

The Lines Company
Limited



ASSET
MANAGEMENT
PLAN

2016

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

Schedule 17 Certification for Year-beginning Disclosure

Clause 2.9.1 of section 2.9

We, Angus Malcolm DON and John McFadyen RAE, being 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 2.6.1 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.

22 MARCH 2016

Date



Angus Malcolm DON
Chairman

22 MARCH 2016

Date



John McFadyen RAE
Director

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Glossary

ABS.....	Air Break Switch
AC.....	Alternating Current
ACSR.....	Aluminium Conductor Steel Reinforced
Al.....	Aluminium
AMG.....	Asset Management Group
AMP	Asset Management Plan
CAPEX	Capital Expenditure
CPI	Consumer Price Index
Cu.....	Copper
DC	Direct Current
DG	Distributed Generation
DGA.....	Dissolved Gas Analysis
DOC.....	Department of Conservation
Dy.....	Delta-star
EGCC	Electricity and Gas Complaints Commission
ETAP.....	Electrical power system analysis software
GIS.....	Geographical Information System
GXP	Grid Exit Point
HFR.....	High Focus Risk
HSE.....	Health and Safety in Employment (formerly OSH)
HV	High Voltage (11kV)
ICP.....	Installation Control Point
KCE.....	King Country Energy
LDC.....	Leased Direct Circuit
LV	Low Voltage (400 Volts)
MDI	Maximum Demand Indicator
MD	Maximum Demand
MRP	Mighty River Power
ODV.....	Optimised Deprival Value
PILC.....	Paper Insulated Lead Cable
POS	Point of Supply
RAB	Regulatory Asset Base
RAL.....	Ruapehu Alpine Lifts Ltd
RCM	Reliability Centred Maintenance
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 followed with an (F).

When actual results are below expectations, the variance is deemed unfavorable and followed by (U).

SUPPORTING DOCUMENTS

Documents supporting the AMP can be found on the TLC website www.thelinescompany.co.nz

These include:

- Pricing Methodology
- Domestic and Commercial Terms and Conditions
- Annual Reports
- Statement of Corporate Intent
- Information Disclosure
- Threshold (DPP) Compliance

Section 1

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1. Executive Summary

The Lines Company (TLC) is custodian of one of the most complex and challenging networks in New Zealand. This is due to the mix of:

- A sparsely populated area with long lines in rugged terrain and few alternative supply options;
- Unpredictable large loads and hydro embedded generation, and;
- A mix of high value industry, dairy farming, economically disadvantaged customers and a high proportion of tenancy or holiday-based accommodation.

In this situation the necessity for innovative, value engineered solutions with asset management strategies integrated with pricing and revenue is high. TLC manages more risk and has less capacity to fund risk mitigation than many networks. This then requires prioritised investment, active customer communication and operational responses to manage risk outcomes including outages.

The good performance of the Network, and its continued improvement, demonstrates the value of the renewal strategies embarked upon some years ago. As this year marks a “half-way point” in delivering those strategies, the process of considering the merits of continuing or modifying those strategies has been commenced. In doing so, a number of comparative benchmarks and evaluations have been introduced for the first time with the implications beginning to be built into forward planning. For example, a continued focus on line renewals needs to be balanced with reconductoring and underground cable replacement considerations as many of these assets are also aged.

This section of the Asset Management Plan (AMP or the Plan) is intended as a summary of all the key information discussed in the balance of the document. It will serve as an update in years when stakeholders do not require a full plan to be produced.

1.1 Asset Management Strategy

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

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

1.2 Purpose of the Asset Management Plan

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

- To minimise and/or eliminate hazards
- To meet reliability targets
- In a manner that keeps charges as affordable as possible.

The Plan provides a formal performance monitoring and reporting framework to demonstrate TLC is meeting its statutory obligations under the Electricity Act 2010. The Plan is drafted to comply with the Electricity Information Disclosure Requirements 2012, Decision No. NZCC 22, covering the period 1st April 2016 through to 31st March 2026.

Principles and Practices

The key features of infrastructure asset management principles and practices TLC uses are:

- Integrated with the strategic direction and other long term plans of the Company
- A whole-of-life asset management approach
- Planning for a defined level of service
- Prioritisation using commercial cost benefit techniques that values reliability
- Performance monitoring
- Meeting the impact of growth through demand management and infrastructure investment
- Managing risks associated with asset and service failures
- Sustainable use of physical resources
- Continuous improvement in asset management practices

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

Key Business processes

To achieve key business outcomes, TLC recognises it must excel at the following:

- Innovation in all aspects of the business
- Asset management including strategy development, prioritisation and implementation
- Customer consultation and promotion of demand side management
- Pricing structures that promote energy efficiency, the reduction of network energy demand and better asset utilisation
- Demand side control systems and advanced metering
- The investigation and promotion of commercially prudent network alternatives

- Asset renewal and hazard control programme management compliant with ISO 31000, including Safety Management Systems (SMS) compliant with the Health and Safety at Work Act, and Public Safety Management Systems (PSMS) strategies compliant with NZS7901:2008
- Network analysis/automation and skills to develop advanced systems
- 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.

Stakeholder Interests

There are a number of key stakeholders including:

- Customers
- Landowners
- Maori
- Distributed generators
- Retailers
- District Councils
- Regional Councils
- Central Government
- Employees
- Contractors and suppliers
- Transpower

Many of the needs of these stakeholders can be determined by individual relationships and discussion. There are however larger groups like customers who cannot be all individually listened to. In this case community group meetings and customer clinics are used. An annual survey of customers' opinions is also undertaken. How these stakeholders' interests are met is discussed in Section 2 of this Plan.

An important stakeholder for a regulated electricity business such as TLC is the Commerce Commission. The Commerce Commission sets revenue for five years and in doing this sets limits on opex and capex, unless the shareholder chooses to fund over the allowed levels. TLC had been struggling to obtain resources to achieve the required work and underspent prior to the current regulatory period of 2015-2019. The level of funding allowed by the Commerce Commission, and underspend in the prior regulatory period, are causing difficult trade-offs in this AMP. This situation is inconsistent with changes to the Health and Safety at Work Act. The arbitrary limit by the Commerce Commission to a 20% increase in capital expenditure for this regulatory period, largely based of historic spend outcomes, places the governance and shareholders of TLC in a difficult position.

Information Systems

TLC has a Basix asset management information system. The BASIX system consists of various modules and includes the following functionality:

- Asset Register
- Regulatory Asset Valuations
- Works Management
- Outage and Reliability
- Reporting
- Vegetation Management

Protection, fault current levels and other technical detail are modelled using a network analysis package (ETAP).

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 platform is ESRI Arc View.

Future Technology

The technology available for more advanced networks is changing rapidly. A central component to most schemes is the need to control demand in customers' installations.

TLC's demand based billing uses the advanced metering and display tools currently available to do this. Technology is being developed that will allow communication between meters and customers to significantly improve leading to further refinement of pricing strategies.

Advances in solar, battery and electric vehicle technologies, and subsequently prices and uptake, are also being factored into network planning. The evaluation of the impact of these disruptive technologies has yet to be recognisable in terms of projected investment expenditure.

Self-Healing Networks

Self-healing networks have been a feature of high density urban areas for some time. As the cost of remote controlled switches reduce, communications costs reduce and software to safely manage automation matures, there is the potential to reduce customer outages using automation. No rural networks in New Zealand or Australia have introduced automated processes for self-healing; however centralised control of switches has improved reliability across the industry. There is more potential for improving reliability in the TLC network over time, using remote controlled reclosers and switches.

A focus is to develop a plan to bring these technologies together in an innovative way to benefit customers. This will likely include inspection and fault data entered at source and the integration of GIS with the other elements of the system.

Key Assumptions

There are a number of key assumptions inherent in the AMP. Commerce Commission revenue is one of the High Focus Risks. High Focus Risks are monitored by the executive and require actions to reduce or manage them. These assumptions include:

- Revenue from the Commerce Commission will be adequate to meet customer and statutory requirements, within acceptable debt servicing levels while allowing an adequate return to shareholders
- Growth will be funded by new customers
- Economic activity will remain based on primary production with downstream industry and tourism or holidaying based around skiing in winter and high scenic amenity values in summer.
- Uneconomic customers will continue to be supplied using existing cross subsidies
- Existing low user cross subsidies will remain
- Changes in Government policy or regulations will not impose unexpected financial costs (including the Health and Safety at Work Act)
- Distributed generation will continue to develop and will be managed appropriately
- Demand side management and demand pricing will be successful in minimising peak growth and hence cost of the network to customers
- TLC will continue with its current demand and other pricing structures
- Customers will want at least the current reliability standards
- Stakeholders will accept hazard minimisation improvements to meet current standards, and these standards will not materially change
- Hazard minimisation will continue to be allowed by progressive removal over a reasonable time period
- Inflation will be as forecast by monetary authorities
- Performance measures developed by the company in consultation with stakeholders and imposed by the Commerce Commission will remain in their current form
- The Asset Management Plan is appropriate and will be implemented over time to manage risks to an acceptable level
- Skilled resources will be available nationally to complete all required activities in the company

1.3 The Network Assets

Distinguishing features

The network covers a large area from Otorohanga in the North to Ohakune in the South. The Eastern boundary extends from Lake Taupo and the Waikato River region across to the West Coast. Development in 2015 has seen the network extended to support farming on the eastern side of the Waikato River near Whakamaru.

In comparisons to other EDB's, The Lines Company is 20th out of 29 companies in terms of the number of customers (ICP's) and yet 12th in terms of the length of network. This illustrates the challenge with a long network and relatively few customers to fund necessary replacement expenditure. The assets have a regulatory value of \$176 million (March 2015 Information Disclosure). This places TLC 18th out of 29 showing an aging but not particularly old network.

There have been no significant asset changes in the last year. Planned asset replacement and refurbishment has occurred largely in line with the 2015 Asset Management Plan. There have been no significant changes to the network. Some additional line has been installed at Whakamaru due to forestry to dairy conversion. There have been transformer changes at two zone substations and upgrades by Transpower of transformers at Ohakune and National Park GXP's.

The TLC network has many contrasts and includes:

- Sparsely populated rugged rural network with no major urban centres
- A declining population base.
- Single wire earth return systems (SWER).
- Approximately 30% of TLC assets are used to supply remote customers.
- A number of distributed generation connections.
- A number of large industrial connections.
- High number of zone substations with single transformers and limited backup
- Long lengths of 33kV lines in rural, rugged and remote areas.
- Long lengths of privately owned 11kV lines connected to the network.
- A direct connection to two major generators upstream of the Transpower grid exit (Atiamuri and Whakamaru)
- A generator directly connected to an energy park network supplying energy intensive industries
- Transmission supplies with single transformers and limited backup from long 33kV line connected to other Points of Supply.

Characteristics of the Network

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 therefore been little replacement of aged assets with higher capacity assets due to growth, which many other networks have experienced in the past.

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

- There is limited ability to cross-subsidise rural supplies. Rural customers must therefore be exposed to a price that is closer to the cost of supplying them than is traditional in other parts of New Zealand. Imposing the renewal costs of all TLC's uneconomic lines, most of which were originally funded by grants from the Rural Electricity Reticulation Committee (RERC), on TLC's customers as a sole funding source means that urban customers will face line charges above the cost of supply. Many of these urban areas cannot sustain substantial price increases to fund this work.
- It is important that the income from the towns is not simply used to subsidise rural supply, leading to the towns themselves receiving a substandard supply. Investment in the infrastructure for these towns, especially Ohakune and Turangi, has been more significant in the recent years, and continues to feature in this Plan.

Renewals will increase the value of these assets and thus revenue requirements. To minimise this effect, renewals need to be balanced with depreciation and reliability. Assets have to be managed in a way that fulfils hazard control requirements, produces the optimum service level and minimises the value increase. This is reflected in our segment-by-segment approach to asset development, renewal, and maintenance, and our commitment to greater information flows to our customers. It places emphasis on cost effective solutions, commonly called value engineering.

