED415	FED415- Cable protection as required. The cable beside the road to the ski fields is inadequately protected in places.	70k in yr9
		Switches (Hazard Improvement)	REG 28	Install bypass protection on Regulator	5k in yr4
		Switches (Hazard)	17N01 17N02 17N04	17N01 Install Switch Gear. 17N02 Install Switch Gear. 17N04 Need a visual break & earths Switch gear needed.	47k in yr8 47k in yr9 47k in yr2
		Low and Hazardous Two Pole Structures	20K09 20L19 20L31 20M01	20L09 Ground mounted with 100 kVA transformer. 20L19 Construct to TLS's current Network Standards. 20L31 Construct to TLS's current Network Standards. 20M01 Construct to TLS's current Network Standards.	47k in yr14 50k in yr7 45k in yr5 40k in yr6

TABLE 7-42: PLANNED DEVELOPMENT WORK FOR 11 KV FEEDERS CONNECTED TO OHAKUNE POS

7.4.1.8 Voltage Regulators Installs in the Development Plan to Counteract Voltage Constraints

As stated in other sections TLC's network analysis package has been built out to expected loadings in 2027/28. 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. Table 7-43 lists the voltage regulators included in the plan for 11 kV lines. (A number of regulators included in the sub-transmission system have been included in earlier sections.)

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.	99k in yr12
	Gravel Scoop	Otewa Road just before Barber. Will mainly be used when back feeding to Rangitoto and Maihiihi feeders.	101k in yr13
	Hangatiki East	Install regulator for Omya if loading increases and 33 kV modular substation option not taken.	99k in yr14
	Mahoenui	Mainly for backup of Mokau Feeder when 33 kV is out.	102k in yr7
	Maihiihi	Replace Whibley Road Regulator. This is an old type of regulator and overloads when back feeding.	106k in yr3
	Mokau	Before Mokau at old killing house site.	105k in yr6
	Mokau	Near Bolts place on top of hill.	126k in yr3
	Mokauiti	Install regulator near switch 1710 to lift voltages in the Mokauiti Valley.	102k in yr8
	Piopio	Prior to Piopio Township.	102k in yr7
	Rangitoto	Regulator towards Otewa Rd also to pick up Otewa when working on Gravel Scoop and Waipa Gorge.	101k in yr4

11 kV REGULATORS (Cumulative Capacity Allocation)			
Supply Point	**Feeder**	**Planning Notes for Voltage & Quality of Supply Improvements**	**Year and Cost Estimate**
OHAKUNE	Ohakune Town	Install regulator after 5715 near Ohakune town boundary.	101k in yr15
	Tangiwai	Assumes new Tangiwai Supply from Transpower; locate at Rangataua.	102k in yr5
	Turoa	Regulator at start of Station Road.	111k in yr2
ONGARUE	Matapuna	Install Regulator on Taupo Road to boost voltage for back feeds and customers further down Taupo Road.	99k in yr14
	Northern	By High School. Depends on load growth.	101k in yr9
	Ohura	One regulator for Ohura assuming that the coal mine venture goes ahead.	102k in yr8
	Ohura	Second Regulator assuming coal mine goes ahead.	99k in yr10
	Ongarue	Install Regulator at State Highway 4 near switch 6640.	101k in yr9
	Southern	Growth in dairying and irrigation along state highway. Just before Otapouri road. Will help lift voltage at Owhango for subdivision growth.	105k in yr13
	Western	Install regulator to accommodate increased load due to the subdivision of land for lifestyle blocks along River Road and the surrounding areas.	99k in yr10
WHAKAMARU	Mokai	Install regulator on Waihora Road before intersection of Whangamata Road so benefits both directions along Whangamata Road.	105k in yr4
	Mokai	Replace Tirohanga Road Regulator.	111k in yr12
	Pureora	Near switch 785 just after Ranganui Road on SH 30.	99K in yr11
	Pureora	Close to Crusaders Meats 4th Regulator for deer plant.	102K in yr5
	Wharepapa	Install regulator on Hingaia Road near T299.	101K in yr1
	Wharepapa	Install regulator just after switch 376 on Whatauri Road.	105K in yr15
	Wharepapa	Install regulator near 499 Aotearoa Road.	101K in yr1

TABLE 7-43: VOLTAGE REGULATORS FOR VOLTAGE CONSTRAINTS

7.4.1.9 *Upgrades of conductor sizes in the Development Plan*

The overhead conductor upgrades listed in Table 7-44 are cumulative capacity upgrades as detailed in earlier sections. 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**
Mokai	FED123	Mink	2017/18	Current & Voltage	7.0km	721k
Ohakune Town	414-01	Ferret	2016/17	Current & Voltage	0.5km	79k
Ohakune Town	414-01	Ferret	2027/28	Current & Voltage	1.5km	210k
Turoa	415-04	Mink	2020/21	Current & Voltage	5.5km	567k

TABLE 7-44: PROPOSED CONDUCTOR UPGRADES FOR CUMULATIVE CAPACITY

7.4.1.10 Analysis of Distribution Transformers (larger sizes: 2 Pole Mounted: SWER and Ground Mounted) 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.

7.4.1.11 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. The timing of many of these renewals coincides with line renewal and other projects in the areas.

7.4.1.12 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.

7.4.1.13 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. The network has been analysed on an area by area basis and the renewal programme is summarised in the tables in section 5.5.1

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.

7.4.1.14 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. Experience and evaluation of the service box stock shows that 50 p.a. need to be renewed out of the total stock of 3600 (approx. life of 60 years).

The cost estimate included for this work from years 2013 to 2028 is $101K p.a. An electrical inspector checks and tests service boxes on a five yearly cycle. Priorities are then set by this work. Refinements to the Basix system are currently being implemented to better manage and plan renewals of service boxes with respect to contractor priorities. Unless they are closely managed, service box renewals are treated with lower priorities and tend to 'slip off the radar'.

(Note: These renewals are not included in the tables above and are an output of the inspection programmes described in Section 8)

7.4.1.15 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 plants were installed in the 2010/11 year. Plan 2013 includes relays that incorporate advanced meters over the years 2013/14 to 2018/19.

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's present voice radio network is an amalgamation of three networked repeaters across the northern area installed during 1997 operating to standards that remain current, with a network of three further repeaters based on older standards in the southern area. Late in 2009 New Zealand's radio licensing authority (Ministry of Economic Development, Radio Spectrum Management) advised this older standard (originally implemented in the 1960s) was to be phased out by 1 November 2015. This requires TLC to upgrade part of their radio system before the end of 2015, so this is an appropriate time to consider options for updating the overall radio network plus adding enhanced features.

TLC has included in its Plan a five year expenditure plan to upgrade the system. Table 7-45 lists the planned capital expenditure on load control, SCADA and communications equipment for the period 2013/14to 2027/28. Provisions are expressed in current dollar value.

SUMMARY OF FORWARD EXPENDITURE PREDICTIONS FOR MISCELLANEOUS EQUIPMENT															
	2013/14	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Radio Specific	630,000	95,619	95,619	69,369	69,369	43,119	43,119	43,119	43,119	43,119	43,119	43,119	43,119	43,119	43,119
Distribution Equipment	58,268	58,268	58,268	58,268	58,268	58,268	58,268	58,268	58,268	58,268	58,268	58,268	58,268	58,268	58,269
Tap-offs with New Connections	34,962	34,962	34,962	34,962	34,962	34,962	34,962	34,962	34,962	34,962	34,962	34,962	34,962	34,962	34,962
Load Control	0	116,538	0	0	0	0	116,538	0	0	0	0	116,538	0	0	0
Protection	11,653	11,653	11,653	11,653	11,653	11,653	11,653	11,653	11,653	11,653	11,653	11,653	11,653	11,653	11,654
Radio Contingency	11,653	11,653	11,653	11,653	11,653	11,653	11,653	11,653	11,653	11,653	11,653	11,653	11,653	11,653	11,654
SCADA Contingency	17,481	17,481	17,481	17,481	17,481	17,481	17,481	17,481	17,481	17,481	17,481	17,481	17,481	17,481	17,481
Other Renewals	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCADA Specific	43,119	43,119	43,119	43,119	43,119	43,119	43,119	43,119	43,119	43,119	43,119	43,119	43,119	43,119	43,119
Transformer Renewals	349,613	349,613	349,613	349,613	349,613	349,613	349,613	349,613	349,613	349,613	349,613	349,613	349,613	349,613	349,613
TOTALS	**1,156,750**	**738,907**	**622,369**	**596,119**	**596,119**	**569,869**	**686,407**	**569,869**	**569,869**	**569,869**	**569,869**	**686,407**	**569,869**	**569,869**	**569,870**

TABLE 7-45: SUMMARY OF ESTIMATED FORWARD EXPENDITURE PREDICTIONS FOR LOAD CONTROLS, SCADA AND COMMUNICATIONS EQUIPMENT (WITHOUT INFLATION)

7.5 Description and Identification of the Network Development Programme 2013/14

This section covers the planned expenditure for capital projects under the following disclosure categories as listed in Table 7-46, along with the proposed expenditure for each category in the next 12 months.

CAPITAL EXPENDITURE PREDICTION SUMMARY - 2013/14	
Description	**Estimate**
Customer Connection	609,656
System Growth	466,454
Quality of Supply	2,069,309
Asset Replacement & Renewal - excluding Line Renewals	1,665,351
Asset Replacement & Renewal - Line Renewals	5,595,495
Asset Relocation	52,442
Non Network Assets	245,616
TOTALS	**10,704,323**

TABLE 7-46: SUMMARY OF CAPITAL EXPENDITURE PREDICTION 2013/14

7.5.1 Customer Connection Development Programme

7.5.1.1 Customer Connection Expenditure Predictions for 2013/14

Table 7-47 summarises the customer connection expenditure budgeted for projects planned for the next 12 months.

CUSTOMER CONNECTION - CAPITAL EXPENDITURE PREDICTION 2013/14	
Description	**Estimate**
General New Connection Contributions	329,544
Subdivision New Connection Contributions	115,340
Industrial New Connection and Unallocated Contributions	164,772
Specific Modifications Associated with Customer Development	0
TOTAL	**609,656**

TABLE 7-47: CUSTOMER CONNECTION CAPITAL EXPENDITURE PREDICTION 2013/14

7.5.1.2 Customer Connection Project Details

7.5.1.2.1 General New Connections Contributions - $329,544

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. Continuing with the present policy of providing customers with transformers and assuming the predicted numbers of new connections means an allowance of $329,544 has been included.

The amount of the allowance expended is dependent on the number of new connections. Customer connections for 2012 are starting to increase after a slump starting in 2008 and bottoming out in 2010. See Graph 7-4 "Applications for Connecting Load onto TLC's Network" (Section 7.3.2.1.2), which indicates the trends in load applications onto TLC network.

Alternative options

The TLC charging structure means that customers have initial and on-going incentives to minimise the capacity of their connection assets by reducing peaks and using non-asset solutions.

A number of the dairy conversions are in areas where there is only a single phase supply. They have used the available supply for vat cooling and generators for milking.

The asset related charges are also arranged to maximise connection asset utilisation. The best way to achieve lower charges is to increase the amount of controllable load and the number of installations connected to a transformer. The non-network approach for customers is to do without load through control periods or use alternative sources of energy.

Another option for TLC would be to charge customers an increased contribution for new connections. This would mean that TLC would then have to charge a lower amount as part of on-going asset related charges. This option is available to customers and a number have opted to supply or fund their own transformers and earthing.

7.5.1.2.2 Subdivision New connection Contributions - $115,340

Scope

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.

It is not possible to provide further detail on the proposed subdivisions until the subdivisions are being constructed. There are a number of small lifestyle subdivisions in the Otorohanga area and Ohakune has seen a number of applications for small residential subdivisions. However, most of these may be supplied from the existing infrastructure.

There are one or two sub-dividers that have applied for resource consent for large subdivisions, but at this stage they will not be developed until there is stronger economic confidence.

Alternative options

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.

7.5.1.2.3 Industrial New Connection Contributions and Unallocated Contributions -$164,772

Scope

TLC supplies various items and recovers these as part of on-going charges to customers when expansions and alterations are taking place. No firm commitment has been made at this time. The known projects have gone on hold; however, one limestone quarry operator is still planning to install value added plant to increase their operations. The amount of the allowance used is dependent on the level of industrial development.

Alternative options

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.

7.5.1.2.4 Specific Modifications Associated with Customer Development - $0.00

There is no allocation in this financial year. The specific needs of large customers are unknown at this time.

7.5.2 System Growth Development Programme

7.5.2.1 System Growth Expenditure Predictions for 2013/14

Table 7-48 summarises the cumulative capacity expenditure budgeted for projects planned in the next 12 months.

SYSTEM GROWTH - CAPITAL EXPENDITURE PREDICTION 2013/14	
Description	**Estimate**
Install 3MVAR capacitor bank at Borough Substation.	123,900
Install 1MVAR capacitor bank at Tuhua Zone Substation	105,000
Atiamuri Supply Point Transformer Cooling	34,962
Install regulators on 11 kV Wharepapa Feeder	101,296
Install regulators on 11 kV Wharepapa Feeder	101,296
TOTALS	**466,454**

TABLE 7-48: SYSTEM GROWTH CAPITAL EXPENDITURE PREDICTION 2013/14

7.5.2.2 System Growth Project Details

7.5.2.2.1 3MVAR Capacitor Bank at Borough Substation- $ 123,900

Scope

When the supply from Transpower (Ongarue) is unavailable TLC relies on the supply from Tokaanu via the Taumarunui/Kuratau 33 kV line. By the time supply travels about 50kms to Manunui substation the voltage is low and below the tapping range of the Borough transformers, as consequence of the low 33kV voltage is low voltage on the 11kV. The installation of a 3MVAr capacitor bank on the 11kV feeders is the most cost effective way to boost this voltage back to normal. The capacitor bank will boost the voltage sufficiently to provide an acceptable voltage to the 11 kV feeders.

Justification:

The voltage is getting down to a level that would make it below regulatory limits (about 15% below regulatory limits in the worst case).

Alternative Options:

- Hire backup generation support to help support the voltage, but this can be an expensive option with no long term benefit from the expense.
- Negotiate contract with Transpower to take supply from Taumarunui railway supply. This is a more expensive option.

7.5.2.2.2 1MVAR Capacitor Bank at Tuhua Substation- $ 105,000

Scope

When the supply from Transpower (Ongarue) is unavailable TLC relies on the supply from Tokaanu via the Taumarunui/Kuratau 33 kV line. By the time supply travels about 75kms to Ongarue the voltage is low and below the tapping range of the Nihoniho transformers, as consequence of the low 33kV voltage is low voltage on the 11kV. The installation of a 1MVAr capacitor bank on the 11kV feeders is the most cost effective way to boost this voltage back to normal. The capacitor bank will boost the voltage sufficiently to provide an acceptable voltage to the 11 kV feeders.

Justification:

The voltage is getting down to a level that would make it below regulatory limits (about 15% below regulatory limits in the worst case).

Alternative Options:

- Hire backup generation support to help support the voltage, but this can be an expensive option with no long term benefit from the expense.
- Negotiate contract with Transpower to take supply from Taumarunui railway supply. This is a more expensive option.

7.5.2.2.3 Atiamuri Supply Point Transformer - Cooling - $34,962

Scope

This project had two stages the first will be completed in 2012/13 (SCADA upgrade to include information regarding the transformer temperature). The second stage is to install cooling fans on the transformer in 2013/14.
In year 2022/23 TLC has programmed a transformer upgrade for this site. This work is a cost effective solution to allow the existing transformer to remain in service until its upgrade.

Justification

Collection of data will give TLC's planners better direction. This is the most cost effective solution and maybe modified in the long term plan if required. This transformer is in a critical location and it is often required to provide alternative supply backup. In these situations, it is called on for short term capacity at the upper end of its capacity rating. The controller needs accurate transformer temperatures at these times so better objective calls can be made on the implication of pushing this capacity. The cost of putting a second transformer into the site is significant as is the cost of failure of the present unit.

Alternative Options

The site could be left as is and the transformer could overheat reducing its life.

7.5.2.2.4 11kV Regulator on Wharepapa Feeder - $101,296

This is a long feeder supplying dairy load; the feeder currently has one regulator on it. The increasing dairy load will mean that potentially voltage will drop below regulatory limits. The installation of a Regulator in asset group 112-02 (near Aotearoa Road) of the feeder has been programmed into the plan

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.

Alternative Options:

- The feeder could be left as is, but the consequences of increased dairy load will lead to voltage breaches and extended outages to restore the site.
- 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.

7.5.2.2.5 11kV Regulator on Wharepapa Feeder - $101,296

This is a long feeder supplying dairy load; the feeder currently has one regulator on it. The increasing dairy load will mean that potentially voltage will drop below regulatory limits. The installation of a Regulator in asset group (112-06) near Hingaia Road of the feeder has been programmed into the plan

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.

Alternative Options:

- The feeder could be left as is, but the consequences of increased dairy load will lead to voltage breaches and extended outages to restore the site.
- 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.

7.5.3 Quality of Supply Development Programme

Table 7-49 summarises the capital expenditure budgets for quality of supply development for the next 12 months.

QUALITY OF SUPPLY- CAPITAL EXPENDITURE PREDICTION 2013/14	
Description	**Estimate**
Quality of supply	411,193
Hazardous Equipment Renewals (Safety)	1,299,436
Environmental Projects	358,679
TOTAL	**2,069,309**

TABLE 7-49: QUALITY OF SUPPLY CAPITAL EXPENDITURE PREDICTIONS FOR 2013/14

7.5.3.1 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 use of mobile generators and reactive voltage support units also provide a practical way of increasing network reliability and security.

The risk assessment analysis in Section 10 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

TLC has numerous sites that will give customer benefits in the 5 to 15 cents per customer minute range. These sites have been identified and laid out in the Plan outlined in earlier sections.

There are options for the automation programme. These include:

- Delaying the overall programme.
- Completing works in conjunction with other works and network development in the area.
- Targeting the worst areas.

The option selected is a combination of the latter two. (Targeting worst areas and completing works in conjunction with other projects in the area.) The reliability programme has been set at about $250,000 p.a. Experience to date has shown that this level of expenditure can be accommodated by the organisation and generates an on-going customer benefit through the network. (This current year has more expenditure allocated to allow for capacity increase on the Wharepapa and Hurimu feeders). 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. The overall long term reliability target, however, remains the same and TLC recognises that it is important to achieve this target.

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 weeks (solo staffed depots are normally on a 1 in 2 roster). This means at least a two hour mobilisation delay for the weeks when there is no local cover.

Table 7-50 lists the Quality of Supply projects planned for the next year.

Quality of Supply - 2013/14 PROJECTS AND CAPITAL EXPENDITURE PREDICTIONS		
Feeder	**Activity**	**Cost Estimates**
Manunui	Automate switch 5914	41,000
Te Kuiti South	Install new recloser 730	52,000
Te Mapara	Automate switch 1316	23,308
Tihoi	Automate new switch 454	45,000
Tirohanga	Automate new switch 434	40,000
Waihaha	Automate new switch 5150	46,615
Western	Automate switch 5404	29,135
Western	Automate switch 5795	29,135
No Feeder	Install Capacitors Arohena Zone Substation	105,000
TOTAL		**411,193**

TABLE 7-50: SUMMARY OF FEEDER PROJECTS FOR QUALITY OF SUPPLY

7.5.3.1.1 Manunui – Automate Switch 5914 - $ 41,000

Scope

The project involves the replacement and automation of 5914. This switch is the tie point between Manunui and Matapuna Feeders.

Justification:

This will give an alternative option to back feed for Taumarunui 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 Taumarunui area.

Table 7-51a lists the cost estimate benefit (based on best available data) for this project, aligned to the findings of the 2003 reliability report.

Manunui 5914 SWITCH AUTOMATION: RELIABILITY BENEFIT CALCULATION		
Number of customers that will get improved supply	A	699
Annual estimated reduction in outage minutes	B	90
Project costs	C	$56,275
Annual cost inclusive of finances, maintenance etc.	D	$9,000
Annual direct cost savings (contractors time to operate switches etc.)	E	$120
Annual cost per customer minute	$\frac{(D-E)}{(A \times B)}$	$0.14

TABLE 7-51A: RELIABILITY BENEFIT CALCULATION – MANUNUI 5914

This lies within the 0 to 20 cents per customer minute range that reliability improvement projects have been targeting since 2003.

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.

7.5.3.1.2 Te Kuiti South – Install New Recloser 730 – 52,000

Scope

The Te Kuiti South feeder has a long spur line that supplies electricity to the Arapae area, this line crosses rugged country. The existing recloser is one of the older McGraw Edison RXE which does not give us the flexibility in setting. A smarter recloser on this spur line would allow Te Kuiti Township to be unaffected by faults beyond this recloser.

Justification

Businesses in Te Kuiti Town are 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.

Table 7-51b gives the cost estimate benefit (based on best available data) for this project, aligned to the findings of the 2003 reliability report.

TE KUITI SOUTH 730 RECLOSER: RELIABILITY BENEFIT CALCULATION		
Number of customers that will get improved supply	A	520
Annual estimated reduction in outage minutes	B	90
Project costs	C	$52,000
Annual cost inclusive of finances, maintenance etc.	D	$9,000
Annual direct cost savings (contractors time to operate switches etc.)	E	$120
Annual cost per customer minute	$\frac{(D-E)}{(A \times B)}$	$0.19

TABLE 7-51B: RELIABILITY BENEFIT CALCULATION – TE KUITI SOUTH RECLOSER

This lies within the 0 to 20 cents per customer minute range that reliability improvement projects have been targeting since 2003.

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.

7.5.3.1.3 Te Mapara – Automate Switch 1316 - $23,308

FIGURE 7-18: ABS 1316

Scope

The project involves automation of an existing manually operated switch. The existing site, as shown in Figure 7-18, has a new pole and switch; therefore the most cost effective solution is a Schneider motorised unit fitted to the existing switch with an aerial and RTU for remote operation.

Justification

The automation of the existing will allow quicker power and 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.

Table 7-51c gives the cost benefit estimate (based on best available data) for this project, aligned to the findings of the 2003 reliability report.

TE MAPARA 1316 SWITCH AUTOMATION: RELIABILITY BENEFIT CALCULATION		
Number of customers that will get improved supply	A	100
Annual estimated reduction in outage minutes	B	160
Project costs	C	$23,308
Annual cost inclusive of finances, maintenance etc.	D	$3,600
Annual direct cost savings (contractors time to operate switches etc.)	E	$330
Annual cost per customer minute	$\frac{(D-E)}{(A \times B)}$	$0.20

TABLE 7-51C: RELIABILITY BENEFIT CALCULATION – TE MAPARA 1316

This lies within the 0 to 20 cents per customer minute range that reliability improvement projects have been targeting since 2003.

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.

7.5.3.1.4 Tihoi – Automate Switch 454 - $45,000

Scope

The project involves installing an ENTEC switch and RTU. The section of line beyond the 454 of the Tihoi line has no back feeds facilities in place and an automated switch will assist in quicker restoration of supply.

Justification:

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.

Table 7-51d lists the cost estimate benefit (based on best available data) for this project, aligned to the findings of the 2003 reliability report.

TIHOI 454 SWITCH AUTOMATION: RELIABILITY BENEFIT CALCULATION		
Number of customers that will get improved supply	A	85
Annual estimated reduction in outage minutes	B	170
Project costs	C	$45,000
Annual cost inclusive of finances, maintenance etc.	D	$3,600
Annual direct cost savings (contractors time to operate switches etc.)	E	$500
Annual cost per customer minute	$\frac{(D-E)}{(A \times B)}$	$0.20

TABLE 7-51D: RELIABILITY BENEFIT CALCULATION – TIHOI FEEDER RECLOSER

The results lay in the 0 to 20 cents per customer minute range that reliability improvement projects have been targeting since 2003.

Alternative Options

This site could be left as a manual switch with no automation. However, in after hours situation on alternate weekends, fault-man may have to travel from Te Kuiti which is 60 minutes away, to restore power should a fault occur. This could extend to 90min including establishment times. This would mean that TLC would not be able to meet its target service level and improve Network performance.

7.5.3.1.5 Tirohanga – Automate 434 - $40,000

Scope

The project involves the replacement and automation of 434. Automation of this switch will allow the Controller to speed up restoration to Tirohanga Road and Serenity Cove area where there are a number of dairy farms connected.

Justification

The automation of this switch will assist in reducing fault-man travelling time that will lower fault restoration times.

Table 7-51e gives the cost benefit estimate (based on best available data) for this project, aligned to the findings of the 2003 reliability report.

TIROHANGA 434 SWITCH AUTOMATION: RELIABILITY BENEFIT CALCULATION		
Number of customers that will get improved supply	A	180
Annual estimated reduction in outage minutes	B	120
Project costs	C	$40,000
Annual cost inclusive of finances, maintenance etc.	D	$3,600
Annual direct cost savings (contractors time to operate switches etc.)	E	$300
Annual cost per customer minute	$\frac{(D-E)}{(A \times B)}$	$0.15

TABLE 7-51E: RELIABILITY BENEFIT CALCULATION – TIROHANGA 434

This lies within the 0 to 20 cents per customer minute range that reliability improvement projects have been targeting since 2003.

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.

7.5.3.1.6 Waihaha – Automate 5150 - $46,615

Scope

The project involves the installation of a new switch and automation unit with a RTU Automation of this The most cost effective solution is a Schneider motorised unit fitted to the existing switch with an aerial and RTU for remote operation.

Justification

The switch supplies a remote rural area with 4km of line. 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.

Table 7-51f gives the cost benefit estimate (based on best available data) for this project, aligned to the findings of the 2003 reliability report.

WAIHAHA 5150 SWITCH AUTOMATION: RELIABILITY BENEFIT CALCULATION		
Number of customers that will get improved supply	A	500
Annual estimated reduction in outage minutes	B	60
Project costs	C	$22,511
Annual cost inclusive of finances, maintenance etc.	D	$3,600
Annual direct cost savings (contractors time to operate switches etc.)	E	$120
Annual cost per customer minute	$\frac{(D-E)}{(A \times B)}$	$0.12

TABLE 7-51F: RELIABILITY BENEFIT CALCULATION – WAIHAHA 5150

This lies within the 0 to 20 cents per customer minute range that reliability improvement projects have been targeting since 2003. .

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.

7.5.3.1.7 Western – Automate 5404 - $29,135

Scope

Automation of existing switch will allow the Controller to quickly isolate any cable faults that occur beyond this switch. The most cost effective solution is a Schneider motorised unit fitted to the existing switch with an aerial and RTU for remote operation.

Justification

Saving will be made by allowing the control room to remotely control the switch and speed fault finding if there is a cable.

Table 7-51g gives the cost benefit estimate (based on best available data) for this project, aligned to the findings of the 2003 reliability report.

WESTERN 5404 SWITCH AUTOMATION: RELIABILITY BENEFIT CALCULATION		
Number of customers that will get improved supply	A	352
Annual estimated reduction in outage minutes	B	60
Project costs	C	$29,135
Annual cost inclusive of finances, maintenance etc.	D	$3,600
Annual direct cost savings (contractors time to operate switches etc.)	E	$120
Annual cost per customer minute	$\frac{(D-E)}{(A \times B)}$	$0.15

TABLE 7-51G: RELIABILITY BENEFIT CALCULATION – WESTERN 5404

This lies within the 0 to 20 cents per customer minute range that reliability improvement projects have been targeting since 2003.

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.

7.5.3.1.8 Western – Automate 5795 - $29,135

Scope

Automation of existing switch will allow the Controller to quickly isolate fault and restore power to the Whareroa area. The most cost effective solution is a Schneider motorised unit fitted to the existing switch with an aerial and RTU for remote operation.

Justification

The Western feeder has a large amount of remote rural line. If faults occur past the switch the automation will aid in the restoration of the Pongahura area. 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.

Table 7-51h gives the cost benefit estimate (based on best available data) for this project, aligned to the findings of the 2003 reliability report.

WESTERN 5795 SWITCH AUTOMATION: RELIABILITY BENEFIT CALCULATION		
Number of customers that will get improved supply	A	260
Annual estimated reduction in outage minutes	B	65
Project costs	C	$29,135
Annual cost inclusive of finances, maintenance etc.	D	$3,600
Annual direct cost savings (contractors time to operate switches etc.)	E	$120
Annual cost per customer minute	$\frac{(D-E)}{(A \times B)}$	$0.20

TABLE 7-51H: RELIABILITY BENEFIT CALCULATION – WESTERN 5795

This lies within the 0 to 20 cents per customer minute range that reliability improvement projects have been targeting since 2003.

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.

7.5.3.1.9 Arohena Zone Substation– Capacitor Installation- $46,615

Scope

The installation of 1MVAR capacitor banks on both the Wharepapa and Hurimu feeders.

Justification

The Wharepapa and Hurimu feeder load continues to rise; the most cost effective was to increase capacity and achieve improvement is by installing 1MVAR capacitors on both feeder circuits. This will also minimise the risk of possibly voltage level breaches

Alternative Options

Restrict loading and experience possible voltage level breaches or support voltage with generator and get customers to improve power factor

7.5.3.2 Hazardous Equipment Renewals (Safety)

Hazardous equipment renewals are included in the development section in accordance with the disclosure requirements for capital expenditure. The category includes renewals for reliability, safety and environmental reasons but does not cover line renewal.

A summary of hazard elimination/minimisation projects is given in Table 7-52

HAZARD REMOVAL / MINIMISATION - 2013/14 PROJECTS AND CAPITAL EXPENDITURE PREDICTIONS	
Projects	**Estimate**
Supply Points	699,226
Zone Substations	174,806
Feeder and Switchgear	155,133
Low and Hazardous Two Pole Structures	111,615
Ground Mounted Transformers	69,615
Pillar Boxes	89,040
TOTAL	**1,299,436**

TABLE 7-52: SUMMARY OF CAPITAL EXPENDITURE; HAZARD ELIMINATION/MINIMISATION PROJECTS

7.5.3.2.1 Supply Point Hazard Minimisation Projects

Table 7-53 shows the POS hazardous renewal programmed for 2013/14.

SUPPLY POINT HAZARD REMOVAL / MINIMISATION	
Point of Supply	**Estimate**
National Park POS	699,226
TOTAL	**699,226**

TABLE 7-53: POINT OF SUPPLY HAZARD ELIMINATION/MINIMISATION PROJECTS

7.5.3.2.1.1 National Park Supply Point – Install Switchgear - $ 699,226

Scope

The equipment located at the Transpower National Park site includes a load control plant and 33kV Zone substation. Install ripple plant in a container. Rationalise the number of outgoing feeder circuit breakers and containerise the switch gear for the 11 kV Feeders. This work aligns with the installation of a new modular substation with the switch gear in a container.

Justification

The principle driver of this project is to remove the hazards associated with the existing load control plant and outgoing 11 kV protection. A by product will be lower Transpower connection charges achieved through rationalising the number of outgoing 33 kV circuits. The most cost effective solution is to rebuild the site using a modular approach.

Alternative Options

The site could be left as is with the risk of hazards to staff.

7.5.3.2.2 Zone Substation Hazard Minimisation Projects

Table 7-54 lists the zone substation hazardous renewals planned for 2013/14.

ZONE SUBSTATIONS HAZARD REMOVAL / MINIMISATION	
Zone Substation	**Estimate**
Manunui Zone Substation Circuit Breaker	174,806
TOTAL	**174,806**

TABLE 7-54: ZONE SUBSTATION HAZARD ELIMINATION/MINIMISATION PROJECTS

7.5.3.2.2.1 Manunui Zone Substation- Renew 33 kV Circuit Breaker - $174,806

Scope

Circuit breaker and protection are getting old and need maintenance/renewal to be reliable. Replace the 33 kV circuit breaker with modern equipment to increase the functionality of the breaker. This work aligns with the refurbishment of the power transformer ad the installation on the oil separation system.

Justification

The 33 kV breaker at the Manunui substation is an old bulk oil breaker and it needs upgrading to ensure the protection operates reliably. If 33 kV protection does not operate there is risk of a fault, such as a line down should a car hit a pole, and the circuit not being isolated.

Alternative Options

There are no alternative options if we are going to have reliable protection at zone substations.

7.5.3.2.3 Feeder and Switchgear Hazard Minimisation Projects

Table 7-55 lists the projects planned to minimise hazardous equipment for switchgear in the next year inclusive of engineering costs

FEEDER & SWITCHGEAR HAZARD REMOVAL / MINIMISATION - 2013/14		
Feeder	**Site**	**Estimate**
Hakiaha	FED401	58,268
Benneydale	REG14	5,250
Chateau	16N17	45,000
Ohakune Town	20L15	46,615
	TOTAL	**155,133**

TABLE 7-55: SUMMARY OF FEEDER SAFETY PROJECTS

7.5.3.2.3.1 Hakiaha Feeder – Feeder 401 - $58,268

Scope

Transformers 01A38 and 01A82 are daisy chained. Add 11kV switchgear for 01A38 and 01A82. This will allow isolation of the transformers.

Justification

The present transformers are daisy chained and cannot be isolate. This means that extensive outages are necessary to do relatively minor works. A by-product of this project will be improved reliability given that the transformers will be able to be easily isolated.

Alternative Options

The site could be left as is, but this does not reduce SAIDI minutes and reduce hazards to staff and the public.

7.5.3.2.3.2 Benneydale Feeder – Regulator 14 - $5,250

Scope

The installation of a set of fuse for the bypass protection on regulator 14.

Justification

This prevent damage to the regulator if the bypass is accidently closed when the regulator is not in the neutral tap. Experience has shown that staff, when faced with this situation, often do not understand the implications of closing the bypass when the regulator is not in the neutral tap.

Alternative Options

The site could be left as is, but the consequences of a regulator failing could lead to voltage breaches and extended outages to restore the site.

7.5.3.2.3.3 Chateau Feeder – Transformer 16N17 - $45,000

Scope

Installation of an I tank transformer outside the Meads Wall building Figure 7-19 illustrates the hazardous layout on this transformer

FIGURE 7-19: TRANSFORMER 16N17

Justification

This transformer is currently located inside the Meads Wall building. The current layout creates an access hazard for the public

Alternative Options

The site could be left as is; this does not achieve TLC's commitment to providing a non-hazardous environment for public.

7.5.3.2.3.4 Ohakune Town Feeder – Transformer 20L15 - $46,615

Scope

This transformer is daisy chained with another transformer. Replace the transformer with one containing an RTE. This will allow isolation of the other transformer.

Justification

The present transformer and daisy chained transformer cannot be isolate. This means that extensive outages are necessary to do relatively minor works. A by-product of this project will be improved reliability given that the transformers will be able to be easily isolated.

Alternative Options

The site could be left as is, but this does not reduce SAIDI minutes and reduce hazards to staff and the public.

7.5.3.2.4 Two Pole Structure Hazard Minimisation Projects

Table 7-56 lists the projects planned to minimise hazardous equipment for two pole structures in the next year.

TWO POLES STRUCTURES - 2013/14			
Feeder	**Site**	**Scope**	**Estimate**
National Park	15L05	Transformer is close to motel balcony. Replace with Ground mount transformer.	46,615
Rangipo/Hautu	11S04	Check loading on transformer, and downsize TX as required. Rebuild with standard single pole structure.	33,000
Waihaha	07Q14	Improve structure and replace. Existing equipment below regulation height.	32,000
		TOTAL	**111,615**

TABLE 7-56: TWO POLE STRUCTURE PROJECTS FOR HAZARDOUS RENEWAL IN 2013/14

FIGURE 7-20: TWO POLE STRUCTURE 07Q14

Justification

These 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. Figure 7-20 illustrates an example of one of the structures included in this Plan for improvement. It can be visualised from the photograph that a person standing on top of the fence could touch or be very close to energised exposed terminals. The 11 kV fuses are difficult for a fault-man to access and there is a risk of his ladder falling into HV jumpers.

Alternative Options

Sites could be left as is; this does not achieve TLC's commitment to minimizing hazards for staff and public.

7.5.3.2.5 Ground Mounted Transformer Hazard Minimisation Projects

Table 7-57 lists the projects planned to minimise hazardous equipment for ground mounted transformers in the 2013/14.

GROUND MOUNTED TRANSFORMERS - 2013/14		
Feeder	**Site**	**Estimate**
Mangakino	T701	46,615
Turangi	10S42	23,000
	TOTAL	**69,615**

TABLE 7-57: GROUND MOUNTED TRANSFORMER PROGRAMMED FOR HAZARD MINIMISATION IN 2013/14

7.5.3.2.5.1 Mangakino Feeder – Transformer T701- $46,615

Scope

This transformer is enclosed in a wooden structure and has open bushings inside the enclosure. Check loading and replace with a refurbished I tank of a suitable size. Install a RMU with 2 fuses, one for T2316.

Justification

The wooden structure has deteriorated and can be broken into. The enclosure is located in an area where vandalism is common. It is not difficult to remove the nailed wooden fence palings that protect the public from energised 11 kV jumpers. A double locked I tank transformer will substantially improve security.

Alternative Options

The site could be left as is; but this does not achieve TLC's commitment to minimising hazards for the public

7.5.3.2.5.2 Turangi Feeder – Transformer 10S42- $23,000

Scope

The transformer is located in a tin shed. The transformer has open HV bushing and a low voltage panel that has exposed energised metal. The scope is to replace the LV panel and cover the bushings.

Justification

Figure 7-21 illustrates the present unit working on the LV rack places staff close to the transformer bushing. The wiring on the LV rack is messy and difficult to identify circuits. The tin sheds are not as secure as the I Tank type transformers.

Alternative Options

The site could be left as is; but this does not achieve TLC's commitment to minimising hazards for the public.

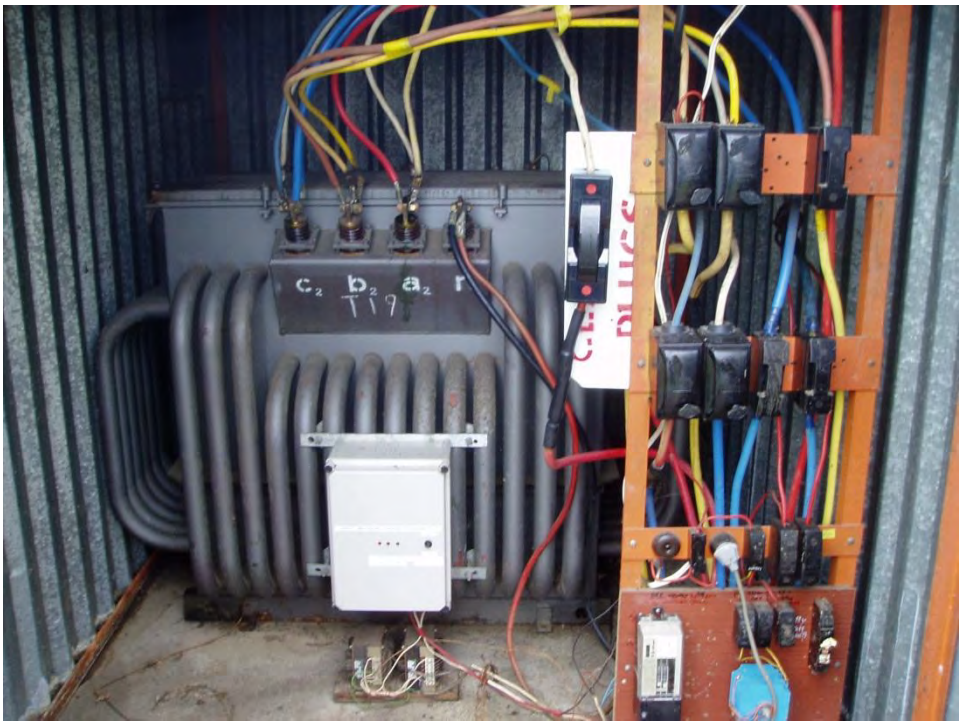


FIGURE 7-21: TRANSFORMER 10S42 LV RACK

7.5.3.2.6 Pillar Box Hazard Minimisation Projects

There are 40 sites planned for renewal in the 2013/14 year at an estimated cost of $ 89040

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.

7.5.3.3 Environmental Projects

This section covers capital expenditure on equipment upgrades associated with meeting environmental requirements. Table 7-58 summarises the planned expenditure for the next 12 months.

ENVIRONMENTAL PROJECT EXPENDITURE 2013/14		
Environmental Renewal Projects	**Scope**	**Estimate**
Manunui Zone Substation	Modify and install oil bunding, oil separation and earthquake restraints.	29,135
National Park Zone Substation	Rebuild site with a modular substation and rationalise CB in conjunction with grid exit work.	329,544
	TOTAL	**358,679**

TABLE 7-58: SUMMARY OF PLANNED EXPENDITURE FOR ENVIRONMENTAL PROJECTS 2013/14

The National Park zone substation is sited on Transpower land. The site is road side to a major State highway, and in a high tourist area with DOC land adjacent to the TP site, therefore a tidy, environmentally sound and secure solution is required.

Manunui Zone substation has no earthquake restraints or oil bunding. TLC is progressively bringing all substations up to today's environmental standards.

Justification

This is a requirement for environmental protection.

Alternative Options

The site could be left as is. There are no non-network options available.

7.5.4 Other Asset Replacement & Renewal (Excluding Line Renewals) Projects for the 2013/14 year

Table 7-59 summaries the asset renewals and replacements planned for the next 12 months.

ASSET RENEWAL AND REPLACEMENT - 2013/14	
Projects	**Estimate**
Tawhai Zone Substation Transformer Refurbish	94,543
Manunui Zone Substation Transformer Refurbish	93,230
Equipment Renewals	1,156,750
Load Control Relays	320,828
TOTAL	**1,665,350**

TABLE 7-59: SUMMARY OF RENEWAL EXPENDITURE

7.5.4.1.1 Tawhai Zone Substation- Refurbish - $94,543

Scope

The project involves removal of the transformer for a period of approximately 6 weeks. During this time the unit will be de-tanked, dried and tightened. Oil test results are showing that provided it is serviced, the transformer will likely give further reliable service.

Justification

Cheaper than letting the transformer rundown and need replacing.

Alternative Options

Replace transformer.

7.5.4.1.2 Manunui Zone Substation- Refurbish - $93,230

Scope

The project involves removal of the transformer for a period of approximately 6 weeks. During this time the unit will be de-tanked, dried and tightened. Oil test results are showing that provided it is serviced, the transformer will likely give further reliable service.

Justification

Cheaper than letting the transformer rundown and need replacing.

Alternative Options

Replace transformer.

7.5.4.1.3 Equipment Renewals - $1,156,750

Equipment renewals cover the following categories as in Table 7-60, which summarises the general non-specific individual equipment renewal contingencies.

EQUIPMENT RENEWALS - 2013/14	
Category	**Cost Estimate**
Tap-offs for new connections – Renewals bought forward	34,962
Radio Specific Renewals	630,000
Radio Contingency (Emergent)	11,653
SCADA Contingency (Emergent)	17,481
SCADA Specific Renewals	43,119
Transformer Renewals (Emergent contingency)	349,613
Protection Renewals (Emergent)	11,653
Distribution Equipment Renewals (Contingency)	58,268
TOTAL	**1,156,750**

TABLE 7-60: RENEWAL PROJECT FOR 2013/14

7.5.4.1.3.1 Tap-offs with new connections - $34,962

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.

7.5.4.1.3.2 Radio Specific - $630,000

TLC is upgrading is radio communication sites over a 3 year period, with the majority of the work being completed in 2013/14. Initially TLC needs to comply with the regulations that have a deadline of 2015 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.

7.5.4.1.3.3 Radio Contingency - $11,653

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.

7.5.4.1.3.4 SCADA Contingency - $17,481

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 70 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.

7.5.4.1.3.5 SCADA Specific – $43,119

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.

7.5.4.1.3.6 Transformer Renewals $349,613

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. The work completed as part of this covers painting and other tidying after about 20 to 30 years of service to allow the unit to run through to about 50 to 60 years of service.

7.5.4.1.3.7 Protection & Voltage Relays - $11,653

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.

7.5.4.1.3.8 Distribution Equipment – 58,268

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.

7.5.4.1.4 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 6 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.

2012/13 saw the roll out of a number of units to test the technology. 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. The estimates are as follows in Table 7-61.

RELAY RENEWAL PROGRAMME		
Year	**Number of relays**	**Estimated cost exclusive of inflation**
Year 1	1500	320,828
Year 2	1500	320,828
Year 3	1500	320,828
Year 4	300	68,828
Year 5	150	37,328
Year 6	50	16,328
	TOTAL	**1,084,968**

TABLE 7-61: RELAY RENEWAL PROGRAMME

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.

7.5.5 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 full details of the line renewal expenditure as summarized in Table 7-62.

ASSET RENEWAL AND REPLACEMENT – LINE RENEWAL CAPITAL EXPENDITURE PREDICTION - 2013/14	
Project	**Estimate**
33 kV Line Renewal (includes emergent)	1,012,660
11 kV Line Renewals (includes emergent)	4,459,256
LV Line Renewals (includes emergent)	123,579
TOTAL	**5,595,495**

TABLE 7-62: SUMMARY OF LINE RENEWAL CAPITAL EXPENDITURE PREDICTIONS

7.5.6 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 $52,442 has been included in estimates for 2013/14.

Note: This expenditure may be varied due to the changing legislation for access to railway and road corridors.

7.5.7 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 $245,616 p.a. has been included for the planning period.