Large Load Customers

There are a number of diverse large load customers that generate considerable economic value to the region, and have increased reliability and quality requirements. A number of these facilities are on the end of long sections of network, sometimes cable (ski fields), with no alternative supply and public safety risk. Some large load customers may not be in a position to pay for the increased reliability they need. This makes maintenance, testing and operational response a key requirement and active communications a necessity. These customers include:

- Taharoa Iron sands processing and loading
- Ski fields at Mt Ruapehu and Turoa
- Corrections facilities
- Limestone extraction and processing
- Meat processing
- Timber processing
- Milk processing and glasshouse food production (Mokai Energy Park)

Distributed Generation

Approximately 20% of the peak load on the TLC network can be supplied by distributed generation. This generation places some complexity in designing and operating the network, especially since they are mostly run of the river plant that can change generation levels over short time frames and with rainfall.

Some of the generation contracts are historical and have inadequate requirements for network voltage support or reduction, power factor correction, voltage surge management, loss management and peak load management.

Load Profile Characteristics

Over the 6 supply areas (regions), there are four distinct load profiles. Two of these, covering the regions of Hangatiki, Tokaanu and Ohakune/National Park, are unpredictable due to the ski season or rainfall affecting generation. Only the Taumarunui region with a domestic/farming profile, and Whakamaru with a dairy profile and the Mokai Energy Park are reasonably certain within normal weather patterns. This creates challenges for peak management and hence capacity from supply points and the network, including charges from Transpower which are peak related. This is one of the most complex environments to operationally manage in New Zealand.

1) *Hangatiki Area Load Characteristics (North Western Region)*

Regional Activities Affecting Load:

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

The peak system load is dominated by the monthly cycle of the loading of the iron sands ship. If this loading coincides with dry periods and low river flows - resulting in low distributed generation output - then a grid exit point connection local peak is set. Limestone and meat processing peaks are seasonal and operate for varying periods throughout the year. Dairy farming is a seasonal activity that produces a peak springtime load.

The cumulative effects of these activities result in a local grid peak in March or April and a late winter/spring system peak.

2) *Whakamaru Area Load Characteristics (North Eastern and Waikato River Region)*

Regional Activities Affecting Load:

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

The peak system load in this area occurs during the dairy season. An additional connection is proposed to increase security for the milk plant or alternatively, strengthening interconnections to other regions. Reliability requirements are increasing due to dairy conversion sometimes including irrigation.

3) *Taumarunui Area Load Characteristics*

Regional Activities Affecting Load:

- Domestic load in Taumarunui.
- Farming
- Kuratau Distributed Generation.

The Taumarunui load follows the normal domestic pattern and typically causes a system peak during the winter period. The timing of the grid exit peak is dependent on rainfall and the generation available.

4) *Round the Mountain Load Characteristics (National Park, Tokaanu and Ohakune)*

Regional Activities Affecting Load:

- Holiday homes and tourism around Lake Taupo, National Park and Ohakune
- Whakapapa and Turoa Ski Fields
- Carrot processing
- Increasing dairying load

The holiday homes around Lake Taupo and the mountain cause an Easter, school holiday and occasional Christmas peak on the Tokaanu, National Park and Ohakune grid exit points, depending on temperature and the ski season. 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 and mountain bikers.

Points of Supply

Transmission supply is constrained or vulnerable apart from Tokaanu. Five of the seven supply points have limited redundancy. Solutions for this are discussed in the Development section of this Plan. The TLC network is supplied from the following locations; the first five are Transpower grid exit points:

1. Hangatiki (Dual transformer supply restricted by load exceeding the capacity of one transformer)
2. Ongarue (Single transformer supply with backup using a long 33kV line to Tokaanu)
3. Tokaanu (Dual transformer supply with load below the capacity of one transformer)
4. National Park (Single transformer supply with backup using a long 33kV line to Tokaanu)
5. Ohakune (Single transformer supply with limited backup from Tangiwai POS)
6. Whakamaru and Atiamuri (Single transformer supply directly from the large hydro generators on the Waikato River with limited backup from Atiamuri)
7. Mokai Energy Park (Single supply from Tuaropaki Mokai Geothermal Power station with limited backup)

Subtransmission and Zone substations

The sparse rural nature of the TLC network causes asset costs to be higher than urban networks. There are efficiencies of size and therefore small rural zone substations tend to cost more than urban ones. TLC has minimised this with innovative and cost effective containerised package substations and using 33kV subtransmission switchgear installed on poles nearby with cable to the package substation.

The length and exposure of the subtransmission network to faults is high. Subtransmission line backups between points of supply are long and amongst the oldest parts of the network. This is an example of reliability-centred maintenance based on the revenue and customer outage exposure, required on the TLC network.

TLC has a number of zone substations with single transformers and only light load backup from other substations via the 11kV distribution network. This is illustrated in Table 1.1 below. This lack of backup places higher requirements for subtransmission and zone substation maintenance and operational response.

ZONE SUBSTATION BACKUP CAPACITY	
Backup Capacity	Number of Substations
High	8
Medium	4
Low	18

Table 1.1: Zone Substation Backup Capacity.

There are 12 transformers over 50 years old. Ten of these are in zone substations with multiple transformers and high levels of backup, illustrating the focus on minimising risk. This is however still a High Focus Risk that is included in development and replacement plans.

11kV Distribution Network

The age profiles of the distribution equipment demonstrate the improvement from systematic inspection and replacement of equipment approaching failure over the last 10 years. This has also substantially improved reliability. The first relates to insulator and conductor failure and the second to the extent of tree exposure on the network and the scale of effort required to bring trees into code clearance. Distribution transformer and switchgear age profiles show the same level of systematic inspection and replacement that benefits reliability and reduces hazards from safety and environmental factors.

Low Voltage Network

The concentrated investment in the 33 and 11kV networks has produced the improvements outlined in the following sections. Consequently, like many networks in New Zealand, the low voltage network is aging and is approaching the time where replacement will be needed to meet hazard requirements.

Communications, Radio and Ripple Plant

Communications, radio and ripple plant are all in average to good condition, demonstrating the benefits of inspection and maintenance processes.

1.4 Network Performance

Performance

The performance of the TLC network has been steadily improving as the renewal programmes embarked upon in the mid-2000's are having an effect. Outage performance has stabilised around the target of 300 SAIDI minutes.

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

Regulatory Targets

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

The SAIDI and SAIFI limits from 2015 are set at one standard deviation above the 10-year historical average, which is the same for the SAIDI and SAIFI caps under the quality incentive scheme. The new regulatory SAIDI and SAIFI targets and incentive limits are outlined in Table 1.2 below. These SAIDI and SAIFI totals emphasise unplanned outages with planned outages being weighted at 50%. To limit the impact of severe weather events on the annual reliability measures the maximum daily SAIDI or SAIFI figures are limited to normalised values of 10.97 SAIDI minutes and 0.144 SAIFI.

The incentive mechanisms for meeting or exceeding the collar and cap provide for either adding or deducting 0.5% from the allowable revenue for each EDB in the year following disclosure. In TLC's case, this amounts to approximately \$175,000 per annum added to or deducted from allowed revenue. The allowance or penalty is applied on a percentage of achieved basis.

The breach provisions from previous regimes remain for exceedances of the Cap limits.

REGULATORY TARGETS AS AT 1ST APRIL 2015			
	Collar	Target	Cap
SAIDI	183.40	208.80	234.20
SAIFI	2.67	3.07	3.47

Table 1.2: Reliability Targets

Figure 1.3 and 1.4 below shows the effect for both SAIDI and SAIFI using the previous 6 years network performance results with the new calculation methodology. This shows that the new methodology will not cause significant changes to reliability targets. TLC would have achieved equal numbers of incentive and penalty applications across the example years, i.e., 3 out of 6 years would each have had an incentive or penalty allowance. That is, in 2009/10, TLC would have achieved the full 0.5% incentive allowance from evaluation of the results that would be disclosed in 2010/11 with the recovery being in the 2011/12 financial year.

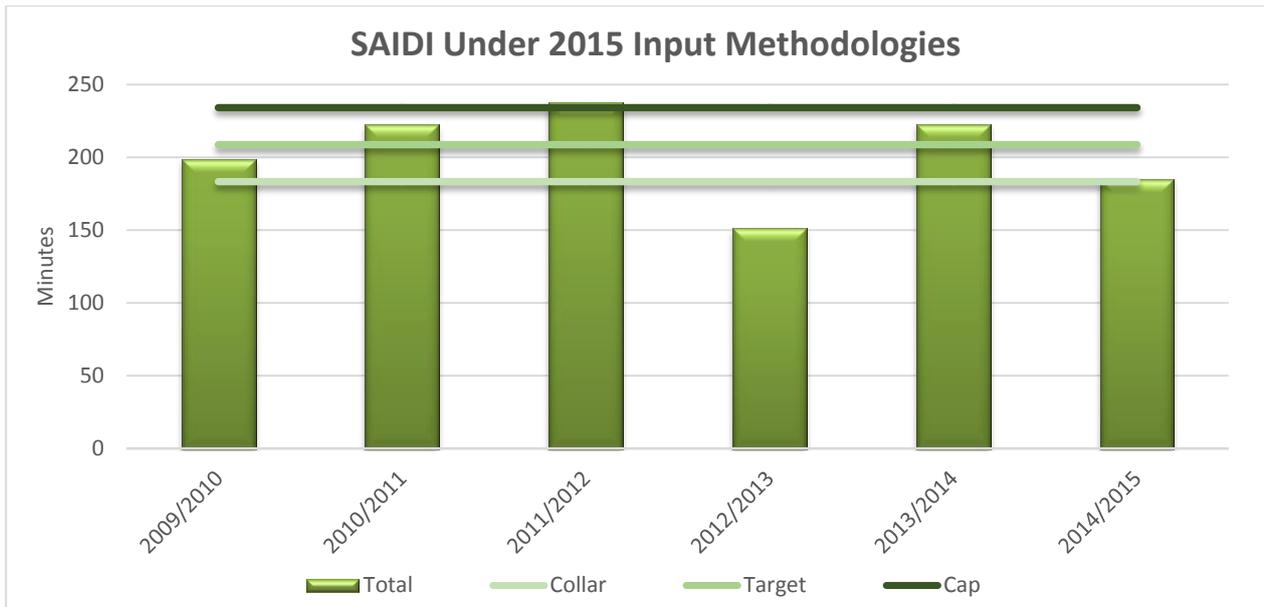


Figure 1.1: 2009-2015 SAIDI calculated using input methodologies from the 2015 DPP

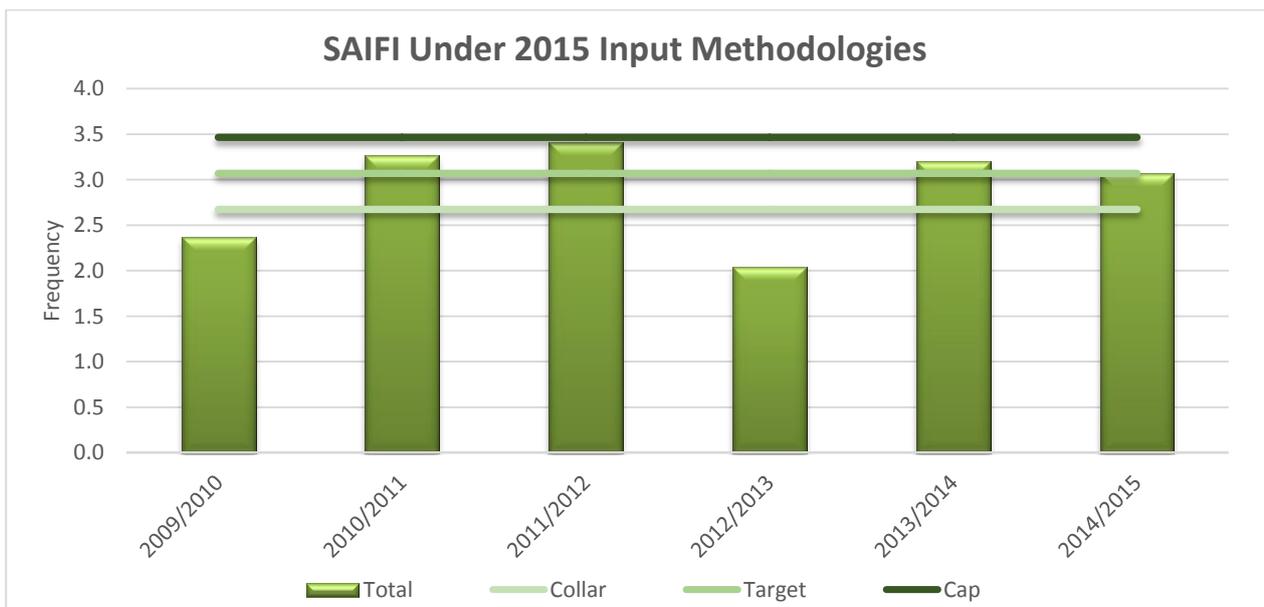


Figure 1.2: 2009-2015 SAIFI calculated using input methodologies from the 2015 DPP

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

Customer Commitment Performance

Table 1.3 below summarises the customer commitment performance against targets for TLC. The overwhelming number are favourable, with those unfavourable generally having small negative variances

PERFORMANCE AGAINST TARGETS 2014/15		
Target	Achievement	Notes
Reliability	Favourable	
Number of outages	Favourable	Unplanned 5.5% unfavourable
Maximum time to restore faults	Unfavourable	Storm impacts
Planned shutdowns	Favourable	1 out of 6 areas unfavourable
Number of long unplanned outages	Favourable	
Number of short unplanned outages	Favourable	
Unresolved complaints	Unfavourable	24 versus target of 20
Voltage complaints	Favourable	
Voltage surge complaints	Favourable	
Harmonic distortion	N/A	
Component failures	Favourable	
Technical losses	Favourable	2 out of 6 areas unfavourable
Grid exit power factor	Unfavourable	Affected by generation output
Load factor	Favourable	
Accident performance	Unfavourable	Injuries and lost hours exceeded target
Removal of hazardous equipment	Favourable	
Diversity Factor	Favourable	
Rate of trees felled to worked on	Favourable	

Table 1.3: Summary of Customer Commitment Performance against Targets

1.5 Development Planning

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

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 at Hanganatiki and the Atiamuri backup 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.

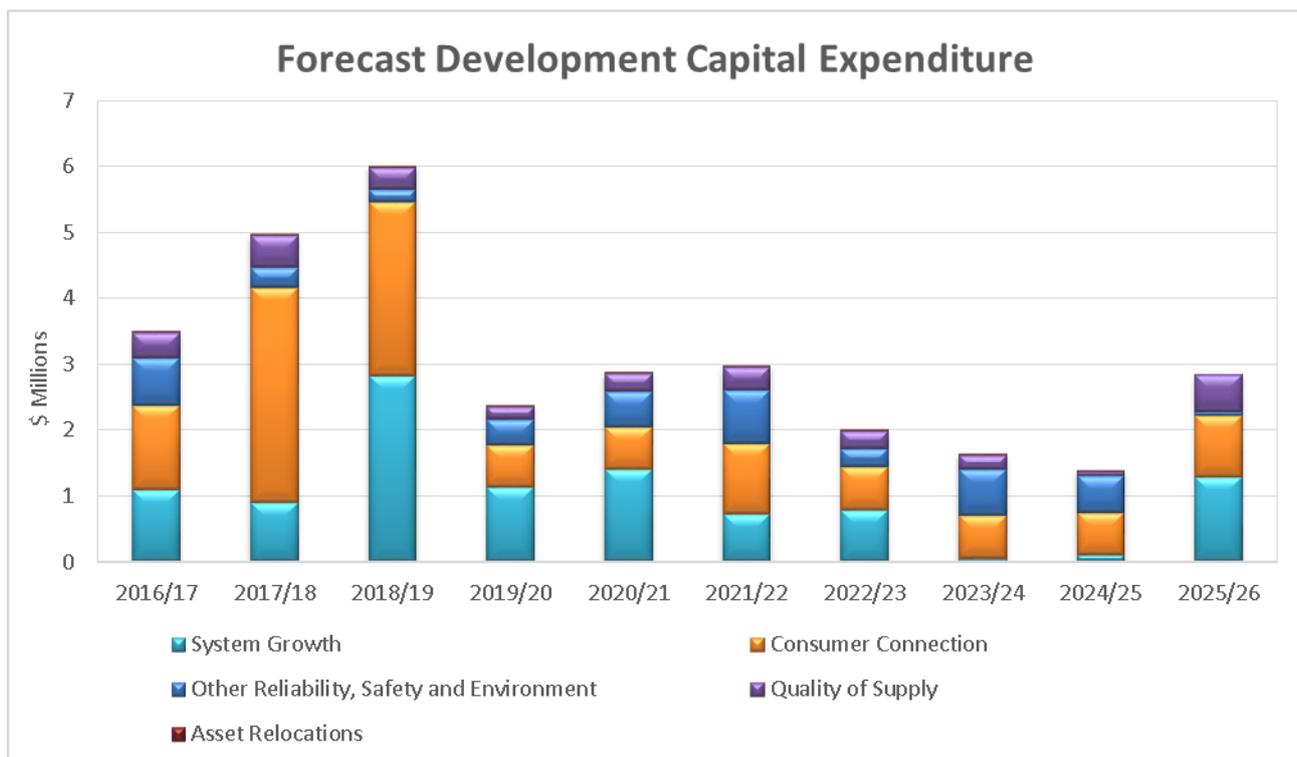


Figure 1.3: Forecast Development Capital Expenditure

Whakamaru POS and dairy growth

There has been continuing dairy growth in the Whakamaru region, in the form of both continued demand increase at existing dairies and new dairy conversions. As a result of this there are a number of capital projects planned to increase capacity and reliability in the area. The major project will be to increase the backup capacity for the point of supply. This will either involve increasing the capacity at the existing backup supply at Atiamuri or by taking a supply from one of the other hydro stations in the area.

Hangatiki POS

Due to increasing industrial and dairy loads the Hangatiki GXP is moving towards capacity in this planning period. TLC is currently in high level discussions with Transpower. The higher level of spend in 2017/18 and 2019/19 seen in Figure 1.3 above are the expected investment for expansion at the Taharoa iron-sand operation, signalled in previous year's AMP's, with timing driven by decisions of the customer.

Other Development

- 33kV backups including condition and age
- Taumarunui/Ongarue POS options
- Feeder ties for single transformer zone subs

There are a number of capital projects to improve the 11kV inter-tie capacity between zone substations that have only a single transformer. The initial focus of this program is around areas with continuing dairy growth.
- Reliability improvement spend

The reliability improvement plan is continuing with an increased focus on adding protection to sectionalise large spurs off the main 11kV feeder.
- Hazard management spend

Work is continuing on removing existing hazards on the network. The focus continues to be on upgrading two pole structures that are below regulation height and replacing ground mount transformers that pose a potential risk to the public or staff.

Alternative supply solutions

Alternative supply solutions are now advanced enough to meet the needs of busy farmers who are focused on maximising the efficiency of their enterprises and low enough cost to be an alternative to uneconomic parts of the network. The concept of regulated off grid supplies will be explored in the next year to determine the value and practicality for the TLC network.

Most lifestyles require a supply reliably available on a 24 hours a day, seven days a week basis. This has been further cemented by the requirement for environmental reasons for farmers to fence water ways. A typical dry stock farm needs 4500 to 5500 stock units to be economic in today's trading environment. These stock numbers result in a daily water need of about 45,000 to 55,000 litres that has to be pumped. Alternative power supplies to cope with supplying the amount of energy to achieve this outcome are relatively large, however technology solutions now mean that the costs of off grid solutions are likely to be less than the replacement cost of remote parts of the network.

The costs, particularly of solar cells, have reduced over the last few years; and, economic analysis shows that they are approaching competing against present energy rates (excluding lines charges). TLC is recommending them to customers when they are more economic and capable of producing similar lifestyle or enterprise outcomes. There is currently a cross subsidy from town, holiday and intensely farmed areas to sparsely populated areas often in rugged terrain. Given the cost reflective principles of TLC tariffs, if true costs were reflected to customers on some SWER parts of the network, it is expected the cheapest solution would be a stand-alone power supply. This is occurring in many remote parts of Australia. While the load profile is different in the TLC network with higher winter loads when solar is less effective, as remote parts of the network come up for replacement, alternatives to on grid supply need to be considered. TLC intends to report this in some detail in the next AMP.

Managing off grid regulatory supplies would require the same attention to reliability and service that are core parts of TLC culture.

Future Distributed Generation

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

Investment to Reduce SAIFI

To control SAIFI outages have to be limited to less than a minute. This necessitates more of an ability to restore power and isolate faults remotely but also potentially automatically, requiring investment in "smart-grid" style control systems and equipment. For a largely rural network of sparse population, the outcomes of balancing further quality improvement (driven by Regulators) with this style of investment will need to be evaluated carefully in coming years. TLC is keeping close track on the technologies becoming available in this field, suited to a rural network. There is no doubt however that reducing the number of customers affected by faults using reclosers is a highly effective solution and this is being increased in this plan.

1.6 Lifecycle Planning

The projected direct maintenance expenditure for the planning period is shown in Figure 1.4. Tree expenditure has increased \$200k from the 2015/16 Asset Management Plan due to increasing costs over time, a consequent increasing backlog of trees to cut and increasing tree faults.

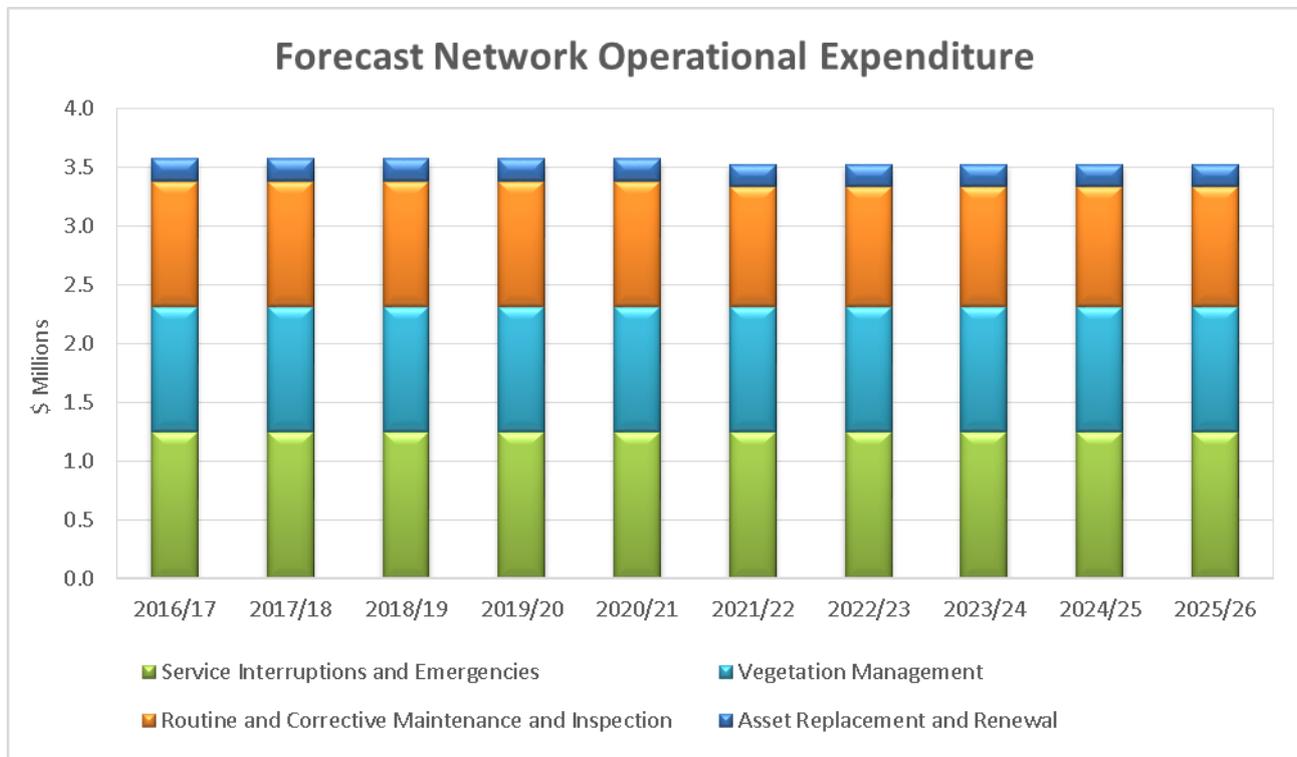


Figure 1.4: Forecast Direct Operational Expenditure

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

There is a cost to TLC from trees outside the regulatory cut zone where the tree owners are unable to be charged if the tree damages lines or causes outages. Where it is clear that risk exists, TLC encourages the owner to remove the tree by offering a free service. The tree regulations do not give adequate responsibility to the tree owner in these situations.