7.6 Summary Description of the Projects Planned for the next 4 years (2014/15 to 2017/18)

7.6.1 Unknowns

The unknowns that will affect plans are:

- Distributed generation development - which schemes will go ahead is unknown.
- 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. The economics of wind farms appear to be marginal and as a consequence of this the commercial negotiations are taking some time to resolve. This has resulted in the transfer of predicted expenditure in earlier plans into years further out. Similarly the resource consent process has slowed a number of proposed hydro developments.

7.6.2 Summary of Expenditure Predictions 2014/15 to 2017/18 in disclosure categories

A summary of the disclosure categories expenditure predictions (without inflation) is listed in Table 7-63.

DISCLOSURE CATEGORY EXPENDITURE PREDICTIONS 2013/14 to 2016/17				
Description	**2014/15**	**2015/16**	**2016/17**	**2017/18**
Customer Connections	609,656	2,518,675	832,697	1,182,311
System Growth	110,711	2,197,487	718,606	949,864
Quality of Supply	1,855,158	2,035,894	847,307	976,123
Asset Replacement & Renewal – excluding Line Renewal	1,059,734	943,196	1,364,172	633,446
Asset Replacement & Renewal – Line Renewal (includes emergent)	5,824,671	5,960,910	5,890,374	6,658,799
Asset Relocation	52,442	52,442	52,442	52,442
Non System Fixed Asset	239,316	239,316	239,316	239,316
TOTALS	**9,751,689**	**13,947,921**	**9,944,914**	**10,692,302**

TABLE 7-63: SUMMARY OF EXPENDITURE PREDICTIONS GROUPED BY DISCLOSURE CATEGORIES FOR THE NEXT 4 YEARS (WITHOUT INFLATION)

7.6.2.1 Customer Connection Capital Expenditure Predictions

Scope of General, Subdivision and Industrial Connection Expenditure

This includes earthing, substations, points of connection, isolation/protection, transformers, switchgear and other items associated with general, subdivision and industrial new connections. Contingencies for general connections, transformers and earthing; subdivisions and unallocated; industrials have been reduced from the boom years of economic activity to a lower level. The estimates have been increased from 2015 onwards to reflect an increased level of activity based on the assumption that the effects of the 2009 recession will likely be over by this time.

Table 7-64 summaries the Customer Connection expenditure predictions for the years 2014/15 through to 2017/18 without inflation.

CUSTOMER CONNECTION EXPENDITURE PREDICTIONS 2014/15 to 2017/18				
Description	**2014/15**	**2015/16**	**2016/17**	**2017/18**
General new connection contributions	329,544	384,468	384,468	384,468
Subdivision new connection contributions	115,340	142,802	142,802	142,802
Industrial new connection and unallocated contributions	164,772	247,158	247,158	247,158
Substation & Supply Points	0	116,247	0	0
33 kV Lines	0	1,628,000	58,268	407,883
TOTALS	**609,656**	**2,518,675**	**832,697**	**1,182,311**

TABLE 7-64: CUSTOMER CONNECTION EXPENDITURE PREDICTIONS FOR THE NEXT 4 YEARS (WITHOUT INFLATION)

Scope of Specific Projects for 2014/15

1. The general new connection contributions, subdivision new connection contributions and industrial new connection and unallocated contributions have been rolled forward at expected levels. (It is not possible to provide any more detail on these because specific customer requirements are unknowns and short term.)

Scope of Specific Projects for 2015/16

1. The general new connection contributions, subdivision new connection contributions and industrial new connection and unallocated contributions have been rolled forward at expected levels. (It is not possible to provide any more detail on these because specific customer requirements are unknowns and short term.)
2. Substation and supply points and 33 kV line projects:
   a. Additional expenditure has been included for improving the reliability of the Taharoa lines in conjunction with expansion proposals at the site. This is based on the expectation that the Iron Sands will require an improved level of reliability. (An allowance of $116,247 has been included.)
   b. Additional expenditure (An allowance of $1,628,000 has been included.)has been included for upgrading the 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 there is an expectation that the Iron Sands will require an improved level of reliability. The second is that the existing equipment is aged and operating in an extreme environment. There are hazards associated with existing equipment and these need considering.

Scope of Specific Projects for 2016/17

1. The general new connection contributions, subdivision new connection contributions and industrial new connection and unallocated contributions have been rolled forward at expected levels.
2. Substation and supply points and 33 kV line projects:
    a. This expenditure is for follow-on work for Taharoa substation if the work in the previous year is finished and the customer wants further upgrade work completed.

Scope of Specific Projects for 2017/18

1. The general new connection contributions, subdivision new connection contributions and industrial new connection and unallocated contributions have been rolled forward at expected levels.
2. Substation and supply points and 33 kV line projects:
    a. This expenditure is for Waitete the project involves the installation of a modular substation at industrial sites.

7.6.2.2 System Growth Capital Expenditure Predictions

Table 7-65 lists the system growth capital expenditure predictions for the period 2014/15 through to 2017/18 without inflation.

SYSTEM GROWTH EXPENDITURE PREDICTIONS 2014/15 to 2017/18				
Description	**2014/15**	**2015/16**	**2016/17**	**2017/18**
11kV Feeders	0	0	221,078	746,540
33kV Feeders	0	106,649	291,348	0
Regulators	110,711	231,336	206,181	203,324
Substations	0	466,151	0	0
Supply Points	0	1,500,000	0	0
TOTAL	**110,711**	**2,197,487**	**718,606**	**949,864**

TABLE 7-65: SYSTEM GROWTH CAPITAL EXPENDITURE PREDICTIONS FOR THE NEXT 4 YEARS (WITHOUT INFLATION)

Scope of Specific Projects for 2014/15

1 Regulators
The allowance is for an additional regulator on the Ohakune town boundary to support voltage into the town during major holiday weekends.

Scope of Specific Projects for 2015/16

1 Substations
The allowance is for a modular substation on Sandal Road in Whakamaru to alleviate the voltage problems in the surrounding area.

2 33 kV Feeders
The allowance is for additional reactive power capacitor installation in Manunui, Taumarunui or Tuhua/Nihoniho to give additional stability and capacity in a back feed situation when the Ongarue Transpower substation is not available.

3 Regulators
Two voltage regulators are proposed. These will be dependent on system growth. The units are proposed for:

a. Whibley Road
The voltage regulator at this existing site is old and overloads when back feeding. The proposal is to replace it with an increased capacity regulator and one that can operate in the reverse direction.

b. Mokau
The Mokau feeder sees voltage drops in the holiday season and over the winter period. The proposal is to install a voltage regulator prior to an existing regulator to increase voltage that is presently marginally compliant.

4 Supply Point
a. Due to the increase in voltage constraints 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.

Scope of Specific Projects for 2016/17

1 11kV Feeders

a. 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.

b. Turoa - Upgrade Cu 16mm Cu XLPE cable between Magnefix switch 6420 and transformer 20L18 to a feeder strength sized cable. Check on loadings and determine cable size from predicted future loadings.

c. Ohakune Town – Re-conductor from ferret to dog between 6644 and 6444 on Ayr Street.

2 33kV Feeders
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.

3 Regulators
An allowance for an additional two voltage regulators is included for the Mokai and Rangitoto feeders. The Mokai regulator is necessary to accommodate lad growth from small lifestyle blocks and dairying. The Rangitoto regulator is to support load growth due to dairying development.

Scope of Specific Projects for 2017/18

1. 11 kV Feeders
Mokai Feeder –Re-conductor Tirohanga Road from New Substation site near injection pumps to Okama Rd. 7 km of line to Mink. This allows for better back feed options and more security of supply

2. Regulators
An allowance for an additional two voltage regulators is included for the Tangiwai and Pureora feeders. Assuming new Tangiwai Supply from Transpower goes ahead a regulator located at Rangatawa will aid in the support of load growth. The Pureora feeder will require a regulator close to Crusaders Meats due to load growth of the deer plant.

7.6.2.3 Quality of Supply Capital Expenditure Predictions

Table 7-66 lists the quality of supply projects and environmental capital expenditure predictions for the period 2014/15 through to 2017/18 without inflation.

Quality of Supply EXPENDITURE PREDICTIONS 2014/15 to 2017/18				
	2014/15	**2015/16**	**2016/17**	**2017/18**
Quality of supply	800,252	487,153	144,253	289,757
Hazardous Equipment Renewals (Safety)	1,054,906	1,548,741	668,093	639,751
Environmental Projects	0	0	34,961	46,615
Totals	**1,855,158**	**2,035,894**	**847,307**	**976,123**

TABLE 7-66: QUALITY OF SUPPLY PROJECT EXPENDITURE PREDICTIONS FOR THE NEXT 4 YEARS (WITHOUT INFLATION)

7.6.2.3.1 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 give customer minutes within the 2003 Reliability Report ranges. (0 to 15 cents per customer minute).

Scope of Specific Projects for 2014/15

1 Switches programmed for automation to improve network reliability include:
   a. ABS 423 on the Pureora Feeder
   b. ABS 5207 on the Rangipo / Hautu Feeder
   c. Links 6127 and ABS 5984 on the Northern Feeder
   d. ABS 5831 on the Hakiaha Feeder
   e. ABS 645 & ABS 308 on the Otorohanga Feeder.

2 Build a semi -mobile load control plant that can be relocated. Reuse the load control plant that is to be removed from National Park. This is the lowest cost option. It would be difficult to justify and construct full redundancy at each site. Work is proposed to be completed in conjunction with the National Park rebuild. A new plant is proposed to be purchased and containerised. The existing National Park plant would then be swapped out and set up as the modular plant.

3 Add additional back up transformer off Mokai 1 bus to supply Mokai Energy Park.

Scope of Specific Projects for 2015/16

1 Switches programmed for automation to improve network reliability include:
   a. Sectionaliser 6353 on the Kuratau Feeder
   b. ABS 5838 on the Matapuna Feeder
   c. ABS 5912 on the Manunui Feeder
   d. ABS 5151 on the National Park Feeder
   e. ABS 288 on the Otorohanga Feeder.
   f. SEC 6353 on the Kuratau Feeder

2 To improve reliability and for added security, build a semi-mobile containerised 2.5 MVA substation. Non network solutions would be to hire in generator or mobile substation at times of network or substation failure, but this would be a more expensive option.

Scope of Specific Projects for 2016/17

1 Switches programmed for automation to improve network reliability include:
   a. Links 6355 on the Kuratau Feeder
   b. ABS 5680 On the Turoa Feeder
   c. ABS 6118 on the Tangiwai Feeder
   d. ABS 387 & ABS 328 on the McDonalds Feeder.

Scope of Specific Projects for 2017/18

1 Switches programmed for automation to improve network reliability include:
   a. ABS 320 on the McDonalds Feeder
   b. ABS 5357 on the Matapuna Feeder
   c. ASB 5921 on the Kuratau Feeder
   d. ABS 463 on the Whakamaru Feeder
   e. ABS 5136 on the Southern Feeder

1 LV Links at T554 on the Otorohanga Feeder

7.6.2.3.2 Hazard Elimination/Minimisation (Safety)

There are no non-asset alternatives to the network having to be hazard controlled for the public and staff.

Scope of Specific Projects for 2014/15

1 Pillar box hazard elimination - 37 pillars programmed for this year.

2 Two pole transformer structures programmed for safety improvements include:
   a. 09T04 - Motuoapa Feeder
   b. 05G03 – Tuhua Feeder
   c. 01K02 - Ongarue Feeder
   d. T2153 - Mokau Feeder.
   e. 08K14 & 07K11 - Manunui Feeder
   f. T559 – Te Kuiti South Feeder
   g. 13I10 & T4132 – Raurimu Feeder

3 Ground mounted transformers programmed for safety improvements include:
   a. T700 - Mangakino Feeder
   b. 10S44 - Turangi Feeder
   c. 14L12 – National Park Feeder
   d. T663 - Oparure Feeder.

4 Switches to be installed in association with transformers programmed for safety improvements include:
   a. 09U11 – Oruatua Feeder
   b. 08R20 - Kuratau Feeder
   c. 08I55 – Western Feeder
   d. 17N04 – Turoa Feeder
   e. 16N21 – Chateau Feeder
   f. REG 26 – Pureora Feeder

5 Tawhai zone substation fence has gaps in it that have been temporarily repaired. The site is located on the edge of a State Highway and main tourist route. Substation security is vital to maintaining a safe environment for the public.

6 Feeder development work is planned for the Oruatua feeder, part of which crosses a trout fishing stream. This line creates a hazard to those fishing. The plan includes installing cable and attaching it to the bridge that crosses the stream. This work is to be done in conjunction with work on transformer 09U11.

Scope of Specific Projects for 2015/16

1 Pillar box hazard elimination - 30 pillars programmed for this year.

2 Two pole transformer structures programmed for safety improvements include:
   a. 09K50 - Southern Feeder
   b. 01A46 - Northern Feeder
   c. 01B11 – Hakiaha Feeder
   d. 20L06 - Tangiwai Feeder
   e. T1777 – Te Mapara Feeder
   f. 09R27 – Kuratau Feeder
   g. T1865, T2520 & T1453 - Mahoenui Feeder.

3 Ground mounted transformers programmed for safety improvements include:
   a. 10S26 - Turangi Feeder
   b. T406 - Waitomo Feeder
   c. T381 – Hangatiki East Feeder.

4 Switches to be installed in association with transformers programmed for safety improvements include:
   a. 09R14 & 09R16 – Kuratau Feeder
   b. 20L43 - Tangiwai Feeder
   c. 20L59 & 20L68 – Ohakune Town Feeder
   d. REG 01 – Maihiihi Feeder

5 Waitete zone substation fence needs replacement to improve security of the site.

6 Turangi Zone Substation - renew 11 kV circuit breakers.

7 Reticulation renewal work is planned for the Whakamaru old hydro village. 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, new 16mm^2 N/S street light cable and TUDs pillar boxes. May need to include replacement of service-mains to boxes currently installed on the house walls.

Scope of Specific Projects for 2016/17

1 Pillar box hazard elimination - 10 pillars programmed for this year. The number has been reduced due to the work done in previous years. (The hazardous legacy sites have now been addressed.)

2 Two pole transformer structures programmed for safety improvements include:
   a. T1081 - Mangakino Feeder
   b. T2506- Benneydale Feeder
   c. 02K08 - Ongarue Feeder
   d. 09K25 – Southern Feeder
   e. 08I21- Western Feeder
   f. 08L17 – Manunui Feeder
   g. T1829 – Te Mapara Feeder

3 Ground mounted transformers programmed for safety improvements include:
   a. 10S29 - Turangi Feeder
   b. 07D24 - Ohura Feeder
   c. T464 – Rangitoto Feeder
   d. T457 - Oparure Feeder.

4 Switches to be installed in association with transformers programmed for safety improvements include:
   a. 10S03 – Rangipo / Hautu Feeder
   b. 20L45 - Tangiwai Feeder
   c. 16N09 – Chateau Feeder
   d. REG 28 – Turoa Feeder

Scope of Specific Projects for 2017/18

1 Pillar box hazard elimination - 3 pillars programmed for this year. The number has been reduced due to the work done in previous years. (The hazardous legacy sites have now been addressed.)

2 Two pole transformer structures programmed for safety improvements include:
   a. 02K16 - Ongarue Feeder
   b. T2177 – Mokau Feeder
   c. 08H03 – Western Feeder
   d. 20L31 – Turoa Feeder
   e. T478 – Te Kuiti South Feeder
   f. 07D08 – Ohura Feeder

3 Ground mounted transformers programmed for safety improvements include:
   a. T547 – Coast Feeder
   b. 01B24 – Matapuna Feeder
   c. T699 – Otorohanga Feeder
   d. 10S39 – Turangi Feeder

4 Switches to be installed in association with transformers programmed for safety improvements include:
   a. 07R16 – Waihaha Feeder
   b. 20L44 – Tangiwai Feeder
   c. 16N01 – Chateau Feeder
   d. 15L07 – National Park Feeder
   e. REG 04 – Benneydale Feeder

7.6.2.3.3 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.

Scope of Specific Projects for 2016/17

1 Borough zone substation has to have manual bund draining done after rain. This is costly and not robust. Install oil separation.
2 Hangatiki zone substation has to have manual bund draining done after rain. This is costly and not robust. Install oil separation.

Scope of Specific Projects for 2017/18

1 Oparure zone substation has to have manual bund draining done after rain. This is costly and not robust. Install oil separation.

7.6.2.4 Asset Replacement & Renewal excluding Line Renewal Capital Expenditure Predictions

Table 7-67 lists the asset replacement and renewal expenditure for the years 2014/15 to 2017/18.

ASSETS RENEWAL AND REPLACEMENT - EXCLUDING LINE RENEWALs CAPITAL EXPENDITURE PREDICTIONS 2014/15 to 2017/18				
Asset	**2014/15**	**2015/16**	**2016/17**	**2017/18**
Equipment Renewals	738,907	622,369	596,119	596,119
Relays	320,828	320,828	68,828	37,328
Supply Points			699,226	
Totals	**1,059,734**	**943,196**	**1,364,172**	**633,446**

TABLE 7-67: ASSET REPLACEMENT & RENEWAL EXPENDITURE (EXCLUDING LINE RENEWALS) FOR THE NEXT 4 YEARS (WITHOUT INFLATION)

7.6.2.4.1 Equipment Renewals

General non-specific individual equipment renewal contingencies for the next four years are summarised in Table 7-68.

EQUIPMENT RENEWAL CAPITAL EXPENDITURE PREDICTIONS 2014/15 to 2017/18				
Category	**2014/15**	**2015/16**	**2016/17**	**2017/18**
Radio Specific	95,619	95,619	69,369	69,369
Radio Contingency	11,653	11,653	11,653	11,653
SCADA Specific	43,119	43,119	43,119	43,119
SCADA Contingency	17,481	17,481	17,481	17,481
Tap-offs with new connections	34,962	34,962	34,962	34,962
Load Control	116,538	0	0	0
Transformer Renewals	349,613	349,613	349,613	349,613
Protection	11,653	11,653	11,653	11,653
Distribution Equipment	58,268	58,268	58,268	58,268
TOTAL	**738,907**	**622,369**	**596,119**	**596,119**

TABLE 7-68: EQUIPMENT RENEWAL EXPENDITURE PREDICTIONS FOR THE NEXT 4 YEARS (WITHOUT INFLATION)

7.6.2.4.1.1 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.

7.6.2.4.1.2 Radio Contingency

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.

7.6.2.4.1.3 SCADA Specific

Annual allowance based on recommendations from SCADA experts to keep equipment up to date.

7.6.2.4.1.4 SCADA Contingency

This is a contingency amount per annum for replacing failed SCADA equipment.

7.6.2.4.1.5 Tap-offs with New Connections

This is a contingency amount per annum to cover brought forward renewals associated with replacing poles when new customer connections are taking place.

7.6.2.4.1.6 Load Control

This is an amount for renewals and upgrades to the load control plants.

7.6.2.4.1.7 Distribution Transformer Renewals

This is a contingency amount per annum for renewal of transformers that are uneconomic to repair. (Generally repair cost is greater than regulatory value). Typically units are renewed when repair cost is greater than regulatory value: see earlier sections for criteria details.

7.6.2.4.1.8 Protection

This is a contingency amount per annum for replacing relays and voltage control equipment on failure.

7.6.2.4.1.9 Distribution Equipment Contingency

This is a contingency amount per annum for failed equipment. (Typically circuit breakers and regulators.)

7.6.2.4.1.10 On-going Radio Equipment Renewals

Annual allowance based on recommendations from communication specialists to keep equipment up to date.

7.6.2.4.2 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.

7.6.2.4.3 Supply Points

Expenditure is for the rationalisation of the number of outgoing feeder breakers. 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.

7.6.2.5 Asset Replacement & Renewal – Line Renewal Capital Expenditure Predictions

The Line Renewal projects planned for 2014/15 to 2017/18 are detailed in Section 6 of the AMP. A summary of the proposed expenditure for the next four years is shown in Table 7-69.

ASSET RENEWAL AND REPLACEMENT – LINE RENEWAL EXPENDITURE PREDICTIONS 2014/15 to 2017/18				
Projects	**2014/15**	**2015/16**	**2016/17**	**2017/18**
33 kV Line Renewal (includes emergent)	593,448	481,456	678,262	1,014,281
11 kV Line Renewals (includes emergent)	5,022,512	4,765,442	4,657,379	4,738,273
LV Line Renewals (includes emergent)	208,711	714,012	554,732	906,246
TOTAL	**5,824,671**	**5,960,910**	**5,890,374**	**6,658,799**

TABLE 7-69: ASSET REPLACEMENT AND RENEWAL – LINE RENEWAL CAPITAL EXPENDITURE PREDICTIONS FOR THE NEXT 4 YEARS (WITHOUT INFLATION)

7.6.2.1 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 $52,442 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.

7.6.2.2 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 $239,316 p.a. has been included for the planning period.

7.6.3 Summary of Capital Projects and Expenditure Predictions 2013/14 to 2017/18

The following tables summarise capital expenditure projects and cost predictions (excluding Line Renewals which are covered in Section 8) by Point of Supply (or GXP) and for the years 2013/14 to 2017/18.

Table 7-70 lists the work that relates to non-specific Point of Supply for the next 5 years. It lists all capital work projects and the estimated costs in current dollars, without inflation and inclusive of engineering costs.

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2013/14	Customer Driven Project	Various	General Connections - Earthing and tap-offs	165k
2013/14	Customer Driven Project	Various	General Connections - Transformers	165k
2013/14	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
2013/14	Customer Driven Project	Various	Industrials - Transformers	110k
2013/14	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
2013/14	Customer Driven Project	Various	Subdivisions - Management	11k
2013/14	Customer Driven Project	Various	Subdivisions - Transformers	82k
2013/14	Line Renewal	Whole Network	11kV Planned Line Renewals	4459k
2013/14	Line Renewal	Whole Network	33kV Planned Line Renewals	1013k
2013/14	Line Renewal	Whole Network	LV Planned Line Renewals	124k
2013/14	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2013/14	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2013/14	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2013/14	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2013/14	Network Equipment Renewal	Whole Network	Protection	12k
2013/14	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2013/14	Network Equipment Renewal	Whole Network	RADIO Specific	630k
2013/14	Network Equipment Renewal	Whole Network	Relay Changes	321k
2013/14	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2013/14	Network Equipment Renewal	Whole Network	SCADA Specific	43k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2013/14	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2013/14	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2013/14	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	89k
2014/15	Customer Driven Project	Various	General Connections - Earthing and tap-offs	165k
2014/15	Customer Driven Project	Various	General Connections - Transformers	165k
2014/15	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
2014/15	Customer Driven Project	Various	Industrials - Transformers	110k
2014/15	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
2014/15	Customer Driven Project	Various	Subdivisions - Management	11k
2014/15	Customer Driven Project	Various	Subdivisions - Transformers	82k
2014/15	Line Renewal	Whole Network	11kV Planned Line Renewals	5023k
2014/15	Line Renewal	Whole Network	33kV Planned Line Renewals	593k
2014/15	Line Renewal	Whole Network	LV Planned Line Renewals	209k
2014/15	Network Equipment Renewal	Whole Network	Semi Mobile Containerised Load Control Plant	70k
2014/15	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2014/15	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2014/15	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2014/15	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2014/15	Network Equipment Renewal	Whole Network	Load Control	117k
2014/15	Network Equipment Renewal	Whole Network	Protection	12k
2014/15	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2014/15	Network Equipment Renewal	Whole Network	RADIO Specific	96k
2014/15	Network Equipment Renewal	Whole Network	Relay Changes	321k
2014/15	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2014/15	Network Equipment	Whole Network	SCADA Specific	43k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
	Renewal			
2014/15	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2014/15	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2014/15	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	82k
2015/16	Customer Driven Project	Various	General Connections - Earthing and tap-offs	192k
2015/16	Customer Driven Project	Various	General Connections - Transformers	192k
2015/16	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
2015/16	Customer Driven Project	Various	Industrials - Transformers	192k
2015/16	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
2015/16	Customer Driven Project	Various	Subdivisions - Management	11k
2015/16	Customer Driven Project	Various	Subdivisions - Transformers	110k
2015/16	Line Renewal	Whole Network	11kV Planned Line Renewals	4765k
2015/16	Line Renewal	Whole Network	33kV Planned Line Renewals	481k
2015/16	Line Renewal	Whole Network	LV Planned Line Renewals	714k
2015/16	Network Equipment Renewal	Whole Network	Semi Mobile Containerised 2.5 MVA Substation	290k
2015/16	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2015/16	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2015/16	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2015/16	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2015/16	Network Equipment Renewal	Whole Network	Load Control	0k
2015/16	Network Equipment Renewal	Whole Network	Protection	12k
2015/16	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2015/16	Network Equipment Renewal	Whole Network	RADIO Specific	96k
2015/16	Network Equipment Renewal	Whole Network	Relay Changes	321k
2015/16	Network Equipment Renewal	Whole Network	SCADA Contingency	17k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2015/16	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2015/16	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2015/16	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2015/16	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	67k
2016/17	Customer Driven Project	Various	General Connections - Earthing and tap-offs	192k
2016/17	Customer Driven Project	Various	General Connections - Transformers	192k
2016/17	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
2016/17	Customer Driven Project	Various	Industrials - Transformers	192k
2016/17	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
2016/17	Customer Driven Project	Various	Subdivisions - Management	11k
2016/17	Customer Driven Project	Various	Subdivisions - Transformers	110k
2016/17	Line Renewal	Whole Network	11kV Planned Line Renewals	4657k
2016/17	Line Renewal	Whole Network	33kV Planned Line Renewals	678k
2016/17	Line Renewal	Whole Network	LV Planned Line Renewals	555k
2016/17	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2016/17	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2016/17	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2016/17	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2016/17	Network Equipment Renewal	Whole Network	Protection	12k
2016/17	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2016/17	Network Equipment Renewal	Whole Network	RADIO Specific	69k
2016/17	Network Equipment Renewal	Whole Network	Relay Changes	69k
2016/17	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2016/17	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2016/17	Network Equipment	Whole Network	Tap Offs with New Connection	35k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
	Renewal			
2016/17	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2016/17	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	22k
2017/18	Customer Driven Project	Various	General Connections - Earthing and tap-offs	192k
2017/18	Customer Driven Project	Various	General Connections - Transformers	192k
2017/18	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
2017/18	Customer Driven Project	Various	Industrials - Transformers	192k
2017/18	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
2017/18	Customer Driven Project	Various	Subdivisions - Management	11k
2017/18	Customer Driven Project	Various	Subdivisions - Transformers	110k
2017/18	Line Renewal	Whole Network	11kV Planned Line Renewals	4738k
2017/18	Line Renewal	Whole Network	33kV Planned Line Renewals	1014k
2017/18	Line Renewal	Whole Network	LV Planned Line Renewals	906k
2017/18	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2017/18	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2017/18	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2017/18	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2017/18	Network Equipment Renewal	Whole Network	Protection	12k
2017/18	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2017/18	Network Equipment Renewal	Whole Network	RADIO Specific	69k
2017/18	Network Equipment Renewal	Whole Network	Relay Changes	37k
2017/18	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2017/18	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2017/18	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2017/18	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2017/18	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	7k

TABLE 7-220: SUMMARY OF PROJECTS AND EXPENDITURE PREDICTIONS 2013/14 TO 2017/18 FOR NON SPECIFIC POS (WITHOUT INFLATION)

Table 7-71 lists the work that relates to Hangatiki Point of Supply for the next 5 years. It lists all capital work projects and the estimated costs in current dollars, without inflation and inclusive of engineering costs.

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2013/14	Switches (Hazard)	Benneydale	REG14 Install bypass protection on regulator.	5k
2013/14	Switches (Reliability Improvement)	Te Kuiti South	730 Replace recloser.	52k
2013/14	Switches (Reliability Improvement)	Te Mapara	1316 Automate switch.	23k
2014/15	Switches (Reliability Improvement)	Otorohanga	645 Automate switch.	23k
2014/15	Switches (Reliability Improvement)	Otorohanga	308 Automate switch.	23k
2014/15	Transformer - 2 Pole Structures	Mokau	T2153 Rebuild restructure with standard single pole design.	28k
2014/15	Transformer - 2 Pole Structures	Te Kuiti South	T559 Replace with ground mounted transformer.	48k
2014/15	Transformers - Ground Mounted	Oparure	T663 Replace with refurbished I tank transformer.	36k
2015/16	Regulators	Maihiihi	REG06 Replace Whibley Road Regulator. This is an old type of regulator which gets overload when back feeding.	106k
2015/16	Regulators	Mokau	FED128 Install Regulator near Bolts place on top of hill.	126k
2015/16	Substation, Supply Point and 33kV Development	Taharoa B 33	FED302 Renew and remove hazardous equipment.	116k
2015/16	Substation, Supply Point and 33kV Development	Taharoa Zone Substation	ZSub201 Upgrade to customers' requirements and specifications. Funded through on-going charges to industrial customers.	1628k
2015/16	Substation, Supply Point and 33kV Development	Waitete Zone Substation	ZSub206 Replace fence.	70k
2015/16	Switches (Hazard)	Maihiihi	REG01 Install bypass protection on regulators.	5k

2015/16	Switches (Reliability Improvement)	Otorohanga	288 Automate switch.	34k
2015/16	Transformer - 2 Pole Structures	Mahoenui	T1453 Structure needs to be rebuilt on single pole.	41k
2015/16	Transformer - 2 Pole Structures	Mahoenui	T1865 Move platform up the pole.	6k
2015/16	Transformer - 2 Pole Structures	Mahoenui	T2520 Using existing poles raise structure and replace reclosers.	41k
2015/16	Transformer - 2 Pole Structures	Te Mapara	T1777 Single pole SWER. Upgrade to current TLC design standards.	47k
2015/16	Transformers - Ground Mounted	Hangatiki East	T381 Replace with I tank or front access transformer. Use a refurbished transformer if available.	47k
2015/16	Transformers - Ground Mounted	Waitomo	T406 Replace transformer.	47k
2016/17	Regulators	Rangitoto	FED106 Install regulator towards Otewa Rd also to pick up Otewa when working on Gravel Scoop and Waipa Gorge.	101k
2016/17	Substation, Supply Point and 33kV Development	Hangatiki Zone Substation	ZSub204 Install oil separation.	17k
2016/17	Substation, Supply Point and 33kV Development	Taharoa Zone Substation	ZSub201 Upgrade to customers' requirements and specifications. Funded through on-going charges to industrial customers.	58k
2016/17	Switches (Reliability Improvement)	McDonalds	387 Automate Switch, replace pole and install ENTEC.	35k
2016/17	Switches (Reliability Improvement)	McDonalds	328 Automate Switch. Install a Motor Actuator onto existing ABS.	23k
2016/17	Transformer - 2 Pole Structures	Benneydale	T2506 Rebuild with a standard single pole structure. Use existing transformer and replace reclosers.	37k
2016/17	Transformer - 2 Pole Structures	Te Mapara	T1829 Check ground clearance raise transformer on Pole and replace recloser.	20k
2016/17	Transformers - Ground Mounted	Oparure	T457 Install a front access transformer 300 kVA with I Blade RTE switch.	47k
2016/17	Transformers - Ground Mounted	Rangitoto	T464 Replace with a refurbished I Tank. Check loading and size transformer appropriately.	47k
2017/18	Substation, Supply Point and 33kV Development	Oparure Zone Substation	ZSub208 Install bunding, oil separation and earthquake restraints.	47k
2017/18	Substation, Supply Point and 33kV Development	Waitete Zone Substation	ZSub206 Install modular substation at industrial sites.	408k
2017/18	Switches (Hazard)	Benneydale	REG04 Install bypass protection on regulator.	5k
2017/18	Switches (Reliability Improvement)	McDonalds	320 Automate Switch	23k
2017/18	Switches (Reliability Improvement)	Otorohanga	FED112 LV Link T554 to adjacent transformers.	117k

2017/18	Transformer - 2 Pole Structures	Mokau	T2177 Rebuild structure and replace transformer.	47k
2017/18	Transformer - 2 Pole Structures	Te Kuiti South	T478 Check loading. See if 300kVA is necessary, if not replace with 200kVA pole mounted transformer	45k
2017/18	Transformers - Ground Mounted	Coast	T547 Upgrade transformer to I tank.	47k
2017/18	Transformers - Ground Mounted	Otorohanga	T699 Replace transformer with standard industrial transformer $	47k

TABLE 7-71: SUMMARY OF PROJECTS AND EXPENDITURE PREDICTIONS 2013/14 TO 2017/18 FOR HANGATIKI POS (WITHOUT INFLATION)

Table 7-72 lists the work that relates to National Park Point of Supply for the next 5 years. It lists all capital work projects and the estimated costs in current dollars, without inflation and inclusive of engineering costs.

POS: NATIONAL PARK				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2013/14	Substation, Supply Point and 33kV Development	National Park Zone Substation	ZSub501 Rebuild with a modular substation and rationalise CB in conjunction with grid exit work.	330k
2013/14	Substation, Supply Point and 33kV Development	Tawhai Zone Substation	ZSub513 Refurbish transformer.	95k
2013/14	Substation, Supply Point and 33kV Development	National Park POS Compound	ZSub516 Install ripple plant in a container. Rationalise the number of outgoing feeder circuit breakers.	699k
2013/14	Switches (Hazard)	Chateau	16N17 Install I tank transformer outside building.	45k
2013/14	Transformer - 2 Pole Structures	National Park	15L05 Replace with Ground mounted transformer; the transformer is close to motel balcony.	47k
2014/15	Substation, Supply Point and 33kV Development	Tawhai Zone Substation	ZSub513 Replace zone substation fence.	58k
2014/15	Switches (Hazard)	Chateau	16N21 Install transformer with RTE switch	47k
2014/15	Transformer - 2 Pole Structures	Raurimu	13I10 Renew Structure. Check the loading on this transformer ETAP load flows indicate that it may be overloaded. Rebuild site. Costs split over 13I10 and T4132 as there are two SWER isolating transformers on the one structure.	35k
2014/15	Transformer - 2 Pole Structures	Raurimu	T4132 Check the loading on this transformer, ETAP load flows indicate that it may be overloaded. Rebuild site. Costs split over 13I10 and T4132 as there are two SWER isolating transformers on the one structure.	35k

POS: NATIONAL PARK				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2014/15	Transformers - Ground Mounted	National Park	14L12 Install transformer with RTE switch.	40k
2015/16	Switches (Reliability Improvement)	Tawhai Zone Substation	5151 Automate switch in Substation.	47k
2016/17	Switches (Hazard)	Chateau	16N09 Install new Xiria unit and transformer.	47k
2017/18	Switches (Hazard)	Chateau	16N01 Replace with refurbished transformer and install Xiria.	47k
2017/18	Switches (Hazard)	National Park	15L07 Install Switch Gear	47k

TABLE 7-72: SUMMARY OF PROJECTS AND EXPENDITURE PREDICTIONS 2013/14 TO 2017/18 FOR NATIONAL PARK POS (WITHOUT INFLATION)

Table 7-73 lists the work that relates to Ohakune Point of Supply for the next 5 years. It lists all capital work projects and the estimated costs in current dollars, without inflation and inclusive of engineering costs.

POS: OHAKUNE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2013/14	Substation, Supply Point and 33kV Development	Borough Zone Substation	ZSub508 Install 3MVAR capacitor bank that can be remotely switched with controllers at Borough Substation for 11 kV voltage support.	124k
2013/14	Substation, Supply Point and 33kV Development	Manunui Zone Substation	ZSub510 Rebuild site. Replace incoming 33 kV Breaker. Do it in conjunction with regulator installation and transformer refurbishment.	175k
2013/14	Substation, Supply Point and 33kV Development	Manunui Zone Substation	ZSub510 Refurbish transformer 510T1.	93k
2013/14	Substation, Supply Point and 33kV Development	Manunui Zone Substation	ZSub510 Install oil separation unit.	29k
2013/14	Substation, Supply Point and 33kV Development	Tuhua Zone Substation	ZSub502 Install 1MVAR capacitor bank that can be remotely switched with controllers at Tuhua Substation for 11 kV voltage support.	105k
2013/14	Switches (Hazard)	Ohakune Town	20L15 Install transformer with RTE	47k
2014/15	Regulators	Turoa	FED415 Regulator at start of Station Road.	111k
2014/15	Switches (Hazard)	Turoa	17N04 Install ring main unit. Needs a visual break & earths Switch gear needed. Install ring main unit.	47k
2015/16	Switches (Hazard)	Ohakune Town	20L68 Install additional switch gear. Difficult site, on bank.	80k
2015/16	Switches (Hazard)	Ohakune Town	20L59 Install transformer with RTE switch.	47k
2015/16	Switches (Hazard)	Tangiwai	20L43 Install RTE switch.	47k

POS: OHAKUNE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2015/16	Transformer - 2 Pole Structures	Tangiwai	20L06 Stick with pole mounted transformer. Move 1 span and reinsulate LV. Put tap off on single pole.	45k
2016/17	Feeder Development	Ohakune Town	414-01 Re-conductor from ferret to dog between 6644 and 6444 on Ayr street.	79k
2016/17	Feeder Development	Turoa	415-04 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. Check that there are no other problem areas in Rangataua.	87k
2016/17	Feeder Development	Turoa	415-01 Upgrade Cu 16mm Cu XLPE cable between Magnefix switch 6420 and transformer 20L18 to a feeder strength sized cable. Check on loadings and determine cable size from predicted future loadings.	55k
2016/17	Substation, Supply Point and 33kV Development	Borough Zone Substation	ZSub508 Install oil separation.	17k
2016/17	Switches (Hazard)	Ohakune Town	20L18 Install switch gear.	47k
2016/17	Switches (Hazard)	Tangiwai	20L45 Install Xiria unit.	40k
2016/17	Switches (Hazard)	Turoa	REG28 Install bypass protection on regulator.	5k
2016/17	Switches (Reliability Improvement)	Tangiwai	6118 Automate Switch.	26k
2016/17	Switches (Reliability Improvement)	Turoa	5680 Automate Switch.	26k
2017/18	Regulators	Tangiwai	FED416 Install regulator at Rangatawa.	102k
2017/18	Switches (Hazard)	Tangiwai	20L44 Install Switch Gear ring main unit	47k
2017/18	Transformer - 2 Pole Structures	Turoa	20L31 Replace transformer.	45k

TABLE 7-73: SUMMARY OF PROJECTS AND EXPENDITURE PREDICTIONS 2013/14 TO 2017/18 FOR OHAKUNE POS (WITHOUT INFLATION)

Table 7-74 lists the work that relates to Ongarue Point of Supply for the next 5 years. It lists all capital work projects and the estimated costs in current dollars, without inflation and inclusive of engineering costs.

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2013/14	Switches (Hazard)	Hakiaha	FED401 Add 11 kV switch gear for 01A38 and 01A82.	58k
2013/14	Switches (Reliability Improvement)	Manunui	5914 Automate Switch.	41k
2013/14	Switches (Reliability Improvement)	Western	5795 Automation switch.	29k
2013/14	Switches (Reliability Improvement)	Western	5404 Automation unit $8000. SCADA and RTU $6000. Technician $6000. Labour $6000. Engineering $2139.	29k
2014/15	Switches (Hazard)	Western	08I55 Install transformer with RTE switch.	47k
2014/15	Switches (Reliability Improvement)	Hakiaha	5831 Replace ABS and automate switch.	41k
2014/15	Switches (Reliability Improvement)	Northern	6127 Replace links with ENTEC switch.	30k
2014/15	Switches (Reliability Improvement)	Northern	5984 Replace ABS and automate switch.	41k
2014/15	Transformer - 2 Pole Structures	Manunui	07K11 Replace two pole structure with standard single pole SWER isolating structure.	46k
2014/15	Transformer - 2 Pole Structures	Manunui	08K14 Replace pole mounted transformer with ground mounted transformer, use refurbished transformer if possible.	51k
2014/15	Transformer - 2 Pole Structures	Ongarue	01K02 Check loading on this transformer. Mill is now closed and structure changed to a standard structure single pole with a 30 kVA TX.	38k
2014/15	Transformer - 2 Pole Structures	Tuhua	05G03 Lift equipment over regulation height, maintain clearances and replace recloser.	28k
2015/16	Switches (Reliability Improvement)	Manunui	5912 Automate switch.	35k
2015/16	Switches (Reliability Improvement)	Matapuna	5838 Automate switch.	47k
2015/16	Transformer - 2 Pole Structures	Hakiaha	01B11 New single pole structure, replace transformer.	47k
2015/16	Transformer - 2 Pole Structures	Northern	01A46 Replace structure and install a refurbished ground mounted transformer.	47k
2015/16	Transformer - 2 Pole Structures	Southern	09K50 Replace structure with single pole structure with 100kVA transformer.	44k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2016/17	Substation, Supply Point and 33kV Development	Ongarue POS Compound	ZSub514 Rationalise the number of outgoing feeder circuit breakers. Put breaker on Taumarunui and Nihoniho; remove Nihoniho breaker. Allows splitting of feeders and isolation of Transpower supply. Reduce the number of circuit breakers from 3 to two and upgrade the bypass option.	699k
2016/17	Transformer - 2 Pole Structures	Manunui	08L17 Lift equipment on poles so all equipment is above regulation height. Recloser bushings are 3.75 m from ground level. Tidy structure and replace recloser.	30k
2016/17	Transformer - 2 Pole Structures	Ongarue	02K08 Equipment is under regulation height on structure. If possible rebuild structure with single pole standard structure one pole away. Replace reclosers.	58k
2016/17	Transformer - 2 Pole Structures	Southern	09K25 Rebuild structure with standard single pole Isolating SWER structure and replace reclosers.	44k
2016/17	Transformer - 2 Pole Structures	Western	08I21 Rebuild structure. Replace recloser and transformer.	58k
2016/17	Transformers - Ground Mounted	Ohura	07D24 Industrial on roadside exposed drywell fuses, was installed for the prison. Check loading and replace with I tank ground mounted transformer.	31k
2017/18	Switches (Reliability Improvement)	Matapuna	5357 Automate switch.	36k
2017/18	Switches (Reliability Improvement)	Southern	5136 Install new switch and automate.	47k
2017/18	Transformer - 2 Pole Structures	Ohura	07D08 Install new recloser and SCADA.	30k
2017/18	Transformer - 2 Pole Structures	Ongarue	02K16 Rebuild structure, 11 kV bushing are below regulation height, replace recloser.	58k
2017/18	Transformer - 2 Pole Structures	Western	08H03 Install new Transformer	47k
2017/18	Transformers - Ground Mounted	Matapuna	01B24 Upgrade LV rack.	47k

TABLE 7-74: SUMMARY OF PROJECTS AND EXPENDITURE PREDICTIONS 2013/14 TO 2017/18 FOR ONGARUE POS (WITHOUT INFLATION)

Table 7-75 lists the work that relates to Tokaanu Point of Supply for the next 5 years. It lists all capital work projects and the estimated costs in current dollars, without inflation and inclusive of engineering costs.

POS: TOKAANU				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2013/14	Switches (Reliability Improvement)	Waihaha	5150 Install new switch and automate.	47k
2013/14	Transformer - 2 Pole Structures	Rangipo / Hautu	11S04 Check loading on transformer, Downsize TX as required. Rebuild with standard single pole structure.	33k
2013/14	Transformer - 2 Pole Structures	Waihaha	07Q14 Existing equipment is below regulation height. Raise equipment and replace recloser.	32k
2013/14	Transformers - Ground Mounted	Turangi	10S42 Replace LV racks.	23k
2014/15	Switches (Hazard)	Kuratau	08R20 Install transformer with RTE switch.	47k
2014/15	Switches (Hazard)	Oruatua	FED417 Remove dangerous overhead river crossing where trout fishing occurs and lines tangle with overhead conductors, underground cable across bridge. Work in association with 09U11.	163k
2014/15	Switches (Hazard)	Oruatua	09U11 Install RTE switch near or associated with 09U11. I	51k
2014/15	Switches (Reliability Improvement)	Rangipo / Hautu	5207 Install recloser.	50k
2014/15	Transformer - 2 Pole Structures	Motuoapa	09T04 Replace with 300 kVA ground mounted transformer, use a refurbished transformer if possible.	48k
2014/15	Transformers - Ground Mounted	Turangi	10S44 Replace with ground mounted Transformer and LV rack.	45k
2015/16	Substation, Supply Point and 33kV Development	Turangi Zone Substation	ZSub505 Add additional 33 and 11 kV switchgear. Install 4 way Xiria and leave existing reclosers. Upgrade protection schemes to ensure primary and backup protection is reliable. New 33 kV installed in year 12/13 and 11 kV breakers to be installed year 16/17. UG and remove double circuit to be done at same time as far as 5673 tap-off (see 11 kV line renewals). Tony to provide cost estimate.	160k
2015/16	Switches (Hazard)	Kuratau	09R14 Install a Xiria in association with Transformer 09R14 and work on 09R16.	47k
2015/16	Switches (Hazard)	Kuratau	09R16 Install RTE switch.	47k
2015/16	Switches (Reliability Improvement)	Kuratau	6353 Automate recloser.	35k

POS: TOKAANU				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2015/16	Transformer - 2 Pole Structures	Kuratau	09R27 Rebuilt with single pole and upgrade earthing.	41k
2015/16	Transformers - Ground Mounted	Turangi	10S26 Replace LV rack, cover exposed bushings.	30k
2016/17	Switches (Hazard)	Rangipo / Hautu	10S03 Install Xiria switch gear.	47k
2016/17	Switches (Reliability Improvement)	Kuratau	6355 Automate switch.	35k
2016/17	Transformers - Ground Mounted	Turangi	10S29 T Replace LV rack and cove exposed terminals.	31k
2017/18	Switches (Hazard)	Waihaha	07R13 Install ring main unit.	47k
2017/18	Switches (Reliability Improvement)	Kuratau	5921 Automate switch.	23k
2017/18	Transformers - Ground Mounted	Turangi	10S39 Install LV rack and cover exposed terminals.	30k

TABLE 7-75: SUMMARY OF PROJECTS AND EXPENDITURE PREDICTIONS 2013/14 TO 2017/18 FOR TOKAANU POS (WITHOUT INFLATION)

Table 7-76 lists the work that relates to Whakamaru & Mokai Point of Supply for the next 5 years. It lists all capital work projects and the estimated costs in current dollars, without inflation and inclusive of engineering costs.

POS: WHAKAMARU & MOKAI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2013/14	Regulators	Wharepapa	122-02 Install regulator near 499 Aotearoa Road.	101k
2013/14	Regulators	Wharepapa	122-06 Install regulator on Hingaia Road.	101k
2013/14	Substation, Supply Point and 33kV Development	Arohena Zone Substation	ZSub211 Install 1MVAR of capacitors on both Wharepapa and Hurimu feeder.	105k
2013/14	Substation, Supply Point and 33kV Development	Atiamuri Supply Compound	ZSub215 Install cooling fans on the transformer.	35k
2013/14	Switches (Reliability Improvement)	Tihoi	454 Replace with ENTEC switch and automate.	45k
2013/14	Switches (Reliability Improvement)	Tirohanga	434 Replace switch and automate.	40k
2013/14	Transformers - Ground Mounted	Mangakino	T701 Check loading and replace with a refurbished I tank of a suitable size. Install a ring main unit with 2 fuses, one for T2316.	47k
2014/15	Switches (Hazard)	Pureora	REG26 Install bypass protection on regulator.	5k
2014/15	Switches (Reliability Improvement)	Pureora	423 Switch automation.	23k
2014/15	Transformers - Ground Mounted	Mangakino	T700 Replace with I tank transformer.	30k

POS: WHAKAMARU & MOKAI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2014/15	Substation, Supply Point and 33kV Development	Mokai Zone Substation	ZSub3358 Add additional back up transformer off Mokai 1 bus to supply Mokai Energy Park.	500k
2015/16	Substation, Supply Point and 33kV Development	Atiamuri Supply Compound	ZSub215 Install supply from Transpower at Whakamaru on the 220 kV or Mokai's 110 kV supply connection at Whakamaru.	1500k
2015/16	Substation, Supply Point and 33kV Development	Maraetai Zone Substation	ZSub210 Install modular substation on Sandel Road in Whakamaru.	466k
2015/16	Switches (Hazard)	Whakamaru	FED120 ring main unit and 300 kVA TX for T2523 and remove T2524 and T2521. Through Joint at T2523 to T2525. Replace LV cable around village with 4c Cable, new 16mm N/S street light cable and TUDs pillar boxes. May need to include replacement of service-main to boxes on side of houses.	500k
2016/17	Regulators	Mokai	123-02 Install regulator on Waihora road before intersection of Whangamata Road so benefits both directions along Whangamata Road.	105k
2016/17	Substation, Supply Point and 33kV Development	Whakamaru 33	FED310 Install second regulator at Maraetai substation site on 33 kV line.	291k
2016/17	Transformer - 2 Pole Structures	Mangakino	T1081 11 kV below regulation height. Check loading and rebuild structure with 100 kVA if loading light enough otherwise use refurbished ground mount 200 kVA.	58k
2017/18	Feeder Development	Mokai	FED123 Re-conductor Tirohanga Road from New Substation site near injection pumps to Okama Rd. 7 km of line to Mink. This allows for better back feed options and more security of supply.	747k
2017/18	Regulators	Pureora	FED119 Install regulator close to Crusaders Meats 4th Regulator for deer plant.	102k
2017/18	Switches (Reliability Improvement)	Whakamaru	463 Automate switch and replace pole.	45k

TABLE 7-76: SUMMARY OF PROJECTS AND EXPENDITURE PREDICTIONS 2013/14 TO 2017/18 FOR WHAKAMARU & MOKAI POS (WITHOUT INFLATION)

7.7 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 to 2027/28year.

Earlier sections provide in depth detail of this programme for the 2013/14 year and summary for the 2014/15 to 2017/18 years. The model is summarised in this section from 2018/19 to 2027/28. It should be noted that there are no overhead to underground conversions included in the planning period estimates.

The changes since the 2011 AMP are associated with updating expenditure to make cash flow funding possible and some delaying of capacity projects due to the 2009-2011 recession. Additional voltage regulators to improve voltages have been included in the Plan and the forecast effects of demand side management.

Table 7-77 summarises the programme total capital expenditure including renewals in the disclosure formats as described in Appendix A of the disclosure handbook.

CAPITAL EXPENDITURE PREDICTIONS FOR THE REMAINDER OF THE 15 YEAR PLANNING PERIOD (WITHOUT INFLATION)										
Capital Expenditure	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
	2018/19	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Customer Connection	1,123,169	1,021,586	1,021,586	1,429,469	1,021,586	1,021,586	1,302,963	1,021,586	1,021,586	1,021,586
System Growth	512,767	1,485,238	1,420,959	1,193,162	431,189	623,477	792,457	905,406	2,055,204	416,181
Quality of Supply	644,671	1,242,531	994,169	922,923	539,288	1,142,122	1,258,803	550,167	508,093	296,677
Asset Replacement & Renewal excluding Line Renewals	731,926	686,407	802,143	569,869	622,369	628,138	738,907	637,755	569,869	569,870
Asset Replacement & Renewal Line Renewals	6,529,834	7,158,176	6,334,156	6,611,266	5,861,084	5,030,991	6,229,656	5,134,221	5,554,032	4,690,625
Asset Relocations	52,442	52,442	52,442	52,442	52,442	52,442	52,442	52,442	52,442	52,442
Non System Fixed Assets	239,316	239,316	239,316	239,316	239,316	239,316	239,316	239,316	239,316	239,316
TOTALS	9,834,126	11,885,696	10,864,772	11,018,448	8,767,275	8,738,072	10,614,544	8,540,893	10,000,543	7,286,697

TABLE 7-77: SUMMARY OF CAPITAL EXPENDITURE PREDICTIONS INCLUDING RENEWALS IN DISCLOSURE FORMAT **(WITHOUT INFLATION)**

7.7.1 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:

7.7.1.1 Sub transmission Customer Connection Related Development

Significant projects and summary scopes of work allowed for in the planning period 2018/19 to 2027/28 include:

- Industrial modular substation for customer in Te Kuiti to meet plant expansion.
- Industrial modular substation in the Hangatiki area for customer to meet plant expansion.
- Taharoa area Distributed Generation sites – upgrade of lines to carry generated capacity.
- Regulators on the Wairere / Gadsby 33 kV line for distributed generation to pull down voltage.

It is assumed that customers will use various technologies to reduce peaks and use non-asset solutions such as power factor correction.

7.7.1.2 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.

7.7.1.3 Subdivision Development

Assumes a continuing, but reduced level of subdivision as compared to the exceptional years of 2007/08 to 2008/09. The scope of works includes supplying and installing new transformers, substations and fusing associated with subdivisions.

7.7.1.4 Industrial Development

Assumes a continuing, but reduced, level of industrial activity compared to the exceptional years of 2007/08 and 2008/09. 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.

7.7.2 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.

7.7.2.1 Sub Transmission System Growth Capital Expenditure

Significant projects and summary scope of works allowed for in the planning period 2018/19 to 2027/28 include:

- Modular substation in the Otorohanga area for lifestyle and dairying growth in the area.
- Modular substations at Kuratau/ Waihi for proposed distributed generation.
- Modular substation in Ranganui Rd area meat industry and dairying growth in the area.
- Additional transformer at Tawhai zone substation to supply increased load at Whakapapa ski field.
- New POS supply from Whakamaru
- Load Control plant at Mokai
- Additional capacity from Mokai.

It is assumed TLC will continue to promote demand side management and advise customers on non-asset solutions, such as power factor correction.

Figure 7-22 is a photo of a modular substation installed for a customer.

FIGURE 7-192: MODULAR SUBSTATION WITH PLANTING TO SCREEN FROM ROAD.

7.7.2.2 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.

7.7.2.3 Feeder Development

Summary scope of works allowed for in the planning period 2018/19 to 2027/28 includes:

- Second cable from Tawhai Substation to Whakapapa Ski Field.
- Strengthening projects involved with supply to Ohakune.
- Strengthening projects for urban/lifestyle development to north of Otorohanga.
- Strengthening projects in Turangi.
- Conversion of SWER systems to 3 phase lines as part of holiday home development in the Kuratau and Waihaha areas.
- Advance the 33 kV line towards Mokau to support system growth.

These projects assume increasing success of demand side management schemes by customers including the deployment of generators, (active and reactive power), for peak reduction.

7.7.3 Quality of Supply Projects

7.7.3.1 Quality of Supply

The projects allowed for in the planning period 2018/19 to 2027/28 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.

Included in the planning is also a focus on automation of switches in the urban centres. This is to ensure faster restore times for the higher density urban population when field staff are deployed in the rural areas. The scope of works includes automating existing switches and reclosers.

Major projects programmed for these years include:

- Another mobile generator plant to reduce costs of hiring generators.

7.7.3.2 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 2018/19 to 2027/28 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 33 kV circuit breakers at Mahoenui zone substation
- Renewal of switchgear at Wairere zone substation
- Renewal of Nihoniho zone substation's fence.

7.7.3.3 Environmental

The projects allowed for in the planning period 2017/18 to 2027/28 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.

7.7.4 Asset Replacement and Renewal Projects

7.7.4.1 Equipment Renewals

Major projects programmed for these years include:

- Refurbishment of Wairere zone substation's two transformers.
- Refurbishment of Mahoenui zone substation transformer.
- Refurbishment of Tawhai zone substation transformer.
- Renewal of circuit breakers at Atiamuri POS
- Renewal of circuit breakers at Maraetai zone substation.
- Renewal of indoor oil circuit breakers at various zone substation.

7.7.4.2 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.

7.7.4.3 Load Control Relays

Expenditure is for the continuation with the upgrade of relays to the advanced meter type within TLC's network.

7.7.4.4 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 6 of this document.

7.7.5 Asset Relocation Projects

Asset relocations are typically associated with road realignment and slips. TLC cannot forward plan for these; an allowance of $52,442p.a. has been allocated.

7.8 Capital Expenditure Predictions for the Planning Period in Disclosure Format

Table 7-78 lists the capital expenditure predictions in disclosure format, inflation adjusted at 2.5% based on current dollar estimates.

	FORECAST EXPENDITURE PREDICTIONS FOR YEARS 1 to 8							
CAPITAL EXPENDITURE PREDICTIONS	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**
	2013/14	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**
Customer Connection	624,898	640,520	2,712,338	919,141	1,337,676	1,302,531	1,214,344	1,244,702
System Growth	478,115	116,315	2,366,454	793,207	1,074,683	594,652	1,765,480	1,731,299
Quality of Supply	2,121,042	1,949,075	2,192,436	935,268	1,104,394	747,621	1,476,978	1,211,298
Asset Replacement & Renewal excluding Line Renewals	1,706,984	1,113,383	1,015,720	1,505,791	716,686	848,809	815,922	977,332
Asset Replacement & Renewal Line Renewals	5,735,382	6,119,545	6,419,248	6,501,871	7,533,820	7,572,605	8,508,821	7,717,553
Asset Relocations	53,753	55,097	56,475	57,886	59,334	60,817	62,337	63,896
Non System Fixed Assets	251,757	251,432	257,718	264,161	270,765	277,534	284,472	291,584
Total	**10,971,930**	**10,245,368**	**15,020,389**	**10,977,325**	**12,097,357**	**11,404,569**	**14,128,353**	**13,237,664**

	FORECAST EXPENDITURE PREDICTIONS FOR YEARS 9 to 15						
CAPITAL EXPENDITURE	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
	2021/22	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Customer Connection	1,785,210	1,307,716	1,340,409	1,752,339	1,408,267	1,443,473	1,479,560
System Growth	1,490,095	551,959	818,055	1,065,766	1,248,111	2,903,948	602,753
Reliability, Safety & Environment	1,152,603	690,334	1,498,562	1,692,949	758,410	717,922	429,676
Asset Replacement & Renewal excluding Line Renewals	711,688	796,684	824,171	993,747	879,151	805,209	825,341
Asset Replacement & Renewal Line Renewals	8,256,564	7,502,682	6,601,095	8,378,193	7,077,579	7,847,701	6,793,418
Asset Relocations	65,493	67,131	68,809	70,529	72,292	74,100	75,952
Non System Fixed Assets	298,873	306,345	314,004	321,854	329,900	338,148	346,601
Total	**13,760,526**	**11,222,851**	**11,465,104**	**14,275,378**	**11,773,711**	**14,130,500**	**10,553,301**

TABLE 7-78: CAPITAL PREDICTIONS IN DISCLOSURE FORMAT INFLATION ADJUSTED

7.8.1 Specific projects in the planning system for the years 2018/19to 2027/28 (years 6 to 15)

Table 7-79 lists all capital projects (excluding Line Renewals which are covered in Section 8) in TLC's forward planning system; determined in accordance with the policies and procedures determined in earlier sections. The list is ordered by across the network Non-Specific locations and Point of Supply (or GXP). The figures are in current dollar values, without inflation and inclusive of engineering costs.

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2018/19	Customer Driven Project	Various	General Connections - Earthing and tap-offs	192k
2018/19	Customer Driven Project	Various	General Connections - Transformers	192k
2018/19	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
2018/19	Customer Driven Project	Various	Industrials - Transformers	192k
2018/19	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
2018/19	Customer Driven Project	Various	Subdivisions - Management	11k
2018/19	Customer Driven Project	Various	Subdivisions - Transformers	110k
2018/19	Line Renewal	Whole Network	11kV Planned Line Renewals	4687k
2018/19	Line Renewal	Whole Network	33kV Planned Line Renewals	1195k
2018/19	Line Renewal	Whole Network	LV Planned Line Renewals	648k
2018/19	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2018/19	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2018/19	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2018/19	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2018/19	Network Equipment Renewal	Whole Network	Protection	12k
2018/19	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2018/19	Network Equipment Renewal	Whole Network	RADIO Specific	43k
2018/19	Network Equipment Renewal	Whole Network	Relay Changes	16k
2018/19	Network Equipment Renewal	Whole Network	SCADA Contingency	17k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2018/19	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2018/19	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2018/19	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2019/20	Customer Driven Project	Various	General Connections - Earthing and tap-offs	275k
2019/20	Customer Driven Project	Various	General Connections - Transformers	275k
2019/20	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
2019/20	Customer Driven Project	Various	Industrials - Transformers	275k
2019/20	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
2019/20	Customer Driven Project	Various	Subdivisions - Management	11k
2019/20	Customer Driven Project	Various	Subdivisions - Transformers	110k
2019/20	Line Renewal	Whole Network	11kV Planned Line Renewals	4628k
2019/20	Line Renewal	Whole Network	33kV Planned Line Renewals	2031k
2019/20	Line Renewal	Whole Network	LV Planned Line Renewals	500k
2019/20	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2019/20	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2019/20	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2019/20	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2019/20	Network Equipment Renewal	Whole Network	Load Control	117k
2019/20	Network Equipment Renewal	Whole Network	Protection	12k
2019/20	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2019/20	Network Equipment Renewal	Whole Network	RADIO Specific	43k
2019/20	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2019/20	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2019/20	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2019/20	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2020/21	Customer Driven Project	Various	General Connections - Earthing and tap-offs	275k
2020/21	Customer Driven Project	Various	General Connections - Transformers	275k
2020/21	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
2020/21	Customer Driven Project	Various	Industrials - Transformers	275k
2020/21	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
2020/21	Customer Driven Project	Various	Subdivisions - Management	11k
2020/21	Customer Driven Project	Various	Subdivisions - Transformers	110k
2020/21	Line Renewal	Whole Network	11kV Planned Line Renewals	4254k
2020/21	Line Renewal	Whole Network	33kV Planned Line Renewals	1425k
2020/21	Line Renewal	Whole Network	LV Planned Line Renewals	654k
2020/21	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2020/21	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2020/21	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2020/21	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2020/21	Network Equipment Renewal	Whole Network	Protection	12k
2020/21	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2020/21	Network Equipment Renewal	Whole Network	RADIO Specific	43k
2020/21	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2020/21	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2020/21	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2020/21	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2021/22	Customer Driven Project	Various	General Connections - Earthing and tap-offs	275k
2021/22	Customer Driven Project	Various	General Connections - Transformers	275k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2021/22	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
2021/22	Customer Driven Project	Various	Industrials - Transformers	275k
2021/22	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
2021/22	Customer Driven Project	Various	Subdivisions - Management	11k
2021/22	Customer Driven Project	Various	Subdivisions - Transformers	110k
2021/22	Line Renewal	Whole Network	11kV Planned Line Renewals	4625k
2021/22	Line Renewal	Whole Network	33kV Planned Line Renewals	1611k
2021/22	Line Renewal	Whole Network	LV Planned Line Renewals	375k
2021/22	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2021/22	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2021/22	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2021/22	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2021/22	Network Equipment Renewal	Whole Network	Protection	12k
2021/22	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2021/22	Network Equipment Renewal	Whole Network	RADIO Specific	43k
2021/22	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2021/22	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2021/22	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2021/22	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2022/23	Customer Driven Project	Various	General Connections - Earthing and tap-offs	275k
2022/23	Customer Driven Project	Various	General Connections - Transformers	275k
2022/23	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
2022/23	Customer Driven Project	Various	Industrials - Transformers	275k
2022/23	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2022/23	Customer Driven Project	Various	Subdivisions - Management	11k
2022/23	Customer Driven Project	Various	Subdivisions - Transformers	110k
2022/23	Line Renewal	Whole Network	11kV Planned Line Renewals	4703k
2022/23	Line Renewal	Whole Network	33kV Planned Line Renewals	351k
2022/23	Line Renewal	Whole Network	LV Planned Line Renewals	807k
2022/23	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2022/23	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2022/23	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2022/23	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2022/23	Network Equipment Renewal	Whole Network	Protection	12k
2022/23	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2022/23	Network Equipment Renewal	Whole Network	RADIO Specific	43k
2022/23	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2022/23	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2022/23	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2022/23	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2023/24	Customer Driven Project	Various	General Connections - Earthing and tap-offs	275k
2023/24	Customer Driven Project	Various	General Connections - Transformers	275k
2023/24	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
2023/24	Customer Driven Project	Various	Industrials - Transformers	275k
2023/24	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
2023/24	Customer Driven Project	Various	Subdivisions - Management	11k
2023/24	Customer Driven Project	Various	Subdivisions - Transformers	110k
2023/24	Line Renewal	Whole Network	11kV Planned Line Renewals	4127k
2023/24	Line Renewal	Whole Network	33kV Planned Line Renewals	739k
2023/24	Line Renewal	Whole Network	LV Planned Line Renewals	165k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2023/24	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2023/24	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2023/24	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2023/24	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2023/24	Network Equipment Renewal	Whole Network	Protection	12k
2023/24	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2023/24	Network Equipment Renewal	Whole Network	RADIO Specific	43k
2023/24	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2023/24	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2023/24	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2023/24	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2024/25	Customer Driven Project	Various	General Connections - Earthing and tap-offs	275k
2024/25	Customer Driven Project	Various	General Connections - Transformers	275k
2024/25	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
2024/25	Customer Driven Project	Various	Industrials - Transformers	275k
2024/25	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
2024/25	Customer Driven Project	Various	Subdivisions - Management	11k
2024/25	Customer Driven Project	Various	Subdivisions - Transformers	110k
2024/25	Line Renewal	Whole Network	11kV Planned Line Renewals	3886k
2024/25	Line Renewal	Whole Network	33kV Planned Line Renewals	2157k
2024/25	Line Renewal	Whole Network	LV Planned Line Renewals	187k
2024/25	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2024/25	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2024/25	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2024/25	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2024/25	Network Equipment Renewal	Whole Network	Load Control	117k
2024/25	Network Equipment Renewal	Whole Network	Protection	12k
2024/25	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2024/25	Network Equipment Renewal	Whole Network	RADIO Specific	43k
2024/25	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2024/25	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2024/25	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2024/25	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2025/26	Customer Driven Project	Various	General Connections - Earthing and tap-offs	275k
2025/26	Customer Driven Project	Various	General Connections - Transformers	275k
2025/26	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
2025/26	Customer Driven Project	Various	Industrials - Transformers	275k
2025/26	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
2025/26	Customer Driven Project	Various	Subdivisions - Management	11k
2025/26	Customer Driven Project	Various	Subdivisions - Transformers	110k
2025/26	Line Renewal	Whole Network	11kV Planned Line Renewals	4332k
2025/26	Line Renewal	Whole Network	33kV Planned Line Renewals	366k
2025/26	Line Renewal	Whole Network	LV Planned Line Renewals	437k
2025/26	Network Equipment Renewal	Whole Network	Upgrade Existing Mobile Generator	175k
2025/26	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2025/26	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2025/26	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2025/26	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2025/26	Network Equipment	Whole Network	Protection	12k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
	Renewal			
2025/26	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2025/26	Network Equipment Renewal	Whole Network	RADIO Specific	43k
2025/26	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2025/26	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2025/26	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2025/26	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2026/27	Customer Driven Project	Various	General Connections - Earthing and tap-offs	275k
2026/27	Customer Driven Project	Various	General Connections - Transformers	275k
2026/27	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
2026/27	Customer Driven Project	Various	Industrials - Transformers	275k
2026/27	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
2026/27	Customer Driven Project	Various	Subdivisions - Management	11k
2026/27	Customer Driven Project	Various	Subdivisions - Transformers	110k
2026/27	Line Renewal	Whole Network	11kV Planned Line Renewals	4971k
2026/27	Line Renewal	Whole Network	33kV Planned Line Renewals	288k
2026/27	Line Renewal	Whole Network	LV Planned Line Renewals	295k
2026/27	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2026/27	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2026/27	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2026/27	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2026/27	Network Equipment Renewal	Whole Network	Protection	12k
2026/27	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2026/27	Network Equipment Renewal	Whole Network	RADIO Specific	43k
2026/27	Network Equipment Renewal	Whole Network	SCADA Contingency	17k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2026/27	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2026/27	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2026/27	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2027/28	Customer Driven Project	Various	General Connections - Earthing and tap-offs	275k
2027/28	Customer Driven Project	Various	General Connections - Transformers	275k
2027/28	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
2027/28	Customer Driven Project	Various	Industrials - Transformers	275k
2027/28	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
2027/28	Customer Driven Project	Various	Subdivisions - Management	11k
2027/28	Customer Driven Project	Various	Subdivisions - Transformers	110k
2027/28	Line Renewal	Whole Network	11kV Planned Line Renewals	3982k
2027/28	Line Renewal	Whole Network	33kV Planned Line Renewals	476k
2027/28	Line Renewal	Whole Network	LV Planned Line Renewals	233k
2027/28	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2027/28	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2027/28	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2027/28	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2027/28	Network Equipment Renewal	Whole Network	Protection	12k
2027/28	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2027/28	Network Equipment Renewal	Whole Network	RADIO Specific	43k
2027/28	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2027/28	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2027/28	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2027/28	Network Equipment Renewal	Whole Network	Transformer Renewals	350k

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2018/19	Regulators	Mokau	FED128 Before Mokau at old killing house site.	105k
2018/19	Substation, Supply Point and 33kV Development	Taharoa A 33	FED301 Upgrade line to higher transmission voltage and capacity. Split between 2013/14 and 2014/15	349k
2018/19	Substation, Supply Point and 33kV Development	Wairere Zone Substation	ZSub207 Refurbish transformers (T1).	93k
2018/19	Substation, Supply Point and 33kV Development	Wairere Zone Substation	ZSub207 Install oil separation.	17k
2018/19	Substation, Supply Point and 33kV Development	Waitete Zone Substation	ZSub206 Replace 11kV bulk oil breakers due to age, reliability and condition. Replace with vacuum track breakers.	53k
2018/19	Switches (Reliability Improvement)	Hangatiki East	336 Automate switch	40k
2018/19	Transformer - 2 Pole Structures	Mahoenui	T1692 Rebuild structure and replace transformer.	41k
2018/19	Transformer - 2 Pole Structures	Mokau	T2208 Rebuilt structure with standard single pole design. Replace transformer and recloser.	47k
2018/19	Transformer - 2 Pole Structures	Mokau	T2194 Raise transformer.	6k
2018/19	Transformers - Ground Mounted	Oparure	T9 Reuse 200kVA ground mounted transformer and replace LV panel.	40k
2019/20	Feeder Development	Mokau	FED128 Mokau Generator: Add remotely controlled diesel gas injection for holiday periods and during shutdown interruptions. (Alternate to 22kV conversion or extend 33kV South from Mahoenui.	350k
2019/20	Regulators	Mahoenui	FED113 Install regulators for backup of Mokau Feeder when 33 kV is out.	102k
2019/20	Regulators	Piopio	FED116 Install new regulators	102k
2019/20	Substation, Supply Point and 33kV Development	Wairere Zone Substation	ZSub207 Install 5MVAR capacitors on the 11kV bus to support voltage during heavy load times.	210k
2019/20	Switches (Hazard)	Mokau	REG03 Install bypass protection on regulator.	5k
2019/20	Switches (Reliability Improvement)	Hangatiki East	361 Install ENTEC switch and automate. New pole required.	35k
2019/20	Switches (Reliability Improvement)	Mahoenui	1343 Install new recloser and automate.	35k
2019/20	Transformers - Ground Mounted	Coast	T640 Rebuild and install ground mounted transformer.	47k
2019/20	Transformers - Ground Mounted	Mokau	T2155 Install ground mounted transformer.	47k
2019/20	Transformers - Ground	Mokau	T2154 Replace transformer and re-	47k

	Mounted		terminate cables.	
2019/20	Transformers - Ground Mounted	Mokau	T2140Replace transformer and re-terminate cables.	47k
2019/20	Transformers - Ground Mounted	Otorohanga	T557 Install a 300 kVA transformer fitted with an RTE.	47k
2020/21	Regulators	Mokauiti	115-03 Install regulator near switch 1710 to lift voltages in the Mokauiti Valley.	102k
2020/21	Substation, Supply Point and 33kV Development	Te Waireka Zone Substation	ZSub203 Replace 11kV bulk oil breakers due to age, reliability and condition. Replace with vacuum track breakers.	53k
2020/21	Substation, Supply Point and 33kV Development	Wairere Zone Substation	ZSub207 Renew switchgear and improve protection schemes (33 kV).	350k
2020/21	Substation, Supply Point and 33kV Development	Wairere Zone Substation	ZSub207 Refurbish transformers (T2). Oil tests indicate transformer life can be extended with refurbishment. Cost and network security.	93k
2020/21	Switches (Hazard)	Mokau	REG02 Install bypass protection on regulator.	5k
2020/21	Switches (Reliability Improvement)	Mahoenui	1512 Replace bypass switch.	20k
2020/21	Transformers - Ground Mounted	Gravel Scoop	T1007 Replace with ground mounted transformer.	45k
2020/21	Transformers - Ground Mounted	Rural	T1390 Replace with ground mounted transformer.	47k
2020/21	Transformers - Ground Mounted	Te Kuiti South	T10 Replace with ground mounted transformer.	45k
2021/22	Substation, Supply Point and 33kV Development	Hangatiki Zone Substation	ZSub204 Diversify and encourage industrials downstream to install 33/11 kV modular substations on their sites. Oyma container sub.	408k
2021/22	Switches (Reliability Improvement)	Waitomo	182 Automate switch with motor actuator unit.	23k
2021/22	Transformer - 2 Pole Structures	Caves	T1185 Replace with single pole structure.	30k
2021/22	Transformers - Ground Mounted	Oparure	T1043 Replace transformer with I tank type.	58k
2021/22	Transformers - Ground Mounted	Otorohanga	T170 Replace transformer with I tank.	47k
2021/22	Transformers - Ground Mounted	Rural	T1367 Replace transformer with I tank.	47k
2022/23	Substation, Supply Point and 33kV Development	Gadsby Road Zone Substation	ZSub205 Modify existing site by installing better earthquake restraints.	35k
2022/23	Substation, Supply Point and 33kV Development	Hangatiki Zone Substation	ZSub204 Replace 11kV bulk oil breakers due to age, reliability and condition. Replace with vacuum track breakers.	53k
2022/23	Switches (Hazard)	Maihiihi	REG06 Install bypass protection on regulator.	5k
2022/23	Switches (Reliability Improvement)	Gravel Scoop	304 Install ENTEC switch and automated feeder tie.	45k

2022/23	Transformers - Ground Mounted	Benneydale	T2598 Replace with I tank.	47k
2022/23	Transformers - Ground Mounted	Rural	T1559 Replace with I tank transformer.	47k
2023/24	Substation, Supply Point and 33kV Development	Mahoenui Zone Substation	ZSub209 Refurbish transformer.	58k
2023/24	Substation, Supply Point and 33kV Development	Mahoenui Zone Substation	ZSub209 Increase the height of the oil bund and install oil separation.	17k
2023/24	Switches (Reliability Improvement)	Otorohanga	316 Replace switch with recloser.	47k
2023/24	Transformers - Ground Mounted	Otorohanga	T1552 Replace with ground mounted I tank transformer.	45k
2024/25	Regulators	Caves	FED101 Install regulator.	99k
2024/25	Substation, Supply Point and 33kV Development	Gadsby / Wairere 33	FED307 Install additional Regulators at Wairere to pull down voltage.	281k
2024/25	Switches (Hazard)	Rangitoto	REG30 Install bypass protection on regulator.	5k
2024/25	Switches (Reliability Improvement)	Rangitoto	224 Install modern recloser.	47k
2025/26	Regulators	Gravel Scoop	FED109 Install regulator near Otewa road just before Barber. Will mainly be used when tying to Rangitoto and Maihihi.	101k
2025/26	Substation, Supply Point and 33kV Development	Mahoenui Zone Substation	ZSub209 Replace fault thrower with a 33 kV circuit breaker.	70k
2025/26	Substation, Supply Point and 33kV Development	Wairere / Mahoenui 33	FED309 Built out 33 kV line as load grows in Mokau area.	699k
2025/26	Switches (Hazard)	McDonalds	REG11 Install bypass protection on regulator.	5k
2025/26	Switches (Reliability Improvement)	Mokau	1626 Change sectionaliser to recloser.	47k
2025/26	Switches (Reliability Improvement)	Oparure	242 Replace with ENTEC Load break switch and automate.	23k
2026/27	Regulators	Hangatiki East	FED102 Install regulator for Omya if loading increases and 33 kV modular substation option not taken.	99k
2026/27	Substation, Supply Point and 33kV Development	Te Waireka Zone Substation	ZSub203 Build out along Rangiatea Road with 33 kV extension and install modular substation near Mangaoronga Road.	1463k
2026/27	Transformers - Ground Mounted	Otorohanga	T1174 Replace transformer with I tank	47k
2026/27	Transformers - Ground Mounted	Waitomo	T1003 Replace transformer with I tank	47k
2027/28	Switches (Hazard)	Benneydale	REG07 Install bypass protection on regulator.	5k
2027/28	Transformers - Ground Mounted	Otorohanga	T557 Replace with transformer and RTE switch.	53k
2027/28	Transformers - Ground Mounted	Otorohanga	T2417 Replace ground mounted transformer with I tank.	47k

POS: NATIONAL PARK				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2018/19	Switches (Hazard)	Chateau	16N02 Install 11 kV switch gear to transformer	47k
2018/19	Transformer - 2 Pole Structures	National Park	16L02 Rebuild with single pole, replace transformer and related low voltage.	47k
2018/19	Transformers - Ground Mounted	Chateau	16N05 Replace with 11kV box and LV panel.	35k
2019/20	Substation, Supply Point and 33kV Development	Tawhai Zone Substation	ZSub513 Install a second transformer. Use a transformer out of Turangi.	699k
2019/20	Switches (Hazard)	Chateau	16N28 Move transformer out of club house and install magnefix ring main unit.	47k
2019/20	Switches (Hazard)	Chateau	16N29 Replace transformer and RTE Switch.	47k
2019/20	Transformer - 2 Pole Structures	National Park / Kuratau 33	12N05 Investigate installing a ground mounted transformer, or rebuild 33 kV / 400 V transformer structure to make safer. Investigate a refurbished 33 kV / 400 v transformer.	45k
2020/21	Switches (Hazard)	Chateau	15N11 Install RTE switch	47k
2020/21	Switches (Reliability Improvement)	National Park	5146 Install new recloser and SCADA.	47k
2020/21	Transformer - 2 Pole Structures	Otukou	12O01 Replace with single pole structure and replace recloser. This transformer needs to be checked for loading.	41k
2021/22	Feeder Development	Chateau	FED419 Cable from Tavern to Water Tower, 2nd Cable.	350k
2021/22	Transformer - 2 Pole Structures	Raurimu	T4077 Replace with single pole structure and replace recloser.	47k
2023/24	Substation, Supply Point and 33kV Development	Otukou Zone Substation	ZSub512 Modify existing site by installing bunding, oil separation and earthquake restraints.	40k
2023/24	Switches (Hazard)	Chateau	15N02 Install new transformer and RTE switch	47k
2023/24	Transformer - 2 Pole Structures	National Park	15K06 Rebuild structure to single pole. Replace transformer if necessary.	58k
2023/24	Transformers - Ground Mounted	Chateau	16N04 Replace transformer.	29k
2023/24	Transformers - Ground Mounted	Otukou	12N08 Install new transformer and replace LV rack.	47k
2024/25	Feeder Development	Chateau	FED419 Add second cable from Tawhai to Tavern.	583k
2024/25	Switches (Hazard)	Chateau	15N09 Install RTE switch to transformer.	47k

POS: NATIONAL PARK				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2024/25	Transformers - Ground Mounted	Chateau	16N07 Install new transformer and new LV rack.	52k
2024/25	Transformers - Ground Mounted	Chateau	16N06 Install RTE switch and replace LV racks.	52k
2026/27	Switches (Hazard)	Chateau	15N12 Install RTE switch to transformer.	47k
2026/27	Transformers - Ground Mounted	National Park	14L05 Replace transformer.	47k

POS: OHAKUNE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2018/19	Switches (Hazard)	Tangiwai	20L46 Install ring main unit switch gear.	35k
2018/19	Transformer - 2 Pole Structures	Turoa	20M01 Replace with single pole structure and related low voltage.	40k
2019/20	Transformer - 2 Pole Structures	Turoa	20L19 Rebuild structure to single pole and tidy up LV.	50k
2020/21	Feeder Development	Ohakune Town	FED414 Install underground cable down Shannon Street to link Ohakune Town and Tangiwai feeders. Cable size 95 mm Al XLPE.	107k
2020/21	Feeder Development	Turoa	415-04 Re-conductor the feeder tie to Tangiwai between switch 5695 and 5680. Upgrade conductor to Mink or equivalent AAAC.	587k
2020/21	Switches (Hazard)	Turoa	17N01 Install Switch gear	47k
2020/21	Switches (Reliability Improvement)	Turoa	5695 Install new switch and automate.	47k
2021/22	Substation, Supply Point and 33kV Development	Borough Zone Substation	ZSub508 Diversify with modular substations. Container substation above slip on main road.	390k
2021/22	Substation, Supply Point and 33kV Development	Ohakune POS Compound	ZSub517 The size of the conductor connecting switchgear at Ohakune substation is too small for the present loadings. Install Xiria on incomer. Break into the circuit before the cross bus Split one feeder off. Have capacity for a spare feeder. Transpower planning includes a new 20 MVA transformer.	175k
2021/22	Switches (Hazard)	Turoa	17N02 Install RTE switch.	47k
2021/22	Switches (Hazard)	Turoa	FED415 Mechanical cable protection required for cable to ski fields as it is beside the road and inadequately protected.	70k

POS: OHAKUNE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2024/25	Substation, Supply Point and 33kV Development	Borough Zone Substation	ZSub508 Replace 11kV bulk oil breakers due to age, reliability and condition. Replace with vacuum track breakers.	53k
2024/25	Substation, Supply Point and 33kV Development	Nihoniho Zone Substation	ZSub503 Replace fence and upgrade transformer.	225k
2024/25	Substation, Supply Point and 33kV Development	Tuhua Zone Substation	ZSub502 Replace with modular substation.	382k
2025/26	Transformer - 2 Pole Structures	Tangiwai	20L21with Replace ground mounted 100 kVA transformer, use a refurbished transformer.	45k
2026/27	Transformer - 2 Pole Structures	Turoa	20K09 Replace with ground mounted with 100 kVA transformer.	47k
2027/28	Feeder Development	Ohakune Town	414-01 Re-conductor from ferret to dog between 5925 and 6011 on Goldfinch Street.	210k
2027/28	Regulators	Ohakune Town	414-01 Install regulator after 5715 near Ohakune town boundary.	101k
2027/28	Switches (Hazard)	Turoa	REG20 Install bypass protection on regulator.	33k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2018/19	Transformer - 2 Pole Structures	Hakiaha	01A31 Replace structure with 300kVA ground mounted transformer.	47k
2018/19	Transformer - 2 Pole Structures	Manunui	08J07 Raise structure, replace recloser and upgrade earthing.	25k
2018/19	Transformer - 2 Pole Structures	Southern	11K11 Rebuild structure and replace recloser.	47k
2018/19	Transformers - Ground Mounted	Matapuna	01A70 Replace with ground mounted transformer and ring main unit. Replace LV panel.	47k
2019/20	Transformer - 2 Pole Structures	Manunui	08J10 Raise transformer and tidy up LV.	7k
2019/20	Transformer - 2 Pole Structures	Matapuna	01A75 Rebuild structure to single pole, replace transformer.	47k
2019/20	Transformer - 2 Pole Structures	Nihoniho	06E01 Raise transformer, replace recloser and tidy up the site.	30k
2019/20	Transformer - 2 Pole Structures	Northern	T4055 Raise equipment on structure to over regulation height and maintain clearances.	23k
2019/20	Transformer - 2 Pole Structures	Northern	08I02 Replace with a ground mounted refurbished transformer. Check loadings.	45k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2019/20	Transformer - 2 Pole Structures	Southern	10K14 Rebuild to single pole structure and replace recloser.	40k
2020/21	Regulators	Ohura	FED413 Install regulator for Ohura assuming that the coal mine venture goes ahead.	102k
2020/21	Switches (Hazard)	Northern	01A52 Install new LV board and cover HV terminals.	15k
2020/21	Transformer - 2 Pole Structures	Manunui	08J04 Replace with standard single pole structure.	50k
2020/21	Transformer - 2 Pole Structures	Ohura	07D03 Replace with single pole structure. Install new transformer.	47k
2020/21	Transformer - 2 Pole Structures	Southern	09K02 Raise transformer and install recloser.	20k
2021/22	Regulators	Northern	FED402 Install regulator by high school depends on load growth.	101k
2021/22	Regulators	Ongarue	421-01 Install Regulator at State Highway 4 near switch 6640.	101k
2021/22	Switches (Hazard)	Northern	08I03 Install RTE switch and cover LV.	47k
2021/22	Switches (Reliability Improvement)	Hakiaha	5.19 Install new recloser and SCADA.	47k
2022/23	Regulators	Ohura	FED413 Install second regulator assuming coal mine goes ahead.	99k
2022/23	Regulators	Western	403-02 Install regulation to accommodate increased load due to the subdivisions of land for lifestyle blocks along River Road and the surround areas.	99k
2022/23	Switches (Reliability Improvement)	Ohura	5758 Replace sectionaliser with Nova breaker.	47k
2022/23	Transformer - 2 Pole Structures	Ohura	07D16 Replace with single pole structure and replace recloser.	41k
2022/23	Transformer - 2 Pole Structures	Ohura	10E09 Rebuild site, two SWER transformers, on site visit needed for design. Cost split between T4130 and 10E09.	41k
2022/23	Transformer - 2 Pole Structures	Southern	12K08 Raise equipment and replace recloser.	41k
2022/23	Transformers - Ground Mounted	Northern	T4025 Replace with I tank transformer.	47k
2023/24	Switches (Hazard)	Northern	07I14 Install RTE switch.	47k
2023/24	Switches (Reliability Improvement)	Hakiaha	FED401 Install low voltage ties between transformers in CBD. Do in conjunction with switch gear for 01A38 and 01A82.	117k
2023/24	Switches (Reliability Improvement)	Hakiaha	FED401 Add an 11 kV tie between Matapuna and Hakiaha adjacent to rail bridge where the feeder come within a few metre of one another.	131k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2023/24	Switches (Reliability Improvement)	Northern	5119 Upgrade recloser to a Nova breaker with form 6 controller.	47k
2023/24	Switches (Reliability Improvement)	Northern	5164 Upgrade recloser to a Nova breaker with form 6 controller.	47k
2023/24	Transformer - 2 Pole Structures	Ohura	09C05 Raise equipment, replace recloser and change fuse rack if necessary.	30k
2023/24	Transformers - Ground Mounted	Matapuna	01A36 Replace LV rack and cover exposed bushing.	20k
2023/24	Transformers - Ground Mounted	Northern	07I12 Replace LV rack and cover exposed bushing.	20k
2024/25	Switches (Hazard)	Northern	08I19 Install new LV rack and refurbish transformer.	47k
2024/25	Switches (Hazard)	Western	08I31 Install ring main unit.	47k
2024/25	Transformer - 2 Pole Structures	Ohura	T4130 Rebuild site, two SWER transformers, on site visit needed for design. Cost split between T4130 and 10E09.	41k
2024/25	Transformer - 2 Pole Structures	Ohura	07D11 Replace structure with single pole structure and replace recloser.	41k
2025/26	Regulators	Southern	FED409 Growth in dairying and irrigation along state highway. Install regulator just before Otapouri Road. Will help lift voltage at Owhanga for subdivision growth.	105k
2025/26	Switches (Reliability Improvement)	Ongarue	5462 Change sectionaliser to recloser.	47k
2025/26	Transformers - Ground Mounted	Matapuna	01B21 Replace with I tank ground mounted transformer.	35k
2025/26	Transformers - Ground Mounted	Matapuna	01B25 Install new LV rack and cover exposed terminals.	35k
2025/26	Transformers - Ground Mounted	Matapuna	01B20 Install LV rack and cover exposed HV bushings.	35k
2025/26	Transformers - Ground Mounted	Northern	01A48 Install new LV rack and cover exposed HV terminals.	34k
2026/27	Regulators	Matapuna	FED404 Install Regulator on Taupo Road to boast voltage for back feeds and customers further down Taupo Road.	99k
2026/27	Switches (Reliability Improvement)	Hakiaha	5.3 Upgrade SDAF ring main unit 5-3, 5-23, and 5-4 to modern equivalent. Replace with 3 bay Xiria with remote control.	20k
2026/27	Switches (Reliability Improvement)	Hakiaha	5.4 Upgrade SDAF ring main unit 5-3, 5-23, and 5-4 to modern equivalent. Replace with 3 bay Xiria.	20k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2026/27	Switches (Reliability Improvement)	Hakiaha	5.23 Upgrade SDAF ring main unit 5-3, 5-23, and 5-4 to modern equivalent. Replace with 3 bay Xiria with remote control.	20k
2026/27	Transformers - Ground Mounted	Western	T4012 Industrial with HV and LV cable boxes.	47k
2027/28	Switches (Reliability Improvement)	Matapuna	1.7 Ring main unit Grandstand Replace 1.5, 1.6 and 1.7 to new type ring main unit.	27k
2027/28	Switches (Reliability Improvement)	Matapuna	1.5 Ring main unit Grandstand Replace 1.5, 1.6 and 1.7 to new type ring main unit.	27k
2027/28	Switches (Reliability Improvement)	Matapuna	1.6 Ring main unit Grandstand Replace 1.5, 1.6 and 1.7 to new type ring main unit.	27k

POS: TOKAANU				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2018/19	Switches (Hazard)	Turangi	10S41 Replace LV panel and replace with refurbished transformer.	47k
2018/19	Switches (Reliability Improvement)	Kuratau	6557 Automate switch.	34k
2019/20	Feeder Development	Waihaha	FED425 Build out adjacent 11 kV feeders as development takes place. This will include breaking up existing SWER systems.	233k
2019/20	Switches (Reliability Improvement)	Hirangi	6186 Install 2 Bay Xiria. Leave existing Magnefix.	56k
2019/20	Switches (Reliability Improvement)	Turangi	FED423 Develop an 11 kV link for the Turangi Town Feeder through to Rangipo Hautu 11 kV by bridge on SH 1. This will include changing switchgear at 10S40. Waipa Road, Turangi.	281k
2020/21	Feeder Development	Kuratau	FED405 Line rebuilds: SWER replacement associated with Kuratau development.	58k
2020/21	Switches (Hazard)	Rangipo / Hautu	FED424 Hazard from Genesis 33 kV Line crossing.	58k
2020/21	Transformer - 2 Pole Structures	Oruatua	09U12 Replace with single pole structure and new transformer.	45k
2020/21	Transformer - 2 Pole Structures	Waihaha	04Q06 Raise equipment and replace recloser.	20k
2021/22	Substation, Supply Point and 33kV Development	Kuratau Zone Substation	ZSub509 Put in a modular substation at end of network close to an existing 33kV line.	466k

POS: TOKAANU				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2021/22	Switches (Hazard)	Turangi	10S38 Install new LV board and cover up exposed HV terminals.	20k
2021/22	Transformer - 2 Pole Structures	Kuratau	09R28 Replace with single pole structure and replace transformer.	47k
2022/23	Feeder Development	Kuratau	FED406 Line rebuilds: SWER replacement associated with Kuratau development.	58k
2022/23	Feeder Development	Waihaha	FED426 Build out adjacent 11 kV feeders as development takes place. This will include breaking up existing SWER systems.	175k
2022/23	Switches (Hazard)	Rangipo / Hautu	10S13 Install RTE switch.	47k
2022/23	Switches (Reliability Improvement)	Rangipo / Hautu	5963 Replace recloser with Nova breaker.	52k
2022/23	Transformers - Ground Mounted	Rangipo / Hautu	11S18 Replace with I tank transformer.	47k
2023/24	Substation, Supply Point and 33kV Development	Lake Taupo 33	FED606 - Lake Taupo 33 Put up insulated conductors and raise height of line if possible. Rebuild overhead using insulated conductor and taller poles. Complex job both technically and in terms of landowner issues. Re-conductor using insulated conductor spur line.	350k
2024/25	Switches (Hazard)	Rangipo / Hautu	10S49 Install LV fuse rack, install DDO's or vertical ABS on HV cable at pole.	23k
2024/25	Switches (Reliability Improvement)	Turangi	FED423 Develop LV link through Turangi Town.	117k
2024/25	Transformers - Ground Mounted	Rangipo / Hautu	10S47 Install new LV rack and cover exposed bushings.	20k
2024/25	Transformers - Ground Mounted	Turangi	10S30 Install new LV rack and cover exposed bushings.	20k
2026/27	Switches (Reliability Improvement)	Rangipo / Hautu	FED424 Add LV links through Turangi town with remote control.	117k
2026/27	Transformers - Ground Mounted	Tokaanu	10R20 Install RTE switch.	47k
2027/28	Transformer - 2 Pole Structures	Kuratau	08R09 Replace structure with ground mounted transformer. Check loading and use a refurbished transformer if available.	45k

POS: WHAKAMARU & MOKAI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2018/19	Substation, Supply Point and 33kV Development	Mokai Zone Substation	ZSub3358 Install a load control plant at Mokai. Install ripple signal which generates at 317 Hz signal.	408k
2018/19	Switches (Hazard)	Wharepapa	REG25 Install bypass protection on regulator.	5k
2019/20	Transformer - 2 Pole Structures	Tihoi	T1618 Equipment is below regulation height, raise equipment.	7k
2020/21	Substation, Supply Point and 33kV Development	Atiamuri Supply Compound	ZSub215 Replace breaker due to age, reliability and condition with new type of circuit breaker.	87k
2020/21	Substation, Supply Point and 33kV Development	Maraetai Zone Substation	ZSub210 Diversify off site with a modular substation near Ranganui Road.	466k
2021/22	Switches (Hazard)	Pureora	REG09 Install bypass protection on regulator.	5k
2023/24	Feeder Development	Tirohanga	FED129 Install more feeder ties and a new modular substation at Mine road.	524k
2023/24	Regulators	Pureora	FED119 Install regulator near switch 785 just after Ranganui Road on SH 30.	99k
2023/24	Switches (Hazard)	Mokai	REG24 Install bypass protection on regulator.	5k
2024/25	Regulators	Mokai	FED123 Replace Tirohanga Road Regulator.	111k
2024/25	Switches (Reliability Improvement)	Mokai	474 Upgrade to modern recloser.	47k
2024/25	Switches (Reliability Improvement)	Mokai	446 Upgrade to modern recloser.	47k
2025/26	Substation, Supply Point and 33kV Development	Maraetai Zone Substation	ZSub210 Replace breakers due to age, reliability and condition.	68k
2026/27	Substation, Supply Point and 33kV Development	Mokai Zone Substation	ZSub3358 Further develop supply from Mokai Geothermal and Mighty River Power.	394k
2026/27	Switches (Hazard)	Tirohanga	REG23 Install bypass protection on regulator.	5k
2027/28	Regulators	Wharepapa	122-03 Install regulator just after switch 376 on Whatauri Road.	105k
2027/28	Switches (Hazard)	Mokai Zone Substation	REG29 Install bypass protection on regulator.	33k

TABLE 7-79: SUMMARY OF CAPITAL PROJECTS AND EXPENDITURE PREDICTIONS 2018/19 TO 2027/28 BY POS (WITHOUT INFLATION)

7.9 Policies on Distributed Generation

7.9.1 Policies for the Connection of Distributed Generation

7.9.1.1 Distributed Generation: 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.

7.9.1.2 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.