Tree management is a high focus risk and the organisation acknowledges it is cutting vegetation in remote parts of the network for reliability and not to Code. This is increasingly untenable due to changes in the Health and Safety at Work Act.

The core elements of maintenance expenditure are:

- Inspection condition monitoring of overhead lines, switches, distribution transformers and associated equipment.
- Inspection, routine and corrective maintenance of zone substations and associated equipment.
- Vegetation control.
- Inspection, routine and corrective maintenance of radios, communications equipment, reclosers, regulators and associated equipment.

As shown in Figure 1.5 below, replacement capital expenditure has remained relatively similar in total with the 2015/16 AMP. Changes to individual categories include:

- \$400k for conductor replacement. Conductor faults have been increasing as conductor ages. This expenditure allows for early projects of reconductoring while more stringent investigations identify targeted replacement assets.
- \$240k for cable replacement. A series of faults in 2015 identified areas of installation in Turangi and Ohakune that were built to “the standard of the day” which are now less than acceptable. Combined with aging assets these faults required unexpected replacement expenditure. Budget has been included on the same basis as conductor replacements, i.e., early projects to allow targeted replacement plans to be established.

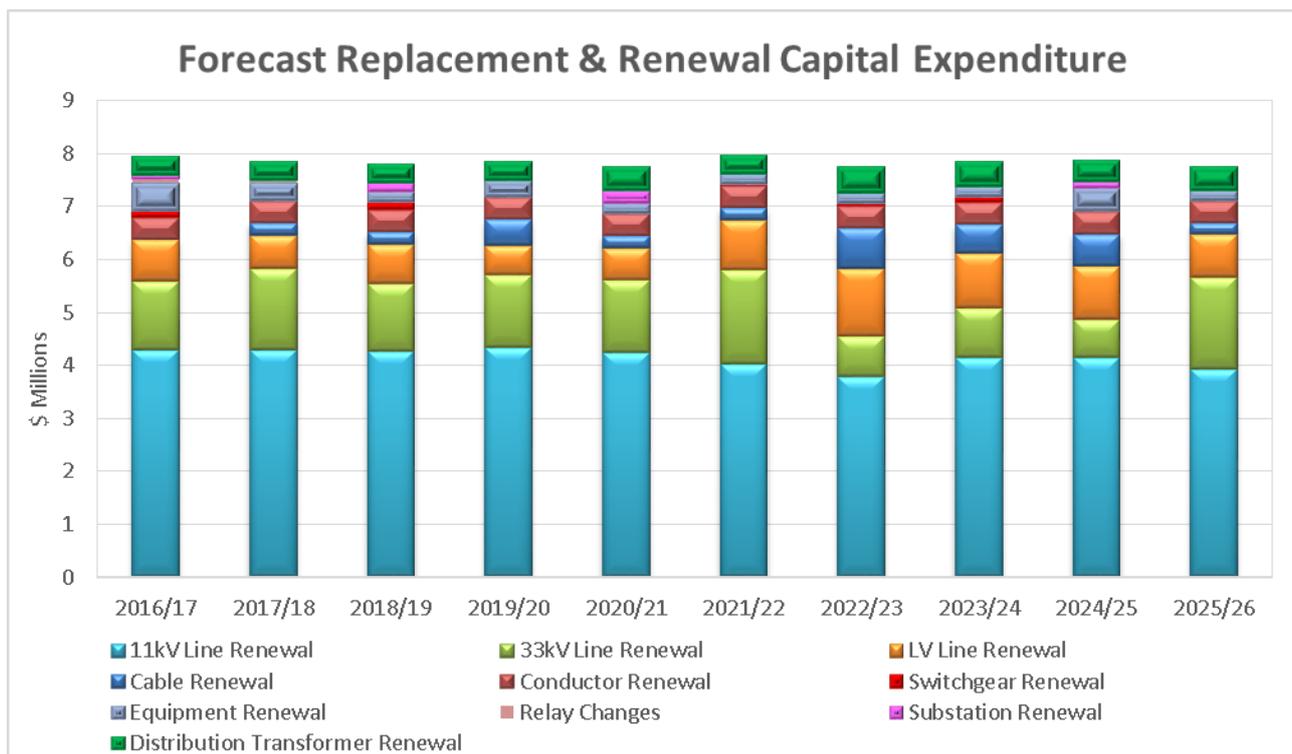


Figure 1.5: Replacement and Renewal Capital Expenditure Forecast

1.7 Operational and Capital Expenditure

Changes in opex from last year’s plan to this year are indicated in Figure 1.6 below. The differences relate to increased tree trimming expense due to escalating costs of traffic management and safety no longer being able to be absorbed. Tree reliability has steadily worsened over recent years and trimming for reliability alone is not consistent with changes to the Health and Safety at Work Act.

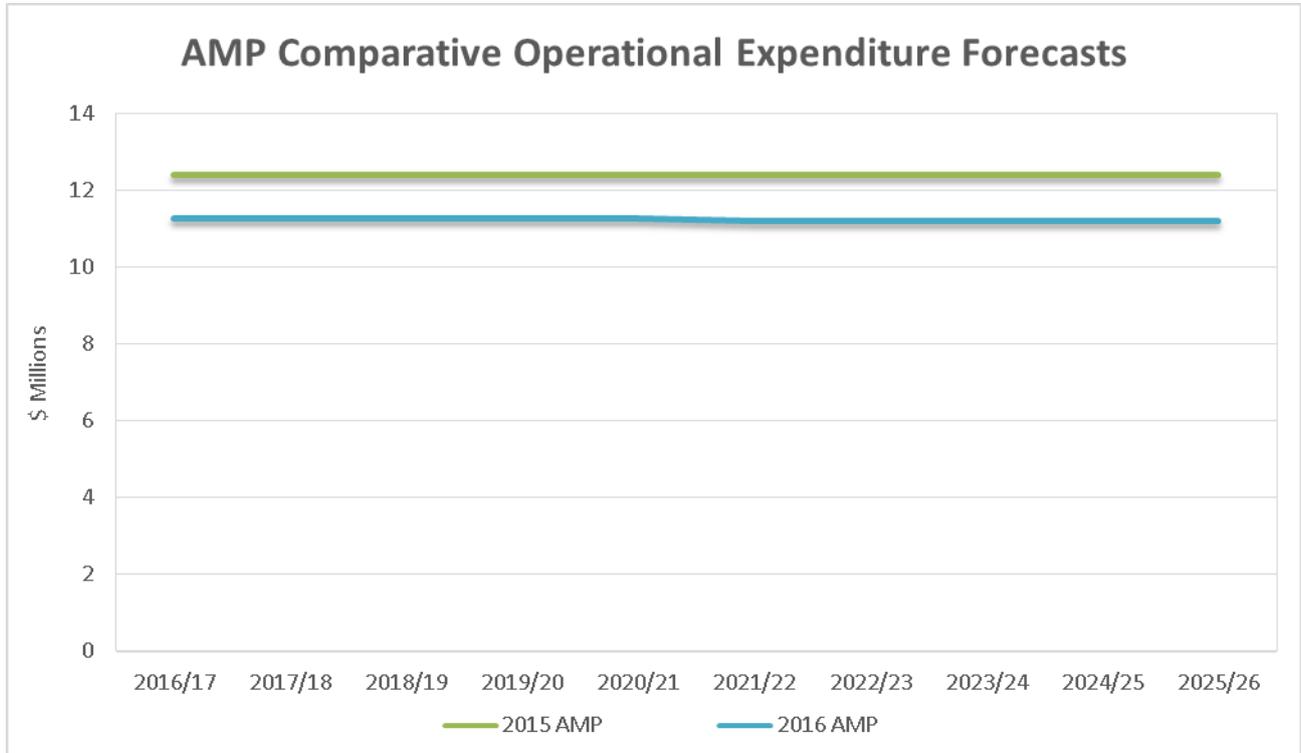


Figure 1.6: Changes in Operation Expenditure Forecasts from Last Year’s Plan

Changes in capital expenditure from last year’s plan to this year are indicated in Figure 1.7 below.

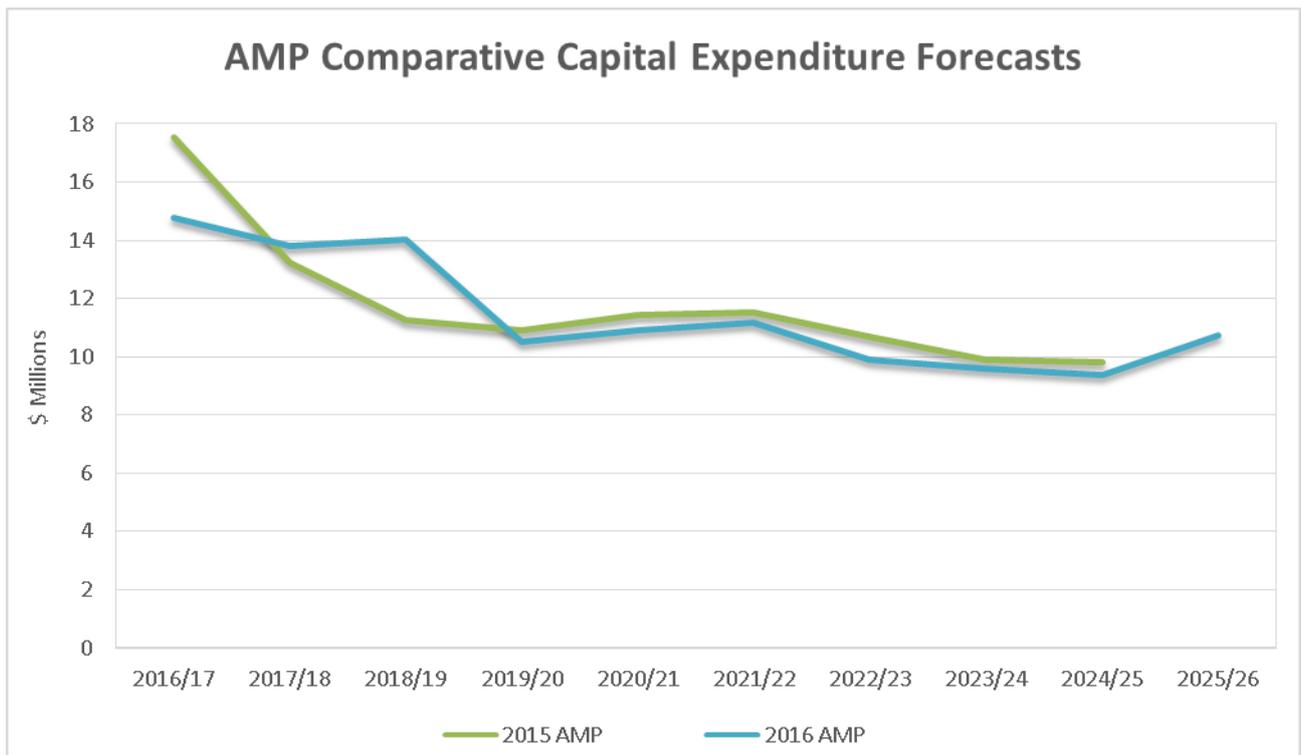


Figure 1.7: Changes in Capital Expenditure Forecasts from Last Year’s Plan

The predicted total expenditure including operating and business costs is included in Figure 1.8. As above costs are stable over time but have increased due to increasing tree cutting costs.