7.9.1.3 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.

7.9.1.4 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.)

7.9.1.5 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 7-22 illustrates the impact of distributed generation on the network.

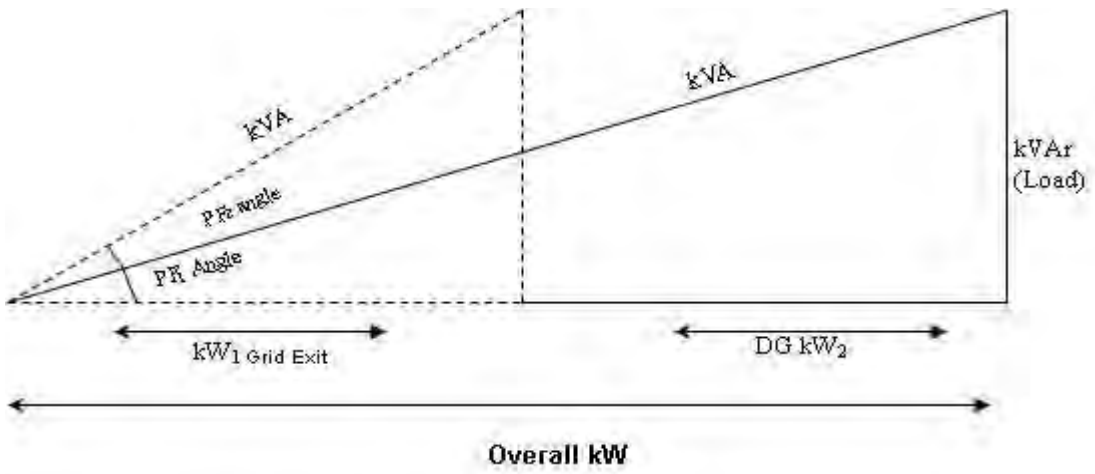


FIGURE 7-20: ILLUSTRATION OF EFFECT OF DISTRIBUTED GENERATION

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.

7.9.1.6 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 7-23 illustrates an example based on actual data from the Hangatiki grid exit.

Figure 7-23 Illustrates power factor every half hour during the year 1st April 2011 to 31st March 2012. Figure 7-24 shows the periods that Electricity Authority rules, Part F; say must be greater than 0.95 during RCPD periods.

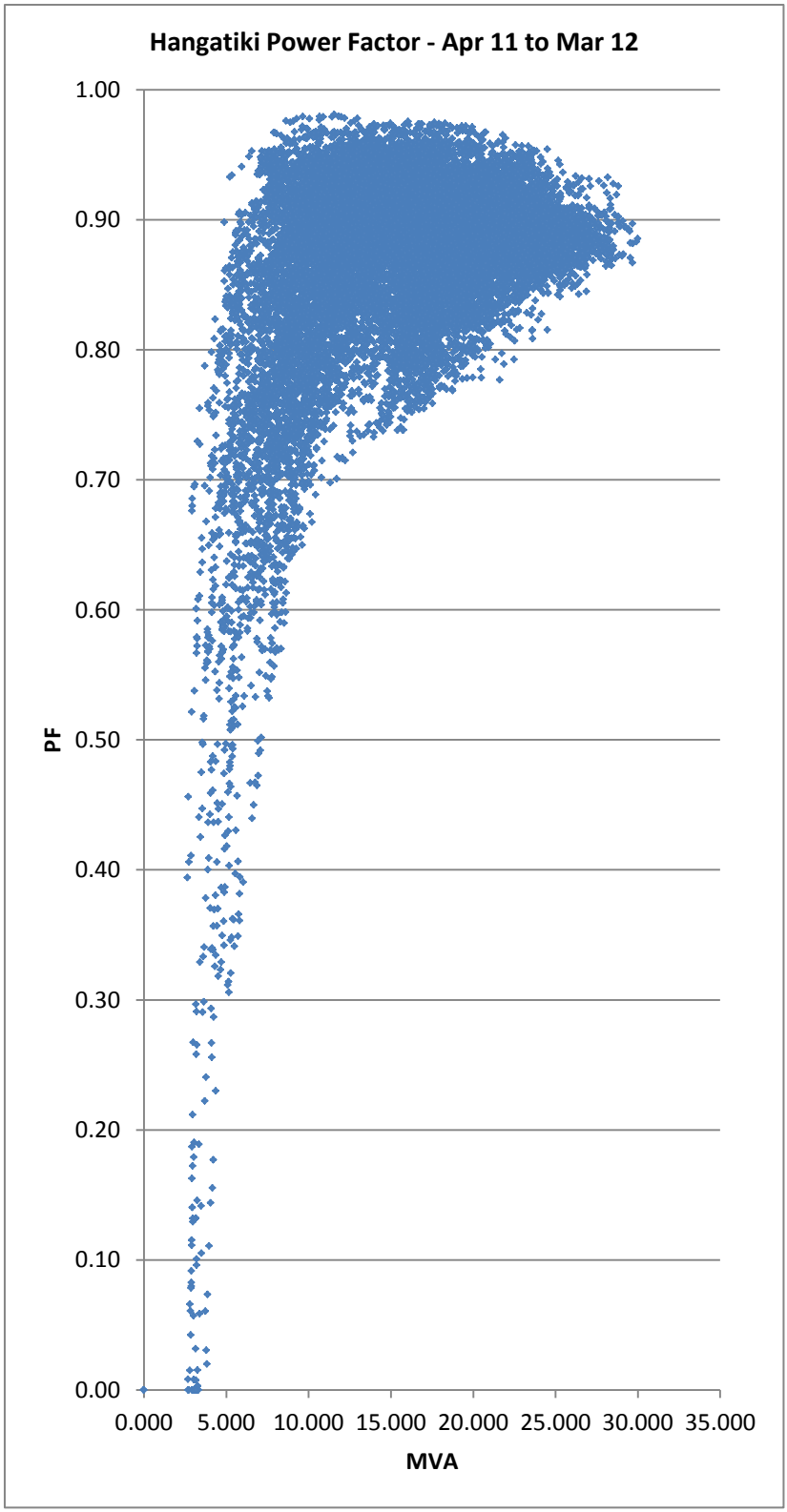


FIGURE 7-23: HANGATIKI POWER FACTOR - FULL YEARS DATA

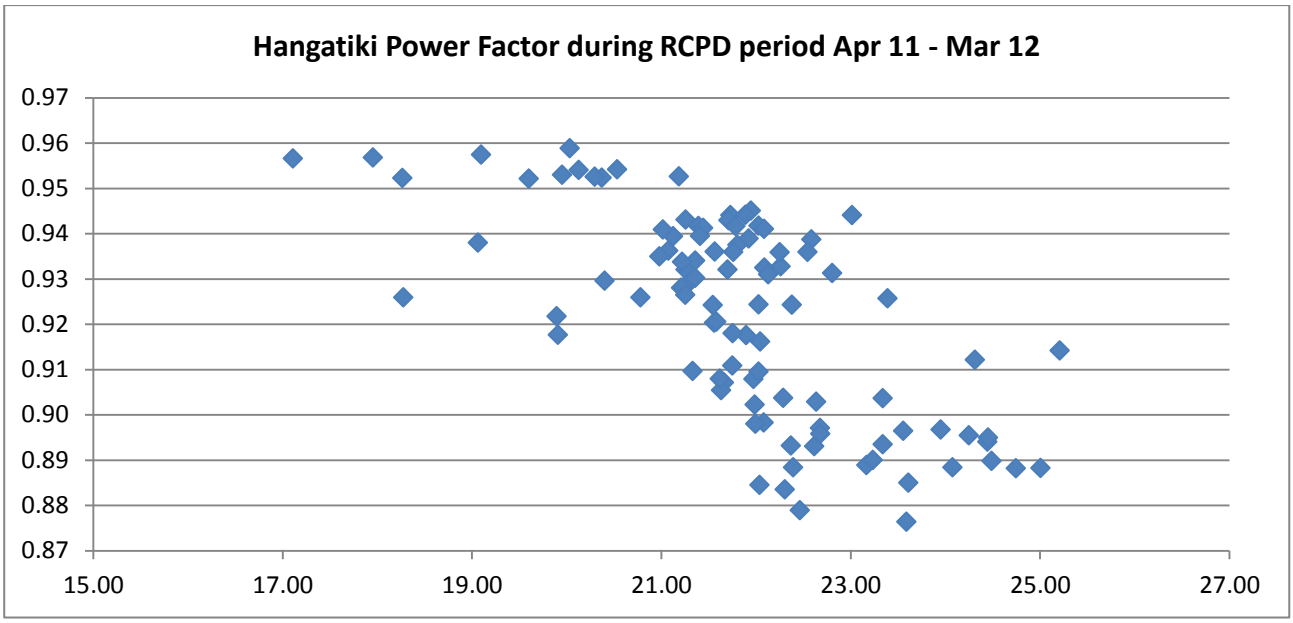


FIGURE 7-24: HANGATIKI POWER FACTOR AT 100 RCPD PEAKS

Figure 7-24 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 0.88. This has showed improvement compared to last year's power factor 0.84.

As a comparison, Figure 7-25 shows the Ohakune power factor, which is above 0.98. Ohakune does not have distributed generation connected. However this power factor is for the Ohakune GXP which includes TLC and PowerCo loads.

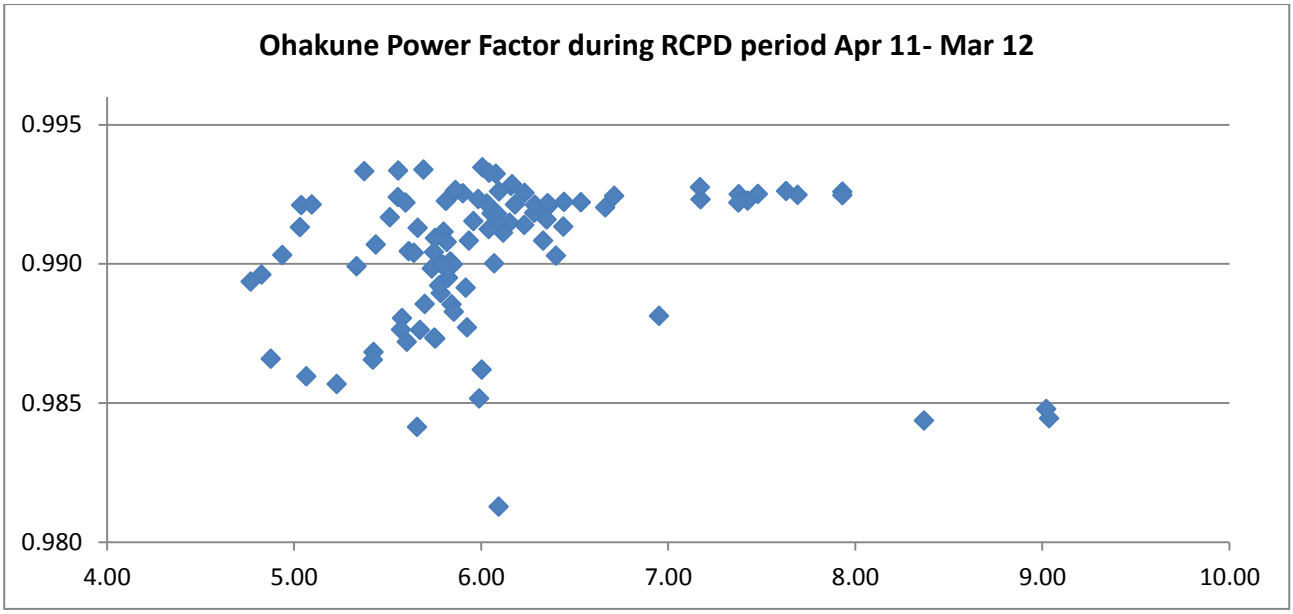


FIGURE 7-25: OHAKUNE POWER FACTOR STUDY

(Figures 7-23, 7-24 and 7-25 are based on data from the Electricity Authority 2011 RCPD by Connection Location.)

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.

7.9.2 Impact of Distributed Generation on Network Development Plans

7.9.2.1 Existing Generation

A summary of the existing known distributed generation connected and injecting into the network is listed in Table 7-80.

Machine	Nameplate (size (kW))	GXP Load Support	Machine	Nameplate (size (kW))	GXP Load Support
Kuratau 1	3000	Ongarue[1]	Wairere 1	450	Hangatiki
Kuratau 2	3000	Ongarue[1]	Wairere 2	250	Hangatiki
Piriaka 1	1000	Ongarue	Wairere 3	900	Hangatiki
Piriaka 2	250	Ongarue	Wairere 4	3000	Hangatiki
Piriaka 3	250	Ongarue	Mokauiti 1	1000	Hangatiki
Moerangi 1	70	Ongarue[1]	Mokauiti 2	600	Hangatiki
Moerangi 2	70	Ongarue1	Mangapehi 1	1500	Hangatiki
Moerangi 3	15	Ongarue[1]	Mangapehi 2	1500	Hangatiki
Marokopa 1	35	Hangatiki	Carters	2	Ongarue2
Marokopa 2	35	Hangatiki	Waihi	0.7	Tokaanu[2]
Speedys Rd	2200	Hangatiki	Maunsell	2	Hangatiki2
Mangaotaki	200	Hangatiki	Trout Hatchery	2	Tokaanu[2]

TABLE 7-80: EXISTING KNOWN DISTRIBUTED GENERATION MACHINES

Notes:

1. *Ongarue is the GXP that these generators generally support; however, they can be switched to support National Park or Tokaanu.*
2. *These generators do not produce sufficient generation to affect the network loadings.*

In addition to this there are currently four approved final applications.

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.

7.9.2.2 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.

TLC is also investing in the development of distributed generation through a wholly owned subsidiary called Clearwater Hydro.

TLC is also looking at running its existing small support generator into the network during periods of high spot prices while fuelled by waste transformer oil to further increase its utilisation.

7.9.2.3 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.
- Upgrade of Taharoa A 33 kV Line.
- Hangatiki point of supply upgrade. The present transformers at the Hangatiki grid exit do not have n-1 capacity. It has been assumed that distributed generation capacity will grow and restore the n-1 capacity at Hangatiki (along with demand side management effects). If this does not take place an investment contract will have to be entered into with Transpower midway through the planning period to increase the capacity of the supply point transformers.
- Waihi modular substation is dependant of the re-development of the hydro site at Waihi near Kuratau.

7.10 Policies on Non-Network Solutions

7.10.1 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 7-26, 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.
- 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.

FIGURE 7-26: GENERATOR BACKUP INSTALLED AT COWSHED

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. However based on the savings that graphs 7-13 and 7-14 are showing and the effects of this as described in sections 7.3.7.4.2 and 7.3.7.4.3 extrapolated out into the network components it is estimated that over the planning period average deferred capital savings of $1 million per annum could be achieved. (Estimate based on calculations using the RAB value and comparing demand growth rates, with and without demand billing.)

7.10.2 Strategies Being Deployed to Promote Non-asset Solutions

7.10.2.1 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. The then technology, (i.e. 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 6.) Customers with other dedicated assets face additional charges associated with these assets. This structure allows customers the option of reducing capacity and demand.

7.10.2.1.1 Where demand meters are installed

FIGURE 7-27:"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 7-27 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.)

7.10.2.1.2 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.

7.10.2.1.3 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.

7.10.2.2 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.

7.10.2.3 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.

7.10.2.4 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.

7.10.2.5 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.

7.10.2.5.1 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 7-28 (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 7-28 each of the layers are outlined and expanded on in the following sections.

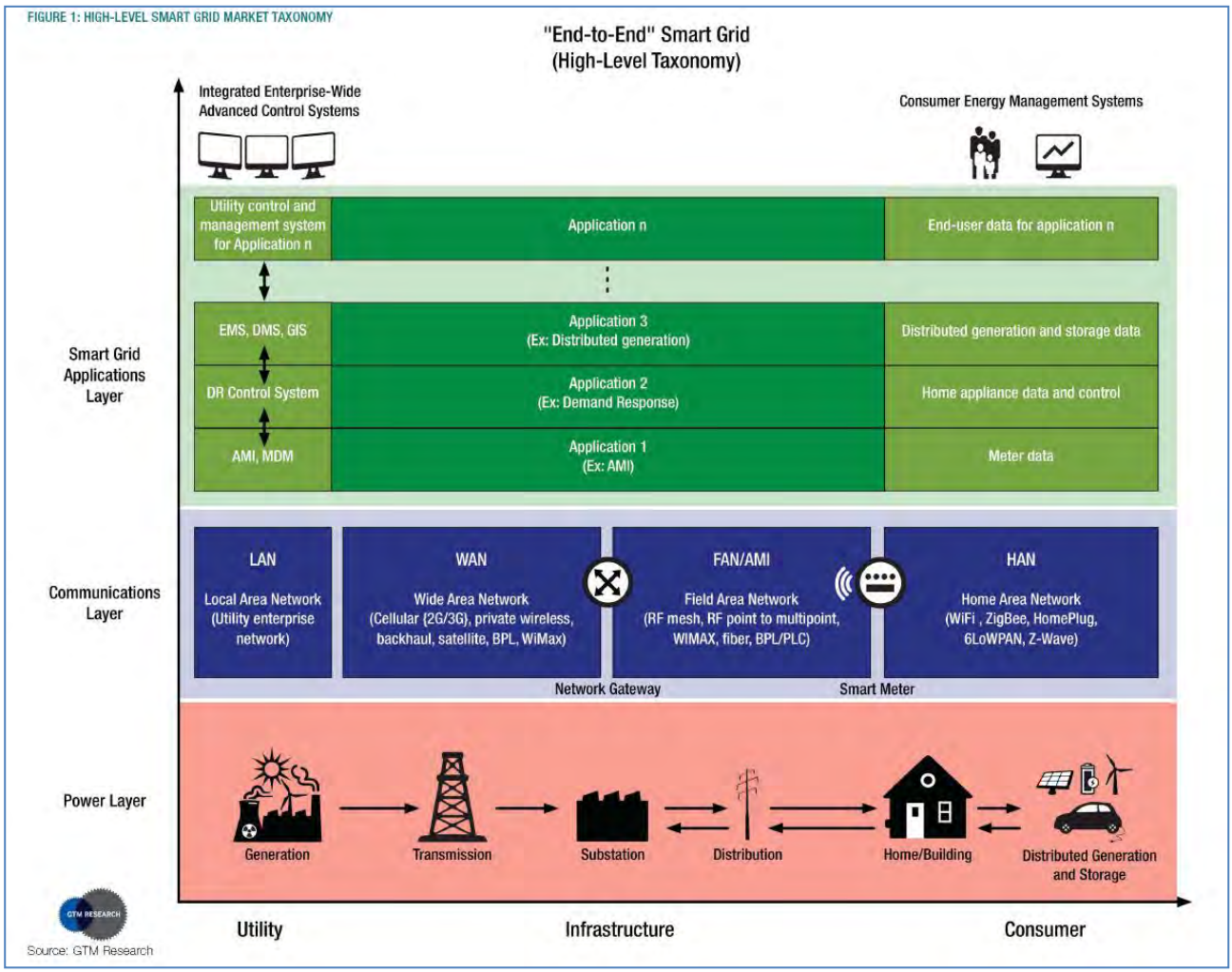


FIGURE 7-28: THREE DISTINCT LAYERS ASSOCIATED WITH AN ADVANCED NETWORK

7.10.2.5.2 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 7-81.

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 in Section 7 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 7-81: STRATEGIES, TOOLS AND DEVELOPMENT VISIONS TLC HAS FOR THE LAYERS ASSOCIATED WITH AN ADVANCED NETWORK

7.10.2.6 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.

7.10.2.7 Ripple Control and Load Shedding

7.10.2.7.1 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.

7.10.2.7.2 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.

7.10.2.8 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.

7.10.2.9 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.

7.10.2.10 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.

7.10.2.11 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.

7.10.2.12 Potential for Distributed Generation or other non-network solutions to address network problems or constraints

Distributed generation will tend to reduce grid exit power factors. Distributed generation connected to appropriate places in the network along with good load control systems that promote demand side management will prolong the time before present assets need upgrading. The strategies for various parts of the network are discussed in the following sections.

7.10.2.13 Impact on Sub-transmission Network of Distributed Generation

7.10.2.13.1 Grid Exits

Additional distributed generation into Hangatiki will have an impact on connection costs. 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.

The possible connection of wind farms at Taharoa may overcome some of the present constraints at Hangatiki. TLC is currently working with Transpower to increase the rating of the present transformers by putting fans on them and is hopeful that customers' reactions to demand billing will buy time to allow the full impact of the wind farms and other distributed generation to be monitored. It is hoped that these combined effects will increase the lifespan of the present Hangatiki supply.

It should be noted that the connection of distributed generation will likely mean that Hangatiki transformers and protection may have to be upgraded to allow for injection as well as off take. Injection will also have an effect on the 110 kV Waikato network and the amount of run back /reactive power generation needed from the major generators on this network, particularly the Arapuni hydro site.

A proposal by Waipa Networks to take supply out of Hangatiki may also further complicate the issue. TLC will likely oppose any implications of this initiative that will increase connection/interconnection costs and/or place constraints on operating flexibility or other factors at this site.

7.10.2.13.2 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 Taharoa, Te Kuiti and Mahoenui 33 kV lines.

7.10.2.13.3 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.

The following sites may need upgrading as a result of potential connected distributed generation:

- National Park

7.10.2.13.4 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.

7.10.2.14 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.

Customers are encouraged to update their meters to a demand meter that allows the customer to use electricity in off peak times and gain the benefit in lower charges. TLC plans to roll out demand meters to all customers over time; however, the initial focus will be on areas such as Ohakune and other areas where there are difficulties with the profiling methodologies due to the high proportion of holiday load.

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.

Section 8

8. Lifecycle Asset Management Planning (Maintenance and Renewal)

8.1 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 7. 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?

Overall focus is on performance to meet customers' reliability, environmental, security, and price and quality expectations in line with Section 7 indices.

8.2 Description and Identification of Routine and Preventative Maintenance Policies, Programmes or Action to be Taken for each Asset Category including Associated Expenditure Predictions

8.2.1 Summary of Maintenance Schedule

The key maintenance schedules are summarised in Table 8-1

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)	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, trippings 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.
Distribution Poles	» Maintenance or renewal as part of the line renewal programme, after faults, or emergent work.
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, painting, protection checking and extensive cleaning of the site. » Hazard elimination/minimisation projects as detailed in Section 7 (Analysis of Network Development Options) of this AMP. Emergent: » Renewals/maintenance necessary due to failures or damage. Other equipment renewals/refurbishment as detailed in Section 7 (Analysis of Network Development Options) 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 7 (Analysis of Network Development Options) 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 7 (Analysis of Network Development Options) of this AMP. » Emergent renewals/maintenance necessary due to failures or damage (typically vehicle impacts). » Renewals/upgrades triggered by changed customer demands.
SCADA	» 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.
Communication	» Maintenance repairs when the system, or parts thereof, do not operate. » 12 monthly inspections of repeater sites and repairs as necessary. » Renewals of software and hardware with modern equivalents on failure. » Planned renewals to keep software and hardware up to date.

MAINTENANCE SCHEDULE SUMMARY	
Item	**Maintenance Framework**
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 7 (Analysis of Network Development Options) 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).
Three Phase Reclosers and Automated Switches	» 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 7 (Analysis of Network Development Options) of this AMP.
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 7 (Analysis of Network Development Options) 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 trippings. » 11 kV lines after recloses or trippings. » 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 8-1: SUMMARY OF MAINTENANCE / RENEWAL STRATEGIES

Note: All patrols, inspections and works are recorded against the assets in the Basix asset management system.

8.2.2 Overhead Lines

Overhead lines form the highest value asset category owned and operated by TLC.

8.2.2.1 Overhead Lines: Inspection, Testing and Condition Monitoring Practices

8.2.2.1.1 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 crossarm 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 trippings. Patrols are also completed after customers express concern or report some type of problem with equipment.

8.2.2.1.2 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.

8.2.2.2 Overhead Lines: Processes for ensuring overhead line defects identified by the Inspection and Condition monitoring programmes are rectified

8.2.2.2.1 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.

8.2.2.2.2 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.

8.2.2.3 Overhead Lines: Systemic Problems and Solutions

Table 8-2 summarises the systemic problems associated with lines and the steps taken to address these. Some of these issues were discussed in Section 4.

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 8-2 SYSTEMIC PROBLEMS ASSOCIATED WITH LINES

8.2.3 Cable (Ski Field Areas): Inspection, Testing and Condition Monitoring Practices

8.2.3.1 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 trippings.

8.2.3.2 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.

8.2.4 Vegetation

8.2.4.1 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.

8.2.4.2 Vegetation: Inspection, Testing and Condition Monitoring Practices

8.2.4.2.1 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.

8.2.4.2.2 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.

8.2.4.3 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.

8.2.4.4 Vegetation: Systemic Problems and Solutions

Table 8-3 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 8-3 SYSTEMIC PROBLEM AND SOLUTIONS ASSOCIATED WITH VEGETATION

NOTE: TLC'S VEGETATION'S PROGRAMMES ARE REVIEWED ANNUALLY WHEN THIS PLAN IS PREPARED.

8.2.5 Zone Substations

8.2.5.1 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 8-4 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 8-4 : 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 (Analysis of Network Development Options) of this AMP. 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.

8.2.5.2 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 8-1 and 8-4.

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.

8.2.5.3 Zone Substations: Systemic problems and solutions

Table 8-5 summarises the systemic problems associated with zone substations and the steps taken to address these. Many of these issues were discussed in more detail in Section 3.3.

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 8-5: SYSTEMIC PROBLEMS ASSOCIATED WITH ZONE SUBSTATIONS

8.2.6 Distribution Pole Mounted Transformers

8.2.6.1 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.

8.2.6.2 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.

8.2.6.3 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.

8.2.7 Ground Mounted Transformers

8.2.7.1 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.

8.2.7.2 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.

8.2.7.3 Ground Mounted Transformers: Systemic Problems and Solutions

8.2.7.3.1 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 8-6.

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 8-6 : GROUND MOUNTED TRANSFORMERS: SYSTEMIC PROBLEMS AND SOLUTIONS

8.2.8 Service Boxes

8.2.8.1 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.

8.2.8.2 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.

8.2.8.3 Service Boxes: Systemic Problems and Solutions

Systemic problems and solutions are summarised in Table 8-7.

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 8-7: SERVICE BOXES: SYSTEMIC PROBLEMS AND SOLUTIONS

8.2.9 SCADA

8.2.9.1 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.

8.2.9.2 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.

8.2.9.3 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.

8.2.10 Radio Repeater Sites

8.2.10.1 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.

8.2.10.2 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.

8.2.10.3 Radio Repeater Sites: Systemic Problems and Solutions

Systemic problems and solutions are summarised in Table 8-8.

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 8-8: RADIO REPEATER SITES: SYSTEMIC PROBLEMS AND SOLUTIONS

8.2.11 Load Control

8.2.11.1 Load Control: Inspection, Testing and Condition Monitoring Practices

8.2.11.1.1 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.

8.2.11.1.2 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.

8.2.11.2 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.

8.2.11.3 Load Control: Systemic Problems and Solutions

Systemic problems and solutions are summarised in Table 8-9.

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 8-9: LOAD CONTROL: SYSTEMIC PROBLEMS AND SOLUTIONS

8.2.12 Three Phase Reclosers and Automated Switches

8.2.12.1 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.

8.2.12.2 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.

8.2.12.3 Three Phase Reclosers and Automated Switches: Systemic Problems and Solutions

The systemic problems with this equipment and the solutions are summarised in Table 8-10.

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 8-10: SYSTEMIC PROBLEMS AND SOLUTIONS FOR THREE PHASE RECLOSERS AND AUTOMATED SWITCHES

8.2.13 Voltage Regulators

8.2.13.1 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.

8.2.13.2 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.

8.2.13.3 Voltage Regulators: Systemic Problems and Solutions

The systemic problems with this equipment and the solutions are summarised in Table 8-11.

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 8-11: SYSTEMIC PROBLEMS AND SOLUTIONS FOR VOLTAGE REGULATORS

8.2.14 Single Wire Earth Return Isolating Transformer Structures

8.2.14.1 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.

8.2.14.2 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.

8.2.14.3 Single Wire Earth Return System Isolating Structures: Systemic Problems and Solutions

The systemic problems with this equipment, and the solutions, are summarised in Table 8-12.

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 8-12: SYSTEMIC PROBLEMS AND SOLUTIONS FOR ISOLATING TRANSFORMER STRUCTURES ON SWER SYSTEMS

8.2.15 SWER (Single Wire Earth Return) Distribution Transformers Structures

8.2.15.1 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. Going forward, 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.

8.2.15.2 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.

8.2.15.3 SWER Distribution Structures: Systemic Problems and Solutions

The systemic problems with this equipment and the solutions are summarised in Table 8-13.

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 8-13: SYSTEMIC PROBLEMS AND SOLUTIONS FOR DISTRIBUTION TRANSFORMERS ON SWER SYSTEMS

8.2.16 Other System Inspections

8.2.16.1 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.

8.2.16.2 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.

8.2.16.3 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.

8.2.17 Power Quality

8.2.17.1 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.

8.2.17.2 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.

8.2.17.3 Power Quality Monitoring: Systemic Problems and Solution

The systemic problems with quality monitoring and the solutions are summarised in Table 8-14.

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 8-14: SYSTEMIC PROBLEMS AND SOLUTIONS IN POWER QUALITY MONITORING

8.2.18 Asset Efficiency

8.2.18.1 Asset Efficiency: Inspection, Testing and Condition Monitoring Practices

8.2.18.1.1 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.

8.2.18.1.2 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.

8.2.18.2 Asset Efficiency Monitoring: Process for Ensuring Defects Identified By Inspection, Tests and Condition Monitoring Programmes Are Rectified

8.2.18.2.1 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. (Note: As part of the 2011/12 plan, TLC is setting up mobile capacitor banks for use when the network is under stress in alternative supply configurations.)

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.

8.2.18.2.2 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)

8.2.18.3 Asset Efficiency Monitoring: Systemic Problems and Solutions

The systemic problems with asset efficiency monitoring and the solutions are summarised in Table 8-15.

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 8-15: SYSTEMIC PROBLEMS AND SOLUTIONS IN ASSET EFFICIENCY MONITORING

8.2.19 Forward Maintenance Expenditure Projections

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 and have been adjusted for inflation (2.5%).

8.2.19.1 Lines Maintenance

Table 8-16 lists the lines maintenance predictions by asset category for the planning period.

LINE MAINTENANCE PREDICTIONS															
Classification	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
LV Lines	35,152	36,031	36,932	37,855	38,802	39,772	40,766	41,785	42,830	43,901	44,998	46,123	47,276	48,458	49,670
11 kV Lines	72,876	74,698	76,566	78,480	80,442	82,453	84,514	86,627	88,793	91,013	93,288	95,620	98,011	100,461	102,973
33 kV Lines	52,055	53,356	54,690	56,057	57,459	58,895	60,367	61,877	63,424	65,009	66,634	68,300	70,008	71,758	73,552
Streetlights	20,822	21,342	21,876	22,423	22,983	23,558	24,147	24,751	25,369	26,004	26,654	27,320	28,003	28,703	29,421
Disconnects for Safety	57,796	59,241	60,722	62,240	63,796	65,390	67,025	68,701	70,418	72,179	73,983	75,833	77,729	79,672	81,664
TOTALS	**238,701**	**244,669**	**250,785**	**257,055**	**263,481**	**270,068**	**276,820**	**283,741**	**290,834**	**298,105**	**305,558**	**313,197**	**321,026**	**329,052**	**337,278**

TABLE 8-16: LINES MAINTENANCE PREDICTIONS FOR THE PLANNING PERIOD (INFLATION ADJUSTED)

8.2.19.2 Cable Maintenance

Table 8-17 lists the cable maintenance predictions by asset category for the planning period.

CABLE MAINTENANCE PREDICTIONS															
Classification	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Cable LV	10,411	10,671	10,938	11,211	11,492	11,779	12,073	12,375	12,685	13,002	13,327	13,660	14,002	14,352	14,710
Cable 33/11 kV	58,442	59,903	61,400	62,935	64,509	66,121	67,774	69,469	71,206	72,986	74,810	76,681	78,598	80,563	82,577
Cable Ski Fields	11,376	11,660	11,952	12,251	12,557	12,871	13,193	13,523	13,861	14,207	14,562	14,926	15,299	15,682	16,074
Cable Location	1,169	1,198	1,228	1,259	1,291	1,323	1,356	1,390	1,424	1,460	1,497	1,534	1,572	1,612	1,652
Ground Pillar Box Repairs	34,129	34,982	35,857	36,753	37,672	38,614	39,579	40,569	41,583	42,623	43,688	44,780	45,900	47,047	48,224
TOTALS	**115,527**	**118,415**	**121,375**	**124,410**	**127,520**	**130,708**	**133,976**	**137,325**	**140,758**	**144,277**	**147,884**	**151,581**	**155,371**	**159,255**	**163,237**

TABLE 8-17: CABLE MAINTENANCE PREDICTIONS FOR THE PLANNING PERIOD (INFLATION ADJUSTED)

8.2.19.3 Faults and Standby

Table 8-18 lists the Faults and Standby cost estimates for the planning period.

FAULTS & STANDBY COSTS PREDICTIONS															
Classification	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
LV Lines	301,917	309,465	317,201	325,131	333,260	341,591	350,131	358,884	367,856	377,053	386,479	396,141	406,045	416,196	426,601
11kV Lines	520,546	533,560	546,899	560,571	574,586	588,950	603,674	618,766	634,235	650,091	666,343	683,002	700,077	717,579	735,518
33kV Lines	72,876	74,698	76,566	78,480	80,442	82,453	84,514	86,627	88,793	91,013	93,288	95,620	98,011	100,461	102,973
Substations	35,152	36,031	36,932	37,855	38,802	39,772	40,766	41,785	42,830	43,901	44,998	46,123	47,276	48,458	49,670
Standby	216,776	222,196	227,751	233,444	239,280	245,262	251,394	257,679	264,121	270,724	277,492	284,429	291,540	298,829	306,299
TOTALS	**1,147,268**	**1,175,950**	**1,205,349**	**1,235,483**	**1,266,370**	**1,298,029**	**1,330,480**	**1,363,742**	**1,397,835**	**1,432,781**	**1,468,600**	**1,505,315**	**1,542,948**	**1,581,522**	**1,621,060**

TABLE 8-18: FAULTS AND STANDBY PREDICTIONS FOR THE PLANNING PERIOD (INFLATION ADJUSTED)

8.2.19.4 Zone Substation Maintenance

Table 8-19 lists the Zone substation maintenance predictions broken down by activity for the planning period.

ZONE SUBSTATION MAINTENANCE PREDICTIONS															
Classification	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Planned Maintenance	135,342	138,726	142,194	145,749	149,392	153,127	156,955	160,879	164,901	169,024	173,249	177,580	182,020	186,570	191,235
Unplanned Maintenance	20,822	21,342	21,876	22,423	22,983	23,558	24,147	24,751	25,369	26,004	26,654	27,320	28,003	28,703	29,421
Battery Charger Replacement	23,436	24,022	24,622	25,238	25,869	26,516	27,179	27,858	28,555	29,268	30,000	30,750	31,519	32,307	33,115
Buildings	23,436	24,022	24,622	25,238	25,869	26,516	27,179	27,858	28,555	29,268	30,000	30,750	31,519	32,307	33,115
Protection & Control	17,577	18,016	18,467	18,928	19,401	19,887	20,384	20,893	21,416	21,951	22,500	23,062	23,639	24,230	24,836
Substation Grounds	7,288	7,470	7,657	7,848	8,044	8,245	8,451	8,663	8,879	9,101	9,329	9,562	9,801	10,046	10,297
Substation Energy Costs	18,740	19,209	19,689	20,181	20,686	21,203	21,733	22,276	22,833	23,404	23,989	24,589	25,203	25,833	26,479
Rates & General Maintenance	12,493	12,805	13,125	13,453	13,790	14,134	14,488	14,850	15,221	15,602	15,992	16,392	16,801	17,221	17,652
Rents for Zones and GMTs	9,374	9,608	9,849	10,095	10,347	10,606	10,871	11,143	11,421	11,707	12,000	12,300	12,607	12,922	13,245
Transformer - Planned	93,741	96,085	98,487	100,949	103,473	106,059	108,711	111,429	114,214	117,070	119,996	122,996	126,071	129,223	132,454
Transformer - Unplanned	20,822	21,342	21,876	22,423	22,983	23,558	24,147	24,751	25,369	26,004	26,654	27,320	28,003	28,703	29,421
TOTALS	**383,070**	**392,647**	**402,463**	**412,524**	**422,838**	**433,409**	**444,244**	**455,350**	**466,734**	**478,402**	**490,362**	**502,621**	**515,187**	**528,066**	**541,268**

TABLE 8-19: ZONE SUBSTATION MAINTENANCE PREDICTIONS FOR PLANNING PERIOD (INFLATION ADJUSTED)

8.2.19.5 Distribution Transformer and Site Maintenance

Table 8-20 lists the Distribution transformer and site maintenance predictions broken down by activity for the planning period.

DISTRIBUTION TRANSFORMER AND SITE MAINTENANCE PREDICTIONS															
Classification	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
GMT Maintenance: Hazard Elimination Projects	45,505	46,643	47,809	49,004	50,229	51,485	52,772	54,091	55,444	56,830	58,250	59,707	61,199	62,729	64,298
GMT Maintenance: Paint and Other Works	34,129	34,982	35,857	36,753	37,672	38,614	39,579	40,569	41,583	42,623	43,688	44,780	45,900	47,047	48,224
Pole & GMT Workshop Refurbishment	62,570	64,134	65,737	67,381	69,065	70,792	72,562	74,376	76,235	78,141	80,094	82,097	84,149	86,253	88,409
Transformer Changes for Corrosion, etc.	10,250	10,506	10,769	11,038	11,314	11,597	11,887	12,184	12,489	12,801	13,121	13,449	13,785	14,130	14,483
SWER Isolating & Distribution Earth Improvements	41,644	42,685	43,752	44,846	45,967	47,116	48,294	49,501	50,739	52,007	53,307	54,640	56,006	57,406	58,841
Other Site Distribution Transformer Maintenance	5,689	5,831	5,977	6,126	6,279	6,436	6,597	6,762	6,931	7,104	7,282	7,464	7,650	7,842	8,038
TOTALS	**199,786**	**204,781**	**209,900**	**215,148**	**220,526**	**226,040**	**231,691**	**237,483**	**243,420**	**249,505**	**255,743**	**262,137**	**268,690**	**275,407**	**282,293**

TABLE 8-20: DISTRIBUTION TRANSFORMER AND SITE MAINTENANCE PREDICTIONS FOR THE PLANNING PERIOD (INFLATION ADJUSTED)

8.2.19.6 Network Equipment Maintenance

Table 8-21 lists other network equipment maintenance predictions broken down by asset activity for the planning period.

NETWORK EQUIPMENT MAINTENANCE PREDICTIONS															
Classification	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Northern Load Plant	24,606	25,221	25,852	26,498	27,161	27,840	28,536	29,249	29,980	30,730	31,498	32,285	33,093	33,920	34,768
Southern Load Plant	26,028	26,679	27,345	28,029	28,730	29,448	30,184	30,939	31,712	32,505	33,318	34,151	35,005	35,880	36,777
SCADA	35,152	36,031	36,932	37,855	38,802	39,772	40,766	41,785	42,830	43,901	44,998	46,123	47,276	48,458	49,670
Repeater Sites	17,699	18,141	18,595	19,059	19,536	20,024	20,525	21,038	21,564	22,103	22,656	23,222	23,803	24,398	25,008
Repeater Sites Rentals	7,288	7,470	7,657	7,848	8,044	8,245	8,452	8,663	8,879	9,101	9,329	9,562	9,801	10,046	10,297
Radio Licenses	29,294	30,027	30,777	31,547	32,335	33,144	33,972	34,822	35,692	36,585	37,499	38,437	39,398	40,382	41,392
Headend Voice Radio	14,576	14,940	15,313	15,696	16,089	16,491	16,903	17,326	17,759	18,203	18,658	19,124	19,602	20,092	20,595
Line Circuit Breaker	38,729	39,697	40,689	41,707	42,749	43,818	44,913	46,036	47,187	48,367	49,576	50,815	52,086	53,388	54,723
Line Regulator	40,603	41,618	42,658	43,725	44,818	45,938	47,087	48,264	49,470	50,707	51,975	53,274	54,606	55,971	57,370
Fuse Switch	5,206	5,336	5,470	5,606	5,746	5,890	6,037	6,188	6,343	6,502	6,664	6,831	7,001	7,176	7,356
Strategic Spares Storage	23,436	24,022	24,622	25,238	25,869	26,516	27,179	27,858	28,555	29,268	30,000	30,750	31,519	32,307	33,115
Generator Truck	11,718	12,010	12,311	12,618	12,934	13,257	13,589	13,928	14,277	14,634	14,999	15,374	15,759	16,153	16,557
TOTALS	**274,333**	**281,192**	**288,221**	**295,427**	**302,813**	**310,383**	**318,143**	**326,096**	**334,249**	**342,605**	**351,170**	**359,949**	**368,948**	**378,172**	**387,626**

TABLE 8-21: OTHER NETWORK EQUIPMENT MAINTENANCE PREDICTIONS FOR THE PLANNING PERIOD (INFLATION ADJUSTED)

8.2.19.7 Vegetation Control Maintenance

Table 8-22 lists the vegetation control maintenance predictions for the planning period.