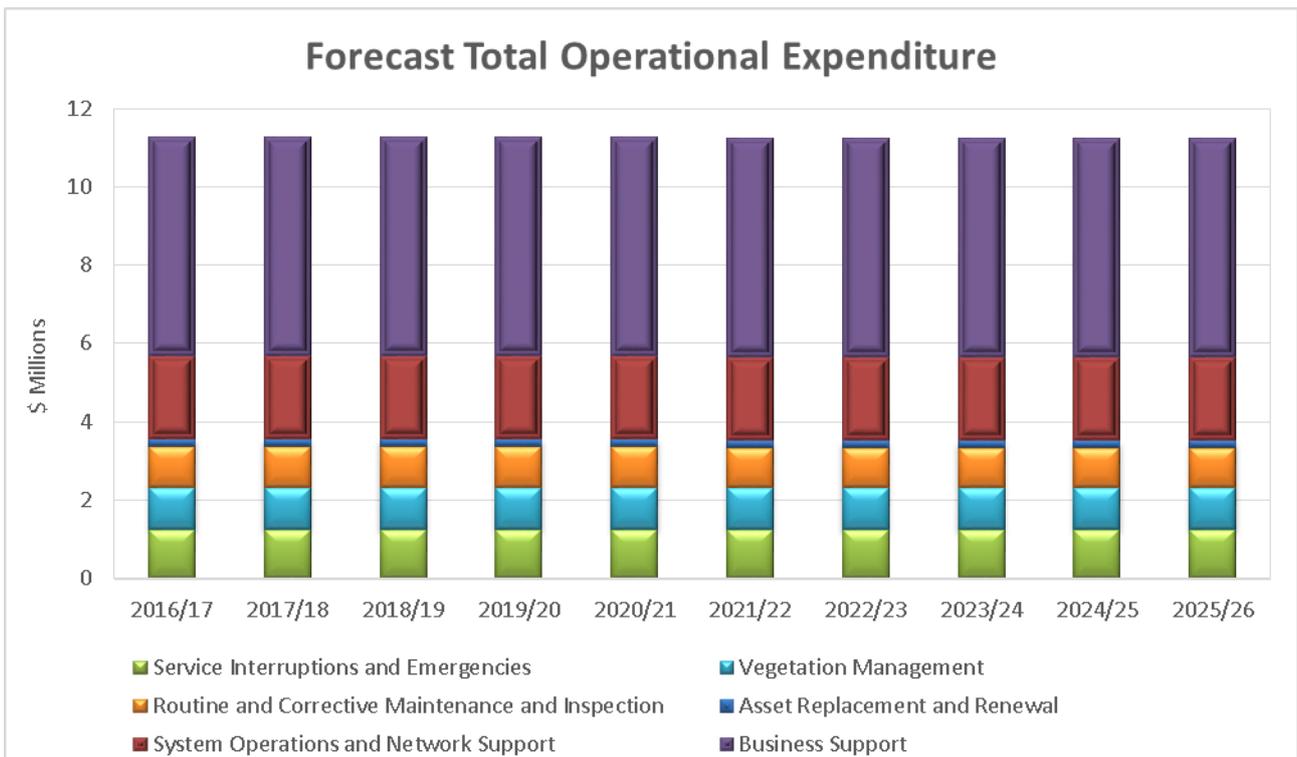


Figure 1.8: Forecast Total Operational expenditure

Business support costs are a large proportion of the costs, the key influence being TLC’s engagement model with its customers.

Figure 1.9 illustrates forecast capital expenditure for the planning period in current dollars

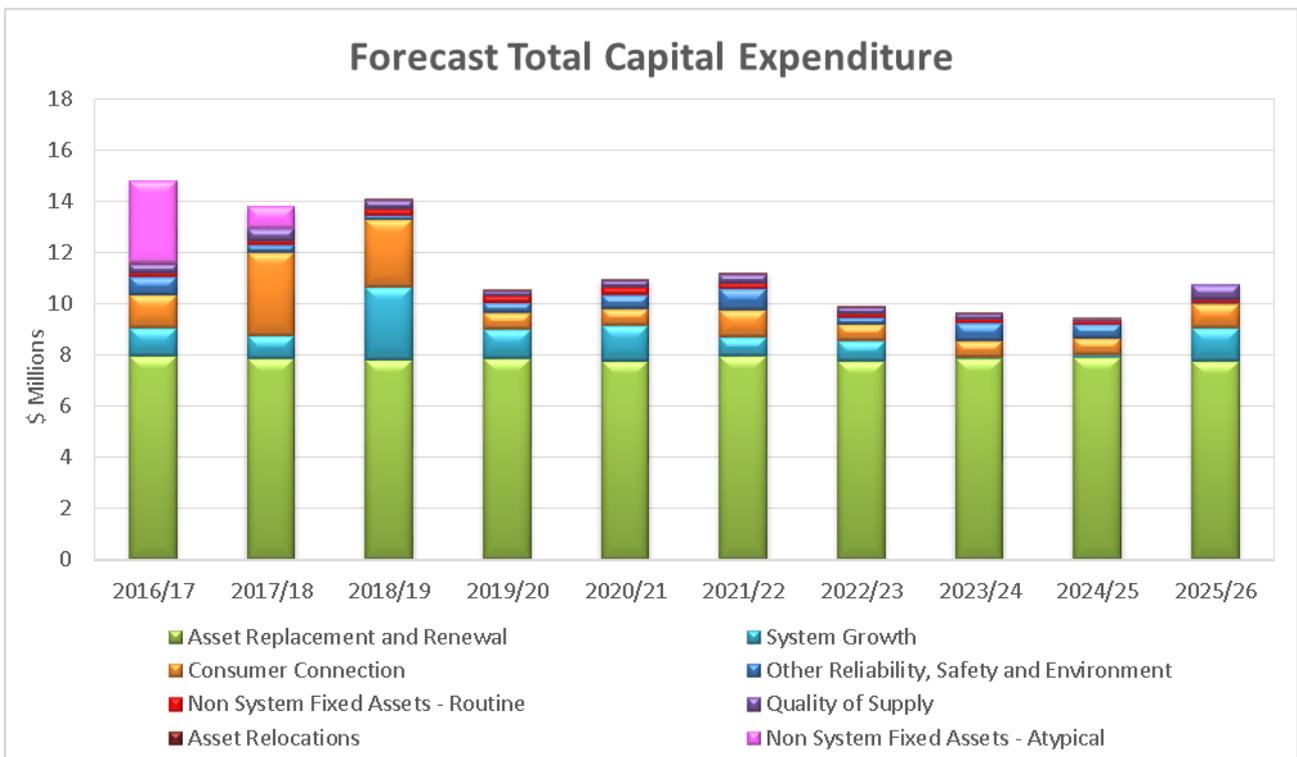


Figure 1.9: Forecast Total Capital Expenditure

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

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

- Expectation of continued line renewal
- Half-life servicing of zone substation transformers
- Replacement of zone substation bulk oil breaker.
- Replacement of ground mounted transformers that have reached their end of life.
- Renewal of deteriorating cables in urban area.

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

- The increase of capacity at Taharoa substation (Customer Connection category, iron-sand mining)
- The rebuild of the King Street office (Non-system Fixed Assets – Atypical category).

1.8 Risk Management

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 for 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 built to current standards.

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.

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 an unacceptable 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 requires 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.

This year the risk framework has been reviewed to be compliant with ISO 31000. This has highlighted a number of High Focus Risks (HFR). These are risks that require senior management review and actions to manage the risk. Section 8 provides details the analysis and actions to be taken.

1.9 Asset Management Improvement

TLC has assessed its maturity level and is consistently at Maturity Level 2 (Development). A number of areas are targeted for improvement to Level 3 has developing an appropriate improvement plan. As part of revisiting its asset management capabilities TLC has engaged external consultants to review the following areas;

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

The results of the review have highlighted a number of areas in which TLC requires improvements; this has formed the basis of the improvement plan.

The areas identified for improvement to be at Maturity Level 3 (competent) across all areas are:

AMMAT IMPROVEMENT OPPORTUNITIES	
ISO 55000 SECTION	INTERMEDIATE (Maturity Level 3 – Competent)
2.1 AM Policy Development	<ul style="list-style-type: none"> • Wide engagement with Stakeholders and communication of Strategy and Policy. • Expectations of each activity area defined with detailed action plans, resources, responsibilities and timeframes. • Communication of the Asset Management Plan.
2.2 Levels of Service and Performance Management	<ul style="list-style-type: none"> • Customer Group needs analysed. • Customers are consulted on significant service levels and options.
2.3 Demand Forecasting	<ul style="list-style-type: none"> • A range of demand scenarios is developed (e.g.: high/medium/ low).
2.4 Asset Register Data	<ul style="list-style-type: none"> • Systematic and documented data collection process in place. • High level of confidence in critical asset data.
2.5 Asset Condition	<ul style="list-style-type: none"> • Condition assessment programme derived from benefit- cost analysis of options. • Condition assessment of assets documented to allow review of key life cycle decisions and outcomes of Data validation process in place.
2.6 Risk Management	<ul style="list-style-type: none"> • Risk Framework embedded in the organisation. • Risk managed consistently across the organisation. • High Focus Risk Actions Monitored.
3.1 Decision Making	<ul style="list-style-type: none"> • Formal decision-making and prioritisation techniques are applied to all operational and capital asset programmes within each main budget category. • Critical assumptions and estimates are tested for sensitivity to results.
3.2 Operational Planning	<ul style="list-style-type: none"> • Emergency response plans and business continuity plans are routinely developed and tested. • Documented incident and Root Cause Analysis (RCA).
3.3 Maintenance Planning	<ul style="list-style-type: none"> • Contingency plans for all key maintenance activities. • Asset failure modes understood. • Frequency of major preventative maintenance optimised using benefit-cost analysis. • Life Cycle Planning of all assets. • Maintenance Backlog Transparent.
3.4 Capital Works Planning	<ul style="list-style-type: none"> • Formal options analysis and business case development has been completed for major projects in the 3-5 year period. • Processes for Design, modification and procurement documented including safety aspects.
3.5 Financial and Funding Strategies	<ul style="list-style-type: none"> • Asset revaluations have data confidence. • Ten year+ financial forecasts based on current comprehensive AMPS with detailed supporting assumptions / reliability factors. • Asset Expenditure easily linked to finance databases.
4.1 AM Teams	<ul style="list-style-type: none"> • All staff in the organisation understand their role in AM, it is defined in their job descriptions, performance plans, performance reviews and they receive supporting training aligned to that role.
4.2 AM Plans	<ul style="list-style-type: none"> • Effective customer engagement in setting Levels of Service, ODM/risk techniques applied to major programmes.
4.3 Information Systems	<ul style="list-style-type: none"> • Input of Data at Source to improve accuracy. • More automated analysis reporting on a wider range of information. • Asset information systems Plan.
4.4 Service Delivery Mechanisms	<ul style="list-style-type: none"> • Internal service level agreements in place with internal service providers. • Contracting approaches reviewed to identify best delivery mechanism. • Tendering / contracting policy in place. • Competitive tendering practices applied. • Prioritisation and resourcing is planned to deliver AMP.
4.5 Quality Management	<ul style="list-style-type: none"> • Process documentation implemented in accordance with the Quality Management System plan. • All processes documented to appropriate level of detail. (Inspection, Design, Auditing, Asset Planning, Life cycle, AMP) • Auditing of Asset Management processes.
4.6 Improvement Planning	<ul style="list-style-type: none"> • Formal monitoring and reporting on the improvement programme to Executive Team. • Project briefs developed for all key improvement actions.