VEGETATION CONTROL MAINTENANCE PREDICTIONS															
Classification	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Recoveries	-34,470	-35,331	-36,215	-37,120	-38,048	-38,999	-39,974	-40,973	-41,998	-43,048	-44,124	-45,227	-46,358	-47,517	-48,705
Initial Work	206,136	211,290	216,572	221,986	227,536	233,224	239,055	245,031	251,157	257,436	263,872	270,469	277,230	284,161	291,265
Maintenance of Existing	480,985	493,009	505,335	517,968	530,917	544,190	557,795	571,740	586,033	600,684	615,701	631,094	646,871	663,043	679,619
TOTALS	**652,652**	**668,968**	**685,692**	**702,834**	**720,405**	**738,415**	**756,876**	**775,798**	**795,192**	**815,072**	**835,449**	**856,335**	**877,744**	**899,687**	**922,180**

TABLE 8-22: VEGETATION CONTROL MAINTENANCE PREDICTIONS FOR THE PLANNING PERIOD (INFLATION ADJUSTED)

8.2.19.8 Summary Maintenance Activities

Table 8-23 lists forward budgets for summary of maintenance activities by asset category.

SUMMARY OF DIRECT MAINTENANCE COST ESTIMATES															
Description	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Line Maintenance	238,701	244,669	250,785	257,055	263,481	270,068	276,820	283,741	290,834	298,105	305,558	313,197	321,026	329,052	337,278
Cable Maintenance	115,527	118,415	121,375	124,410	127,520	130,708	133,976	137,325	140,758	144,277	147,884	151,581	155,371	159,255	163,237
Faults and Standby	1,147,268	1,175,950	1,205,349	1,235,483	1,266,370	1,298,029	1,330,480	1,363,742	1,397,835	1,432,781	1,468,600	1,505,315	1,542,948	1,581,522	1,621,060
Zone Substation Maintenance	383,070	392,647	402,463	412,524	422,838	433,409	444,244	455,350	466,734	478,402	490,362	502,621	515,187	528,066	541,268
Distribution Transformer Maintenance	199,786	204,781	209,900	215,148	220,526	226,040	231,691	237,483	243,420	249,505	255,743	262,137	268,690	275,407	282,293
Network Equipment Maintenance	274,333	281,192	288,221	295,427	302,813	310,383	318,143	326,096	334,249	342,605	351,170	359,949	368,948	378,172	387,626
Vegetation Control	652,652	668,968	685,692	702,834	720,405	738,415	756,876	775,798	795,192	815,072	835,449	856,335	877,744	899,687	922,180
TOTAL DIRECT COST ESTIMATES	**3,011,337**	**3,086,621**	**3,163,786**	**3,242,881**	**3,323,953**	**3,407,052**	**3,492,228**	**3,579,534**	**3,669,022**	**3,760,748**	**3,854,766**	**3,951,135**	**4,049,914**	**4,151,162**	**4,254,941**

TABLE 8-23: FORWARD BUDGET SUMMARY FOR MAINTENANCE ACTIVITIES (INFLATION ADJUSTED)

Table 8-24 lists forward budgets for summary of maintenance activities by asset category. The figures are in current dollars without CPI.

SUMMARY OF DIRECT MAINTENANCE COST ESTIMATES WITHOUT CPI															
Description	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Line Maintenance	232,879	232,879	232,879	232,879	232,879	232,879	232,879	232,879	232,879	232,879	232,879	232,879	232,879	232,879	232,879
Cable Maintenance	112,709	112,709	112,709	112,709	112,709	112,709	112,709	112,709	112,709	112,709	112,709	112,709	112,709	112,709	112,709
Faults and Standby	1,119,286	1,119,286	1,119,286	1,119,286	1,119,286	1,119,286	1,119,286	1,119,286	1,119,286	1,119,286	1,119,286	1,119,286	1,119,286	1,119,286	1,119,286
Zone Substation Maintenance	373,727	373,727	373,727	373,727	373,727	373,727	373,727	373,727	373,727	373,727	373,727	373,727	373,727	373,727	373,727
Distribution Transformer Maintenance	194,913	194,913	194,913	194,913	194,913	194,913	194,913	194,913	194,913	194,913	194,913	194,913	194,913	194,913	194,913
Network Equipment Maintenance	267,642	267,642	267,642	267,642	267,642	267,642	267,642	267,642	267,642	267,642	267,642	267,642	267,642	267,642	267,642
Vegetation Control	636,733	636,733	636,733	636,733	636,733	636,733	636,733	636,733	636,733	636,733	636,733	636,733	636,733	636,733	636,733
TOTAL DIRECT COST ESTIMATES	**2,937,890**	**2,937,890**	**2,937,890**	**2,937,890**	**2,937,890**	**2,937,890**	**2,937,890**	**2,937,890**	**2,937,890**	**2,937,890**	**2,937,890**	**2,937,890**	**2,937,890**	**2,937,890**	**2,937,890**

TABLE 8-24: FORWARD BUDGET SUMMARY FOR MAINTENANCE ACTIVITIES WITHOUT CPI

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.

8.3 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.

8.3.1 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.

8.3.1.1 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.

8.3.1.2 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 maintenance sections are then followed to ensure the best option is taken for the permanent, emergent repairs. As described in Section 6.1 and 6.2, 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.

8.3.2 Other Equipment Renewal Policies and Procedures

8.3.2.1 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 (as described in Sections 8.1 and 8.2) 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.

8.3.2.2 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).

8.4 Description and Identification of Renewal or Refurbishment Programmes or Actions to be Taken for each Asset Category, including Associated Expenditure Projections

8.4.1 Detailed Description of the Projects Currently Underway or Planned for the Next 12 Months

8.4.1.1 Line Renewals

The 2013/14 programme targets 377 km of line to be inspected and assessed for renewal. The estimated cost for 2013/14 is $5,595,495 (including an engineering on-cost of 2.5%). The length is slightly more than previous years due to the way the 15 yearly cycle programme works out with the asset groups. The breakdown of this estimate is detailed in the following sections.

As outlined in earlier sections, before work is issued to the Service Provider, lines are inspected, data are analysed and designs for replacements completed. Asset group work is then packaged up into folders. In addition to work instructions, this documentation includes plans, photographs, landowner details, access details, special requirement forms such as forest entry permits and any special hazard considerations. A pre-job continuous improvement and briefing meeting also takes place.

About 60% of the Line Renewal work is completed internally and 40% by contractors. Once work is completed, audits to specifications are carried out. A post job continuous improvement meeting takes place that, amongst other things, examines the poles removed (either directly or via photographs), and continually reviews, procedures, polices, and other factors that feed into the renewal decisions.

Table 8-25 lists the line renewal projects for 2013/14. A breakdown of activities has been included in the tables for these. It is interesting to note that the expected 19% pole replacement is tracking higher for the period. Rotten and poor condition poles in many of the projects have pushed this up. Analysis and calculation work based on the inspection to date shows that it is not possible to reduce this, i.e. the poles have to be replaced.

LINE RENEWAL PROJECTS FOR 2013/14								
Point of Supply	**Description**	**Sites Inspected**	**TLC Network Sites**	**Privately Owned Sites**	**Sites Requiring Renewal/ Maint'nce**	**Total Pole Changes**	**% of Network Pole Changes**	**Cost Estimate**
LV LINES								
Hangatiki	Mahoenui 113-03	9	9	0	2	1	11%	6,866
Hangatiki	Mokau 128-08	24	24	0	11	7	29%	6,866
LV Line Total								**13,732**
11 kV LINES								
Hangatiki	Gravel Scoop 109-04	144	137	7	51	18	13%	329,311
Hangatiki	Gravel Scoop 109-05	106	84	22	53	27	32%	234,630
Hangatiki	Mahoenui 113-03	107	75	32	57	1	1%	208,640
Hangatiki	Oparure 107-05	124	110	14	41	25	23%	228,484
Hangatiki	Oparure 107-06	107	71	36	32	8	11%	228,484
Hangatiki	Piopio 116-05	120	81	39	56	14	17%	137,615
Hangatiki	Rangitoto 106-05	122	52	70	37	21	40%	316,175
Hangatiki	Te Kuiti Town 105-01	27	27	0	15	4	15%	142,802
Hangatiki	Te Mapara 117-04	136	109	27	28	16	15%	309,396
National Park	Raurimu 410-02	133	93	40	69	28	30%	239,664
Ongarue	Northern 402-05	1701	135	35	98	33	24%	347,581
Ongarue	Ohura 413-08	180	148	32	64	28	19%	279,125
Ongarue	Ongarue 421-02	122	117	5	53	20	17%	209,165
Ongarue	Western 403-06	148	128	20	52	20	16%	281,835
Whakamaru	Wharepapa 122-07							273,134
11 kV Line Total								**3,766,041**
33 kV LINES								
Ongarue	Ongarue / Taumarunui 604-01	129	129	0	47	18	14%	517,916
Ongarue	Taumarunui / Kuratau 608-03							248,544
Ongarue	Tuhua 602-01							32,902
33 kV Line Total								**799,363**
EMERGENT								
LV Emergent								109,848
11 kV Emergent								693,215
33 kV Emergent								213,297
Total Emergent								**1,016,360**
TOTAL		**3439**	**1529**	**379**	**766**	**289**	**19%**	**5,595,495**

TABLE 8-25: LINE RENEWAL PROJECTS WORK FOR 2013/14

Figure 8-1 indicates the location of the 2013/14 line renewal projects

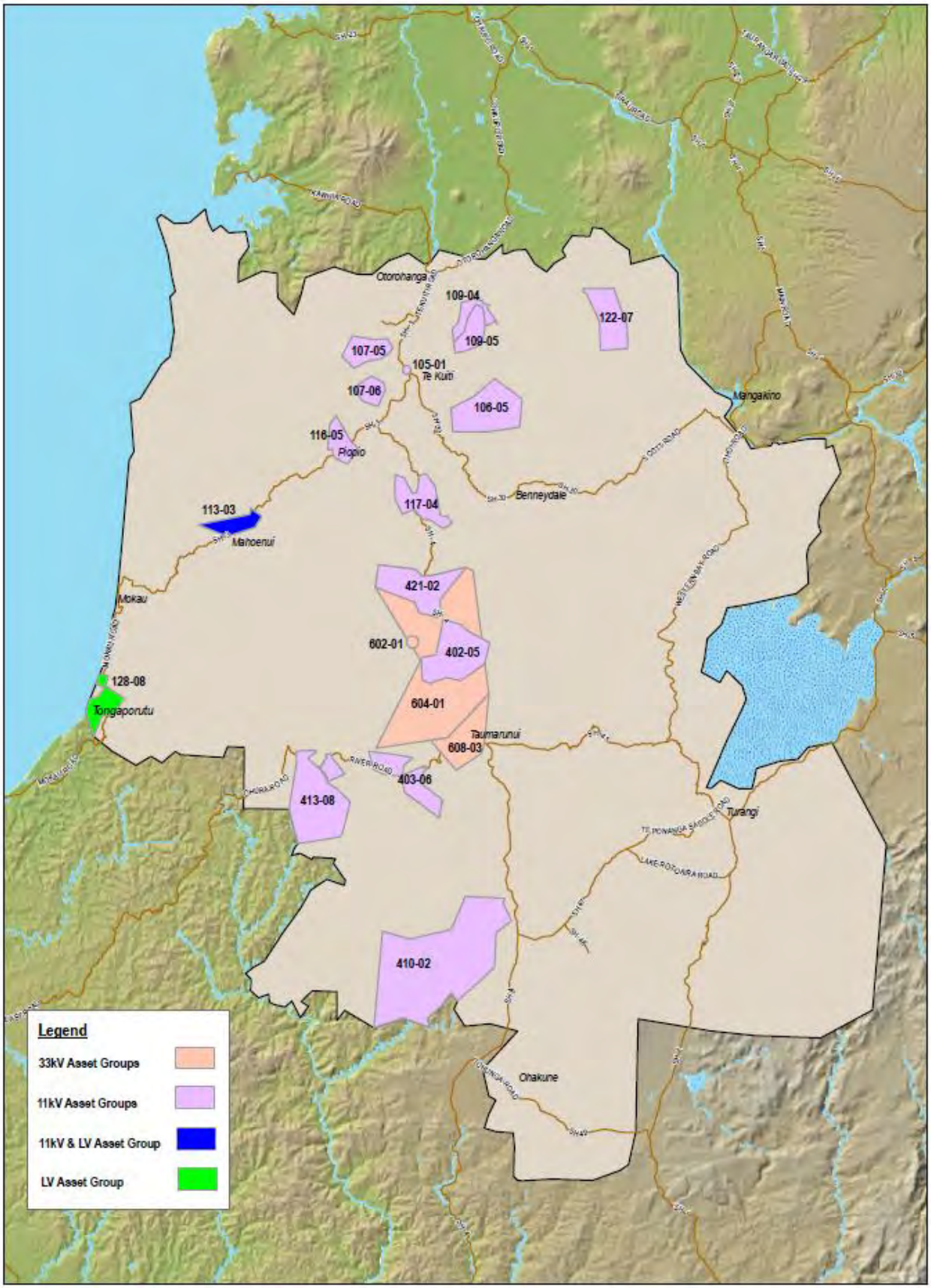


FIGURE 8-1: LOCATION OF 2013/14 LINE RENEWAL PROJECTS

8.4.1.2 Renewals other than Line Renewals

Full details of renewals other than line renewals have been included in section 5. The definitions and expectations of *Renewal*, *Asset Replacement and Development* are confusing if one studies the definitions in the 2008 Commerce Commission Information Disclosure requirements. Specifically, for example, there is an overlap between *Asset Renewal and Replacement* with the development category of *Reliability, Safety and Environmental*. In TLC's case, safety or hazard control expenditure is mostly associated with renewing old out dated hazardous equipment. For the purposes of compliance however the following sections are based on the definition of renewal in the 2012 disclosure information for renewal and asset replacement.

Because of this difficulty, table 8-26 lists the asset renewal and replacement projects (excluding line renewals and substations) in summary form (see section 7 for more detail) proposed for 2013/14 by Point of Supply. The values given are in current dollars, without inflation and inclusive of engineering costs.

2013/14 ASSET RENEWAL AND REPLACEMENT PROJECTS (excluding Line Renewals and Substations)				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non Specific	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	89k
Non Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non Specific	Network Equipment Renewal	Whole Network	Protection	12k
Non Specific	Network Equipment Renewal	Whole Network	Radio Contingency	12k
Non Specific	Network Equipment Renewal	Whole Network	RADIO Specific	630k
Non Specific	Network Equipment Renewal	Whole Network	Relay Changes - Special	321k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non Specific	Network Equipment Renewal	Whole Network	SCADA Specific	43k
Non Specific	Network Equipment Renewal	Whole Network	Tap-offs with New Connection	35k
Non Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
National Park	Transformers - Ground Mounted	National Park	15L05 Transformer is close to motel balcony. Replace with Ground mount transformer. Check loadings for transformer size.	47k

2013/14 ASSET RENEWAL AND REPLACEMENT PROJECTS (excluding Line Renewals and Substations)				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Tokaanu	Transformers - 2 Pole Structures	Rangipo / Hautu	11S04 Check loading on transformer, Downsize TX as required. Rebuild with standard single pole structure.	33k
Tokaanu	Transformers - 2 Pole Structures	Waihaha	07Q14 Rebuild structure. Next to State Highway. Existing equipment below regulation height. Raise and replace recloser.	32k
Tokaanu	Transformers - Ground Mounted	Turangi	10S42 Install a Front Access Transformer with11 kV internal fusing. Replace LV rack	23k
Whakamaru	Transformers - Ground Mounted	National Park	T701 Check loading and replace with I tank transformer and RTE switch	47k

TABLE 8-26: SUMMARY OF ASSET RENEWAL AND REPLACEMENT PROJECTS FOR 2013/14 EXCLUDING LINE RENEWALS & SUBSTATIONS (WITHOUT INFLATION)

These projects and more detail about them have been included in section 7.

8.4.2 Summary Description of the Projects Planned for the Next 4 Years (2014/15 to 2017/18)

8.4.2.1 Line Renewal Summary

The renewal of lines as part of the 15 year programme is targeted at achieving about 300km of line per year. Table 8-27 provides a summary of the planned line renewal expenditure predictions for the next four years. The figures are in current year dollars and do not include any adjustment for inflation.

PREDICTED LINE RENEWAL EXPENDITURE 2013/14 to 2016/17				
Description	**2014/15**	**2015/16**	**2016/17**	**2017/18**
LV Planned Line Renewals	98,863	604,164	444,884	796,398
11kV Planned Line Renewals	4,329,297	4,072,227	3,964,164	4,045,058
33kV Planned Line Renewals	380,151	268,159	464,965	800,984
Emergent	1,016,360	1,016,360	1,016,360	1,016,360
Total	**5,824,671**	**5,960,910**	**5,890,374**	**6,658,800**

TABLE 8-27: SUMMARY OF PREDICTED LINE RENEWAL EXPENDITURE FOR NEXT 4 YEARS

8.4.2.2 Low Voltage Renewals

The expenditure follows the programme as outlined in the constraints section. Table 8-28 details the Low Voltage line renewals scheduled for the next 4 years and associated expenditure predictions.The figures are in current year dollars and do not include any adjustment for inflation.

LOW VOLTAGE PLANNED LINE RENEWALS AND EXPENDITURE PREDICTIONS FOR THE NEXT 4 YEARS					
Point of Supply	**Description**	**2014/15**	**2015/16**	**2016/17**	**2017/18**
Hangatiki	Benneydale 103-07	65,909	0	0	0
Hangatiki	Te Kuiti South 104-01	0	0	0	329,544
Hangatiki	Otorohanga 112-01	0	0	0	219,696
Hangatiki	Coast 125-05	0	32,954	0	0
Ohakune	Ohakune Town 414-01	0	131,818	131,818	0
Ohakune	Turoa 415-01	0	109,848	137,310	0
Ongarue	Affco 407-01	32,954	0	0	0
Ongarue	Ongarue 421-03	0	27,462	0	0
Ongarue	Ongarue 421-03	0	0	10,985	0
Tokaanu	Kuratau 406-03	0	0	0	109,848
Tokaanu	Oruatua 417-01	0	192,234	0	0
Tokaanu	Motuoapa 425-01	0	0	164,772	0
Whakamaru	Mangakino 118-01	0	0	0	137,310
Whakamaru	Whakamaru 120-01		109,848		
	Subtotal	98,863	604,164	444,884	796,398
All Areas	Emergent	109,848	109,848	109,848	109,848
Total Planned Expenditure		**208,711**	**714,012**	**554,732**	**906,246**

TABLE 8-28: LOW VOLTAGE PREDICTED LINE RENEWAL EXPENDITURE FOR NEXT FOUR YEARS

8.4.2.3 11 kV Line Renewals

Expenditure follows the programme as outlined in the constraints section. Table 8-29 (split into two parts) shows the expenditure allowances to renew the following 11 kV feeder asset groups over the next 4 years.

The figures are in current year dollars and do not include any adjustment for inflation.

11kV PLANNED LINE RENEWALS AND EXPENDITURE PREDICTIONS 2014/15		
Point of Supply	**Description**	**Estimate**
Hangatiki	Aria 114-04	166,622
Hangatiki	Aria 114-05	270,490
Hangatiki	Benneydale 103-08	70,533
Hangatiki	Caves 101-09	30,908
Hangatiki	Caves 101-10	89,246
Hangatiki	Gravel Scoop 109-06	288,418
Hangatiki	Gravel Scoop 109-14	241,725
Hangatiki	Mahoenui 113-05	252,737
Hangatiki	Mokau 128-08	500,767
Hangatiki	Mokau 128-09	102,389
Hangatiki	Mokauiti 115-05	211,156
Hangatiki	Mokauiti 115-06	159,995
Hangatiki	Otorohanga 112-07	101,344
National Park	National Park 411-02	414,813
National Park	Raurimu 410-02	239,664
Ohakune	Ohakune Town 414-01	156,249
Ongarue	Affco 407-01	130,270
Ongarue	Ohura 413-03	168,603
Ongarue	Southern 409-07	172,711
Ongarue	Western 403-07	173,070
Whakamaru	Huirimu 121-03	279,424
Whakamaru	Tihoi 124-03	108,164
	Subtotal	*4,329,297*
All Areas	Emergent	693,215
Total Planned for 2014/15		**5,022,512**

11kV PLANNED LINE RENEWALS AND EXPENDITURE PREDICTIONS 2015/16		
Point of Supply	**Description**	**Estimate**
Hangatiki	Benneydale 103-08	70,533
Hangatiki	Caves 101-11	53,179
Hangatiki	Coast 125-05	317,810
Hangatiki	Coast 125-06	185,095
Hangatiki	Mahoenui 113-06	230,072
Hangatiki	Mahoenui 113-07	110,929
Hangatiki	Maihiihi 111-10	331,658
Hangatiki	Rural 126-03	3,356
Hangatiki	Te Mapara 117-06	228,484
National Park	Raurimu 410-02	239,664
Ohakune	Ohakune Town 414-01	156,249
Ohakune	Turoa 415-01	290,374
Ongarue	Nihoniho 412-02	203,373
Ongarue	Ohura 413-04	296,033
Ongarue	Ohura 413-09	131,789
Ongarue	Ongarue 421-03	213,472
Ongarue	Southern 409-08	237,372
Ongarue	Western 403-03	145,508
Ongarue	Western 403-07	173,070
Tokaanu	Oruatua 417-01	232,139
Whakamaru	Huirimu 121-04	64,758
Whakamaru	Whakamaru 120-03	157,311
	Subtotal	*4,072,227*
All Areas	Emergent	693,215
Total Planned for 2015/16		**4,765,442**

11kV PLANNED LINE RENEWALS AND EXPENDITURE PREDICTIONS 2016/17			11kV PLANNED LINE RENEWALS AND EXPENDITURE PREDICTIONS 2017/18		
Point of Supply	**Description**	**Estimate**	**Point of Supply**	**Description**	**Estimate**
Hangatiki	Aria 114-06	146,663	Hangatiki	Benneydale 103-09	395,043
Hangatiki	Benneydale 103-10	276,477	Hangatiki	Maihiihi 111-06	216,431
Hangatiki	Benneydale 103-11	276,289	Hangatiki	Mokau 128-03	360,212
Hangatiki	Caves 101-12	262,139	Hangatiki	Mokau 128-10	269,937
Hangatiki	Caves 101-13	130,684	Hangatiki	Otorohanga 112-01	335,048
Hangatiki	Gravel Scoop 109-07	323,931	Hangatiki	Te Kuiti South 104-01	377,455
Hangatiki	Gravel Scoop 109-08	81,501	National Park	Raurimu 410-04	121,958
Hangatiki	Mahoenui 113-08	224,485	Ongarue	Ohura 413-07	141,271
Hangatiki	Maihiihi 111-11	151,368	Ongarue	Tuhua 422-03	129,923
Hangatiki	McDonalds 110-03	87,165	Tokaanu	Kuratau 406-03	247,790
Hangatiki	McDonalds 110-04	40,013	Whakamaru	Mangakino 118-01	377,398
Hangatiki	Mokau 128-07	77,522	Whakamaru	Whakamaru 120-01	351,094
Hangatiki	Otorohanga 112-05	3,369	Whakamaru	Wharepapa 122-01	243,304
Hangatiki	Otorohanga 112-06	106,930	Whakamaru	Wharepapa 122-02	478,194
National Park	Raurimu 410-03	318,163			
Ohakune	Ohakune Town 414-01	220,238			
Ohakune	Turoa 415-01	290,374			
Ongarue	Ongarue 421-04	384,901			
Ongarue	Southern 409-09	185,620			
Ongarue	Western 403-04	100,178			
Tokaanu	Motuoapa 425-01	104,792			
Tokaanu	Waiotaka 427-01	171,363			
	Subtotal	*3,964,164*		*Subtotal*	*4,045,058*
All Areas	Emergent	693,215	All Areas	Emergent	693,215
Total Planned for 2016/17		**4,657,379**	**Total Planned for 2017/18**		**4,738,273**

TABLE 8-29: 11 KV LINE RENEWALS PLANNED EXPENDITURE FOR NEXT 4 YEARS

8.4.2.4 33 kV Line Renewals

Expenditure follows the programme as outlined in the constraints section. Table 8-30 shows the expenditure allowances to renew the following 33 kV feeder asset groups over the next 4 years.

The figures are in current year dollars and do not include any adjustment for inflation.

33kV PLANNED LINE RENEWALS AND EXPENDITURE PREDICTIONS 2014/15 to 2017/18					
Point of Supply	**Description**	**2014/15**	**2015/16**	**2016/17**	**2017/18**
Hangatiki	Te Waireka Road 303-01	0	0	187,357	0
Hangatiki	Te Kawa Street 304-01	0	0	0	203,561
Hangatiki	Gadsby / Wairere 307-03	0	0	0	284,622
National Park	National Park 601-01	31,931	0	0	0
National Park	National Park / Kuratau 609-04	0	0	277,608	0
National Park	Kuratau Pole Structure 610-01	0	52,551	0	0
Ongarue	Nihoniho 603-02	0	0	0	312,800
Ongarue	Taumarunui / Kuratau 608-01	0	215,608	0	0
Ongarue	Taumarunui / Kuratau 608-02	348,220	0	0	0
	Subtotal	380,151	268,159	464,965	800,984
All Areas	Emergent	213,297	213,297	213,297	213,297
Total Planned Expenditure		**593,448**	**481,456**	**678,262**	**1,014,281**

TABLE 8-30: 33KV LINE RENEWALS PLANNED EXPENDITURE FOR NEXT 4 YEARS

An allowance for emergent work has been included in LV, 11 kV and 33 kV estimates. Emergent work is repairs that have to be completed to maintain supply that requires component renewal that has to be capitalised. This allowance is used from time to time for other, unable to be predicted, urgent needs such as slips, vegetation deviations and similar issues.The allowance will also be used for costs associated with almost completed jobs at year end that span the balance date due to creditors timing etc.

8.4.2.5 Line Renewal Summary with CPI

Table 8-31 provides a summary of the planned line renewal expenditure predictions for the next four years. The figures include an adjustment for inflation of 2.5%.

PREDICTED LINE RENEWAL EXPENDITURE 2014/15 to 2017/18 WITHOUT CPI				
Description	**2014/15**	**2015/16**	**2016/17**	**2017/18**
LV Planned Line Renewals	103,868	650,618	491,069	901,051
LV Emergent	115,409	118,294	121,252	124,283
Total LV	219,277	768,913	612,321	1,025,334
11kV Planned Line Renewals	4,548,467	4,385,343	4,375,696	4,576,611
11 kV Emergent	728,309	746,517	765,180	784,309
Total 11 kV	5,276,777	5,131,860	5,140,876	5,360,921
33kV Planned Line Renewals	399,396	288,778	513,234	906,239
33 kV Emergent	224,095	229,698	235,440	241,326
Total 33 kV	623,491	518,476	748,674	1,147,565
Total Predicted Expenditure	**6,119,545**	**6,419,248**	**6,501,871**	**7,533,820**

TABLE 8-31: SUMMARY OF PREDICTED LINE RENEWAL EXPENDITURE FOR NEXT 4 YEARS WITH CPI

8.4.3 Summary of Asset Renewal and Replacement Projects Planned for 2014/15 to 2017/18 by Point of Supply

Table 8-32 lists the renewal and asset replacement projects (excluding line renewals and substations) for the following 4 years (2014/15 to 2017/18) by Point of Supply. The values are in current dollars, without inflation and inclusive of engineering costs.

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2014/15	Network Equipment Renewal	Whole Network	Have a semi mobile Load Control plant that can be relocated. Reuse the load control plant that is removed from National Park.	70k
2014/15	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	78k
2014/15	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2014/15	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2014/15	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2014/15	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2014/15	Network Equipment Renewal	Whole Network	Load Control	117k
2014/15	Network Equipment Renewal	Whole Network	Protection	12k
2014/15	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2014/15	Network Equipment Renewal	Whole Network	Radio Specific	96k
2014/15	Network Equipment Renewal	Whole Network	Relay Changes	321k
2014/15	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2014/15	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2014/15	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2014/15	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2015/16	Network Equipment Renewal	Whole Network	Semi Mobile containerised 2.5 MVA Substation.	290k
2015/16	Network Equipment Renewal	Whole Network	Semi Mobile Load Control Plant	70k
2015/16	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	64k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2015/16	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2015/16	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2015/16	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2015/16	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2015/16	Network Equipment Renewal	Whole Network	Protection	12k
2015/16	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2015/16	Network Equipment Renewal	Whole Network	Radio Specific	96k
2015/16	Network Equipment Renewal	Whole Network	Relay Changes	321k
2015/16	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2015/16	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2015/16	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2015/16	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2016/17	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	22k
2016/17	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2016/17	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2016/17	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2016/17	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2016/17	Network Equipment Renewal	Whole Network	Protection	12k
2016/17	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2016/17	Network Equipment Renewal	Whole Network	Radio Specific	69k
2016/17	Network Equipment Renewal	Whole Network	Relay Changes	69k
2016/17	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2016/17	Network Equipment Renewal	Whole Network	SCADA Specific	43k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2016/17	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2016/17	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2017/18	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	7k
2017/18	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2017/18	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2017/18	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2017/18	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2017/18	Network Equipment Renewal	Whole Network	Protection	12k
2017/18	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2017/18	Network Equipment Renewal	Whole Network	Radio Specific	69k
2017/18	Network Equipment Renewal	Whole Network	Relay Changes	37k
2017/18	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2017/18	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2017/18	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2017/18	Network Equipment Renewal	Whole Network	Transformer Renewals	350k

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2014/15	Transformer - Two Pole Structures	Mokau	T2153 Rebuild restructure with standard single pole design.	28k
2014/15	Transformer - Two Pole Structures	Te Kuiti South	T559 -Replace with ground mount transformer	48k
2014/15	Transformers - Ground Mounted	Oparure	T663 -Replace with refurbished ground mounted transformer.	36k
2015/16	Transformer - Two Pole Structures	Mahoenui	T1865 Move platform up the pole.	6k
2015/16	Transformer - Two Pole Structures	Mahoenui	T1453 Structure needs to be rebuilt to a single pole.	41k
2015/16	Transformer - Two Pole Structures	Mahoenui	T2520 using existing poles raise structure and install new reclosers.	41k

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2015/16	Transformer - Two Pole Structures	Te Mapara	T1777 Rebuild structure with transformer higher up pole. Use single pole design if practical.	47k
2015/16	Transformers - Ground Mounted	Hangatiki East	T381 -Replace with ground mounted transformer.	47k
2015/16	Transformers - Ground Mounted	Waitomo	T406 -Replace transformer.	47k

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2016/17	Transformer - Two Pole Structures	Benneydale	T2506 Rebuild with a standard single pole structure. Use existing transformer.	37k
2016/17	Transformer - Two Pole Structures	Te Mapara	T1829 Check ground clearance raise transformer on Pole.	20k
2016/17	Transformers - Ground Mounted	Oparure	T457 -Install a front access transformer 300 kVA with I Blade RTE switch	47k
2016/17	Transformers - Ground Mounted	Rangitoto	T464 -Replace with a refurbished I Tank. Check loading and size transformer appropriately.	47k
2017/18	Transformer - Two Pole Structures	Mokau	T2177 Under regulation height hazardous two pole structure to be rebuilt to current TLC standards	47k
2017/18	Transformer - Two Pole Structures	Te Kuiti South	T478 -Check loading. See if 300kVA is necessary, if 300kVA is needed, change it to ground mount. If not replace with 200kVA pole mount transformer.	45k
2017/18	Transformers - Ground Mounted	Coast	T547 -Upgrade transformer to I tank	47k
2017/18	Transformers - Ground Mounted	Otorohanga	T699 -Replace transformer with standard industrial transformer.	47k

POS: NATIONAL PARK				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2014/15	Transformers - 2 Pole Structures	Raurimu	T4132 Check the loading on this transformer. ETAP load flows indicate that it may be overloaded. Rebuild site. Costs split over 13I10 and T4132 as there are two SWER isolating transformers on the one structure.	35k
2014/15	Transformers - 2 Pole Structures	Raurimu	13I10 Renew Structure. Check the loading on this transformer. ETAP load flows indicate that it may be overloaded. Rebuild site. Costs split over 13I10 and T4132 as there are two SWER isolating transformers on the one structure.	35k
2014/15	Transformers - Ground Mounted	National Park	14L12 Install transformer with RTE switch.	40k

POS: OHAKUNE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2015/16	Transformers - 2 Pole Structures	Tangiwai	20L06 Replace structure with ground mounted transformer.	45k
2017/18	Transformers - 2 Pole Structures	Turoa	20L31 Replace transformer with standard industrial transformer.	45k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2014/15	Transformer - Two Pole Structures	Manunui	07K11 Replace two pole structure with standard single pole SWER isolating structure.	46k
2014/15	Transformer - Two Pole Structures	Manunui	08K14 Replace pole mounted transformer with refurbished ground mounted transformer	51k
2014/15	Transformer - Two Pole Structures	Ongarue	01K02 Check loading on this transformer. Mill is now closed and structure changed to a standard structure single pole with a 30 kVA TX	38k
2014/15	Transformer - Two Pole Structures	Tuhua	05G03 Lift equipment over regulation height and maintain clearances.	28k
2015/16	Transformer - Two Pole Structures	Hakiaha	01B11 Replace with single pole structure. .	47k
2015/16	Transformer - Two Pole Structures	Northern	01A46 Replace structure and install a refurbished ground mounted transformer. Replace 2 LV poles with one pole.	47k
2015/16	Transformer - Two Pole Structures	Southern	09K50 Single pole structure with 100kVA transformer and tidy up.	44k
2016/17	Transformer - Two Pole Structures	Manunui	08L17 Lift equipment on poles so all equipment is above regulation height. Recloser bushings are 3.75 m from ground level. Tidy structure and replace recloser. May need to replace some of the by pass links.	30k
2016/17	Transformer - Two Pole Structures	Ongarue	02K08 Equipment is under regulation height on structure. Rebuild structure with single pole standard structure, if possible, or rebuild one pole away.	58k
2016/17	Transformer - Two Pole Structures	Southern	09K25 Rebuild structure with standard single pole Isolating SWER structure.	44k
2016/17	Transformer - Two Pole Structures	Western	08I21 Rebuild structure. Replace recloser and transformer.	58k
2016/17	Transformers - Ground Mounted	Ohura	07D24 Industrial on roadside exposed drywell fuses, was installed for the prison. Check loading and replace with I tank ground mounted transformer.	31k
2017/18	Transformer - Two Pole Structures	Ohura	07D08 Replace reclosers and tidy up structure.	30k
2017/18	Transformer - Two Pole Structures	Ongarue	02K16 Rebuild structure 11 kV bushing are below regulation height. Replace reclosers.	58k
2017/18	Transformer - Two Pole Structures	Western	08H03 Replace transformer and rebuild structure to current TLC standards.	47k
2017/18	Transformers - Ground Mounted	Matapuna	01B24 Upgrade LV rack.	47k

POS: TOKAANU				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2014/15	Transformer - Two Pole Structures	Motuoapa	09T04 Replace with ground mounted 300 kVA use a refurbished transformer.	48k
2014/15	Transformers - Ground Mounted	Turangi	10S44 Tin shed roadside. Open LV rack in tin shed, messy layout of leads. Replace with ground mounted Transformer and LV rack	45k
2015/16	Transformer - Two Pole Structures	Kuratau	09R27 Rebuilt with single pole and earthing upgrade	41k
2015/16	Transformers - Ground Mounted	Turangi	10S26 Tin shed roadside. Open LV rack in tin shed. Replace LV rack and cover bushings.	30k
2016/17	Transformers - Ground Mounted	Turangi	10S29 Tin shed roadside. Open LV rack in tin shed. Replace LV rack and cover bushings.	31k
2017/18	Transformers - Ground Mounted	Turangi	10S39 Install new LV rack	30k

POS: WHAKAMARU & MOKAI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2014/15	Transformers - Ground Mounted	Mangakino	T700 Rebuild to regulations and current TLC standards.	30k
2016/17	Transformers - 2 Pole Structures	Mangakino	T1081 Check loading; rebuild structure with 100 kVA if loading light enough otherwise use refurbished ground mount 200 kVA. 11 kV below regulation height.	58k

TABLE 8-32: SUMMARY OF ASSET RENEWAL AND REPLACEMENT PROJECTS (EXCLUDING LINE RENEWALS AND SUBSTATIONS) PLANNED FOR 2014/15 TO 2017/18 BY POINT OF SUPPLY (WITHOUT INFLATION)

8.4.4 Line Renewal Forecast for the Remainder of the Planning Period (2018/19 to 2027/28)

8.4.4.1 Line Renewal Summary

Table 8-33 summarises the planned expenditure for line renewals for the remainder of the planning period. The figures are in current year dollars and do not include any adjustment for inflation.

PREDICTED LINE RENEWAL EXPENDITURE SUMMARY FOR THE REMAINDER OF THE PLANNING PERIOD (2018/19 to 2027/28)										
Description	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
	2018/19	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
LV Planned Line Renewals	538,255	389,960	544,593	264,734	696,985	54,924	76,894	327,347	185,643	122,850
11kV Planned Line Renewals	3,993,920	3,934,343	3,561,242	3,932,227	4,010,225	3,434,147	3,192,701	3,638,292	4,277,555	3,288,915
33kV Planned Line Renewals	981,300	1,817,512	1,211,961	1,397,945	137,514	525,560	1,943,701	152,222	74,474	262,500
Emergent	1,016,360	1,016,360	1,016,360	1,016,360	1,016,360	1,016,360	1,016,360	1,016,360	1,016,360	1,016,360
Total	**6,529,834**	**7,158,176**	**6,334,156**	**6,611,266**	**5,861,084**	**5,030,990**	**6,229,656**	**5,134,221**	**5,554,032**	**4,690,625**

TABLE 8-33: PREDICTED LINE RENEWAL EXPENDITURE SUMMARY FOR THE REMAINDER OF THE PLANNING PERIOD

8.4.4.2 Low Voltage Renewals

Table 8-34 shows the low voltage line renewal assets and planned expenditure for the current planning period. The figures are in current year dollars and do not include any adjustment for inflation. Data is displayed by Point of Supply.

PREDICTED LOW VOLTAGE LINE RENEWAL PROJECTS EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2018/19 to 2027/28)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2018/19	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Hangatiki	Aria 114-01	21,970									
Hangatiki	Benneydale 103-07										
Hangatiki	Coast 125-01		5,492								
Hangatiki	Coast 125-03									14,280	
Hangatiki	Coast 125-05										
Hangatiki	Gravel Scoop 109-01					43,939					
Hangatiki	Gravel Scoop 109-10					65,909					
Hangatiki	Mahoenui 113-03										

PREDICTED LOW VOLTAGE LINE RENEWAL PROJECTS EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2018/19 to 2027/28)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2018/19	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Hangatiki	Aria 114-01	21,970									
Hangatiki	Coast 125-01		5,492								
Hangatiki	Coast 125-03									14,280	
Hangatiki	Gravel Scoop 109-01					43,939					
Hangatiki	Gravel Scoop 109-10					65,909					
Hangatiki	Maihiihi 111-00				13,182						
Hangatiki	Maihiihi 111-01				32,954						
Hangatiki	Maihiihi 111-02				98,863						
Hangatiki	McDonalds 110-01					13,182					
Hangatiki	Mokau 128-02			27,462							
Hangatiki	Mokau 128-05			96,117							
Hangatiki	Mokau 128-06										45,150
Hangatiki	Oparure 107-02									171,363	
Hangatiki	Oparure 107-04					8,239					
Hangatiki	Piopio 116-02		137,310								
Hangatiki	Rangitoto 106-01	131,818									
Hangatiki	Rangitoto 106-07	16,477									
Hangatiki	Rural 126-01			5,492							
Hangatiki	Waitomo 108-03										67,200
National Park	National Park 411-01	197,726									
National Park	Otukou 418-01			65,909							
National Park	Raurimu 410-01								49,432		

PREDICTED LOW VOLTAGE LINE RENEWAL PROJECTS EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2018/19 to 2027/28)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2018/19	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Ohakune	Tangiwai 416-02					96,117					
Ohakune	Tangiwai 416-03						27,462				
Ongarue	Manunui 408-01	115,340									
Ongarue	Manunui 408-02		27,462								
Ongarue	Manunui 408-04						27,462				
Ongarue	Matapuna 404-01			349,613							
Ongarue	Northern 402-01		219,696								
Ongarue	Ohura 413-02					131,818					
Ongarue	Southern 409-02					54,924					
Ongarue	Southern 409-03					54,924					
Ongarue	Southern 409-04					96,117					
Ongarue	Tuhua 422-01				9,886						
Ongarue	Western 403-01							76,894			
Tokaanu	507-01 Tokaanu	54,924									
Tokaanu	Hirangi 405-01								49,432		
Tokaanu	Kuratau 406-02					131,818					
Tokaanu	Rangipo / Hautu 424-01								228,484		
Whakamaru	Mokai 123-04										10,500
Whakamaru	Whakamaru 120-02				109,848						
	Subtotal	538,255	389,960	544,593	264,734	696,985	54,924	76,894	327,347	185,643	122,850
All Areas	Emergent	109,484	109,484	109,484	109,484	109,484	109,484	109,484	109,484	109,484	109,484
Total		**648,103**	**499,808**	**654,441**	**374,582**	**806,833**	**164,772**	**186,742**	**437,195**	**295,491**	**232,698**

TABLE 8-34: PREDICTED LOW VOLTAGE LINE RENEWAL EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD

8.4.4.3 11 kV Line Renewals

Table 8-35 shows the 11kV line renewal assets and planned expenditure for the current planning period. The figures are in current year dollars and do not include any adjustment for inflation. Data is displayed by Point of Supply.

PREDICTED 11kV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2018/19 to 2027/28)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2018/19	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Hangatiki	Aria 114-01		286,119								
Hangatiki	Aria 114-01	240,882									
Hangatiki	Aria 114-02								86,938		128,993
Hangatiki	Aria 114-03										128,993
Hangatiki	Benneydale 103-01								5,295		
Hangatiki	Benneydale 103-02								10,876		
Hangatiki	Benneydale 103-03								10,714		262,500
Hangatiki	Benneydale 103-04									429,737	
Hangatiki	Benneydale 103-05										263,498
Hangatiki	Benneydale 103-06										157,500
Hangatiki	Benneydale 103-09	395,043									
Hangatiki	Caves 101-01			174,219							
Hangatiki	Caves 101-02			73,320							
Hangatiki	Caves 101-03			43,389							
Hangatiki	Caves 101-04			87,578							
Hangatiki	Caves 101-05			89,794							
Hangatiki	Caves 101-06			68,020							
Hangatiki	Caves 101-07			51,843							
Hangatiki	Caves 101-08			34,867							
Hangatiki	Coast 125-01		279,597								
Hangatiki	Coast 125-02							325,274			
Hangatiki	Coast 125-03									199,803	

PREDICTED 11kV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2018/19 to 2027/28)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2018/19	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Hangatiki	Coast 125-04							198,089			
Hangatiki	Gravel Scoop 109-01						17,982				
Hangatiki	Gravel Scoop 109-02						146,669				
Hangatiki	Gravel Scoop 109-03						191,561				
Hangatiki	Hangatiki East 102-01					121,096					
Hangatiki	Hangatiki East 102-02					171,615					
Hangatiki	Hangatiki East 102-03										78,278
Hangatiki	Mahoenui 113-01		220,293								
Hangatiki	Mahoenui 113-02								54,561		
Hangatiki	Maihiihi 111-01				63,828						
Hangatiki	Maihiihi 111-02				69,053						
Hangatiki	Maihiihi 111-03				167,367						
Hangatiki	Maihiihi 111-04				240,183						
Hangatiki	Maihiihi 111-05					140,306					
Hangatiki	Maihiihi 111-07									209,714	
Hangatiki	Maihiihi 111-08										105,000
Hangatiki	Maihiihi 111-09								75,868		
Hangatiki	Maihiihi 111-10				85,842						
Hangatiki	Maihiihi 111-12					258,562					
Hangatiki	Maihiihi 111-13								118,091		
Hangatiki	McDonalds 110-01					42,052					
Hangatiki	McDonalds 110-02								160,463		
Hangatiki	McDonalds 110-05										253,575
Hangatiki	Mokau 128-01						566,868				
Hangatiki	Mokau 128-02			209,902							

PREDICTED 11kV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2018/19 to 2027/28)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2018/19	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Hangatiki	Mokau 128-04									97,025	
Hangatiki	Mokau 128-05			190,916							
Hangatiki	Mokau 128-06										128,993
Hangatiki	Mokauiti 115-01		133,650								
Hangatiki	Mokauiti 115-02								171,317		
Hangatiki	Mokauiti 115-03									284,951	
Hangatiki	Mokauiti 115-04										105,000
Hangatiki	Oparure 107-01									74,920	
Hangatiki	Oparure 107-02									112,780	
Hangatiki	Oparure 107-03					123,358					
Hangatiki	Oparure 107-04					327,303					
Hangatiki	Oparure 107-07					340,784					
Hangatiki	Oparure 107-08	214,446									
Hangatiki	Otorohanga 112-02							65,393			
Hangatiki	Otorohanga 112-03							163,563			
Hangatiki	Otorohanga 112-04									101,337	
Hangatiki	Piopio 116-01		420,299								
Hangatiki	Piopio 116-02		192,611								
Hangatiki	Piopio 116-03							74,457			
Hangatiki	Piopio 116-04					472,048					
Hangatiki	Rangitoto 106-01	165,937									
Hangatiki	Rangitoto 106-02	31,417									
Hangatiki	Rangitoto 106-04							517,944			
Hangatiki	Rangitoto 106-06								462,851		
Hangatiki	Rangitoto 106-07	285,605									

PREDICTED 11kV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2018/19 to 2027/28)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2018/19	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Hangatiki	Rural 126-01			78,048							
Hangatiki	Te Kuiti South 104-02	361,901									
Hangatiki	Te Mapara 117-01		311,503								
Hangatiki	Te Mapara 117-02				214,837						
Hangatiki	Te Mapara 117-03						235,213				
Hangatiki	Te Mapara 117-05							219,975			
Hangatiki	Waitomo 108-01								57,977		
Hangatiki	Waitomo 108-02								149,771		
Hangatiki	Waitomo 108-03										115,500
National Park	Chateau 419-01	148,514									
National Park	Chateau 419-01		148,514								
National Park	National Park 411-01	152,422									
National Park	National Park 411-03								305,163		
National Park	Otukou 418-01			346,784							
National Park	Raurimu 410-01								367,317	367,316	
National Park	Raurimu 410-04	121,958									
National Park	Raurimu 410-04		121,958								

PREDICTED 11kV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2018/19 to 2027/28)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2018/19	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Ohakune	Tangiwai 416-01					193,805					
Ohakune	Tangiwai 416-02					69,175					
Ohakune	Tangiwai 416-03						229,401				
Ohakune	Tangiwai 416-04								154,263	154,263	
Ohakune	Tangiwai 416-04							154,263			
Ohakune	Turoa 415-01									580,749	
Ohakune	Turoa 415-01								580,749		
Ohakune	Turoa 415-02									44,691	
Ohakune	Turoa 415-03										73,500
Ohakune	Turoa 415-04			91,242							
Ohakune	Turoa 415-04		104,278								
Ongarue	Hakiaha 401-02								126,580		
Ongarue	Manunui 408-01	313,183									
Ongarue	Manunui 408-02			409,667							
Ongarue	Manunui 408-02		409,667								
Ongarue	Manunui 408-03				144,133						
Ongarue	Manunui 408-04						239,376				
Ongarue	Manunui 408-05							358,502			
Ongarue	Matapuna 404-01			539,432							
Ongarue	Nihoniho 412-01							241,278			
Ongarue	Northern 402-01		617,648								
Ongarue	Northern 402-02			604,910							
Ongarue	Northern 402-03				416,458						
Ongarue	Northern 402-04					255,902					
Ongarue	Northern 402-04						255,902				

PREDICTED 11kV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2018/19 to 2027/28)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2018/19	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Ongarue	Ohura 413-01						137,690				
Ongarue	Ohura 413-02					327,623					
Ongarue	Ohura 413-05										115,763
Ongarue	Ohura 413-06									188,792	
Ongarue	Ongarue 421-01									443,446	
Ongarue	Southern 409-01	350,720									
Ongarue	Southern 409-01		350,720								
Ongarue	Southern 409-02					98,157					
Ongarue	Southern 409-03					99,642					
Ongarue	Southern 409-04					62,205					
Ongarue	Southern 409-05			343,188							
Ongarue	Southern 409-06									73,058	
Ongarue	Tuhua 422-01				560,196						
Ongarue	Tuhua 422-02										116,865
Ongarue	Tuhua 422-03	129,923									
Ongarue	Tuhua 422-03		129,923								
Ongarue	Western 403-01							23,837			
Ongarue	Western 403-02							476,198			
Ongarue	Western 403-05										199,500

PREDICTED 11kV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2018/19 to 2027/28)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2018/19	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Tokaanu	Hirangi 405-01									33,466	
Tokaanu	Kuratau 406-01										34,178
Tokaanu	Kuratau 406-02					271,084					
Tokaanu	Rangipo / Hautu 424-01								404,416		
Tokaanu	Rangipo / Hautu 424-02					115,031					
Tokaanu	Rangipo / Hautu 424-03									130,090	
Tokaanu	Tokaanu 420-01	30,251									
Tokaanu	Turangi 423-01										105,000
Tokaanu	Waihaha 426-01			10,995							
Tokaanu	Waihaha 426-02			113,128							
Tokaanu	Waihaha 426-03				373,929						
Tokaanu	Waihaha 426-03						373,929				
Tokaanu	Waihaha 426-03					373,929					
Tokaanu	Waihaha 426-03							373,929			
Tokaanu	Waihaha 426-04										234,833
Whakamaru	Huirimu 121-01		253,974								
Whakamaru	Huirimu 121-02										202,860
Whakamaru	Mokai 123-00						27,247				
Whakamaru	Mokai 123-01						368,933				
Whakamaru	Mokai 123-02						279,013				
Whakamaru	Mokai 123-03								335,082		
Whakamaru	Mokai 123-04						98,535				
Whakamaru	Pureora 119-02				699,631						
Whakamaru	Tihoi 124-00		10,081								
Whakamaru	Tihoi 124-01		171,817								

PREDICTED 11kV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2018/19 to 2027/28)											
Point of Supply	**Description**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2018/19	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Whakamaru	Tihoi 124-02										157,500
Whakamaru	Tirohanga 129-01										216,090
Whakamaru	Tirohanga 129-02									489,138	
Whakamaru	Tirohanga 129-03						265,829				
Whakamaru	Whakamaru 120-02	228,484									
Whakamaru	Whakamaru 120-04				896,770						
Whakamaru	Whakamaru 120-05		57,809								
Whakamaru	Whakamaru 120-06					146,549					
Whakamaru	Wharepapa 122-03	263,971									
Whakamaru	Wharepapa 122-04	256,684									
Whakamaru	Wharepapa 122-05									262,280	
Whakamaru	Wharepapa 122-06	302,581									
Whakamaru	Wharepapa 122-08										105,000
	Subtotal	*3,993,920*	*3,934,343*	*3,561,242*	*3,932,227*	*4,010,225*	*3,434,147*	*3,192,701*	*3,638,292*	*4,277,555*	*3,288,915*
All Areas	Emergent	693,215	693,215	693,215	693,215	693,215	693,215	693,215	693,215	693,215	693,215
Total		**4,687,135**	**4,627,558**	**4,254,457**	**4,625,442**	**4,703,440**	**4,127,362**	**3,885,916**	**4,331,507**	**4,970,770**	**3,982,130**

TABLE 8-35: PREDICTED 11KVLINE RENEWAL EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD

8.4.4.4 33kV Line Renewals

Table 8-36 shows the 33kV line renewal assets and planned expenditure for the remainder of the current planning period. The figures are in current year dollars and do not include any adjustment for inflation. Data is displayed by Point of Supply.

PREDICTED 33KV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2018/19 to 2027/28)											
GXP	Asset Group	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
		2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28
Hangatiki	Gadsby / Wairere 307-01	125,060									
Hangatiki	Gadsby / Wairere 307-02			95,553							
Hangatiki	Gadsby / Wairere 307-03		284,622								
Hangatiki	Gadsby Road 305-01							271,542			
Hangatiki	Gadsby Road 305-02			256,394							
Hangatiki	Gadsby Road 305-03				60,971						
Hangatiki	Mahoenui 309-01							125,552			
Hangatiki	Mahoenui 309-02							125,552			
Hangatiki	Taharoa A 301-01		573,908								
Hangatiki	Taharoa A 301-02				275,026	137,514	137,514				
Hangatiki	Taharoa B 302-01	573,908									
Hangatiki	Taharoa B 302-02				495,046						
Hangatiki	Waitete 306-01		240,823								
National Park	National Park / Kuratau 609-01			275,312							
National Park	National Park / Kuratau 609-02				566,902						
National Park	National Park / Kuratau 609-03		596,103								
Ongarue	Nihoniho 603-01	282,332									
Tokaanu	Lake Taupo 606-01									74,474	
Tokaanu	Lake Taupo 606-02								69,181		
Tokaanu	Tokaanu / Kuratau 607-01										262,500
Tokaanu	Tokaanu / Kuratau 607-02			306,500							

PREDICTED 33KV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2018/19 to 2027/28)											
GXP	**Asset Group**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
		2018/19	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Tokaanu	Turangi 605-01								83,041		
Whakamaru	Whakamaru-33 310-01		122,056								
Whakamaru	Whakamaru-33 310-02							1,421,055			
Whakamaru	Whakamaru-33 310-03			278,202							
Whakamaru	Whakamaru-33 310-04						388,046				
	Subtotal	*981,300*	*1,817,512*	*1,211,961*	*1,397,945*	*137,514*	*525,560*	*1,943,701*	*152,222*	*74,474*	*262,500*
All Areas	Emergent	213,297	213,297	213,297	213,297	213,297	213,297	213,297	213,297	213,297	213,297
Total		**1,194,597**	**2,030,809**	**1,425,258**	**1,611,242**	**350,811**	**738,857**	**2,156,998**	**365,519**	**287,771**	**475,797**

TABLE 8-36: PREDICTED 33KV LINE RENEWAL EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD

Programmes based on 15 year cycle for 33 kV, 11 kV and LV lines. The individual asset groups making up the work pack have been reviewed and expenditure levelled since the 2009 AMP. The objective of this was to set up a smoother year-to-year cash flow programme.

Beyond 2022/23 the predicted line renewal expenditure reduces marginally due to the completion of the first 15 yearly cycle. At this time the result of the first pass are indicating that the second pass will require less work than the first pass through the assets. The first pass rectified many legacy issues and renewed some very old poor condition assets. It should be noted however that it is likely standards would have moved on by these times and that expenditure would have to be similar to present levels to meet ever increasing standards.

8.4.4.5 Line Renewal Summary CPI

Table 8-37 provides a summary of the planned line renewal expenditure predictions for the remainder of the planning period. Estimate figures have been adjusted to allow for inflation of 2.5% .

PREDICTED 33KV LINE RENEWAL PROJECTS AND EXPENDITURE FOR THE REMAINDER OF THE PLANNING PERIOD (2018/19 to 2027/28)										
Description	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
	2018/19	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
LV Planned Line Renewals	624,211	463,540	663,534	330,616	892,200	72,065	103,413	451,251	262,309	177,923
LV Emergent	127,390	130,575	133,839	137,185	140,615	144,130	147,733	151,427	155,212	159,092
Total LV	**751,601**	**594,115**	**797,373**	**467,801**	**1,032,815**	**216,195**	**251,146**	**602,678**	**417,521**	**337,016**
11kV Planned Line Renewals	4,631,722	4,676,698	4,339,027	4,910,812	5,133,427	4,505,898	4,293,828	5,015,426	6,044,072	4,763,326
11 kV Emergent	803,917	824,015	844,615	865,730	887,374	909,558	932,297	955,604	979,494	1,003,982
Total 11 kV	**5,435,639**	**5,500,712**	**5,183,642**	**5,776,542**	**6,020,800**	**5,415,456**	**5,226,125**	**5,971,030**	**7,023,567**	**5,767,307**
33kV Planned Line Renewals	1,138,007	2,160,451	1,476,657	1,745,842	176,029	689,580	2,614,062	209,839	105,230	380,178
33 kV Emergent	247,359	253,543	259,881	266,379	273,038	279,864	286,861	294,032	301,383	308,917
Total 33 kV	**1,385,366**	**2,413,994**	**1,736,538**	**2,012,221**	**449,067**	**969,444**	**2,900,922**	**503,871**	**406,613**	**689,095**
TOTAL PREDICTED EXPENDITURE	**7,572,605**	**8,508,821**	**7,717,553**	**8,256,564**	**7,502,682**	**6,601,095**	**8,378,193**	**7,077,579**	**7,847,701**	**6,793,418**

TABLE 8-37: SUMMARY OF PREDICTED LINE RENEWAL EXPENDITURE 2018/19 TO 2027/28 WITH CPI

8.4.5 Asset Renewal and Replacement Projects 2018/19 to 2027/28

Table 8-38 lists the Asset Renewal and Replacement projects (excluding line renewals and substations) for the remainder of the planning period (2018/19 to 2027/28) by Point of Supply. The values are in current dollars, without inflation and inclusive of engineering costs.

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2018/19	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2018/19	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2018/19	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2018/19	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2018/19	Network Equipment Renewal	Whole Network	Protection	12k
2018/19	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2018/19	Network Equipment Renewal	Whole Network	Radio Specific	43K
2018/19	Network Equipment Renewal	Whole Network	Relay Changes	16k
2018/19	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2018/19	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2018/19	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2018/19	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2019/20	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2019/20	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2019/20	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2019/20	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2019/20	Network Equipment Renewal	Whole Network	Load Control	117k
2019/20	Network Equipment Renewal	Whole Network	Protection	12k
2019/20	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2019/20	Network Equipment Renewal	Whole Network	Radio Specific	43K

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2019/20	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2019/20	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2019/20	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2019/20	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2020/21	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2020/21	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2020/21	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2020/21	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2020/21	Network Equipment Renewal	Whole Network	Protection	12k
2020/21	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2020/21	Network Equipment Renewal	Whole Network	Radio Specific	43K
2020/21	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2020/21	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2020/21	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2020/21	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2021/22	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2021/22	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2021/22	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2021/22	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2021/22	Network Equipment Renewal	Whole Network	Protection	12k
2021/22	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2021/22	Network Equipment Renewal	Whole Network	Radio Specific	43K
2021/22	Network Equipment Renewal	Whole Network	SCADA Contingency	17k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2021/22	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2021/22	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2021/22	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2022/23	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2022/23	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2022/23	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2022/23	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2022/23	Network Equipment Renewal	Whole Network	Protection	12k
2022/23	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2022/23	Network Equipment Renewal	Whole Network	Radio Specific	43K
2022/23	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2022/23	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2022/23	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2022/23	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2023/24	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2023/24	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2023/24	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2023/24	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2023/24	Network Equipment Renewal	Whole Network	Protection	12k
2023/24	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2023/24	Network Equipment Renewal	Whole Network	Radio Specific	43K
2023/24	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2023/24	Network Equipment Renewal	Whole Network	SCADA Specific	43k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2023/24	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2023/24	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2024/25	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2024/25	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2024/25	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2024/25	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2024/25	Network Equipment Renewal	Whole Network	Load Control	117k
2024/25	Network Equipment Renewal	Whole Network	Protection	12k
2024/25	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2024/25	Network Equipment Renewal	Whole Network	Radio Specific	43K
2024/25	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2024/25	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2024/25	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2024/25	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2025/26	Network Equipment Renewal	Whole Network	Upgrade Existing Mobile Generator	175k
2025/26	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2025/26	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2025/26	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2025/26	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2025/26	Network Equipment Renewal	Whole Network	Protection	12k
2025/26	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2025/26	Network Equipment Renewal	Whole Network	Radio Specific	43K
2025/26	Network Equipment Renewal	Whole Network	SCADA Contingency	17k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2025/26	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2025/26	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2025/26	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2026/27	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2026/27	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2026/27	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2026/27	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2026/27	Network Equipment Renewal	Whole Network	Protection	12k
2026/27	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2026/27	Network Equipment Renewal	Whole Network	Radio Specific	43K
2026/27	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2026/27	Network Equipment Renewal	Whole Network	SCADA Specific	43k
2026/27	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2026/27	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
2027/28	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
2027/28	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
2027/28	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
2027/28	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
2027/28	Network Equipment Renewal	Whole Network	Protection	12k
2027/28	Network Equipment Renewal	Whole Network	Radio Contingency	12k
2027/28	Network Equipment Renewal	Whole Network	Radio Specific	43K
2027/28	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
2027/28	Network Equipment Renewal	Whole Network	SCADA Specific	43k

POS: NON SPECIFIC				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2027/28	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
2027/28	Network Equipment Renewal	Whole Network	Transformer Renewals	350k

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2018/19	Transformers - 2 Pole Structures	Mahoenui	T1692 Install new transformer and rebuild structure.	41k
2018/19	Transformers - 2 Pole Structures	Mokau	T2194 Raise transformer	6k
2018/19	Transformers - 2 Pole Structures	Mokau	T2208 Rebuilt structure with standard single pole design. Replace transformer and recloser.	47k
2018/19	Transformers - Ground Mounted	Oparure	T9 Reuse 200kVA GMT and replace LV panel.	40k
2019/20	Transformers - Ground Mounted	Coast	T640 Rebuild and install new ground mounted transformer.	47k
2019/20	Transformers - Ground Mounted	Mokau	T2140 Install New ground mounted transformer and re-terminate cables	47k
2019/20	Transformers - Ground Mounted	Mokau	T2154 Install New ground mounted transformer and re-terminate cables	47k
2019/20	Transformers - Ground Mounted	Mokau	T2155 Install new ground mounted transformer	47k
2019/20	Transformers - Ground Mounted	Otorohanga	T557 Install a 300 kVA transformer fitted with an RTE.	47k
2020/21	Transformers - Ground Mounted	Gravel Scoop	T1007 Replace with ground mounted transformer (I tank)	45k
2020/21	Transformers - Ground Mounted	Rural	T1390 Replace with ground mounted transformer (I tank)	47k
2020/21	Transformers - Ground Mounted	Te Kuiti South	T10 Replace with ground mounted transformer (I tank)	45k
2021/22	Transformers - 2 Pole Structures	Caves	T1185 Replace with single pole structure.	30k
2021/22	Transformers - Ground Mounted	Oparure	T1043 Replace with ground mounted transformer (I tank)	58k
2021/22	Transformers - Ground Mounted	Otorohanga	T170 Replace with ground mounted transformer (I tank).	47k
2021/22	Transformers - Ground Mounted	Rural	T1367 Replace with ground mounted transformer (I tank)	47k
2022/23	Transformers - Ground Mounted	Benneydale	T2598 Replace with I tank. Crusader Meats will require generator	47k

POS: HANGATIKI				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2022/23	Transformers - Ground Mounted	Rural	T1559 Replace with ground mounted transformer (I tank)	47k
2023/24	Transformers - Ground Mounted	Otorohanga	T1552 Replace with ground mounted transformer (I tank)	45k
2026/27	Transformers - Ground Mounted	Otorohanga	T1174 Replace with ground mounted transformer (I tank)	47k
2026/27	Transformers - Ground Mounted	Waitomo	T1003 Replace with ground mounted transformer (I tank)	47k
2027/28	Transformers - Ground Mounted	Otorohanga	T2417 Replace with ground mounted transformer (I tank)	47k
2027/28	Transformers - Ground Mounted	Otorohanga	T557 Replace with transformer and RTE switch.	53k

POS: NATIONAL PARK				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2018/19	Transformers - 2 Pole Structures	National Park	16L02 Rebuild with single pole. New transformer and related low voltage.	47k
2018/19	Transformers - Ground Mounted	Chateau	16N05 Replace with 11kV box and LV panel. Replace transformer and raise existing enclosure	35k
2019/20	Transformers - 2 Pole Structures	National Park / Kuratau 33	12N05 Investigate installing a ground mounted transformer, or rebuild 33 kV / 400 V transformer structure to make safer.	45k
2020/21	Transformers - 2 Pole Structures	Otukou	12O01 Replace with single pole structure and replace recloser .	41k
2021/22	Transformers - 2 Pole Structures	Raurimu	T4077 Replace with single pole structure and replace recloser.	47k
2023/24	Transformers - 2 Pole Structures	National Park	15K06 Rebuild structure to single pole. Replace transformer if necessary.	58k
2023/24	Transformers - Ground Mounted	Chateau	16N04 Replace transformer	29k
2023/24	Transformers - Ground Mounted	Otukou	12N08 Install new transformer and replace LV rack	47k
2024/25	Transformers - Ground Mounted	Chateau	16N06 Install RTE switch and replace LV racks	52k
2024/25	Transformers - Ground Mounted	Chateau	16N07 Install new transformer and new LV rack.	52k
2026/27	Transformers - Ground Mounted	National Park	14L05 replace transformer	47k

POS: OHAKUNE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2018/19	Transformers - 2 Pole Structures	Turoa	20M01 Replace with single pole structure and related low voltage.	40k
2019/20	Transformers - 2 Pole Structures	Turoa	20L19 Rebuild structure to single pole and tidy up LV.	50k
2025/26	Transformers - 2 Pole Structures	Tangiwai	20L21 Ground mount 100 kVA transformer, use a refurbished transformer.	45k
2026/27	Transformers - 2 Pole Structures	Turoa	20K09 Ground mount with 100 kVA transformer.	47k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2018/19	Transformers - 2 Pole Structures	Hakiaha	01A31 GMT 300kVA Transformer	47k
2018/19	Transformers - 2 Pole Structures	Manunui	08J07 Raise, replace recloser and upgrade earthing.	25k
2018/19	Transformers - 2 Pole Structures	Southern	11K11 Rebuild structure and replace recloser.	47k
2018/19	Transformers - Ground Mounted	Matapuna	01A70 Replace transformer with Ground mounted transformer and RMU. Replace LV panel.	47k
2019/20	Transformers - 2 Pole Structures	Manunui	08J10 Raise transformer and tidy up LV	7k
2019/20	Transformers - 2 Pole Structures	Matapuna	01A75 Rebuild structure to single pole ad new transformer.	47k
2019/20	Transformers - 2 Pole Structures	Nihoniho	60 Raise transformer, replace recloser and tidy up the site.	30k
2019/20	Transformers - 2 Pole Structures	Northern	08I02 Replace with a ground mounted refurbished transformer. Check loadings.	45k
2019/20	Transformers - 2 Pole Structures	Northern	T4055 Raise equipment on structure to over regulation height and maintain clearances.	23k
2019/20	Transformers - 2 Pole Structures	Southern	10K14 Rebuild to single pole structure and replace recloser.	40k
2020/21	Transformers - 2 Pole Structures	Manunui	08J04 Replace with standard single pole structure.	50k
2020/21	Transformers - 2 Pole Structures	Ohura	07D03 Replace with single pole structure. Install new transformer.	47k
2020/21	Transformers - 2 Pole Structures	Southern	09K02 Raise transformer and replace recloser.	20k

POS: ONGARUE				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2022/23	Transformers - 2 Pole Structures	Ohura	07D16 Replace with single pole structure and replace recloser.	41k
2022/23	Transformers - 2 Pole Structures	Ohura	10E09 Rebuild site with two SWER transformers, Cost split between T4130 and 10E09	41k
2022/23	Transformers - 2 Pole Structures	Southern	12K08 Raise equipment and replace recloser.	41k
2022/23	Transformers - Ground Mounted	Northern	T4025 Replace with I tank transformer	47k
2023/24	Transformers - 2 Pole Structures	Ohura	09C05 Raise equipment, replace recloser and change fuse rack if necessary.	30k
2023/24	Transformers - Ground Mounted	Matapuna	01A36 Replace LV rack and cover exposed bushing.	20k
2023/24	Transformers - Ground Mounted	Northern	07I12 Replace LV rack and cover exposed bushing.	20k
2024/25	Transformers - 2 Pole Structures	Ohura	07D11 Replace structure with single pole structure and replace recloser.	41k
2024/25	Transformers - 2 Pole Structures	Ohura	T4130 Rebuild site with two SWER transformers, on site visit needed for design. Cost split between T4130 and 10E09	41k
2025/26	Transformers - Ground Mounted	Matapuna	01B20 Install LV rack and cover exposed HV bushings. TLC generator to be used.	35k
2025/26	Transformers - Ground Mounted	Matapuna	01B21 Replace with ground mounted transformer (I tank)	35k
2025/26	Transformers - Ground Mounted	Matapuna	01B25 Install new LV rack and cover exposed terminals. Use TLC generator.	35k
2025/26	Transformers - Ground Mounted	Northern	01A48 Install new LV rack and cover exposed HV terminals. Use TLC generator.	34k
2026/27	Transformers - Ground Mounted	Western	T4012 Industrial with HV and LV cable boxes, cable unprotected	47k

POS: TOKAANU				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2020/21	Transformers - 2 Pole Structures	Oruatua	09U12 Replace with single pole structure and new transformer	45k
2020/21	Transformers - 2 Pole Structures	Waihaha	04Q06 Raise equipment and replace recloser.	20k
2021/22	Transformers - 2 Pole Structures	Kuratau	09R28 Replace with single pole structure and replace transformer.	47k
2022/23	Transformers - Ground Mounted	Rangipo / Hautu	11S18 Replace with I tank transformer.	47k
2024/25	Transformers - Ground Mounted	Rangipo / Hautu	10S47 Install new LV rack and insulate exposed bushings.	20k
2024/25	Transformers - Ground Mounted	Turangi	10S30 Tin shed roadside. Open LV rack in tin shed. Install new LV rack and insulate exposed bushings.	20k
2026/27	Transformers - Ground Mounted	Tokaanu	10R20 Install RTE switch	47k
2027/28	Transformers - 2 Pole Structures	Kuratau	08R09 Ground mount transformer. Check loading and use a refurbished transformer if available.	45k

POS: WHAKAMARU				
Year	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
2019/20	Transformers - 2 Pole Structures	Tihoi	T1618 Raise equipment on structure.	7k

TABLE 8-38: SUMMARY ASSET RENEWAL AND REPLACEMENT PROJECTS (EXCLUDING LINE RENEWALS AND SUBSTATIONS) PLANNED FOR 2018/19 TO 2027/28 BY POINT OF SUPPLY (WITHOUT INFLATION)

Section 9

9. Non-Network Development, Maintenance and Renewal

9.1 Summary Description of Non-network Assets

9.1.1 Information and Technology Systems

TLC has a number of information and technology system that are used for network analysis, line design and mapping.

Table 9.1 Description of 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	TLC has recently purchased a CATAN package software, which 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, 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 9.1: DESCRIPTION OF TLC'S INFORMATION AND TECHNOLOGY SYSTEMS

9.1.2 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 5 and Section 6 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.

9.1.3 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. The TLC network control room and executive's offices are located on the top floor. The engineering, finance, billing and database staff occupy the bottom level of the building. 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 can be found in Section 9.3 of this AMP.

9.1.4 Tools, Plant and Machinery

TLC has a number of tools, plant and machinery associate with line inspections and patrols. Line inspectors are equipped with cameras, GPS devices, pole testers and scrub cutters. Listed below is a brief description of the tools, plant and machinery used by the line inspectors.

Table 9.2 Description of TLC's Tools, Plant and Machinery.

DESCRIPTION OF TLC'S TOOLS, PLANT AND MACHINERY	
Tool, Plant and Machinery	**Description**
Cameras	During line inspections cameras are used to take photos of assets. These are then loaded into the Basix database along with other inspection details such as GPS position and asset condition.
GPS Devices	GPS devices provide latitude and longitude information of network assets such as poles, Ground mount transformers and regulators. These are then loaded into the Basix database and the ESRI GIS system for mapping.
Pole Testers	Pole testers are used to determine the mechanical strength of a pole and its saves poles from premature replacement and pinpoints all dangerous poles. It not only provides a more cost effective maintenance of power pole assets but at the same time increases the safety of the public and utility personnel.
Scrub Cutters	Scrub cutters are often used during line inspections when staff have to clear scrub, gorse, brush, saplings and small trees to gain access to network equipment.

TABLE 9.2: DESCRIPTION OF TLC'S TOOLS, PLANT AND MACHINERY

9.1.5 Motor Vehicles

TLC has a pool of vehicle which are used for the provision of electricity supply. The vehicles listed in Table 9.3 are asset management vehicles and do not include TLC Contracting and other organisational vehicles. Currently TLC has 4 Utes and 3 quad bikes which are used for line inspections and vegetation control management. 2 cars which are used for the network controllers to carry out network duties after hour as well as asset inspections. Finally, there are 5 cars which are assigned to the engineers for on call engineering duties and day to day work on the network. The assignee of the vehicle is responsible for insuring the following vehicle checks are completed:

- Warrant of Fitness
- Certificate of Fitness
- Registration
- Road user licence
- Tread depth

Table 9.3 Description of TLC's Motor Vehicle Fleet.

TLC MOTOR VEHICLE FLEET		
Operator	**Vehicle**	**Vehicle Use**
Line Inspector (Overhead)	Holden Space Cab Ute	Line Inspection
Line Inspector (Overhead)	Honda Quad Bike 1 (2010)	Line Inspection
Line Inspector (General and Design)	Holden Rodeo (2006)	Line Inspection
Line Inspector (General and Design)	Honda Quad Bike 3 (2012)	Line Inspection
Line Inspector (Low Voltage)	Nissan Navara (2011)	Line Inspection
Line Inspector (Low Voltage)	Honda Quad Bike 2	Line Inspection
Network Activity Controller	Toyota Hilux Double Cab (2011)	Line Inspection and Vegetation Control
Control Room Operator	Toyota Corolla	Network Control
New Connection and Backup Controller	Subaru Forrester	Network Control
Network Asset Manager	Hyundai Sante Fe (2008)	Engineering Use
Network Senior Engineer	Nissan X-Trail (2011)	Engineering Use
Technical Engineer	Nissan X Trail (2010)	Engineering Use
Network Performance Engineer	Subaru Forrester (2007)	Engineering Use
Shared Use	Honda Jazz (2008)	Engineering Use

TABLE 9.3: DESCRIPTION OF TLC'S MOTOR VEHICLE FLEET

9.1.6 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, (commissioned June 2011), 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.

9.1.7 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.

9.2 Development, Maintenance and Renewal Policies

At the time of writing; TLC is in the process of documenting all non-asset related policies and procedures.

9.2.1 Information and Technology Systems

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. Information and technology systems are continually under review and are developed to meet the increasing regulatory requirements and latest design techniques. Updates, development and purchase of new information and technology system are approved by the Engineering Manager or the Network Information Systems Controller.

9.2.2 Asset Management Systems

The BASIX system is also continually under review and is not only developed to meet the increasing regulatory requirements but also to meet the network needs in term of outage notification and work management. Requests for alterations to the Basix database are made to the Network Information Systems Controller, who then authorises and arranges for the changes and updates to be carried out.

9.2.3 Office Buildings, Depots and Workshops

Development of TLC's office building, depots and workshops are accessed on a case by case basis. These are generally reviewed by management and submitted to the Director. Final approval for development of the office building, depots and workshops is obtained from the Board of Directors. Maintenance and general repairs are done as and when needed by external contactors. Office building projects in the planning period include the seismic reinforcing of the King Street office in years 2013/14 and 2014/15, an allowance of $500,000 has allocated for this.

9.2.4 Tools, Plant and Machinery

Tools, plant and machinery are inspected prior to each use. Servicing of machinery is done on an annual basis. If the equipment fails and is no longer serviceable or operational the assignee of the equipment shall notify their supervisor of the status of the equipment. The supervisor shall then arrange (in consultation with the assignee) a replacement piece of equipment.

9.2.5 Motor Vehicles

Once a motor vehicle reaches the age of 6years or has an odometer reading of 200,000km or more the vehicle will be reviewed by the department manager and CFO. If a decision is made by the department manager and CFO to replace a Company vehicle the Employee responsible for purchasing the vehicle shall endeavour to obtain a replacement vehicle at the best purchase price. Where possible, consideration should be given to replace all non-executive vehicles with demonstration models. No conditions shall prevent or restrict vehicle replacement in the event of an accident in which the vehicle is written off. Motor vehicle such as quad bike, diggers etc. shall be replaced after due consultation between the party making the request and the purchase staff. All vehicles are disposed of according to the Sale of Assets policy.

9.2.6 Other Non-Network Fixed Assets

When meters are reported as faulty or inoperative a faultmen is sent out to assess the fault. When the faultmen confirms that the meter is in fact faulty he will replace it with a new meter. The faultmen will return the faulty meter to TLC Metering Business Supervisor for special test report to Dispatch and completed job sheet. The Metering Business Supervisor will then arrange for the work to be charged to FCL.

9.2.7 Other Organisation Non-system Fixed Assets

With respect to Navision, TLC carries out periodic software updates covering development and maintenance as appropriate and at present has no plans to change it core accounting software.

With respect to Gentrack, TLC is planning to evaluate other options over the next two years, with a view that Gentrack may be replaced.

9.3 Non System Fixed Assets Capital Expenditure Forecast

Table 9.4 shows the Capital expenditure for non-system fixed assets.

NON SYSTEM FIXED ASSETS CAPITAL EXPENDITURE															
Item	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Information Systems	137,819	137,819	137,819	137,819	137,819	137,819	137,819	137,819	137,819	137,819	137,819	137,819	137,819	137,819	137,819
Building	520,708	520,708	20,708	20,708	20,708	20,708	20,708	20,708	20,708	20,708	20,708	20,708	20,708	20,708	20,708
Tools, Plant and Machinery	23,100	16,800	16,800	16,800	16,800	16,800	16,800	16,800	16,800	16,800	16,800	16,800	16,800	16,800	16,800
Vehicle	63,989	63,989	63,989	63,989	63,989	63,989	63,989	63,989	63,989	63,989	63,989	63,989	63,989	63,989	63,989
Meters	400,000	400,000	400,000	400,000	400,000	0	0	0	0	0	0	0	0	0	0
TOTAL	**1,145,616**	**1,139,316**	**239,316**	**639,316**	**639,316**	**239,316**	**239,316**	**239,316**	**239,316**	**239,316**	**239,316**	**239,316**	**239,316**	**239,316**	**239,316**

TABLE 9.4: CAPITAL EXPENDITURE FOR NON- SYSTEM FIXED ASSETS (DOES NOT INCLUDE INFLATION ADJUSTMENT)

Note: The vehicles listed in Table 9.4 are asset management vehicles and do not include TLC Contracting and other organisational vehicles.

9.4 Non System Fixed Assets Maintenance Expenditure Forecast

Table 9.5 shows the Maintenance expenditure for non-system fixed assets.

NON SYSTEM FIXED ASSETS MAINTENANCE EXPENDITURE															
Item	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Information Systems	78,850	68,850	68,850	68,850	68,850	68,850	68,850	68,850	68,850	68,850	68,850	68,850	68,850	68,850	68,850
Tools, Plant and Machinery	11,407	11,407	11,407	11,407	11,407	11,407	11,407	11,407	11,407	11,407	11,407	11,407	11,407	11,407	11,407
Vehicle	102,362	102,362	102,362	102,362	102,362	102,362	102,362	102,362	102,362	102,362	102,362	102,362	102,362	102,362	102,362
TOTAL	**192,619**	**182,619**	**182,619**	**182,619**	**182,619**	**182,619**	**182,619**	**182,619**	**182,619**	**182,619**	**182,619**	**182,619**	**182,619**	**182,619**	**182,619**

TABLE 9.5: MAINTENANCE EXPENDITURE FOR NON- SYSTEM FIXED ASSETS (DOES NOT INCLUDE INFLATION ADJUSTMENT)

Note: The vehicles listed in Table 9.5 are asset management vehicles and do not include TLC Contracting and other organisational vehicles.

Section 10

10. Risk Management

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.

Most of TLC's business processes and activities have some 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).

10.1Risk Policies

10.1.1 Corporate Risk Policies

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 10.1.

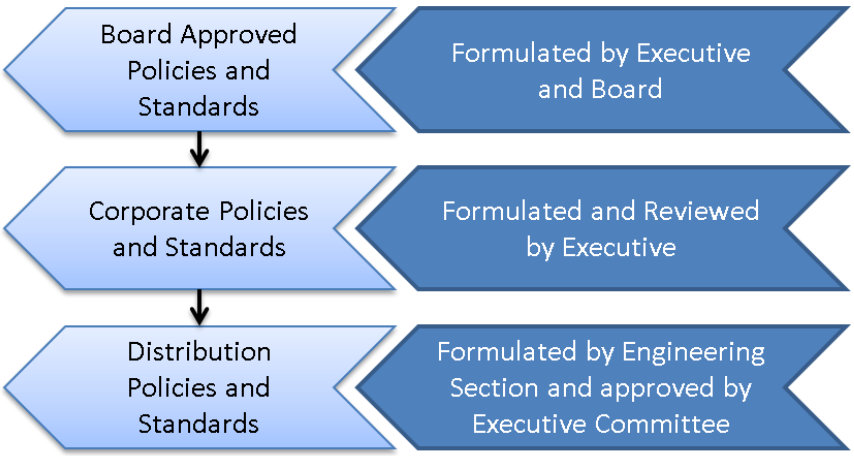


FIGURE 10.1: STRUCTURE OF CORPORATE POLICIES AND STANDARDS

The methods used to assess corporate 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 corporate 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.

10.1.2 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 7, 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.

10.2Risk Assessment and Analysis

10.2.1 Corporate Risk

Table 10.1 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 10.1: CORPORATE RISK ASSESSMENT AND ANALYSIS

TLC has insurance to mitigate corporate risk should incidents occur.

10.3Network Risk and Methods to Mitigate Risk Events

10.3.1 Overhead Lines

Table 10.2 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.

OVERHEAD LINE RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
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.
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.

OVERHEAD LINE RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
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.
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 10.2: IDENTIFIED RISKS AND MITIGATION OF RISKS TO OVERHEAD LINES

10.3.2 Zone Substations and Voltage Regulation Equipment

Table 10.3 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 10.3: 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.

10.3.3 Distribution Substations, Switchgear and Underground Systems

Table 10.4 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 10.4: IDENTIFIED RISKS AND MITIGATION OF RISKS TO DISTRIBUTION SUBSTATIONS, SWITCHGEAR AND UNDERGROUND SYSTEMS

Distribution substations, switchgear and underground systems are generally not insured.

10.3.4 Other Equipment

Table 10.5 summarises other secondary distribution assets risk assessment and mitigation.

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.

OTHER SECONDARY DISTRIBUTION ASSETS RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
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.
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.

OTHER SECONDARY DISTRIBUTION ASSETS RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
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.
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.
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 news letters, customer clinics, focus groups and newspaper articles. Conclusion: Surge suppression from a customer perspective is a low probability high consequence event.

OTHER SECONDARY DISTRIBUTION ASSETS RISK ASSESSMENT AND MITIGATION	
Risk	**Mitigation**
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 10.5: 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.

10.3.5 Risk Focus of Plan

The TLC legacy network was constructed in times when customers had different quality and reliability expectations. Hazard control was to different standards from those that exist today. A high level of risk was acceptable. Today's reliability and loading requirements are pushing much of this old equipment harder than it has ever been pushed over its life.

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.

10.4Risk evaluation

10.4.1 Potential Liability Analysis

Table 10.6 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**
CORPORATE		
Corporate systems not in place	Fraud	Experience has shown that fraud could typically cost $200,000 or more per annum. An insurance backstop is in place.
	Strategic plans and direction	Lack of strategic plans and direction will cost the organisation in all aspects of its operation. The cost of lack of direction, motivation and disorganisation/ inefficiency would quickly amount to costs of $1m p.a.
	Environmental	Environmental costs from clean-ups and fines after events such as oil spills. Fines, legal costs and clean-up costs could typically be $100,000 per event.
	Human Resources	High employee turnover quickly adds to costs. A turnover of 20 people p.a. has been estimated to add about $200,000 p.a. to direct and indirect operating costs.
Public Relations	Customer Interfaces	A poor customer relationship leads to many difficulties within the organisation. These include: • Landowner issues. • Repeated complaints to Regulators. • Low staff morale. • Poor and often incorrect public perceptions. The cost of poor public relations is significant and difficult to estimate due to the flow down instabilities that will occur through the organisation and with its customers. Direct expenditure on improving public relations can typically add $200,000 to operating costs. Indirect costs are likely to be greater than these amounts.
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.

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		
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 10.6: CURRENT BEST ESTIMATES OF THE POTENTIAL COSTS OF NOT CONTROLLING RISKS

10.4.2 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 7 and 8 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.

10.4.2.1 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.

10.4.2.2 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.

10.5Risks 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.

10.6Details of Emergency Response and Contingency Plans

10.6.1 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.

10.6.2 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.

10.6.3 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.

10.6.4 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.

10.6.5 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.

10.6.6 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.

10.6.7 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.

Section 11

11. Capability to Deliver

11.1 Processes used to Ensure the Asset Management Plan is Realistic

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.

11.1.1 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.

11.1.2 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.

11.2 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. It is likely to be amended in the near future due to a number of resignations, increasing compliance requirements and the need to do capital works at the lowest possible cost.

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 12

12. Stakeholder Requested Information

12.1 Background

The format of this plan follows that specified in the Commerce Commission requirements. TLC has followed this format as closely as possible to ensure compliance with the Commissions assessment, and the building of this information suitable for other related disclosure and mandatory reporting requirements.

TLC has had a number of stake holder requests for the works programme to be presented in a more understandable (concise), format. Section 13 has been added to fulfil these requests.

It needs to be recognised that the works programme consists of many integrated activities. Unbundling these into a simple format is a challenge. TLC also receives various other requests for specific information that often takes a relatively long time to prepare, and may be of interest to other stakeholders.

It is envisioned that Section 13 of the AMP will be developed to provide commonly requested information. Preparing and submitting it as part of the annual planning process will be a more efficient and effective use of time as opposed to one off requests.

12.2 Proposed Capital Works 2013/14 to 2027/28

The list in table 12-1 includes all capital work proposed out to 2027/28. All projects are subject to review until the work is actually commenced to ensure they are necessary and the timing is appropriate. The projects are listed by year, point of supply (GXP), category, location, a brief description and cost. The values are in current dollars, without inflation and inclusive of engineering costs.