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2. Background and Objectives

2.1 The Purpose of the Plan

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

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

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

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

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

2.1.1 Principles and Practices

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

- Integration with the strategic direction and other long term plans in the company
- A whole-of-life asset management approach
- Planning for a defined level of service
- Prioritisation using commercial cost benefit techniques
- Performance monitoring
- Meeting the impact of growth through demand management and infrastructure investment
- Managing risks associated with asset and service failures
- Sustainable use of physical resources
- Continuous improvement in asset management practices.

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

2.1.2 Benefits

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

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

The application of asset management principles encourages a holistic, integrated approach to guide where and how finances and resources are allocated, based on commercial business cases and rates of return consistent with a regulated electricity distribution business.

2.1.3 Current status

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

2.2 Relationship with Other Planning Functions

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

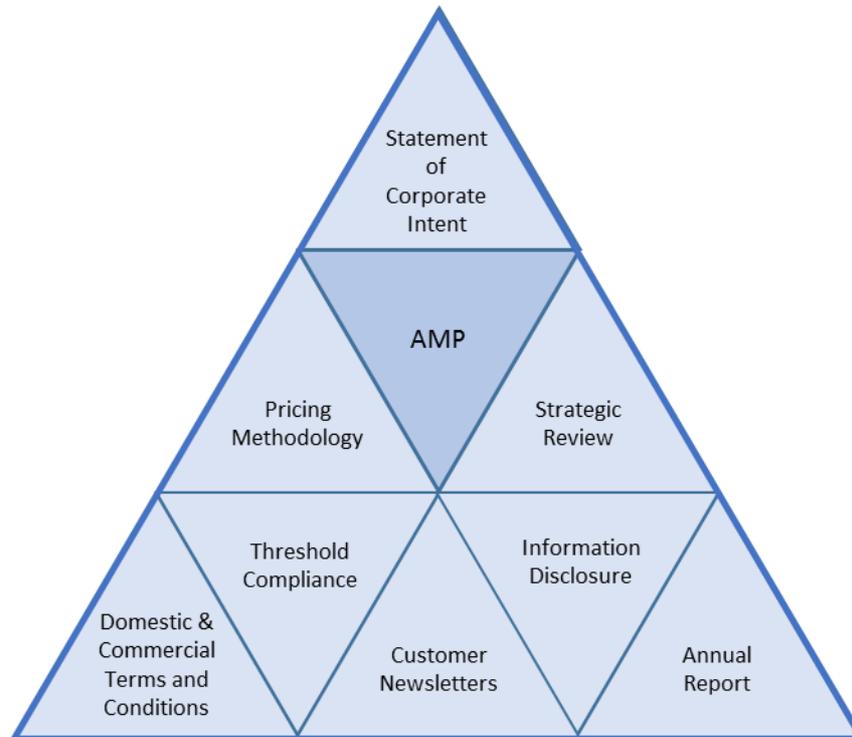


Figure 2.1: Relationship Pyramid of AMP

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

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

- Asset management including strategy development and implementation.
- Pricing structures that promote energy efficiency, the reduction of network energy demand and better asset utilisation.
- Customer consultation and promotion of demand side management.
- Demand side control systems and advanced metering.
- The investigation and promotion of commercially prudent network alternatives.
- Asset renewal and hazard control programme management compliant with ISO 31000, including Safety Management System (SMS) compliant with the Health and Safety at Work Act and Public Safety Management Systems (PSMS) strategies compliant with NZS7901:2008.
- Network analysis/automation and the learning needed to develop advanced systems.
- Innovation in all aspects of the business.

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

2.3 Key Planning Documents and Processes

Listed in Figure 2.2 are the documented plans that are produced as a result of the annual business planning process

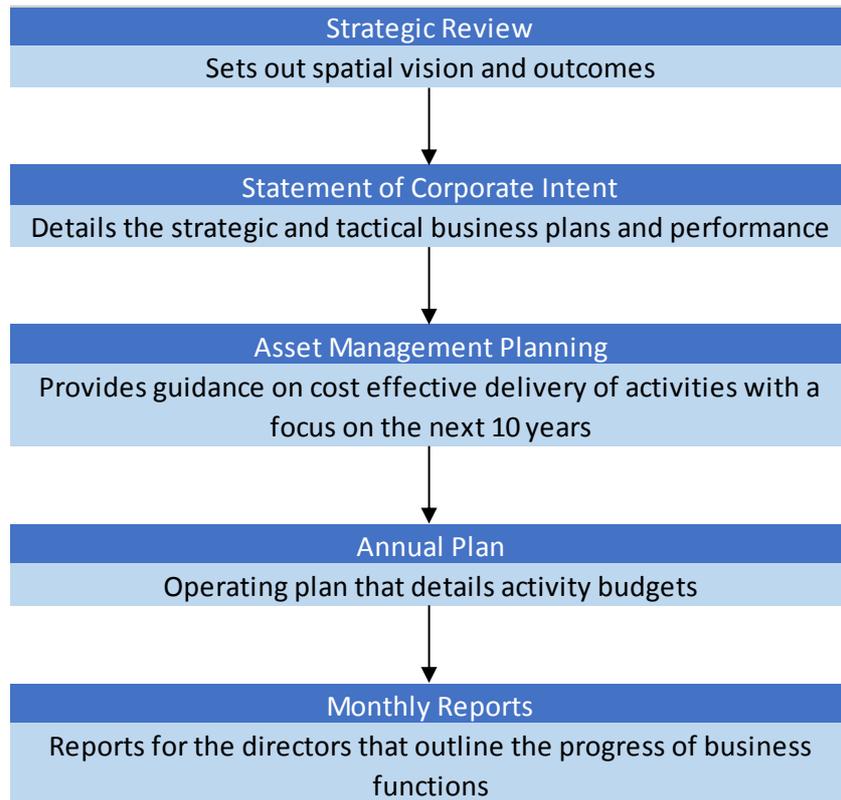


Figure 2.2: Documented Plans Produced as Outputs of the Annual Business Planning Process

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

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

2.4 The Planning Period

This Plan is approved by the Board of Directors; it covers the period 1st April 2016 through to 31st March 2026. The Plan is reviewed annually, although there is now provision under Information Disclosure regulations to only produce an update document in specific years.

It needs to be acknowledged that the TLC network covers a large area with low population densities. There are no fast growing urban areas. The growth of the network in the planning period will be dominated by the primary processing industrial sector, farming, tourism, 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 for customer growth means that the difference between medium and long term forward predictions and actual will vary. Assets needed to support a customer's specific need can only be added when customer contractual details are confirmed.

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

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. Variation will come from levels of hazard and risk 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 $\pm 10\%$ for the next 10 years.
Quality of Supply	Estimates out to 2026 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 high, i.e. within $\pm 10\%$.
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 may occur should there be changes in business strategies or opportunities.
Operational Expenditure	
Routine and Corrective Maintenance and Inspection	Estimates are based on present activities and are known for next 5 years. Beyond this, various issues have not been detailed or studied at this time. 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. Some variation may occur where expenditure benefits are identified.
Service Interruptions and Emergencies	Expenditure will fluctuate, mostly dependent on the weather. Using historical data, estimates are based on average expectations and the assumption that comprehensive renewal and vegetation programmes will reduce fluctuations.
Vegetation Management	Estimates based on the effectiveness and limitations of past expenditure.
System Operation and Network Support	Estimates are based on present activities. Predictions reasonably accurate for the next 5 to 10 years.

Table 2. 1: Level of Detail and Expected Causes of Fluctuations in Estimates

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

2.5 Stakeholder Interests

In developing the Asset Management Plan, TLC has taken into account the interests of the following key groups outlined in Table 2.2 below.

STAKEHOLDER INTERESTS			
Stakeholder	Interests	How Interests are Identified	How Interests are Met
Shareholders	<ul style="list-style-type: none"> • Long term business sustainability and the strategies to achieve this. • Public relations are improving and complaints are reducing. • A reasonable standard of service being given to customers. • The price to customers being equivalent to that charged in other rural areas. • A network that meets acceptable industry hazard related risk standard as well as environmental and efficiency expectations. • The development of innovative solutions focused on reducing hazards, maintaining reliability and promoting customer choice - including demand side management - while saving costs. • An acceptable return being earned from the assets. • An acceptable cash return from the network, as cash return is the only way that customers who are the beneficiaries of the trust can receive benefit from their ownership. (Customers leaving the area cannot receive cash for any capital growth they have funded while with TLC.) 	<ul style="list-style-type: none"> • The interests of TLC shareholders are identified through the Corporate Review process, director reviews and appointments, regular discussions, presentations and meetings. • TLC conducts stakeholder management surveys to benchmark against other similar businesses and assist in improving relationships. 	<ul style="list-style-type: none"> • Strategic and tactical planning. • Investment in public relations and demand side management. • Dividends and revenue aligned to Commerce Commission limits. • Regular meetings and communication with shareholders. • Adjustment of policies and pricing to be more aligned to customers' perceptions and expectations. • The requirement that any customer-driven development work returns 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. • Using performance targets. • Strong, but targeted, re-investment in renewals to provide a long-term hazard controlled and sustainable network. • Charging systems that give choice to customers. • This asset management plan and communication of the key parts and related strategies.

STAKEHOLDER INTERESTS			
Stakeholder	Interests	How Interests are Identified	How Interests are Met
Customers	<ul style="list-style-type: none"> Receiving a secure and reliable supply of known and agreed quality. Receiving timely information that enables them to know the service they can expect from the network so that they can plan accordingly. Receiving up to date information if an outage occurs on the network so that they can plan accordingly. Being charged a fair price, with information to justify that price. (Individually most want to pay the least amount possible whilst the present quality is either maintained or improved.) Long term, the lowest charges possible for present and slowly improving quality. Receiving information updates on what is being done to ensure the network infrastructure is hazard controlled and sustainable. Having choice to reduce charges by reducing demand/energy use and improving power factor. Having clear claim and compensation systems when TLC assets do not perform. Having several pricing options available. 	<ul style="list-style-type: none"> 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. It is planned to begin direct customers surveys to benchmark customer satisfaction against other similar businesses. 	<ul style="list-style-type: none"> A corporate culture based around keeping customers connected and delivering this service with unyielding pride in the organisation and be passionately focused on driving customer success in a culture of constant innovation, excitement, informality, team work, trust, hazard control and environmental focus Reliability targets that are as focused as possible. By performance targets, including the asset group based performance targets (and evaluating gaps in this performance), to ensure each customer is receiving the promised standard of service. Re-investment in renewals. Strong customer consultation and information commitment including mechanisms to communicate the key issues, impacts and strategies in this plan that are likely to affect them. Direct customer billing, including demand based charges for all customers. This signals demand, leading to fairer charging and better asset utilisation. Customer and tradesman education. Public meetings.

STAKEHOLDER INTERESTS			
Stakeholder	Interests	How Interests are Identified	How Interests are Met
Customers (continued)			<ul style="list-style-type: none"> • 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 customers. • 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.

STAKEHOLDER INTERESTS			
Stakeholder	Interests	How Interests are Identified	How Interests are Met
Employees	<ul style="list-style-type: none"> • Advance knowledge of work requirements so that they can plan their lives. • A network and working practices with acceptable hazard related risks so that they are not harmed. • Fair remuneration. • Enjoyable work. • Being part of an organisation with a positive culture. • Having a clear purpose for coming to work and “making a difference” for the benefit of customers and their personal development. • A safe working environment. 	<ul style="list-style-type: none"> • The interests of our employees are identified through direct discussion with them and their representatives. • TLC does not currently engage through an employee climate survey. 	<ul style="list-style-type: none"> • The high priority given to eliminating or mitigating hazards. • Adoption of SMS. • Advance planning of work. • The recognition that our staff have unique skills, associated with a rural network in a rugged environment. • Creating a positive work environment. • Communicating the long-term Asset Management Plan and Statement of Corporate Intent to them so they can understand company direction. • On-going development of innovative techniques and work practices. • Supporting personal development and training. • A continuous improvement asset management strategy driven by this plan.
Transpower	<ul style="list-style-type: none"> • 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. 	<ul style="list-style-type: none"> • Transpower’s interests are identified through communication and direct discussion. 	<ul style="list-style-type: none"> • Interests are recognised in the Plan by the sums programmed for expenditure due to anticipated growth in distributed generation and load. A significant proportion of this is to ensure the protection of the Transpower Grid.