PROPOSED CAPITAL WORKS: 2013/14				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non-Specific	Customer Driven Project	Various	General Connections - Earthing and tap-offs	165k
Non-Specific	Customer Driven Project	Various	General Connections - Transformers	165k
Non-Specific	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
Non-Specific	Customer Driven Project	Various	Industrials - Transformers	110k
Non-Specific	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
Non-Specific	Customer Driven Project	Various	Subdivisions - Management	11k
Non-Specific	Customer Driven Project	Various	Subdivisions - Transformers	82k
Non-Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k

PROPOSED CAPITAL WORKS: 2013/14				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non-Specific	Network Equipment Renewal	Whole Network	Protection	12k
Non-Specific	Network Equipment Renewal	Whole Network	Radio Contingency	12k
Non-Specific	Network Equipment Renewal	Whole Network	RADIO Specific	630k
Non-Specific	Network Equipment Renewal	Whole Network	Relay Changes	321k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
Non-Specific	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	89k
Non-Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
Hangatiki	Line Renewals	Gravel Scoop	109-04 11kV Line Renewal	329k
Hangatiki	Line Renewals	Gravel Scoop	109-05 11kV Line Renewal	235k
Hangatiki	Line Renewals	Mahoenui	113-03 11kV Line Renewal	209k
Hangatiki	Line Renewals	Mahoenui	113-03 LV Line Renewal	7k
Hangatiki	Line Renewals	Mokau	128-08 LV Line Renewal	7k
Hangatiki	Line Renewals	Oparure	107-05 11kV Line Renewal	228k
Hangatiki	Line Renewals	Oparure	107-06 11kV Line Renewal	228k
Hangatiki	Line Renewals	Piopio	116-05 11kV Line Renewal	138k
Hangatiki	Line Renewals	Rangitoto	106-05 11kV Line Renewal	316k
Hangatiki	Line Renewals	Te Kuiti Town	105-01 11kV Line Renewal	143k
Hangatiki	Line Renewals	Te Mapara	117-04 11kV Line Renewal	309k
Hangatiki	Switches (Hazard)	Benneydale	REG14 Install bypass protection on regulator.	5k
Hangatiki	Switches (Reliability Improvement)	Te Kuiti South	730 Replace recloser.	52k
Hangatiki	Switches (Reliability Improvement)	Te Mapara	1316 Automate switch.	23k
National Park	Line Renewals	Raurimu	410-02 11kV Line Renewal	240k
National Park	Substation, Supply Point and 33kV Development	National Park Zone Substation	ZSub501 Rebuild with a modular substation and rationalise CB in conjunction with grid exit work.	330k
National Park	Substation, Supply Point and 33kV Development	Tawhai Zone Substation	ZSub513 Refurbish transformer.	95k

PROPOSED CAPITAL WORKS: 2013/14				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
National Park	Substation, Supply Point and 33kV Development	ZSub516 - National Park POS Compound	ZSub516 Install ripple plant in a container. Rationalise the number of outgoing feeder circuit breakers .	699k
National Park	Switches (Hazard)	Chateau	16N17 Install I tank transformer outside building.	45k
National Park	Transformer - 2 Pole Structures	National Park	15L05 Replace with Ground mounted transformer, transformer is close to motel balcony.	47k
Ohakune	Line Renewals	Turoa	415-01 11kV Line Renewal	290k
Ohakune	Substation, Supply Point and 33kV Development	Borough Zone Substation	ZSub508 Install 3MVAR capacitor bank that can be remotely switched with controllers at Borough Substation for 11 kV voltage support.	124k
Ohakune	Substation, Supply Point and 33kV Development	Manunui Zone Substation	ZSub510 Install oil separation unit.	29k
Ohakune	Substation, Supply Point and 33kV Development	Manunui Zone Substation	ZSub510 Rebuild site. Replace incoming 33 kV Breaker. Do it in conjunction with regulator installation and transformer refurbishment.	175k
Ohakune	Substation, Supply Point and 33kV Development	Manunui Zone Substation	ZSub510 Refurbish transformer 510T1.	93k
Ohakune	Substation, Supply Point and 33kV Development	Tuhua Zone Substation	ZSub502 Install 1MVAR capacitor bank that can be remotely swithced with controllers at Tuhua Substation for 11 kV voltage support.	105k
Ohakune	Switches (Hazard)	Ohakune Town	20L15 Install transformer with RTE	47k
Ongarue	Line Renewals	Northern	402-05 11kV Line Renewal	348k
Ongarue	Line Renewals	Ohura	413-08 11kV Line Renewal	279k
Ongarue	Line Renewals	Ongarue	421-02 11kV Line Renewal	209k
Ongarue	Line Renewals	Ongarue / Taumarunui 33	604-01 33kV Line Renewal	518k
Ongarue	Line Renewals	Taumarunui / Kuratau 33	608-03 33kV Line Renewal	249k
Ongarue	Line Renewals	Tuhua 33	602-01 33kV Line Renewal	33k
Ongarue	Line Renewals	Western	403-06 11kV Line Renewal	282k
Ongarue	Switches (Hazard)	Hakiaha	FED401 Add 11 kV switch gear for 01A38 and 01A82.	58k
Ongarue	Switches (Reliability Improvement)	Manunui	5914 Automate Switch.	41k
Ongarue	Switches (Reliability Improvement)	Western	5404 Automation unit $8000. SCADA and RTU $6000. Technician $6000. Labour $6000. Engineering $2139.	29k
Ongarue	Switches (Reliability Improvement)	Western	5795 Automation switch.	29k

PROPOSED CAPITAL WORKS: 2013/14				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Tokaanu	Switches (Reliability Improvement)	Waihaha	5150 Install new switch and automate.	47k
Tokaanu	Transformer - 2 Pole Structures	Rangipo / Hautu	11S04 Check loading on transformer, Downsize TX as required. Rebuild with standard single pole structure.	33k
Tokaanu	Transformer - 2 Pole Structures	Waihaha	07Q14 Existing equipment is below regulation height. Raise equipment and replace recloser.	32k
Tokaanu	Transformers - Ground Mounted	Turangi	10S42 Replace LV racks.	23k
Whakamaru	Line Renewals	Wharepapa	122-07 11kV Line Renewal	273k
Whakamaru	Regulators	Wharepapa	122-02 Install regulator near 499 Aotearoa Road.	101k
Whakamaru	Regulators	Wharepapa	122-06 Install regulator on Hingaia Road.	101k
Whakamaru	Substation, Supply Point and 33kV Development	Arohena Zone Substation	ZSub211 Install 1MVAR of capacitors on both Wharepapa and Hurimu feeder.	105k
Whakamaru	Substation, Supply Point and 33kV Development	Atiamuri Supply Compound	ZSub215 Install cooling fans on the transformer.	35k
Whakamaru	Switches (Reliability Improvement)	Tihoi	454 Replace with ENTEC switch and automate.	45k
Whakamaru	Switches (Reliability Improvement)	Tirohanga	434 Replace switch and automate.	40k
Whakamaru	Transformers - Ground Mounted	Mangakino	T701 Check loading and replace with a refurbished I tank of a suitable size. Install a ring main unit with 2 fuses, one for T2316.	47k

PROPOSED CAPITAL WORKS: 2014/15				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non-Specific	Customer Driven Project	Various	General Connections - Earthing and tap-offs	165k
Non-Specific	Customer Driven Project	Various	General Connections - Transformers	165k
Non-Specific	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
Non-Specific	Customer Driven Project	Various	Industrials - Transformers	110k
Non-Specific	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
Non-Specific	Customer Driven Project	Various	Subdivisions - Management	11k
Non-Specific	Customer Driven Project	Various	Subdivisions - Transformers	82k
Non-Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non-Specific	Network Equipment Renewal	Whole Network	Load Control	117k
Non-Specific	Network Equipment Renewal	Whole Network	Protection	12k
Non-Specific	Network Equipment Renewal	Whole Network	Radio Contingency	12k
Non-Specific	Network Equipment Renewal	Whole Network	RADIO Specific	96k
Non-Specific	Network Equipment Renewal	Whole Network	Relay Changes	321k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
Non-Specific	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	82k
Non-Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
Hangatiki	Line Renewals	Aria	114-04 11kV Line Renewal	167k
Hangatiki	Line Renewals	Aria	114-05 11kV Line Renewal	270k
Hangatiki	Line Renewals	Benneydale	103-07 LV Line Renewal	66k
Hangatiki	Line Renewals	Benneydale	103-08 11kV Line Renewal	71k

PROPOSED CAPITAL WORKS: 2014/15				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Line Renewals	Caves	101-09 11kV Line Renewal	31k
Hangatiki	Line Renewals	Caves	101-10 11kV Line Renewal	89k
Hangatiki	Line Renewals	Gravel Scoop	109-06 11kV Line Renewal	288k
Hangatiki	Line Renewals	Gravel Scoop	109-14 11kV Line Renewal	242k
Hangatiki	Line Renewals	Mahoenui	113-05 11kV Line Renewal	253k
Hangatiki	Line Renewals	Mokau	128-08 11kV Line Renewal	501k
Hangatiki	Line Renewals	Mokau	128-09 11kV Line Renewal	102k
Hangatiki	Line Renewals	Mokauiti	115-05 11kV Line Renewal	211k
Hangatiki	Line Renewals	Mokauiti	115-06 11kV Line Renewal	160k
Hangatiki	Line Renewals	Otorohanga	112-07 11kV Line Renewal	101k
Hangatiki	Switches (Reliability Improvement)	Otorohanga	308 Automate switch.	23k
Hangatiki	Switches (Reliability Improvement)	Otorohanga	645 Automate switch.	23k
Hangatiki	Transformer - 2 Pole Structures	Mokau	T2153 Rebuild restructure with standard single pole design.	28k
Hangatiki	Transformer - 2 Pole Structures	Te Kuiti South	T559 Replace with ground mounted transformer.	48k
Hangatiki	Transformers - Ground Mounted	Oparure	T663 Replace with refurbished I tank transformer.	36k
Mokai Supply Point	Substation, Supply Point and 33kV Development	Mokai Zone Substation	ZSub3358 Add additional back up transformer off Mokai 1 bus to supply Mokai Energy Park.	500k
National Park	Line Renewals	National Park	411-02 11kV Line Renewal	415k
National Park	Line Renewals	National Park 33	601-01 33kV Line Renewal	32k
National Park	Line Renewals	Raurimu	410-02 11kV Line Renewal	240k
National Park	Substation, Supply Point and 33kV Development	Tawhai Zone Substation	ZSub513 Replace zone substaiton fence.	58k
National Park	Switches (Hazard)	Chateau	16N21 Install transformer with RTE switch	47k
National Park	Transformer - 2 Pole Structures	Raurimu	13I10 Renew Structure. Check the loading on this transformer ETAP loadflows indicate that it may be overloaded. Rebuild site. Costs split over 13I10 and T4132 as there are two SWER isolating transformers on the one structure.	35k
National Park	Transformer - 2 Pole Structures	Raurimu	T4132 Check the loading on this transformer ETAP loadflows indicate that it may be overloaded. Rebuild site. Costs split over 13I10 and T4132 as there are two SWER isolating transformers on the one structure.	35k
National Park	Transformers - Ground Mounted	National Park	14L12 Install transformer with RTE switch.	40k

PROPOSED CAPITAL WORKS: 2014/15				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Ohakune	Line Renewals	Ohakune Town	414-01 11kV Line Renewal	156k
Ohakune	Regulators	Turoa	FED415 Regulator at start of Station Road.	111k
Ohakune	Switches (Hazard)	Turoa	17N04 Install ring main unit. Needs a visual break & earths Switch gear needed. Install ring main unit.	47k
Ongarue	Line Renewals	Manunui	407-01 11kV Line Renewal	130k
Ongarue	Line Renewals	Manunui	407-01 LV Line Renewal	33k
Ongarue	Line Renewals	Ohura	413-03 11kV Line Renewal	169k
Ongarue	Line Renewals	Southern	409-07 11kV Line Renewal	173k
Ongarue	Line Renewals	Taumarunui / Kuratau 33	608-02 33kV Line Renewal	348k
Ongarue	Line Renewals	Western	403-07 11kV Line Renewal	173k
Ongarue	Switches (Hazard)	Western	08I55 Install transformer with RTE switch.	47k
Ongarue	Switches (Reliability Improvement)	Hakiaha	5831 Replace ABS and automate switch.	41k
Ongarue	Switches (Reliability Improvement)	Northern	5984 Replace ABS and automate switch.	41k
Ongarue	Switches (Reliability Improvement)	Northern	6127 Replace links with ENTEC switch.	30k
Ongarue	Transformer - 2 Pole Structures	Manunui	07K11 Replace two pole structure with standard single pole SWER isolating structure.	46k
Ongarue	Transformer - 2 Pole Structures	Manunui	08K14 Replace pole mounted transformer with ground mounted transformer, use refurbished transformer if possible.	51k
Ongarue	Transformer - 2 Pole Structures	Ongarue	01K02 Check loading on this transformer. Mill is now closed and structure changed to a standard structure single pole with a 30 kVA TX.	38k
Ongarue	Transformer - 2 Pole Structures	Tuhua	05G03 Lift equipment over regulation height, maintain clearances and replace recloser.	28k
Tokaanu	Switches (Hazard)	Kuratau	08R20 Install transformer with RTE switch.	47k
Tokaanu	Switches (Hazard)	Oruatua	09U11 Install RTE switch near or associated with 09U11. I	51k
Tokaanu	Switches (Hazard)	Oruatua	FED417 Remove dangerous overhead river crossing where trout fishing occurs and lines tangle with overhead conductors, underground cable across bridge. Work in association with 09U11.	163k
Tokaanu	Switches (Reliability Improvement)	Rangipo / Hautu	5207 Install recloser.	50k

PROPOSED CAPITAL WORKS: 2014/15				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Tokaanu	Transformer - 2 Pole Structures	Motuoapa	09T04 Replace with 300 kVA ground mounted transformer, use a refurbished transformer if possible.	48k
Tokaanu	Transformers - Ground Mounted	Turangi	10S44 Replace with ground mounted Transformer and LV rack.	45k
Whakamaru	Line Renewals	Huirimu	121-03 11kV Line Renewal	279k
Whakamaru	Line Renewals	Tihoi	124-03 11kV Line Renewal	108k
Whakamaru	Switches (Hazard)	Pureora	REG26 Install bypass protection on regulator.	5k
Whakamaru	Switches (Reliability Improvement)	Pureora	423 Automate switch	23k
Whakamaru	Transformers - Ground Mounted	Mangakino	T700 Replace with I tank transformer.	30k

PROPOSED CAPITAL WORKS: 2015/16				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non-Specific	Customer Driven Project	Various	General Connections - Earthing and tap-offs	192k
Non-Specific	Customer Driven Project	Various	General Connections - Transformers	192k
Non-Specific	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
Non-Specific	Customer Driven Project	Various	Industrials - Transformers	192k
Non-Specific	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
Non-Specific	Customer Driven Project	Various	Subdivisions - Management	11k
Non-Specific	Customer Driven Project	Various	Subdivisions - Transformers	110k
Non-Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non-Specific	Network Equipment Renewal	Whole Network	Protection	12k
Non-Specific	Network Equipment Renewal	Whole Network	Radio Contingency	12k
Non-Specific	Network Equipment Renewal	Whole Network	RADIO Specific	96k
Non-Specific	Network Equipment Renewal	Whole Network	Relay Changes	321k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
Non-Specific	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	67k
Non-Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
Hangatiki	Line Renewals	Benneydale	103-08 11kV Line Renewal	71k
Hangatiki	Line Renewals	Caves	101-11 11kV Line Renewal	53k
Hangatiki	Line Renewals	Coast	125-05 11kV Line Renewal	318k
Hangatiki	Line Renewals	Coast	125-05 LV Line Renewal	33k
Hangatiki	Line Renewals	Coast	125-06 11kV Line Renewal	185k
Hangatiki	Line Renewals	Mahoenui	113-06 11kV Line Renewal	230k

PROPOSED CAPITAL WORKS: 2015/16				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Line Renewals	Mahoenui	113-07 11kV Line Renewal	111k
Hangatiki	Line Renewals	Maihiihi	111-10 11kV Line Renewal	332k
Hangatiki	Line Renewals	Rural	126-03 11kV Line Renewal	3k
Hangatiki	Line Renewals	Te Mapara	117-06 11kV Line Renewal	228k
Hangatiki	Regulators	Maihiihi	REG06 Replace Whibley Road Regulator. This is an old type of regulator that gets overload when back feeding.	106k
Hangatiki	Regulators	Mokau	FED128 Install Regulator near Bolts place on top of hill.	126k
Hangatiki	Substation, Supply Point and 33kV Development	Taharoa B 33	FED302 Renew and remove hazardous equipment.	116k
Hangatiki	Substation, Supply Point and 33kV Development	Taharoa Zone Substation	ZSub201 Upgrade to customers requirements and specifications. Funded through on-going charges to industrial customers.	1628k
Hangatiki	Substation, Supply Point and 33kV Development	Waitete Zone Substation	ZSub206 Replace fence.	70k
Hangatiki	Switches (Hazard)	Maihiihi	REG01 Install bypass protection on regulators.	5k
Hangatiki	Switches (Reliability Improvement)	Otorohanga	288 Automate switch.	34k
Hangatiki	Transformer - 2 Pole Structures	Mahoenui	T1453 Structure needs to be rebuild on single pole.	41k
Hangatiki	Transformer - 2 Pole Structures	Mahoenui	T1865 Move platform up the pole.	6k
Hangatiki	Transformer - 2 Pole Structures	Mahoenui	T2520 Using existing poles raise structure and replace reclosers.	41k
Hangatiki	Transformer - 2 Pole Structures	Te Mapara	T1777 Single pole SWER. Upgrade to current TLC design standards.	47k
Hangatiki	Transformers - Ground Mounted	Hangatiki East	T381 Replace with I tank or front access transformer. Use a refurbished transformer if available.	47k
Hangatiki	Transformers - Ground Mounted	Waitomo	T406 Replace transformer.	47k
National Park	Line Renewals	No Feeder	610-01 33kV Line Renewal	53k
National Park	Line Renewals	Raurimu	410-02 11kV Line Renewal	240k
National Park	Switches (Reliability Improvement)	Tawhai Zone Substation	5151 Automate switch in Substation.	47k
Ohakune	Line Renewals	Ohakune Town	414-01 11kV Line Renewal	156k
Ohakune	Line Renewals	Ohakune Town	414-01 LV Line Renewal	132k
Ohakune	Line Renewals	Turoa	415-01 LV Line Renewal	110k
Ohakune	Switches (Hazard)	Ohakune Town	20L59 Install transformer with RTE switch.	47k

PROPOSED CAPITAL WORKS: 2015/16				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Ohakune	Switches (Hazard)	Ohakune Town	20L68 Install additional switch gear. Difficult site, on bank.	80k
Ohakune	Switches (Hazard)	Tangiwai	20L43 Install RTE switch.	47k
Ohakune	Transformer - 2 Pole Structures	Tangiwai	20L06 Stick with pole mounted transformer. Move 1 span and reinsulate LV. Put tap off on single pole.	45k
Ongarue	Line Renewals	Nihoniho	412-02 11kV Line Renewal	203k
Ongarue	Line Renewals	Ohura	413-04 11kV Line Renewal	296k
Ongarue	Line Renewals	Ohura	413-09 11kV Line Renewal	132k
Ongarue	Line Renewals	Ongarue	421-03 11kV Line Renewal	213k
Ongarue	Line Renewals	Ongarue	421-03 LV Line Renewal	27k
Ongarue	Line Renewals	Southern	409-08 11kV Line Renewal	237k
Ongarue	Line Renewals	Taumarunui / Kuratau 33	608-01 33kV Line Renewal	216k
Ongarue	Line Renewals	Western	403-03 11kV Line Renewal	146k
Ongarue	Line Renewals	Western	403-07 11kV Line Renewal	173k
Ongarue	Switches (Reliability Improvement)	Manunui	5912 Automate switch.	35k
Ongarue	Switches (Reliability Improvement)	Matapuna	5838 Automate switch.	47k
Ongarue	Transformer - 2 Pole Structures	Hakiaha	01B11 New single pole structure, replace transformer.	47k
Ongarue	Transformer - 2 Pole Structures	Northern	01A46 Replace structure and install a refurbished ground mounted transformer.	47k
Ongarue	Transformer - 2 Pole Structures	Southern	09K50 Replace structure with single pole structure with 100kVA transformer.	44k
Tokaanu	Line Renewals	Oruatua	417-01 11kV Line Renewal	232k
Tokaanu	Line Renewals	Oruatua	417-01 LV Line Renewal	192k
Tokaanu	Substation, Supply Point and 33kV Development	Turangi Zone Substation	ZSub505 Add additional 33 and 11 kV switchgear. Install 4 way Xiria and leave existing reclosers. Upgrade protection schemes to ensure primary and backup protection is reliable. New 33 kV installed in year 12/13 and 11 kV breakers to be installed year 16/17. UG and remove double cct to be done at same time as far as 5673 tap-off (see 11 kV line renewals). Tony to provide cost estimate.	160k
Tokaanu	Switches (Hazard)	Kuratau	09R14 Install a Xiria in association with Transformer 09R14 and work on 09R16.	47k
Tokaanu	Switches (Hazard)	Kuratau	09R16 Install RTE switch.	47k
Tokaanu	Switches (Reliability	Kuratau	6353 Automate recloser.	35k

PROPOSED CAPITAL WORKS: 2015/16				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
	Improvement)			
Tokaanu	Transformer - 2 Pole Structures	Kuratau	09R27 Rebuilt with single pole and upgrade earthing.	41k
Tokaanu	Transformers - Ground Mounted	Turangi	10S26 Replace LV rack, cover exposed bushings.	30k
Whakamaru	Line Renewals	Huirimu	121-04 11kV Line Renewal	65k
Whakamaru	Line Renewals	Whakamaru	120-03 11kV Line Renewal	157k
Whakamaru	Line Renewals	Whakamaru	120-03 LV Line Renewal	110k
Whakamaru	Substation, Supply Point and 33kV Development	Atiamuri Supply Compound	ZSub215 Install supply from Transpower at Whakamaru on the 220 kV or Mokai's 110 kV supply connection at Whakamaru.	1500k
Whakamaru	Substation, Supply Point and 33kV Development	Maraetai Zone Substation	ZSub210 Install modular substation on Sandel Road in Whakamaru.	466k
Whakamaru	Switches (Hazard)	Whakamaru	FED120 ring main unit and 300 kVA TX for T2523 and remove T2524 and T2521. Through Joint at T2523 to T2525. Replace LV cable around village with 4c Cable, new 16mm N/S street light cable and TUDs pillar boxes. May need to include replacement of service-main to boxes on side of houses.	500k

PROPOSED CAPITAL WORKS: 2016/17				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non-Specific	Customer Driven Project	Various	General Connections - Earthing and tap-offs	192k
Non-Specific	Customer Driven Project	Various	General Connections - Transformers	192k
Non-Specific	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
Non-Specific	Customer Driven Project	Various	Industrials - Transformers	192k
Non-Specific	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
Non-Specific	Customer Driven Project	Various	Subdivisions - Management	11k
Non-Specific	Customer Driven Project	Various	Subdivisions - Transformers	110k
Non-Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non-Specific	Network Equipment Renewal	Whole Network	Protection	12k
Non-Specific	Network Equipment Renewal	Whole Network	Radio Contingency	12k
Non-Specific	Network Equipment Renewal	Whole Network	RADIO Specific	69k
Non-Specific	Network Equipment Renewal	Whole Network	Relay Changes	69k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
Non-Specific	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	22k
Non-Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
Hangatiki	Line Renewals	Aria	114-06 11kV Line Renewal	147k
Hangatiki	Line Renewals	Benneydale	103-10 11kV Line Renewal	276k
Hangatiki	Line Renewals	Benneydale	103-11 11kV Line Renewal	276k
Hangatiki	Line Renewals	Caves	101-12 11kV Line Renewal	262k
Hangatiki	Line Renewals	Caves	101-13 11kV Line Renewal	131k
Hangatiki	Line Renewals	Gravel Scoop	109-07 11kV Line Renewal	324k
Hangatiki	Line Renewals	Mahoenui	113-08 11kV Line Renewal	224k
Hangatiki	Line Renewals	Maihiihi	111-11 11kV Line Renewal	151k
Hangatiki	Line Renewals	Maihiihi	111-14 11kV Line Renewal	82k
Hangatiki	Line Renewals	McDonalds	110-03 11kV Line Renewal	87k
Hangatiki	Line Renewals	McDonalds	110-04 11kV Line Renewal	40k
Hangatiki	Line Renewals	Mokau	128-07 11kV Line Renewal	78k
Hangatiki	Line Renewals	Otorohanga	112-05 11kV Line Renewal	3k

PROPOSED CAPITAL WORKS: 2016/17				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Line Renewals	Otorohanga	112-06 11kV Line Renewal	107k
Hangatiki	Line Renewals	Te Waireka Rd 33	303-01 33kV Line Renewal	187k
Hangatiki	Regulators	Rangitoto	FED106 Install regulator towards Otewa Rd also to pick up Otewa when working on Gravel Scoop and Waipa Gorge.	101k
Hangatiki	Substation, Supply Point and 33kV Development	Hangatiki Zone Substation	ZSub204 Install oil separation.	17k
Hangatiki	Substation, Supply Point and 33kV Development	Taharoa Zone Substation	ZSub201 Upgrade to customers requirements and specifications. Funded through on-going charges to industrial customers.	58k
Hangatiki	Switches (Reliability Improvement)	McDonalds	328 Automate Switch. Install a Motor Actuator onto existing ABS.	23k
Hangatiki	Switches (Reliability Improvement)	McDonalds	387 Automate Switch, replace pole and install ENTEC.	35k
Hangatiki	Transformer - 2 Pole Structures	Benneydale	T2506 Rebuild with a standard single pole structure. Use existing transformer and replace reclosers.	37k
Hangatiki	Transformer - 2 Pole Structures	Te Mapara	T1829 Check ground clearance raise transformer on Pole and replace recloser.	20k
Hangatiki	Transformers - Ground Mounted	Oparure	T457 Install a front access transformer 300 kVA with I Blade RTE switch.	47k
Hangatiki	Transformers - Ground Mounted	Rangitoto	T464 Replace with a refurbished I Tank. Check loading and size transformer appropriately.	47k
National Park	Line Renewals	National Park / Kuratau 33	609-04 33kV Line Renewal	278k
National Park	Line Renewals	Raurimu	410-03 11kV Line Renewal	318k
National Park	Switches (Hazard)	Chateau	16N09 Install new Xiria unit and transformer.	47k
Ohakune	Feeder Development	Ohakune Town	414-01 Re-conductor from ferret to dog between 6644 and 6444 on Ayr street.	79k
Ohakune	Feeder Development	Turoa	415-01 Upgrade Cu 16mm Cu XLPE cable between Magnefix switch 6420 and transformer 20L18 to a feeder strength sized cable. Check on loadings and determine cable size from predicted future loadings.	55k
Ohakune	Feeder Development	Turoa	415-04 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. Check that there are no other problem areas in Rangataua.	87k

PROPOSED CAPITAL WORKS: 2016/17				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Ohakune	Line Renewals	Ohakune Town	414-01 11kV Line Renewal	220k
Ohakune	Line Renewals	Ohakune Town	414-01 LV Line Renewal	132k
Ohakune	Line Renewals	Turoa	415-01 11kV Line Renewal	290k
Ohakune	Line Renewals	Turoa	415-01 LV Line Renewal	137k
Ohakune	Substation, Supply Point and 33kV Development	Borough Zone Substation	ZSub508 Install oil separation.	17k
Ohakune	Switches (Hazard)	Ohakune Town	20L18 Install switch gear.	47k
Ohakune	Switches (Hazard)	Tangiwai	20L45 Install Xiria unit.	40k
Ohakune	Switches (Hazard)	Turoa	REG28 Install bypass protection on regulator.	5k
Ohakune	Switches (Reliability Improvement)	Tangiwai	6118 Automate Switch.	26k
Ohakune	Switches (Reliability Improvement)	Turoa	5680 Automate Switch.	26k
Ongarue	Line Renewals	Ongarue	421-03 LV Line Renewal	11k
Ongarue	Line Renewals	Ongarue	421-04 11kV Line Renewal	385k
Ongarue	Line Renewals	Southern	409-09 11kV Line Renewal	186k
Ongarue	Line Renewals	Western	403-04 11kV Line Renewal	100k
Ongarue	Substation, Supply Point and 33kV Development	Ongarue POS Compound	ZSub514 Rationalise the number of outgoing feeder circuit breakers. Put breaker on Taumarunui and Nihoniho; remove Nihoniho breaker. Allows splitting of feeders and isolation of Transpower supply. Reduce the number of circuit breakers from 3 to two and upgrade the bypass option.	699k
Ongarue	Transformer - 2 Pole Structures	Manunui	08L17 Lift equipment on poles so all equipment is above regulation height. Recloser bushings are 3.75 m from ground level. Tidy structure and replace recloser.	30k
Ongarue	Transformer - 2 Pole Structures	Ongarue	02K08 Equipment is under regulation height on structure. If possible rebuild structure with single pole standard structure one pole away. Replace reclosers.	58k
Ongarue	Transformer - 2 Pole Structures	Southern	09K25 Rebuild structure with standard single pole Isolating SWER structure and replace reclosers.	44k
Ongarue	Transformer - 2 Pole Structures	Western	08I21 Rebuild structure. Replace recloser and transformer.	58k
Ongarue	Transformers - Ground Mounted	Ohura	07D24 Industrial on roadside exposed drywell fuses, was installed for the prison. Check loading and replace with I tank ground mounted transformer.	31k
Tokaanu	Line Renewals	Motuoapa	425-01 11kV Line Renewal	105k
Tokaanu	Line Renewals	Motuoapa	425-01 LV Line Renewal	165k
Tokaanu	Line Renewals	Waiotaka	427-01 11kV Line Renewal	171k
Tokaanu	Switches (Hazard)	Rangipo / Hautu	10S03 Install Xiria switch gear.	47k

PROPOSED CAPITAL WORKS: 2016/17				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Tokaanu	Switches (Reliability Improvement)	Kuratau	6355 Automate switch.	35k
Tokaanu	Transformers - Ground Mounted	Turangi	10S29 T Replace LV rack and cove exposed terminals.	31k
Whakamaru	Regulators	Mokai	123-02 Install regulator on Waihora road before intersection of Whangamata Road so benefits both directions along Whangamata Road.	105k
Whakamaru	Substation, Supply Point and 33kV Development	Whakamaru 33	FED310 Install second regulator at Maraetai substation site on 33 kV line.	291k
Whakamaru	Transformer - 2 Pole Structures	Mangakino	T1081 11 kV below regulation height. Check loading and rebuild structure with 100 kVA if loading light enough otherwise use refurbished ground mount 200 kVA.	58k

PROPOSED CAPITAL WORKS: 2017/18				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non-Specific	Customer Driven Project	Various	General Connections - Earthing and tap-offs	192k
Non-Specific	Customer Driven Project	Various	General Connections - Transformers	192k
Non-Specific	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
Non-Specific	Customer Driven Project	Various	Industrials - Transformers	192k
Non-Specific	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
Non-Specific	Customer Driven Project	Various	Subdivisions - Management	11k
Non-Specific	Customer Driven Project	Various	Subdivisions - Transformers	110k
Non-Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non-Specific	Network Equipment Renewal	Whole Network	Protection	12k
Non-Specific	Network Equipment Renewal	Whole Network	Radio Contingency	12k
Non-Specific	Network Equipment Renewal	Whole Network	RADIO Specific	69k
Non-Specific	Network Equipment Renewal	Whole Network	Relay Changes	37k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
Non-Specific	Network Equipment Renewal	Whole Network	Transformer & Service Boxes - Capital Pillar Boxes	7k
Non-Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
Hangatiki	Line Renewals	Benneydale	103-09 11kV Line Renewal	395k
Hangatiki	Line Renewals	Gadsby / Wairere 33	307-03 33kV Line Renewal	285k
Hangatiki	Line Renewals	Maihiihi	111-06 11kV Line Renewal	216k
Hangatiki	Line Renewals	Mokau	128-03 11kV Line Renewal	360k
Hangatiki	Line Renewals	Mokau	128-10 11kV Line Renewal	270k
Hangatiki	Line Renewals	Otorohanga	112-01 11kV Line Renewal	335k

PROPOSED CAPITAL WORKS: 2017/18				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Line Renewals	Otorohanga	112-01 LV Line Renewal	220k
Hangatiki	Line Renewals	Te Kawa St 33	304-01 33kV Line Renewal	204k
Hangatiki	Line Renewals	Te Kuiti South	104-01 11kV Line Renewal	377k
Hangatiki	Line Renewals	Te Kuiti South	104-01 LV Line Renewal	330k
Hangatiki	Substation, Supply Point and 33kV Development	Oparure Zone Substation	ZSub208 Install bunding, oil separation and earthquake restraints.	47k
Hangatiki	Substation, Supply Point and 33kV Development	Waitete Zone Substation	ZSub206 Install modular substation at industrial sites.	408k
Hangatiki	Switches (Hazard)	Benneydale	REG04 Install bypass protection on regulator.	5k
Hangatiki	Switches (Reliability Improvement)	McDonalds	320 Automate Switch	23k
Hangatiki	Switches (Reliability Improvement)	Otorohanga	FED112 LV Link T554 to adjacent transformers.	117k
Hangatiki	Transformer - 2 Pole Structures	Mokau	T2177 Rebuild structure and replace transformer.	47k
Hangatiki	Transformer - 2 Pole Structures	Te Kuiti South	T478 Check loading. See if 300kVA is necessary, if not replace with 200kVA pole mounted transformer	45k
Hangatiki	Transformers - Ground Mounted	Coast	T547 Upgrade transformer to I tank.	47k
Hangatiki	Transformers - Ground Mounted	Otorohanga	T699 Replace transformer with standard industrial transformer $	47k
National Park	Line Renewals	Raurimu	410-04 11kV Line Renewal	122k
National Park	Switches (Hazard)	Chateau	16N01 Replace with refurbished transformer and install Xiria.	47k
National Park	Switches (Hazard)	National Park	15L07 Install Switchgear	47k
Ohakune	Regulators	Tangiwai	FED416 Install regulator at Rangatawa.	102k
Ohakune	Switches (Hazard)	Tangiwai	20L44 Install Switchgear ring main unit	47k
Ohakune	Transformer - 2 Pole Structures	Turoa	20L31 Replace transformer.	45k
Ongarue	Line Renewals	Nihoniho 33	603-02 33kV Line Renewal	313k
Ongarue	Line Renewals	Ohura	413-07 11kV Line Renewal	141k
Ongarue	Line Renewals	Tuhua	422-03 11kV Line Renewal	130k
Ongarue	Switches (Reliability Improvement)	Matapuna	5357 Automate switch.	36k
Ongarue	Switches (Reliability Improvement)	Southern	5136 Install new switch and automate.	47k
Ongarue	Transformer - 2 Pole Structures	Ohura	07D08 Install new recloser and SCADA.	30k
Ongarue	Transformer - 2 Pole Structures	Ongarue	02K16 Rebuild structure, 11 kV bushing are below regulation height, replace recloser.	58k

PROPOSED CAPITAL WORKS: 2017/18				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Ongarue	Transformer - 2 Pole Structures	Western	08H03 Install new Transformer	47k
Ongarue	Transformers - Ground Mounted	Matapuna	01B24 Upgrade LV rack.	47k
Tokaanu	Line Renewals	Kuratau	406-03 11kV Line Renewal	248k
Tokaanu	Line Renewals	Kuratau	406-03 LV Line Renewal	110k
Tokaanu	Switches (Hazard)	Waihaha	07R13 Install ring main unit.	47k
Tokaanu	Switches (Reliability Improvement)	Kuratau	5921 Automate switch.	23k
Tokaanu	Transformers - Ground Mounted	Turangi	10S39 Install LV rack and cover exposed terminals.	30k
Whakamaru	Feeder Development	Mokai	FED123 Re-conductor Tirohanga Road from New Substation site near injection pumps to Okama Rd. 7 km of line to Mink. This allows for better back feed options and more security of supply.	747k
Whakamaru	Line Renewals	Mangakino	118-01 11kV Line Renewal	377k
Whakamaru	Line Renewals	Mangakino	118-01 LV Line Renewal	137k
Whakamaru	Line Renewals	Whakamaru	120-01 11kV Line Renewal	351k
Whakamaru	Line Renewals	Wharepapa	122-01 11kV Line Renewal	243k
Whakamaru	Line Renewals	Wharepapa	122-02 11kV Line Renewal	478k
Whakamaru	Regulators	Pureora	FED119 Install regulator close to Crusaders Meats 4th Regulator for deer plant.	102k
Whakamaru	Switches (Reliability Improvement)	Whakamaru	463 Automate switch and replace pole.	45k

PROPOSED CAPITAL WORKS: 2018/19				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non-Specific	Customer Driven Project	Various	General Connections - Earthing and tap-offs	192k
Non-Specific	Customer Driven Project	Various	General Connections - Transformers	192k
Non-Specific	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
Non-Specific	Customer Driven Project	Various	Industrials - Transformers	192k
Non-Specific	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
Non-Specific	Customer Driven Project	Various	Subdivisions - Management	11k
Non-Specific	Customer Driven Project	Various	Subdivisions - Transformers	110k
Non-Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non-Specific	Network Equipment Renewal	Whole Network	Protection	12k
Non-Specific	Network Equipment Renewal	Whole Network	Radio Contingency	12k
Non-Specific	Network Equipment Renewal	Whole Network	RADIO Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	Relay Changes	16k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
Non-Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
Hangatiki	Line Renewals	Aria	114-01 11kV Line Renewal	241k
Hangatiki	Line Renewals	Aria	114-01 LV Line Renewal	22k
Hangatiki	Line Renewals	Benneydale	103-09 11kV Line Renewal	395k
Hangatiki	Line Renewals	Gadsby / Wairere 33	307-01 33kV Line Renewal	125k
Hangatiki	Line Renewals	Oparure	107-08 11kV Line Renewal	214k
Hangatiki	Line Renewals	Rangitoto	106-01 11kV Line Renewal	166k
Hangatiki	Line Renewals	Rangitoto	106-01 LV Line Renewal	132k

PROPOSED CAPITAL WORKS: 2018/19				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Line Renewals	Rangitoto	106-02 11kV Line Renewal	31k
Hangatiki	Line Renewals	Rangitoto	106-07 11kV Line Renewal	286k
Hangatiki	Line Renewals	Rangitoto	106-07 LV Line Renewal	16k
Hangatiki	Line Renewals	Taharoa B 33	302-01 33kV Line Renewal	574k
Hangatiki	Line Renewals	Te Kuiti South	104-02 11kV Line Renewal	362k
Hangatiki	Regulators	Mokau	FED128 Before Mokau at old killing house site.	105k
Hangatiki	Substation, Supply Point and 33kV Development	Taharoa A 33	FED301 Upgrade line to higher transmission voltage and capacity. Split between 2013/14 and 2014/15	349k
Hangatiki	Substation, Supply Point and 33kV Development	Wairere Zone Substation	ZSub207 Install oil separation.	17k
Hangatiki	Substation, Supply Point and 33kV Development	Wairere Zone Substation	ZSub207 Refurbish transformers (T1).	93k
Hangatiki	Substation, Supply Point and 33kV Development	Waitete Zone Substation	ZSub206 Replace 11kV bulk oil breakers due to age, reliability and condition. Replace with vacuum track breakers.	53k
Hangatiki	Switches (Reliability Improvement)	Hangatiki East	336 Automate switch	40k
Hangatiki	Transformer - 2 Pole Structures	Mahoenui	T1692 Rebuild structure and replace transformer.	41k
Hangatiki	Transformer - 2 Pole Structures	Mokau	T2194 Raise transformer.	6k
Hangatiki	Transformer - 2 Pole Structures	Mokau	T2208 Rebuilt structure with standard single pole design. Replace transformer and recloser.	47k
Hangatiki	Transformers - Ground Mounted	Oparure	T9 Reuse 200kVA ground mounted transformer and replace LV panel.	40k
Mokai Supply Point	Substation, Supply Point and 33kV Development	Mokai Zone Substation	ZSub3358 Install a load control plant at Mokai. Install ripple signal which generates at 317 Hz signal.	408k
National Park	Line Renewals	Chateau	419-01 11kV Line Renewal	149k
National Park	Line Renewals	National Park	411-01 11kV Line Renewal	152k
National Park	Line Renewals	National Park	411-01 LV Line Renewal	198k
National Park	Line Renewals	Raurimu	410-04 11kV Line Renewal	122k
National Park	Switches (Hazard)	Chateau	16N02 Install 11 kV switch gear to transformer	47k
National Park	Transformer - 2 Pole Structures	National Park	16L02 Rebuild with single pole, replace transformer and related low voltage.	47k
National Park	Transformers - Ground Mounted	Chateau	16N05 Replace with 11kV box and LV panel.	35k

PROPOSED CAPITAL WORKS: 2018/19				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Ohakune	Switches (Hazard)	Tangiwai	20L46 Install ring main unit switch gear.	35k
Ohakune	Transformer - 2 Pole Structures	Turoa	20M01 Replace with single pole structure and related low voltage.	40k
Ongarue	Line Renewals	Manunui	408-01 11kV Line Renewal	313k
Ongarue	Line Renewals	Manunui	408-01 LV Line Renewal	115k
Ongarue	Line Renewals	Nihoniho 33	603-01 33kV Line Renewal	282k
Ongarue	Line Renewals	Southern	409-01 11kV Line Renewal	351k
Ongarue	Line Renewals	Tuhua	422-03 11kV Line Renewal	130k
Ongarue	Transformer - 2 Pole Structures	Hakiaha	01A31 Replace structure with 300kVA ground mounted transformer.	47k
Ongarue	Transformer - 2 Pole Structures	Manunui	08J07 Raise structure, replace recloser and upgrade earthing.	25k
Ongarue	Transformer - 2 Pole Structures	Southern	11K11 Rebuild structure and replace recloser.	47k
Ongarue	Transformers - Ground Mounted	Matapuna	01A70 Replace with ground mounted transformer and ring main unit. Replace LV panel.	47k
Tokaanu	Line Renewals	No Feeder	507-01 LV Line Renewal	55k
Tokaanu	Line Renewals	Tokaanu	420-01 11kV Line Renewal	30k
Tokaanu	Switches (Hazard)	Turangi	10S41 Replace LV panel and replace with refurbished transformer.	47k
Tokaanu	Switches (Reliability Improvement)	Kuratau	6557 Automate switch.	34k
Whakamaru	Line Renewals	Whakamaru	120-02 11kV Line Renewal	228k
Whakamaru	Line Renewals	Wharepapa	122-03 11kV Line Renewal	264k
Whakamaru	Line Renewals	Wharepapa	122-04 11kV Line Renewal	257k
Whakamaru	Line Renewals	Wharepapa	122-06 11kV Line Renewal	303k
Whakamaru	Switches (Hazard)	Wharepapa	REG25 Install bypass protection on regulator.	5k

PROPOSED CAPITAL WORKS: 2019/20				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non-Specific	Customer Driven Project	Various	General Connections - Earthing and tap-offs	275k
Non-Specific	Customer Driven Project	Various	General Connections - Transformers	275k
Non-Specific	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
Non-Specific	Customer Driven Project	Various	Industrials - Transformers	275k
Non-Specific	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
Non-Specific	Customer Driven Project	Various	Subdivisions - Management	11k
Non-Specific	Customer Driven Project	Various	Subdivisions - Transformers	110k
Non-Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non-Specific	Network Equipment Renewal	Whole Network	Load Control	117k
Non-Specific	Network Equipment Renewal	Whole Network	Protection	12k
Non-Specific	Network Equipment Renewal	Whole Network	Radio Contingency	12k
Non-Specific	Network Equipment Renewal	Whole Network	RADIO Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
Non-Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
Hangatiki	Feeder Development	Mokau	FED128 Mokau Generator : Add remotely controlled diesel gas injection for holiday periods and during shutdown interruptions. .	350k
Hangatiki	Line Renewals	Coast	125-01 11kV Line Renewal	280k
Hangatiki	Line Renewals	Coast	125-01 LV Line Renewal	5k
Hangatiki	Line Renewals	Gadsby / Wairere 33	307-03 33kV Line Renewal	285k
Hangatiki	Line Renewals	Mahoenui	113-01 11kV Line Renewal	220k

PROPOSED CAPITAL WORKS: 2019/20				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Line Renewals	Mokauiti	115-01 11kV Line Renewal	134k
Hangatiki	Line Renewals	Piopio	116-01 11kV Line Renewal	420k
Hangatiki	Line Renewals	Piopio	116-02 11kV Line Renewal	193k
Hangatiki	Line Renewals	Piopio	116-02 LV Line Renewal	137k
Hangatiki	Line Renewals	Taharoa A 33	301-01 33kV Line Renewal	574k
Hangatiki	Line Renewals	Te Mapara	117-01 11kV Line Renewal	312k
Hangatiki	Line Renewals	Waitete 33	306-01 33kV Line Renewal	241k
Hangatiki	Regulators	Mahoenui	FED113 Install regulators for backup of Mokau Feeder when 33 kV is out.	102k
Hangatiki	Regulators	Piopio	FED116 Install new regulators	102k
Hangatiki	Substation, Supply Point and 33kV Development	Wairere Zone Substation	ZSub207 Install 5MVAR capacitors on the 11kV bus to support voltage during heavy load times.	210k
Hangatiki	Switches (Hazard)	Mokau	REG03 Install bypass protection on regulator.	5k
Hangatiki	Switches (Reliability Improvement)	Hangatiki East	361 Install ENTEC switch and automate. New pole required.	35k
Hangatiki	Switches (Reliability Improvement)	Mahoenui	1343 Install new recloser and automate.	35k
Hangatiki	Transformers - Ground Mounted	Coast	T640 Rebuild and install ground mounted transformer.	47k
Hangatiki	Transformers - Ground Mounted	Mokau	T2140Replace transformer and reterminate cables.	47k
Hangatiki	Transformers - Ground Mounted	Mokau	T2154 Replace transformer and reterminate cables.	47k
Hangatiki	Transformers - Ground Mounted	Mokau	T2155 Install ground mounted transformer.	47k
Hangatiki	Transformers - Ground Mounted	Otorohanga	T557 Install a 300 kVA transformer fitted with an RTE.	47k
National Park	Line Renewals	Chateau	419-01 11kV Line Renewal	149k
National Park	Line Renewals	National Park / Kuratau 33	609-03 33kV Line Renewal	596k
National Park	Line Renewals	Raurimu	410-04 11kV Line Renewal	122k
National Park	Substation, Supply Point and 33kV Development	Tawhai Zone Substation	ZSub513 Install a second transformer. Use a transformer out of Turangi.	699k
National Park	Switches (Hazard)	Chateau	16N28 Move transformer out of club house and install magnefix ring main unit.	47k
National Park	Switches (Hazard)	Chateau	16N29 Replace transformer and RTE Switch.	47k
National Park	Transformer - 2 Pole Structures	National Park / Kuratau 33	12N05 Investigate installing a ground mounted transformer, or rebuild 33 kV / 400 V tranformer structure to make safer. Investigate a refurbished 33 kV / 400 v transformer.	45k

PROPOSED CAPITAL WORKS: 2019/20				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Ohakune	Line Renewals	Turoa	415-04 11kV Line Renewal	104k
Ohakune	Transformer - 2 Pole Structures	Turoa	20L19 Rebuild strucutre to single pole and tidy up LV.	50k
Ongarue	Line Renewals	Manunui	408-02 11kV Line Renewal	410k
Ongarue	Line Renewals	Manunui	408-02 LV Line Renewal	27k
Ongarue	Line Renewals	Northern	402-01 11kV Line Renewal	618k
Ongarue	Line Renewals	Northern	402-01 LV Line Renewal	220k
Ongarue	Line Renewals	Southern	409-01 11kV Line Renewal	351k
Ongarue	Line Renewals	Tuhua	422-03 11kV Line Renewal	130k
Ongarue	Transformer - 2 Pole Structures	Manunui	08J10 Raise transformer and tidy up LV.	7k
Ongarue	Transformer - 2 Pole Structures	Matapuna	01A75 Rebuild structure to single pole, replace transformer.	47k
Ongarue	Transformer - 2 Pole Structures	Nihoniho	06E01 Raise transformer, replace recloser and tidy up the site.	30k
Ongarue	Transformer - 2 Pole Structures	Northern	08I02 Replace with a ground mounted refurbished transformer. Check loadings.	45k
Ongarue	Transformer - 2 Pole Structures	Northern	T4055 Raise equipment on structure to over regulation height and maintain clearances.	23k
Ongarue	Transformer - 2 Pole Structures	Southern	10K14 Rebuild to single pole structure and replace recloser.	40k
Tokaanu	Feeder Development	Waihaha	FED425 Build out adjacent 11 kV feeders as development takes place. This will include breaking up existing SWER systems.	233k
Tokaanu	Switches (Reliability Improvement)	Hirangi	6186 Install 2 Bay Xiria. Leave existing Magnefix.	56k
Tokaanu	Switches (Reliability Improvement)	Turangi	FED423 Develop an 11 kV link for the Turangi Town Feeder through to Rangipo Hautu 11 kV by bridge on SH 1. This will include changing switchgear at 10S40. Waipa Road, Turangi.	281k
Whakamaru	Line Renewals	Huirimu	121-01 11kV Line Renewal	254k
Whakamaru	Line Renewals	Tihoi	124-00 11kV Line Renewal	10k
Whakamaru	Line Renewals	Tihoi	124-01 11kV Line Renewal	172k
Whakamaru	Line Renewals	Whakamaru	120-05 11kV Line Renewal	58k
Whakamaru	Line Renewals	Whakamaru 33	310-01 33kV Line Renewal	122k
Whakamaru	Transformer - 2 Pole Structures	Tihoi	T1618 Equipment is below regulation height, raise equipment.	7k