STAKEHOLDER INTERESTS			
Stakeholder	Interests	How Interests are Identified	How Interests are Met
Contractors and Suppliers	<ul style="list-style-type: none"> • 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. 	<ul style="list-style-type: none"> • Contractors' interests are identified through direct discussion. 	<ul style="list-style-type: none"> • The high priority given to eliminating or mitigating hazards. • Advance 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.
Landowners	<ul style="list-style-type: none"> • 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. 	<ul style="list-style-type: none"> • 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. • Feedback from the customer communications and consultation processes. 	<ul style="list-style-type: none"> • Cost conflicts are managed by using cost reflective charge rates and polices.

STAKEHOLDER INTERESTS			
Stakeholder	Interests	How Interests are Identified	How Interests are Met
District Councils	<ul style="list-style-type: none"> • 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. 	<ul style="list-style-type: none"> • District Council interests are identified through direct discussion 	<ul style="list-style-type: none"> • Infrastructure requirements are by customer driven development work returning at least the cost of capital invested. • The Civil Defence requirement is met 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 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.
Regional Councils	<ul style="list-style-type: none"> • 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. 	<ul style="list-style-type: none"> • Regional Council interests are identified mostly by correspondence and written information. 	<ul style="list-style-type: none"> • The contact with regional councils is not extensive; however this Plan is used to communicate TLC's asset strategies and policies.

STAKEHOLDER INTERESTS			
Stakeholder	Interests	How Interests are Identified	How Interests are Met
Central Government	<ul style="list-style-type: none"> Central government interests include ensuring that a reliable and 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. 	<ul style="list-style-type: none"> Central government's interests are identified mostly by internet correspondence, written information, meeting with officials and legislation. 	<ul style="list-style-type: none"> 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 or its customer's needs.
Retailers	<ul style="list-style-type: none"> Retailers are interested in selling energy to customers in order to produce profits. They like to have simple to apply pricing options via automated billing systems. Retailers also want advanced metering systems that have a long term benefit of reducing their operating costs. 	<ul style="list-style-type: none"> Retailers' interests are identified through industry papers, communication and direct discussion. 	<ul style="list-style-type: none"> TLC has representatives on industry working groups associated with pricing and retailer interfaces. This Plan is used as the basis for communicating TLC's asset management strategies to these industry working groups.
Maori	<ul style="list-style-type: none"> Maori are interested in having supply available in their homes and Marae, which are sometimes located in very remote areas. Protection and understanding of cultural values and sites. 	<ul style="list-style-type: none"> Maori interests (such as protecting cultural values especially with long tenure Maori land) are identified through discussions with various groups. 	<ul style="list-style-type: none"> The Maori interests are accommodated in the Plan by the overriding objective of maintaining supply at the lowest possible cost whilst meeting quality expectations. The Plan also includes a commitment to use local labour as far as practicable to create income for people who may live in remote areas.

STAKEHOLDER INTERESTS			
Stakeholder	Interests	How Interests are Identified	How Interests are Met
Distributed Generation	<ul style="list-style-type: none"> • 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. 	<ul style="list-style-type: none"> • Distributed generation investor interests are identified by way of new connection applications and the issues associated with the continuing operations of existing plant. 	<ul style="list-style-type: none"> • Detailed information on existing larger connections and the implications of these. • Technical detail on the general implications of distributed generation connections. • A list of the conditions that must be fulfilled before connecting distributed generation equipment.

Table 2.2: Stakeholder Interests Identified and how they are addressed.

2.6 Differing Interests that are Common and Affect All Stakeholder Groups

2.6.1 Hazard Elimination/Minimisation

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

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

This leads to trade-offs between funding hazard elimination/minimisation work with other renewal and capital expenditure projects.

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 suitably qualified and experienced professionals.
- Audits by the Energy Safety Inspectors.
- Asset management policies that promote a sustainable network, including strategies and policies that take into account the lifecycle of assets and asset types.
- Feedback inter-relationship with the Safety Management System (SMS).
- Feedback and inter-relationship with the Public Safety Management System (PSMS).

2.6.2 Electricity (Continuance of Supply)

Most stakeholders want TLC to have the lowest charges possible. While there are many economically constrained customers, there are also highly valuable business interests for whom reliability and service is a key value driver.

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 lines were constructed using RERC funding. This equates to around 40%.

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 and are now in poor shape. Many of the rural lines were constructed by farmers, and there was little design detail. This has meant that significant numbers 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.

In 2009, TLC completed an exercise confirming the lengths of uneconomic lines in the Network. Lines were considered uneconomic if the load connected was less than 20 kVA per customer (ICP) and the customer density 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.

Some of these rural lines supply national infrastructure in the way of repeater sites. Figure 2.3 illustrates one such site about 10km North West of Taumarunui with approximately 14 repeaters covering all types of essential services.



Figure 2.3: Local Terrain 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, 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 primarily burn petrochemicals, 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. While the technology is evolving, 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 and reliability; 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 to different times of the day without substantially affecting their lifestyles. Controlling demand and not needing to upgrade (for example, SWER systems) will have a long term saving on TLC's pricing to rural areas.

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

2.6.3 Supply to Holiday Home Areas

There was a conflict between TLC shareholders requiring an adequate return on assets and belief by holiday homeowners that consumption based charges was a fair way of pricing. The revenue being received from holiday areas was well below what was necessary to produce a return. 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 acknowledged 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 however understand the separation when it is explained to them via the call centre or in consultation with customer advisors.

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

2.6.4 Retailers

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

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

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

The downside of direct billing and interfaces to customers is some cost to TLC. At the time billing was insourced to TLC, there were no retailers willing or able to manage demand billing. Over time retailers have become more focused on customers and the metering interfaces have settled into more mature industry relationships. This may enable economies of scale to be investigated in the future.

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

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

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

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

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

Most of the initial conflict surrounding demand based charging 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 continues to be managed by customer advice and communication with the affected customers.

There was also conflict caused by TLC not having network-wide advanced meters and, as such, charges were based on calculations. This conflict will be managed going forward by deployment of more advanced meters, due for completion in mid-2017.

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

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

The customers who have had the asset strategies and plans communicated to them are understanding and supportive.

2.6.6 Differing Customer Interests as Customers and Shareholders

As beneficiaries of the shareholders, customers in the Northern area 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 (DPP) to reset regulatory controls of electricity distribution businesses from 2012 to 2015. This document indicated that TLC's return was below the Commission's expectation. The DPP was further reset in 2015 and the output of this process determined that TLC's revenue was still about 7% below the Commerce Commission limits. Price adjustments will be a subject of debate with the stakeholders, along with which areas they should be targeted at. Strategically it has been decided that by 2020 TLC revenue will be tracking as closely as possible to the Commerce Commission limits.

2.6.7 Differences between the Requirements of Legislation

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, the Commerce Act and the Health and Safety at Work Act.

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

Given the rural nature of the TLC network these trade-offs 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 trade-off.

The asset management policies, strategies and plans TLC has in place are focussed on managing all of the trade-offs through asset lifecycles. Once legislation is passed, TLC's task is to understand the rules and then set about developing actions for compliance aligned to providing the best solutions for our stakeholders and asset management policies, strategies and plans.

2.7 Accountabilities and Responsibilities for Asset Management

2.7.1 Governance

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

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

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

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

Key system performance indicators are reported on a monthly basis. These elements form important parts of feedback on asset management plan performance. The Directors approve variations caused by unpredicted work and customer demand upwards of \$100,000, and \$500,000 for budgeted capital works.

2.7.2 Executive Level

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

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

2.7.3 Asset Management and Engineering

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

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

Vegetation work is controlled and issued by Operations to tree contractors who have the necessary quality and hazard control systems in place. Frequently used 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 fault remedial activities to the service provider. External drafting and engineering consultants are used when workloads are high. Specialist data, valuation and safety consultants are also engaged to assist as required.

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

The structure of the Asset Management Group within the corporate structure is illustrated in Figure 2.4.

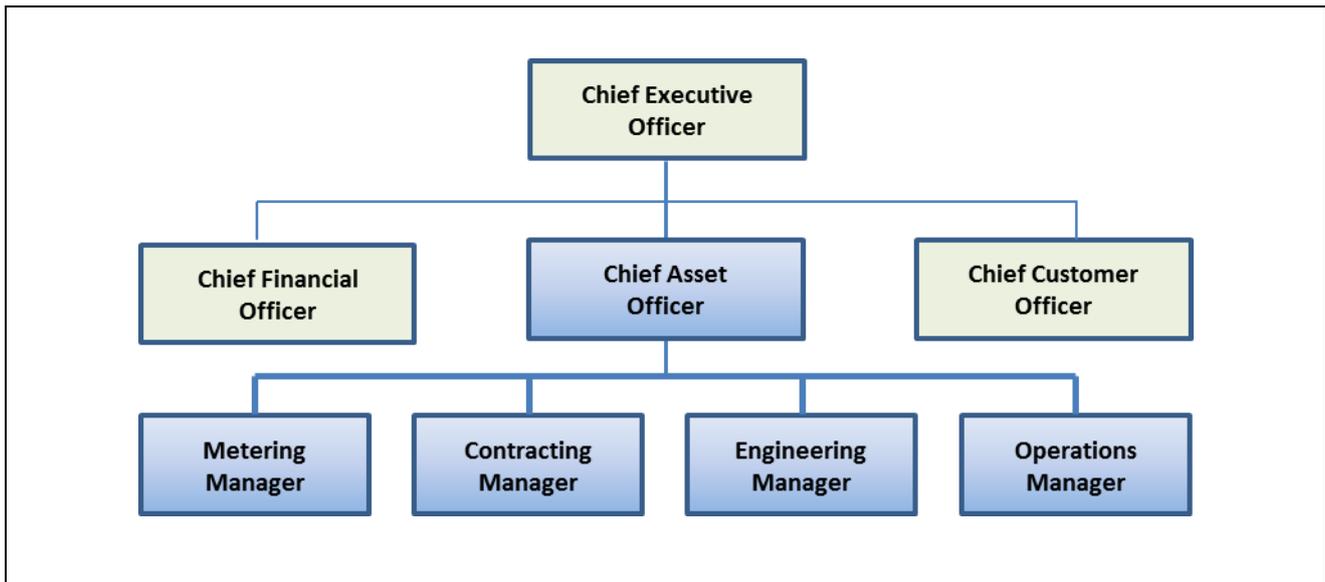


Figure 2.4: Corporate Integration of the Asset Management Group

2.7.4 Field Operation Level

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

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

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

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

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

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

2.8.1 Systems Overview

TLC operates 3 core IT platforms: a Financial System (Navision); Billing System (Gentrack); and an Asset Data System (BASIX). All have SQL server databases and data automatically exchanged between systems. Figure 2.5 illustrates, in a very simplified format, the overall system layout and interaction.