PROPOSED CAPITAL WORKS: 2020/21				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non-Specific	Customer Driven Project	Various	General Connections - Earthing and tap-offs	275k
Non-Specific	Customer Driven Project	Various	General Connections - Transformers	275k
Non-Specific	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
Non-Specific	Customer Driven Project	Various	Industrials - Transformers	275k
Non-Specific	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
Non-Specific	Customer Driven Project	Various	Subdivisions - Management	11k
Non-Specific	Customer Driven Project	Various	Subdivisions - Transformers	110k
Non-Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non-Specific	Network Equipment Renewal	Whole Network	Protection	12k
Non-Specific	Network Equipment Renewal	Whole Network	Radio Contingency	12k
Non-Specific	Network Equipment Renewal	Whole Network	RADIO Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
Non-Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
Hangatiki	Line Renewals	Caves	101-01 11kV Line Renewal	174k
Hangatiki	Line Renewals	Caves	101-02 11kV Line Renewal	73k
Hangatiki	Line Renewals	Caves	101-03 11kV Line Renewal	43k
Hangatiki	Line Renewals	Caves	101-04 11kV Line Renewal	88k
Hangatiki	Line Renewals	Caves	101-05 11kV Line Renewal	90k
Hangatiki	Line Renewals	Caves	101-06 11kV Line Renewal	68k
Hangatiki	Line Renewals	Caves	101-07 11kV Line Renewal	52k
Hangatiki	Line Renewals	Caves	101-08 11kV Line Renewal	35k
Hangatiki	Line Renewals	Gadsby / Wairere 33	307-02 33kV Line Renewal	96k

PROPOSED CAPITAL WORKS: 2020/21				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Line Renewals	Gadsby Rd 33	305-02 33kV Line Renewal	256k
Hangatiki	Line Renewals	Mokau	128-02 11kV Line Renewal	210k
Hangatiki	Line Renewals	Mokau	128-02 LV Line Renewal	27k
Hangatiki	Line Renewals	Mokau	128-05 11kV Line Renewal	191k
Hangatiki	Line Renewals	Mokau	128-05 LV Line Renewal	96k
Hangatiki	Line Renewals	Rural	126-01 11kV Line Renewal	78k
Hangatiki	Line Renewals	Rural	126-01 LV Line Renewal	5k
Hangatiki	Regulators	Mokauiti	115-03 Install regulator near switch 1710 to lift voltages in the Mokauiti Valley.	102k
Hangatiki	Substation, Supply Point and 33kV Development	Te Waireka Zone Substation	ZSub203 Replace 11kV bulk oil breakers due to age, reliability and condition. Replace with vacuum track breakers.	53k
Hangatiki	Substation, Supply Point and 33kV Development	Wairere Zone Substation	ZSub207 Refurbish transformers (T2). Oil tests indicate transformer life can be extended with refurbishment. Cost and network security.	93k
Hangatiki	Substation, Supply Point and 33kV Development	Wairere Zone Substation	ZSub207 Renew switchgear and improve protection schemes (33 kV).	350k
Hangatiki	Switches (Hazard)	Mokau	REG02 Install bypass protection on regulator.	5k
Hangatiki	Switches (Reliability Improvement)	Mahoenui	1512 Replace bypass switch.	20k
Hangatiki	Transformers - Ground Mounted	Gravel Scoop	T1007 Replace with ground mounted transformer.	45k
Hangatiki	Transformers - Ground Mounted	Rural	T1390 Replace with ground mounted transformer.	47k
Hangatiki	Transformers - Ground Mounted	Te Kuiti South	T10 Replace with ground mounted transformer.	45k
National Park	Line Renewals	National Park / Kuratau 33	609-01 33kV Line Renewal	275k
National Park	Line Renewals	Otukou	418-01 11kV Line Renewal	347k
National Park	Line Renewals	Otukou	418-01 LV Line Renewal	66k
National Park	Switches (Hazard)	Chateau	15N11 Install RTE switch	47k
National Park	Switches (Reliability Improvement)	National Park	5146 Install new recloser and SCADA.	47k
National Park	Transformer - 2 Pole Structures	Otukou	12O01 Replace with single pole structure and replace recloser. This transformer needs to be checked for loading.	41k
Ohakune	Feeder Development	Ohakune Town	FED414 Install underground cable down Shannon Street to link Ohakune Town and Tangiwai feeders. Cable size 95 mm Al XLPE.	107k

PROPOSED CAPITAL WORKS: 2020/21				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Ohakune	Feeder Development	Turoa	415-04 This is for the reconductoring of the feeder tie to Tangawai between switch 5695 and 5680. Upgrade conductor to Mink or equivelent AAAC.	587k
Ohakune	Line Renewals	Turoa	415-04 11kV Line Renewal	91k
Ohakune	Switches (Hazard)	Turoa	17N01 Install Switch Gear	47k
Ohakune	Switches (Reliability Improvement)	Turoa	5695 Install new switch and automate.	47k
Ongarue	Line Renewals	Manunui	408-02 11kV Line Renewal	410k
Ongarue	Line Renewals	Matapuna	404-01 11kV Line Renewal	539k
Ongarue	Line Renewals	Matapuna	404-01 LV Line Renewal	350k
Ongarue	Line Renewals	Northern	402-02 11kV Line Renewal	605k
Ongarue	Line Renewals	Southern	409-05 11kV Line Renewal	343k
Ongarue	Regulators	Ohura	FED413 Install regulator for Ohura assuming that the coal mine venture goes ahead.	102k
Ongarue	Switches (Hazard)	Northern	01A52 Install new LV board and cover HV terminals.	15k
Ongarue	Transformer - 2 Pole Structures	Manunui	08J04 Replace with standard single pole structure.	50k
Ongarue	Transformer - 2 Pole Structures	Ohura	07D03 Replace with single pole structure. Install new transformer.	47k
Ongarue	Transformer - 2 Pole Structures	Southern	09K02 Raise transformer and install recloser.	20k
Tokaanu	Feeder Development	Kuratau	FED405 Line rebuilds: SWER replacement associated with Kuratau development.	58k
Tokaanu	Line Renewals	Tokaanu / Kuratau 33	607-02 33kV Line Renewal	307k
Tokaanu	Line Renewals	Waihaha	426-01 11kV Line Renewal	11k
Tokaanu	Line Renewals	Waihaha	426-02 11kV Line Renewal	113k
Tokaanu	Switches (Hazard)	Rangipo / Hautu	FED424 Hazard from Genesis 33 kV Line crossing.	58k
Tokaanu	Transformer - 2 Pole Structures	Oruatua	09U12 Replace with single pole structure and new transformer.	45k
Tokaanu	Transformer - 2 Pole Structures	Waihaha	04Q06 Raise equipment and replace recloser.	20k
Whakamaru	Line Renewals	Whakamaru	310-03 33kV Line Renewal	278k
Whakamaru	Substation, Supply Point and 33kV Development	Atiamuri Supply Compound	ZSub215 Replace breaker due to age, reliability and condition with new type of circuit breaker.	87k
Whakamaru	Substation, Supply Point and 33kV Development	Maraetai Zone Substation	ZSub210 Diversify off site with a modular substation near Ranganui Road.	466k

PROPOSED CAPITAL WORKS: 2021/22				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non-Specific	Customer Driven Project	Various	General Connections - Earthing and tap-offs	275k
Non-Specific	Customer Driven Project	Various	General Connections - Transformers	275k
Non-Specific	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
Non-Specific	Customer Driven Project	Various	Industrials - Transformers	275k
Non-Specific	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
Non-Specific	Customer Driven Project	Various	Subdivisions - Management	11k
Non-Specific	Customer Driven Project	Various	Subdivisions - Transformers	110k
Non-Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non-Specific	Network Equipment Renewal	Whole Network	Protection	12k
Non-Specific	Network Equipment Renewal	Whole Network	Radio Contingency	12k
Non-Specific	Network Equipment Renewal	Whole Network	RADIO Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
Non-Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
Hangatiki	Line Renewals	Gadsby Rd 33	305-03 33kV Line Renewal	61k
Hangatiki	Line Renewals	Maihiihi	111-00 LV Line Renewal	13k
Hangatiki	Line Renewals	Maihiihi	111-01 11kV Line Renewal	64k
Hangatiki	Line Renewals	Maihiihi	111-01 LV Line Renewal	33k
Hangatiki	Line Renewals	Maihiihi	111-02 11kV Line Renewal	69k
Hangatiki	Line Renewals	Maihiihi	111-02 LV Line Renewal	99k
Hangatiki	Line Renewals	Maihiihi	111-03 11kV Line Renewal	167k
Hangatiki	Line Renewals	Maihiihi	111-04 11kV Line Renewal	240k
Hangatiki	Line Renewals	Maihiihi	111-10 11kV Line Renewal	86k

PROPOSED CAPITAL WORKS: 2021/22				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Line Renewals	Taharoa A 33	301-02 33kV Line Renewal	275k
Hangatiki	Line Renewals	Taharoa B 33	302-02 33kV Line Renewal	495k
Hangatiki	Line Renewals	Te Mapara	117-02 11kV Line Renewal	215k
Hangatiki	Substation, Supply Point and 33kV Development	Hangatiki Zone Substation	ZSub204 Diversify and encourage industrials downstream to install 33/11 kV modular substations on their sites. Oyma container sub.	408k
Hangatiki	Switches (Reliability Improvement)	Waitomo	182 Automate switch with motor actuator unit.	23k
Hangatiki	Transformer - 2 Pole Structures	Caves	T1185 Replace with single pole structure.	30k
Hangatiki	Transformers - Ground Mounted	Oparure	T1043 Replace transformer with I tank type.	58k
Hangatiki	Transformers - Ground Mounted	Otorohanga	T170 Replace transformer with I tank.	47k
Hangatiki	Transformers - Ground Mounted	Rural	T1367 Replace transformer with I tank.	47k
National Park	Feeder Development	Chateau	FED419 Cable from Tavern to Water Tower, 2nd Cable.	350k
National Park	Line Renewals	National Park / Kuratau 33	609-02 33kV Line Renewal	567k
National Park	Transformer - 2 Pole Structures	Raurimu	T4077 Replace with single pole structure and replace recloser.	47k
Ohakune	Substation, Supply Point and 33kV Development	Borough Zone Substation	ZSub508 Diversify with modular substations. Container substation above slip on main road.	390k
Ohakune	Substation, Supply Point and 33kV Development	Ohakune POS Compound	ZSub517 The size of the conductor connecting switchgear at Ohakune substation is too small for the present loadings. Install Xiria on incomer. break into the circuit before the cross bus and split one feeder off. Will have capacity for a spare feeder.	175k
Ohakune	Switches (Hazard)	Turoa	17N02 Install RTE switch.	47k
Ohakune	Switches (Hazard)	Turoa	FED415 Mechanical cable protection required for cable to ski fields as it is beside the road and inadequately protected.	70k
Ongarue	Line Renewals	Manunui	408-03 11kV Line Renewal	144k
Ongarue	Line Renewals	Northern	402-03 11kV Line Renewal	416k
Ongarue	Line Renewals	Tuhua	422-01 11kV Line Renewal	560k
Ongarue	Line Renewals	Tuhua	422-01 LV Line Renewal	10k
Ongarue	Regulators	Northern	FED402 Install regulator by high school depends on load growth.	101k
Ongarue	Regulators	Ongarue	421-01 Install Regulator at State Highway 4 near switch 6640.	101k
Ongarue	Switches (Hazard)	Northern	08I03 Install RTE switch and cover LV.	47k

PROPOSED CAPITAL WORKS: 2021/22				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Ongarue	Switches (Reliability Improvement)	Hakiaha	5.19 Install new recloser and SCADA.	47k
Tokaanu	Line Renewals	Waihaha	426-03 11kV Line Renewal	374k
Tokaanu	Substation, Supply Point and 33kV Development	Kuratau Zone Substation	ZSub509 Put in a modular substation at end of network close to an existing 33kV line.	466k
Tokaanu	Switches (Hazard)	Turangi	10S38 Install new LV board and cover up exposed HV terminals.	20k
Tokaanu	Transformer - 2 Pole Structures	Kuratau	09R28 Replace with single pole structure and replace transformer.	47k
Whakamaru	Line Renewals	Pureora	119-02 11kV Line Renewal	700k
Whakamaru	Line Renewals	Whakamaru	120-02 LV Line Renewal	110k
Whakamaru	Line Renewals	Whakamaru	120-04 11kV Line Renewal	897k
Whakamaru	Switches (Hazard)	Pureora	REG09 Install bypass protection on regulator.	5k

PROPOSED CAPITAL WORKS: 2022/23				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non-Specific	Customer Driven Project	Various	General Connections - Earthing and tap-offs	275k
Non-Specific	Customer Driven Project	Various	General Connections - Transformers	275k
Non-Specific	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
Non-Specific	Customer Driven Project	Various	Industrials - Transformers	275k
Non-Specific	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
Non-Specific	Customer Driven Project	Various	Subdivisions - Management	11k
Non-Specific	Customer Driven Project	Various	Subdivisions - Transformers	110k
Non-Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non-Specific	Network Equipment Renewal	Whole Network	Protection	12k
Non-Specific	Network Equipment Renewal	Whole Network	Radio Contingency	12k
Non-Specific	Network Equipment Renewal	Whole Network	RADIO Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
Non-Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
Hangatiki	Line Renewals	Gravel Scoop	109-01 LV Line Renewal	44k
Hangatiki	Line Renewals	Gravel Scoop	109-10 LV Line Renewal	66k
Hangatiki	Line Renewals	Hangatiki East	102-01 11kV Line Renewal	121k
Hangatiki	Line Renewals	Hangatiki East	102-02 11kV Line Renewal	172k
Hangatiki	Line Renewals	Maihiihi	111-05 11kV Line Renewal	140k
Hangatiki	Line Renewals	Maihiihi	111-12 11kV Line Renewal	259k
Hangatiki	Line Renewals	McDonalds	110-01 11kV Line Renewal	42k
Hangatiki	Line Renewals	McDonalds	110-01 LV Line Renewal	13k
Hangatiki	Line Renewals	Oparure	107-03 11kV Line Renewal	123k

PROPOSED CAPITAL WORKS: 2022/23				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Line Renewals	Oparure	107-04 11kV Line Renewal	327k
Hangatiki	Line Renewals	Oparure	107-04 LV Line Renewal	8k
Hangatiki	Line Renewals	Oparure	107-07 11kV Line Renewal	341k
Hangatiki	Line Renewals	Piopio	116-04 11kV Line Renewal	472k
Hangatiki	Line Renewals	Taharoa A 33	301-02 33kV Line Renewal	138k
Hangatiki	Substation, Supply Point and 33kV Development	Gadsby Road Zone Substation	ZSub205 Modify existing site by installing better earthquake restraints.	35k
Hangatiki	Substation, Supply Point and 33kV Development	Hangatiki Zone Substation	ZSub204 Replace 11kV bulk oil breakers due to age, reliability and condition. Replace with vacuum track breakers.	53k
Hangatiki	Switches (Hazard)	Maihiihi	REG06 Install bypass protection on regulator.	5k
Hangatiki	Switches (Reliability Improvement)	Gravel Scoop	304 Install ENTEC switch and automated feeder tie.	45k
Hangatiki	Transformers - Ground Mounted	Benneydale	T2598 Replace with I tank.	47k
Hangatiki	Transformers - Ground Mounted	Rural	T1559 Replace with I tank transformer.	47k
Ohakune	Line Renewals	Tangiwai	416-01 11kV Line Renewal	194k
Ohakune	Line Renewals	Tangiwai	416-02 11kV Line Renewal	69k
Ohakune	Line Renewals	Tangiwai	416-02 LV Line Renewal	96k
Ongarue	Line Renewals	Northern	402-04 11kV Line Renewal	256k
Ongarue	Line Renewals	Ohura	413-02 11kV Line Renewal	328k
Ongarue	Line Renewals	Ohura	413-02 LV Line Renewal	132k
Ongarue	Line Renewals	Southern	409-02 11kV Line Renewal	98k
Ongarue	Line Renewals	Southern	409-02 LV Line Renewal	55k
Ongarue	Line Renewals	Southern	409-03 11kV Line Renewal	100k
Ongarue	Line Renewals	Southern	409-03 LV Line Renewal	55k
Ongarue	Line Renewals	Southern	409-04 11kV Line Renewal	62k
Ongarue	Line Renewals	Southern	409-04 LV Line Renewal	96k
Ongarue	Regulators	Ohura	FED413 Install second regulator assuming coal mine goes ahead.	99k
Ongarue	Regulators	Western	403-02 Install regulation to accommodate increased load due to the subdivisions of land for lifestyle blocks along River Road and the surround areas.	99k
Ongarue	Switches (Reliability Improvement)	Ohura	5758 Replace sectionaliser with Nova breaker.	47k
Ongarue	Transformer - 2 Pole Structures	Ohura	07D16 Replace with single pole structure and replace recloser.	41k

PROPOSED CAPITAL WORKS: 2022/23				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Ongarue	Transformer - 2 Pole Structures	Ohura	10E09 Rebuild site , two SWER transformers, on site visit needed for design. Cost split between T4130 and 10E09.	41k
Ongarue	Transformer - 2 Pole Structures	Southern	12K08 Raise equipment and replace recloser.	41k
Ongarue	Transformers - Ground Mounted	Northern	T4025 Replace with I tank transformer.	47k
Tokaanu	Feeder Development	Kuratau	FED406 Line rebuilds: SWER replacement associated with Kuratau development.	58k
Tokaanu	Feeder Development	Waihaha	FED426 Build out adjacent 11 kV feeders as development takes place. This will include breaking up existing SWER systems.	175k
Tokaanu	Line Renewals	Kuratau	406-02 11kV Line Renewal	271k
Tokaanu	Line Renewals	Kuratau	406-02 LV Line Renewal	132k
Tokaanu	Line Renewals	Rangipo / Hautu	424-02 11kV Line Renewal	115k
Tokaanu	Line Renewals	Waihaha	426-03 11kV Line Renewal	374k
Tokaanu	Switches (Hazard)	Rangipo / Hautu	10S13 Install RTE switch.	47k
Tokaanu	Switches (Reliability Improvement)	Rangipo / Hautu	5963 Replace recloser with Nova breaker.	52k
Tokaanu	Transformers - Ground Mounted	Rangipo / Hautu	11S18 Replace with I tank transformer.	47k
Whakamaru	Line Renewals	Whakamaru	120-06 11kV Line Renewal	147k

PROPOSED CAPITAL WORKS: 2023/24				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non-Specific	Customer Driven Project	Various	General Connections - Earthing and tap-offs	275k
Non-Specific	Customer Driven Project	Various	General Connections - Transformers	275k
Non-Specific	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
Non-Specific	Customer Driven Project	Various	Industrials - Transformers	275k
Non-Specific	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
Non-Specific	Customer Driven Project	Various	Subdivisions - Management	11k
Non-Specific	Customer Driven Project	Various	Subdivisions - Transformers	110k
Non-Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non-Specific	Network Equipment Renewal	Whole Network	Protection	12k
Non-Specific	Network Equipment Renewal	Whole Network	Radio Contingency	12k
Non-Specific	Network Equipment Renewal	Whole Network	RADIO Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
Non-Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
Hangatiki	Line Renewals	Gravel Scoop	109-01 11kV Line Renewal	18k
Hangatiki	Line Renewals	Gravel Scoop	109-02 11kV Line Renewal	147k
Hangatiki	Line Renewals	Gravel Scoop	109-03 11kV Line Renewal	192k
Hangatiki	Line Renewals	Mokau	128-01 11kV Line Renewal	567k
Hangatiki	Line Renewals	Taharoa A 33	301-02 33kV Line Renewal	138k
Hangatiki	Line Renewals	Te Mapara	117-03 11kV Line Renewal	235k
Hangatiki	Substation, Supply Point and 33kV Development	Mahoenui Zone Substation	ZSub209 Increase the height of the oil bund and install oil separation.	17k

PROPOSED CAPITAL WORKS: 2023/24				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Substation, Supply Point and 33kV Development	Mahoenui Zone Substation	ZSub209 Refurbish transformer.	58k
Hangatiki	Switches (Reliability Improvement)	Otorohanga	316 Replace switch with recloser.	47k
Hangatiki	Transformers - Ground Mounted	Otorohanga	T1552 Replace with ground mounted I tank transformer.	45k
National Park	Substation, Supply Point and 33kV Development	Otukou Zone Substation	ZSub512 Modify existing site by installing bunding, oil separation and earthquake restraints.	40k
National Park	Switches (Hazard)	Chateau	15N02 Install new transformer and RTE switch	47k
National Park	Transformer - 2 Pole Structures	National Park	15K06 Rebuild structure to single pole. Replace transformer if necessary.	58k
National Park	Transformers - Ground Mounted	Chateau	16N04 Replace transformer.	29k
National Park	Transformers - Ground Mounted	Otukou	12N08 Install new transformer and replace LV rack.	47k
Ohakune	Line Renewals	Tangiwai	416-03 11kV Line Renewal	229k
Ohakune	Line Renewals	Tangiwai	416-03 LV Line Renewal	27k
Ongarue	Line Renewals	Manunui	408-04 11kV Line Renewal	239k
Ongarue	Line Renewals	Manunui	408-04 LV Line Renewal	27k
Ongarue	Line Renewals	Northern	402-04 11kV Line Renewal	256k
Ongarue	Line Renewals	Ohura	413-01 11kV Line Renewal	138k
Ongarue	Switches (Hazard)	Northern	07I14 Install RTE switch.	47k
Ongarue	Switches (Reliability Improvement)	Hakiaha	FED401 Add an 11 kV tie between Matapuna and Hakiaha adjacent to rail bridge where the feeder come within a few metre of one another.	131k
Ongarue	Switches (Reliability Improvement)	Hakiaha	FED401 Install low voltage tie between transformers in CBD. Do in conjunction with switch gear for 01A38 and 01A82.	117k
Ongarue	Switches (Reliability Improvement)	Northern	5119 Upgrade recloser to a Nova breaker with form 6 controller.	47k
Ongarue	Switches (Reliability Improvement)	Northern	5164 Upgrade recloser to a Nova breaker with form 6 controller.	47k
Ongarue	Transformer - 2 Pole Structures	Ohura	09C05 Raise equipment, replace recloser and change fuse rack if necessary.	30k
Ongarue	Transformers - Ground Mounted	Matapuna	01A36 Replace LV rack and cover exposed bushing.	20k
Ongarue	Transformers - Ground Mounted	Northern	07I12 Replace LV rack and cover exposed bushing.	20k

PROPOSED CAPITAL WORKS: 2023/24				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Tokaanu	Line Renewals	Waihaha	426-03 11kV Line Renewal	374k
Tokaanu	Substation, Supply Point and 33kV Development	Lake Taupo 33	FED606 - Lake Taupo 33 Put up insulated conductors and raise height of line if possible. Rebuild overhead using insulated conductor and taller poles. Complex job both technically and in terms of landowner issues. Re-conductor using insulated conductor spur line.	350k
Whakamaru	Feeder Development	Tirohanga	FED129 Install more feeder ties and a new modular substation at Mine road.	524k
Whakamaru	Line Renewals	Mokai	123-00 11kV Line Renewal	27k
Whakamaru	Line Renewals	Mokai	123-01 11kV Line Renewal	369k
Whakamaru	Line Renewals	Mokai	123-02 11kV Line Renewal	279k
Whakamaru	Line Renewals	Mokai	123-04 11kV Line Renewal	99k
Whakamaru	Line Renewals	Tirohanga	129-03 11kV Line Renewal	266k
Whakamaru	Line Renewals	Whakamaru	310-04 33kV Line Renewal	388k
Whakamaru	Regulators	Pureora	FED119 Install regulator near switch 785 just after Ranganui Road on SH 30.	99k
Whakamaru	Switches (Hazard)	Mokai	REG24 Install bypass protection on regulator.	5k

PROPOSED CAPITAL WORKS: 2024/25				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non-Specific	Customer Driven Project	Various	General Connections - Earthing and tap-offs	275k
Non-Specific	Customer Driven Project	Various	General Connections - Transformers	275k
Non-Specific	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
Non-Specific	Customer Driven Project	Various	Industrials - Transformers	275k
Non-Specific	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
Non-Specific	Customer Driven Project	Various	Subdivisions - Management	11k
Non-Specific	Customer Driven Project	Various	Subdivisions - Transformers	110k
Non-Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non-Specific	Network Equipment Renewal	Whole Network	Load Control	117k
Non-Specific	Network Equipment Renewal	Whole Network	Protection	12k
Non-Specific	Network Equipment Renewal	Whole Network	Radio Contingency	12k
Non-Specific	Network Equipment Renewal	Whole Network	RADIO Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
Non-Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
Hangatiki	Line Renewals	Coast	125-02 11kV Line Renewal	325k
Hangatiki	Line Renewals	Coast	125-04 11kV Line Renewal	198k
Hangatiki	Line Renewals	Gadsby Rd 33	305-01 33kV Line Renewal	272k
Hangatiki	Line Renewals	Otorohanga	112-02 11kV Line Renewal	65k
Hangatiki	Line Renewals	Otorohanga	112-03 11kV Line Renewal	164k
Hangatiki	Line Renewals	Piopio	116-03 11kV Line Renewal	74k
Hangatiki	Line Renewals	Rangitoto	106-04 11kV Line Renewal	518k

PROPOSED CAPITAL WORKS: 2024/25				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Line Renewals	Te Mapara	117-05 11kV Line Renewal	220k
Hangatiki	Line Renewals	Wairere / Mahoenui 33	309-01 33kV Line Renewal	126k
Hangatiki	Line Renewals	Wairere / Mahoenui 33	309-02 33kV Line Renewal	126k
Hangatiki	Regulators	Caves	FED101 Install regulator.	99k
Hangatiki	Substation, Supply Point and 33kV Development	Gadsby / Wairere 33	FED307 Install additional Regulators at Wairere to pull down voltage.	281k
Hangatiki	Switches (Hazard)	Rangitoto	REG30 Install bypass protection on regulator.	5k
Hangatiki	Switches (Reliability Improvement)	Rangitoto	224 Install modern recloser.	47k
National Park	Feeder Development	Chateau	FED419 Add second cable from Tawhai to Tavern.	583k
National Park	Switches (Hazard)	Chateau	15N09 Install RTE switch to transformer.	47k
National Park	Transformers - Ground Mounted	Chateau	16N06 Install RTE switch and replace LV racks.	52k
National Park	Transformers - Ground Mounted	Chateau	16N07 Install new transformer and new LV rack.	52k
Ohakune	Line Renewals	Tangiwai	416-04 11kV Line Renewal	154k
Ohakune	Substation, Supply Point and 33kV Development	Borough Zone Substation	ZSub508 Replace 11kV bulk oil breakers due to age, reliability and condition. Replace with vacuum track breakers.	53k
Ohakune	Substation, Supply Point and 33kV Development	Nihoniho Zone Substation	ZSub503 Replace fence and upgrade transformer.	225k
Ohakune	Substation, Supply Point and 33kV Development	Tuhua Zone Substation	ZSub502 Replace with modular substation.	382k
Ongarue	Line Renewals	Manunui	408-05 11kV Line Renewal	359k
Ongarue	Line Renewals	Nihoniho	412-01 11kV Line Renewal	241k
Ongarue	Line Renewals	Western	403-01 11kV Line Renewal	24k
Ongarue	Line Renewals	Western	403-01 LV Line Renewal	77k
Ongarue	Line Renewals	Western	403-02 11kV Line Renewal	476k
Ongarue	Switches (Hazard)	Northern	08I19 Install new LV rack and refurbish transformer.	47k
Ongarue	Switches (Hazard)	Western	08I31 Install ring main unit.	47k
Ongarue	Transformer - 2 Pole Structures	Ohura	07D11 Replace structure with single pole structure and replace recloser.	41k
Ongarue	Transformer - 2 Pole Structures	Ohura	T4130 Rebuild site, two SWER transformers, on site visit needed for design. Cost split between T4130 and 10E09.	41k

PROPOSED CAPITAL WORKS: 2024/25				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Tokaanu	Line Renewals	Waihaha	426-03 11kV Line Renewal	374k
Tokaanu	Switches (Hazard)	Rangipo / Hautu	10S49 Install LV fuse rack, install DDO's or vertical ABS on HV cable at pole.	23k
Tokaanu	Switches (Reliability Improvement)	Turangi	FED423 Develop LV link through Turangi Town.	117k
Tokaanu	Transformers - Ground Mounted	Rangipo / Hautu	10S47 Install new LV rack and cover exposed bushings.	20k
Tokaanu	Transformers - Ground Mounted	Turangi	10S30 Install new LV rack and cover exposed bushings.	20k
Whakamaru	Line Renewals	Whakamaru 33	310-02 33kV Line Renewal	1421k
Whakamaru	Regulators	Mokai	FED123 Replace Tirohanga Road Regulator.	111k
Whakamaru	Switches (Reliability Improvement)	Mokai	446 Upgrade to modern recloser.	47k
Whakamaru	Switches (Reliability Improvement)	Mokai	474 Upgrade to modern recloser.	47k

PROPOSED CAPITAL WORKS: 2025/26				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non-Specific	Customer Driven Project	Various	General Connections - Earthing and tap-offs	275k
Non-Specific	Customer Driven Project	Various	General Connections - Transformers	275k
Non-Specific	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
Non-Specific	Customer Driven Project	Various	Industrials - Transformers	275k
Non-Specific	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
Non-Specific	Customer Driven Project	Various	Subdivisions - Management	11k
Non-Specific	Customer Driven Project	Various	Subdivisions - Transformers	110k
Non-Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non-Specific	Network Equipment Renewal	Whole Network	Protection	12k
Non-Specific	Network Equipment Renewal	Whole Network	Radio Contingency	12k
Non-Specific	Network Equipment Renewal	Whole Network	RADIO Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
Non-Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
Hangatiki	Line Renewals	Aria	114-02 11kV Line Renewal	87k
Hangatiki	Line Renewals	Benneydale	103-01 11kV Line Renewal	5k
Hangatiki	Line Renewals	Benneydale	103-02 11kV Line Renewal	11k
Hangatiki	Line Renewals	Benneydale	103-03 11kV Line Renewal	11k
Hangatiki	Line Renewals	Mahoenui	113-02 11kV Line Renewal	55k
Hangatiki	Line Renewals	Maihiihi	111-09 11kV Line Renewal	76k
Hangatiki	Line Renewals	Maihiihi	111-13 11kV Line Renewal	118k
Hangatiki	Line Renewals	McDonalds	110-02 11kV Line Renewal	160k
Hangatiki	Line Renewals	Mokauiti	115-02 11kV Line Renewal	171k

PROPOSED CAPITAL WORKS: 2025/26				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Line Renewals	Rangitoto	106-06 11kV Line Renewal	463k
Hangatiki	Line Renewals	Waitomo	108-01 11kV Line Renewal	58k
Hangatiki	Line Renewals	Waitomo	108-02 11kV Line Renewal	150k
Hangatiki	Regulators	Gravel Scoop	FED109 Install regulator near Otewa road just before Barber. Will mainly be used when tieing to Rangitoto and Maihihi.	101k
Hangatiki	Substation, Supply Point and 33kV Development	Mahoenui Zone Substation	ZSub209 Replace fault thrower with 33 kV circuit breaker.	70k
Hangatiki	Substation, Supply Point and 33kV Development	Wairere / Mahoenui 33	FED309 Built out 33 kV line as load grows in Mokau area.	699k
Hangatiki	Switches (Hazard)	McDonalds	REG11 Install bypass protection on regulator.	5k
Hangatiki	Switches (Reliability Improvement)	Mokau	1626 Change sectionaliser to recloser.	47k
Hangatiki	Switches (Reliability Improvement)	Oparure	242 Replace with ENTEC Load break swtich and automate.	23k
National Park	Line Renewals	National Park	411-03 11kV Line Renewal	305k
National Park	Line Renewals	Raurimu	410-01 11kV Line Renewal	367k
National Park	Line Renewals	Raurimu	410-01 LV Line Renewal	49k
Ohakune	Line Renewals	Tangiwai	416-04 11kV Line Renewal	154k
Ohakune	Line Renewals	Turoa	415-01 11kV Line Renewal	581k
Ohakune	Transformer - 2 Pole Structures	Tangiwai	20L21with Replace ground mounted 100 kVA transformer, use a refurbished transformer.	45k
Ongarue	Line Renewals	Hakiaha	401-02 11kV Line Renewal	127k
Ongarue	Regulators	Southern	FED409 Growth in dairying and irrigation along state highway. Install regulator just before Otapouri Road. Will help lift voltage at Owhanga for subdivision growth.	105k
Ongarue	Switches (Reliability Improvement)	Ongarue	5462 Change sectionaliser to recloser.	47k
Ongarue	Transformers - Ground Mounted	Matapuna	01B20 Install LV rack and cover exposed HV bushings.	35k
Ongarue	Transformers - Ground Mounted	Matapuna	01B21 Replace with I tank ground mounted transformer.	35k
Ongarue	Transformers - Ground Mounted	Matapuna	01B25 Install new LV rack and cover exposed terminals.	35k
Ongarue	Transformers - Ground Mounted	Northern	01A48 Install new LV rack and cover exposed HV terminals.	34k
Tokaanu	Line Renewals	Hirangi	405-01 LV Line Renewal	49k
Tokaanu	Line Renewals	Lake Taupo 33	606-02 33kV Line Renewal	69k
Tokaanu	Line Renewals	Rangipo / Hautu	424-01 11kV Line Renewal	404k

PROPOSED CAPITAL WORKS: 2025/26				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Tokaanu	Line Renewals	Rangipo / Hautu	424-01 LV Line Renewal	228k
Tokaanu	Line Renewals	Turangi 33	605-01 33kV Line Renewal	83k
Whakamaru	Line Renewals	Mokai	123-03 11kV Line Renewal	335k
Whakamaru	Substation, Supply Point and 33kV Development	Maraetai Zone Substation	ZSub210 Replace breakers due to age, reliability and condition.	68k

PROPOSED CAPITAL WORKS: 2026/27				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non-Specific	Customer Driven Project	Various	General Connections - Earthing and tap-offs	275k
Non-Specific	Customer Driven Project	Various	General Connections - Transformers	275k
Non-Specific	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
Non-Specific	Customer Driven Project	Various	Industrials - Transformers	275k
Non-Specific	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
Non-Specific	Customer Driven Project	Various	Subdivisions - Management	11k
Non-Specific	Customer Driven Project	Various	Subdivisions - Transformers	110k
Non-Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non-Specific	Network Equipment Renewal	Whole Network	Protection	12k
Non-Specific	Network Equipment Renewal	Whole Network	Radio Contingency	12k
Non-Specific	Network Equipment Renewal	Whole Network	RADIO Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
Non-Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
Hangatiki	Line Renewals	Benneydale	103-04 11kV Line Renewal	430k
Hangatiki	Line Renewals	Coast	125-03 11kV Line Renewal	200k
Hangatiki	Line Renewals	Coast	125-03 LV Line Renewal	14k
Hangatiki	Line Renewals	Maihiihi	111-07 11kV Line Renewal	210k
Hangatiki	Line Renewals	Mokau	128-04 11kV Line Renewal	97k
Hangatiki	Line Renewals	Mokauiti	115-03 11kV Line Renewal	285k
Hangatiki	Line Renewals	Oparure	107-01 11kV Line Renewal	75k
Hangatiki	Line Renewals	Oparure	107-02 11kV Line Renewal	113k
Hangatiki	Line Renewals	Oparure	107-02 LV Line Renewal	171k

PROPOSED CAPITAL WORKS: 2026/27				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Line Renewals	Otorohanga	112-04 11kV Line Renewal	101k
Hangatiki	Regulators	Hangatiki East	FED102 Install regulator for Omya if loading increases and 33 kV modular substation option not taken.	99k
Hangatiki	Substation, Supply Point and 33kV Development	Te Waireka Zone Substation	ZSub203 Build out along Rangiatea Road with 33 kV extension and install modular substation near Mangaoronga Road.	1463k
Hangatiki	Transformers - Ground Mounted	Otorohanga	T1174 Replace transformer with I tank	47k
Hangatiki	Transformers - Ground Mounted	Waitomo	T1003 Replace transformer with I tank	47k
Mokai Supply Point	Substation, Supply Point and 33kV Development	Mokai Zone Substation	ZSub3358 Further develop supply from Mokai Geothermal and Mighty River Power.	394k
National Park	Line Renewals	Raurimu	410-01 11kV Line Renewal	367k
National Park	Switches (Hazard)	Chateau	15N12 Install RTE switch to transformer.	47k
National Park	Transformers - Ground Mounted	National Park	14L05 Replace transformer.	47k
Ohakune	Line Renewals	Tangiwai	416-04 11kV Line Renewal	154k
Ohakune	Line Renewals	Turoa	415-01 11kV Line Renewal	581K
Ohakune	Line Renewals	Turoa	415-02 11kV Line Renewal	45k
Ohakune	Transformer - 2 Pole Structures	Turoa	20K09 Replace with ground mounted with 100 kVA transformer.	47k
Ongarue	Line Renewals	Ohura	413-06 11kV Line Renewal	189k
Ongarue	Line Renewals	Ongarue	421-01 11kV Line Renewal	443k
Ongarue	Line Renewals	Southern	409-06 11kV Line Renewal	73k
Ongarue	Regulators	Matapuna	FED404 Install Regulator on Taupo Road to boast voltage for back feeds and customers further down Taupo Road.	99k
Ongarue	Switches (Reliability Improvement)	Hakiaha	5.23 Upgrade SDAF ring main unit 5-3, 5-23, and 5-4 to modern equivalent. Replace with 3 bay Xiria with remote control.	20k
Ongarue	Switches (Reliability Improvement)	Hakiaha	5.3 Upgrade SDAF ring main unit 5-3, 5-23, and 5-4 to modern equivalent. Replace with 3 bay Xiria with remote control.	20k
Ongarue	Switches (Reliability Improvement)	Hakiaha	5.4 Upgrade SDAF ring main unit 5-3, 5-23, and 5-4 to modern equivalent. Replace with 3 bay Xiria.	20k
Ongarue	Transformers - Ground Mounted	Western	T4012 Industrial with HV and LV cable boxes.	47k

PROPOSED CAPITAL WORKS: 2026/27				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Tokaanu	Line Renewals	Hirangi	405-01 11kV Line Renewal	33k
Tokaanu	Line Renewals	Lake Taupo 33	606-01 33kV Line Renewal	74k
Tokaanu	Line Renewals	Rangipo / Hautu	424-03 11kV Line Renewal	130k
Tokaanu	Switches (Reliability Improvement)	Rangipo / Hautu	FED424 Add LV links through Turangi town with remote control.	117k
Tokaanu	Transformers - Ground Mounted	Tokaanu	10R20 Install RTE switch.	47k
Whakamaru	Line Renewals	Tirohanga	129-02 11kV Line Renewal	489k
Whakamaru	Line Renewals	Wharepapa	122-05 11kV Line Renewal	262k
Whakamaru	Switches (Hazard)	Tirohanga	REG23 Install bypass protection on regulator.	5k

PROPOSED CAPITAL WORKS: 2027/28				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Non-Specific	Customer Driven Project	Various	General Connections - Earthing and tap-offs	275k
Non-Specific	Customer Driven Project	Various	General Connections - Transformers	275k
Non-Specific	Customer Driven Project	Various	Industrials - Earthing and tap-offs	55k
Non-Specific	Customer Driven Project	Various	Industrials - Transformers	275k
Non-Specific	Customer Driven Project	Various	Subdivisions - Earthing and tap-offs	22k
Non-Specific	Customer Driven Project	Various	Subdivisions - Management	11k
Non-Specific	Customer Driven Project	Various	Subdivisions - Transformers	110k
Non-Specific	Network Equipment Renewal	Whole Network	Distribution Equipment	58k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Easements	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Electricity Act	17k
Non-Specific	Network Equipment Renewal	Whole Network	Equipment Relocations - Miscellaneous	17k
Non-Specific	Network Equipment Renewal	Whole Network	Protection	12k
Non-Specific	Network Equipment Renewal	Whole Network	Radio Contingency	12k
Non-Specific	Network Equipment Renewal	Whole Network	RADIO Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Contingency	17k
Non-Specific	Network Equipment Renewal	Whole Network	SCADA Specific	43k
Non-Specific	Network Equipment Renewal	Whole Network	Tap Offs with New Connection	35k
Non-Specific	Network Equipment Renewal	Whole Network	Transformer Renewals	350k
Hangatiki	Line Renewals	Aria	114-02 11kV Line Renewal	129k
Hangatiki	Line Renewals	Aria	114-03 11kV Line Renewal	129k
Hangatiki	Line Renewals	Benneydale	103-03 11kV Line Renewal	263k
Hangatiki	Line Renewals	Benneydale	103-05 11kV Line Renewal	263k
Hangatiki	Line Renewals	Benneydale	103-06 11kV Line Renewal	158k
Hangatiki	Line Renewals	Hangatiki East	102-03 11kV Line Renewal	78k
Hangatiki	Line Renewals	Maihiihi	111-08 11kV Line Renewal	105k
Hangatiki	Line Renewals	McDonalds	110-05 11kV Line Renewal	254k
Hangatiki	Line Renewals	Mokau	128-06 11kV Line Renewal	129k

PROPOSED CAPITAL WORKS: 2027/28				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Hangatiki	Line Renewals	Mokau	128-06 LV Line Renewal	45k
Hangatiki	Line Renewals	Mokauiti	115-04 11kV Line Renewal	105k
Hangatiki	Line Renewals	Waitomo	108-03 11kV Line Renewal	116k
Hangatiki	Line Renewals	Waitomo	108-03 LV Line Renewal	67k
Hangatiki	Switches (Hazard)	Benneydale	REG07 Install bypass protection on regulator.	5k
Hangatiki	Transformers - Ground Mounted	Otorohanga	T2417 Replace ground mounted transformer with I tank.	47k
Hangatiki	Transformers - Ground Mounted	Otorohanga	T557 Replace with transformer and RTE switch.	53k
Mokai Supply Point	Switches (Hazard)	Mokai Zone Substation	REG29 Install bypass protection on regulator.	33k
Ohakune	Feeder Development	Ohakune Town	414-01 Re-conductor from ferret to dog between 5925 and 6011 on Goldfinch Street.	210k
Ohakune	Line Renewals	Turoa	415-03 11kV Line Renewal	74k
Ohakune	Regulators	Ohakune Town	414-01 Install regulator after 5715 near Ohakune town boundary.	101k
Ohakune	Switches (Hazard)	Turoa	REG20 Install bypass protection on regulator.	33k
Ongarue	Line Renewals	Ohura	413-05 11kV Line Renewal	116k
Ongarue	Line Renewals	Tuhua	422-02 11kV Line Renewal	117k
Ongarue	Line Renewals	Western	403-05 11kV Line Renewal	200k
Ongarue	Switches (Reliability Improvement)	Matapuna	1.5 Ring main unit Grandstand Replace 1.5, 1.6, 1.7 to new type ring main unit.	27k
Ongarue	Switches (Reliability Improvement)	Matapuna	1.6 Ring main unit Grandstand Replace 1.5, 1.6, 1.7 to new type ring main unit.	27k
Ongarue	Switches (Reliability Improvement)	Matapuna	1.7 Ring main unit Grandstand Replace 1.5, 1.6, 1.7 to new type ring main unit.	27k
Tokaanu	Line Renewals	Kuratau	406-01 11kV Line Renewal	34k
Tokaanu	Line Renewals	Tokaanu / Kuratau 33	607-01 33kV Line Renewal	263k
Tokaanu	Line Renewals	Turangi	423-01 11kV Line Renewal	105k
Tokaanu	Line Renewals	Waihaha	426-04 11kV Line Renewal	235k
Tokaanu	Transformer - 2 Pole Structures	Kuratau	08R09 Replace structure with ground mounted transformer. Check loading and use a refurbished transformer if available.	45k
Whakamaru	Line Renewals	Huirimu	121-02 11kV Line Renewal	203k
Whakamaru	Line Renewals	Mokai	123-04 LV Line Renewal	11k
Whakamaru	Line Renewals	Tihoi	124-02 11kV Line Renewal	158k

PROPOSED CAPITAL WORKS: 2027/28				
POS	**Category**	**Location**	**Asset/ Description**	**Cost (k)**
Whakamaru	Line Renewals	Tirohanga	129-01 11kV Line Renewal	216k
Whakamaru	Line Renewals	Wharepapa	122-08 11kV Line Renewal	105k
Whakamaru	Regulators	Wharepapa	122-03 Install regulator just after switch 376 on Whatauri Road.	105k

TABLE 12-1: SUMMARY OF PROJECTS AND EXPENDITURE PREDICTIONS 2013/14 TO 2027/28 FOR ALL POS (WITHOUT INFLATION)

Section 13

13. Further Disclosed Schedules

13.1 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

Section 14

14. Acknowledgements

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The efforts of the TLC Engineering and Asset Management Team, contractors and other staff are also acknowledged in the implementation of this plan to ensure TLC customers receive the best value for money possible with the tools we currently have available within the TLC network assets.

Brent Norriss
Acting Chief Executive
March 2013