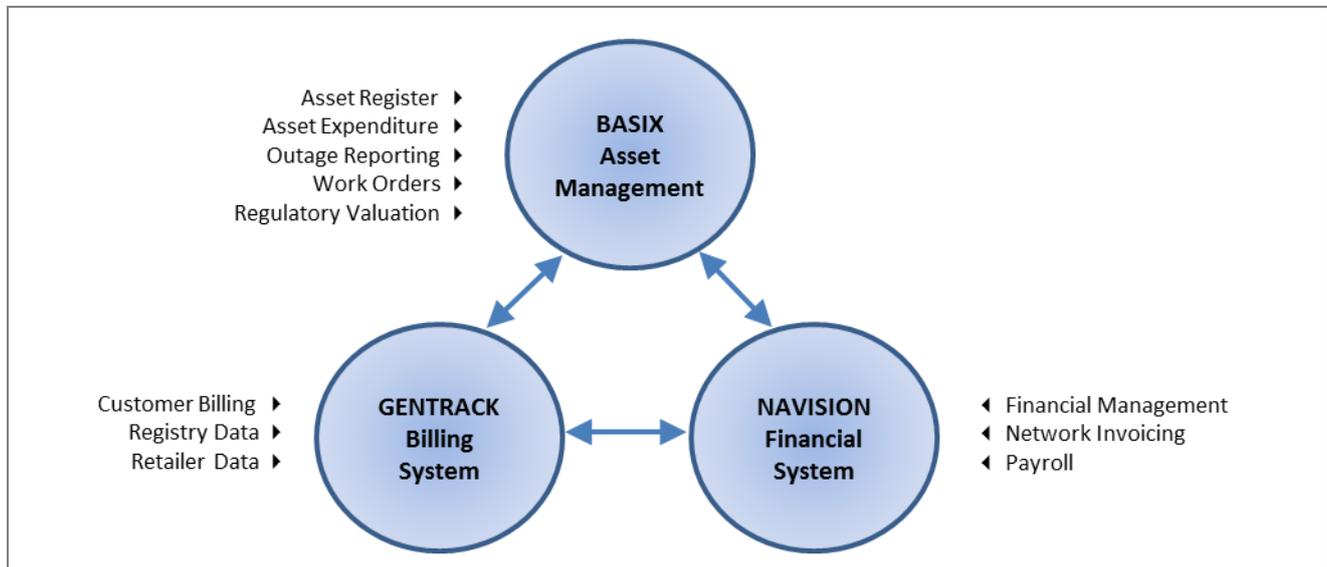


Figure 2.5: Overview of System Layout and Interaction

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

The financial system is based on a Navision software package over an SQL server database. In addition to processing and providing financial information for the various companies associated with TLC, it includes detailed job costing packages. The financial system has been significantly upgraded during 2015.

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

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

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

Currently TLC has an ESRI GIS system (mapping package) that has been operating in a “stand-alone” mode for the last few years. A key future 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.

Backup copies of all TLC's information systems and databases are kept off site to mitigate losses should TLC not be able to operate out of their normal business premises. In the event of a major disaster, this would simplify the relocation and setup of replacement systems and databases.

2.8.2 Asset Data Accuracy

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

It is expected that verification of assets will continue until the entire network is inspected in detail as part of the 15 year renewal programme and other data collection projects.

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

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

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

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

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

2.8.3 Asset Management Information System and Data Structures

The BASIX system consists of various modules including:

- Asset Register
- Works Management
- Outage and Reliability
- Reporting
- Annual Planning

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

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 2.6 shows a typical screen shot of held pole data.

The screenshot displays the BASIX software interface. On the left is a navigation tree under 'Asset Register' with categories like Network, Lines, Pole Sites, Crossarms, Spans, Pillars, Cables Underground, Installations, Zone Sub Stations, Transformers, Switchgear, Protection & Control, Network Model, Property, Batteries, SCADA & Radio, All Assets, Unallocated Assets, Valuations, and Tests. The main area shows 'Pole Sites - 1061287 - RANGITOTO/81/52' with tabs for Master Details, Attributes, Inspections, Financial / ODV, and Regulatory Valuations. The Master Details tab is active, showing fields for Site No (1061287), Local ID (1061287), Description (RANGITOTO/81/52), Asset ID (A0SGTO), Asset Type (Physical), Asset Owner (The Lines Company), Gxp (Hangatiki), Condition Status (Good Condition), Zone Substation (Waite Zone Sub Station), Service Status (In Service), Feeder (Rangitoto), Asset Group (Rangitoto106-04), Line Segment (106SEG192-246), and Council (Waitema). An 'Asset Notes' field contains 'NO LINK NUMBER ON POLE'. An 'Inspection Notes' field contains 'AUDIT 04/12/09 CHANGE POLE P43 CONC 2m 4X3 D.A PINS INS (4) 2m 4X3 D.A S/STRAIN-POLYS (2)'. A photo of a utility pole is displayed on the right. At the bottom, a table shows linked photos:

Classification	Link ID	File Status	Description	Version	URL	File Source	Received
Photos	A00EB6F3	Current	Label			\\Asset\photos\POLE PHOTOS\Wort...	
	B9438AB4	Current	Pole			\\Asset\photos\POLE PHOTOS\W...	
	DF105A2F	Current	Xarm			\\Asset\photos\POLE PHOTOS\Wort...	
	3						

Figure 2.6: Example of BASIX Pole Data Showing Link to Attached Photo

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

Photographs of each pole are taken and used for:

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

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

The BASIX system also includes a reliability calculator that is attached to the asset data. All data in the BASIX database is connected together in single line diagram format. A parent-child connection has been established between assets. Data from the billing system gives accurate details of customers connected to each transformer. The reliability data is entered regularly and results are calculated. All historic outage data has been loaded into the BASIX system and is used for calculating reliability and previous historic data needs. The inclusion of the outage calculator in the Basix system continues to enhance the quality of outage data.

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.

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

2.8.4 Processes for Managing Routine Asset Inspection and Network Maintenance

As part of the preparation of the annual Asset Management Plan review, TLC is continuing to add more detail to its long-term renewal and maintenance plans.

The maintenance plan details activities for the following asset classes:

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

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

The long-term renewal and maintenance plan is on a year-by-year and activity-by-activity basis. 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 or other issues, which mostly feed into the 1 to 5 year forecast period.

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

2.8.4.1 Overhead Lines: Routine Inspection and Network Maintenance

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 assessed for a 15 year period with a reasonable degree of accuracy and this rotation produces manageable work outputs.

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

The data gathered during inspections includes:

- The condition of overhead line hardware
- Line clearances
- Pole condition
- 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)
- Pole date stamp or 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 \$50 to \$60 per km. Ground patrols cost 3 to 4 times this amount in the rugged rural areas of the TLC network.

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

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

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

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

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. For larger faults, field staff often seek advice on the repair from the Asset and Engineering group. This usually involves lines inspectors or technical staff going to site and specifying repair requirements. Work orders against the faulty assets are then issued for their repair.

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

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

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

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

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

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

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

2.8.4.2 Ground Mounted Transformers: Routine Inspection and Network Maintenance

Planned Work

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

The ground mounted equipment site information including type, capacity, current loading and condition is recorded and factored into 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 pertaining to capacity and condition, including full details on the types of locks and other fasteners that secure the units from unauthorised access, is also collected. This detailed information is stored in the BASIX system. Each site is photographed during the five yearly inspections. These photographs are currently accessed from the BASIX system and will be linked to the GIS system in the future. Further integration with SMS information is also being developed.

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

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

Unplanned Work

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

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

2.8.4.3 Zone Substations

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

These systems include the following.

Planned Work

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.

Unplanned Work

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

2.8.4.4 Protection and Switchgear

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

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

2.8.4.5 Overall Zone Substation

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

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

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

2.8.4.6 Low Voltage Overhead Systems

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

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

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

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

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

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

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

2.8.4.7 Distribution Transformers

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

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

2.8.4.8 Other Equipment

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

2.8.4.9 SCADA and Communication Equipment

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

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

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

2.8.4.10 Vegetation Management

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 33kV lines in the network. These patrols also identify other line hazards. Approximately 33% of the network is flown annually in a helicopter.

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

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

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

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

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

2.8.4.11 Pillar Boxes

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

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

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

2.8.5 Processes for Planning and Implementation of Network Development Projects

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

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

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

2.8.5.1 Customer Driven and System Growth Projects

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 viable 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 may be different to the point of supply. Point of connection is where a line joins the Network; 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 implication of ownership such as compliance with the Electricity (Safety) Regulations 2010 is pointed out when this option is chosen.

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

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

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

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

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

2.8.5.2 New Connections and Distributed Generation Projects

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 engaged to handle larger applications. These resources have to be funded by the generation investor.

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

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

2.8.5.3 Other Projects

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

2.8.6 Processes for All Projects

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

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

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

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

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

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

Processes to maintain competitive market prices are used by contracting out to approved suppliers new construction and replacement work. Prices are compared with the internal contractor to ensure the internal contractor is at least as competitive as a quality and safe external provider.

2.9 Future Asset System Integration and Advanced Network Vision

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

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

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

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

Similarly, the present SCADA, billing and asset management packages will all have a place in the asset management processes for advanced network schemes throughout the planning period. Self-healing networks have been a feature of high density urban areas for some time. As the cost of remote controlled switches reduces, communications costs reduce and software to safely manage automation matures, there is the potential to reduce customer outages using automation. No rural networks in New Zealand or Australia have introduced automated processes using software, however centralised control of switches has improved reliability across the industry. There is more potential for improving reliability in the TLC network over time using automation.

A major focus in the future is to develop a plan to bring these technologies together in an innovative way to benefit customers. This may include inspection data entered at source and the integration of GIS with other elements of the system.

2.10 All Significant Assumptions

Growth Funding

Assumption:	It has been assumed the cost of developing the network for growth and customer connections will be financed by the additional income from the increased customer demand.
Principle Sources of Information:	<p>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.</p> <p>The principal sources of information for developing this assumption are:</p> <ul style="list-style-type: none"> • Network models that calculate network capacity and the impacts of growth on the connection chain. • The cost of the necessary network development. • Bankable investment criteria.
Potential Effects of the Uncertainty:	If growth as assumed does not go ahead, the expenditure for customer connections and growth as detailed in the long term plan would reduce. Similarly, if growth increase is greater than estimates, expenditure will be greater.

Continuance of supply

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

Distributed Generation

Assumption:	It is taken distributed generation connections will continue to be developed and that the regulators will resolve rules on complex issues associated with the likes of grid exit power factor. It is also assumed that existing load taking customers will not be penalised in a way that cross subsidises the connection of generation.
Principle Sources of Information:	<ul style="list-style-type: none"> • Government policy statements • Electricity Governance Rules • Transmission connection charges • Various papers produced by officials • Network studies showing the effects of distributed generation
Potential Effects of the Uncertainty:	<p>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.</p> <p>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.</p>

Demand side management and peak control

Assumption:	That the industry will increasingly recognise the importance of demand side management and peak control. A consequence of these will be recognition and support for TLC's demand based charging system by regulators.
Principle Sources of Information:	<ul style="list-style-type: none"> • This assumption is based on the fact that power systems have to be designed for peak capacity. • Network models that calculate power factor • Data analysis of field test results
Potential Effects of the Uncertainty:	<p>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.</p> <p>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.</p> <p>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.</p>

Economic activity

Assumption:	It has been assumed that economic activity based on primary production and processing will continue to develop. It is assumed that when land is converted to dairying, present day technologies will be incorporated into new milking sheds. These tend to be bigger and more automated than older installations. The forward land use assumption does not include large scale development of irrigation.
Principle Sources of Information:	<p>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.</p> <p>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.</p> <p>The principal sources of information for developing these assumptions are:</p> <ul style="list-style-type: none"> • CPI • Land information • Subdivision development: sizes and numbers • Distribution capacity and numbers • New connection numbers • New housing areas • Areas that are static, or depopulating • Industrial customer feedback and comment • Previous energy and demand growth figures

- Primary produce pricing and trends in these
- Predictions on primary produce long term forecasts
- Predictions on the leisure markets

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

Reliability and quality

Assumption: It has been assumed that customers will want reliability and quality standards equivalent to or better than present to support lifestyle tools such as electronic appliances, computers and media devices.

Principle Sources of Information: The reliability and quality assumption is based on the understanding that customers want a continual improvement in reliability and quality. Specifically, this assumption is based on the number of complaints that occur when the power goes off and/or appliances will not go or are destroyed.

The principal sources of information for developing these assumptions are via:

- Customer feedback
- Complaints
- Customer meetings
- Customer surveys
- Customer representatives
- Other community input

Potential Effects of the Uncertainty: If stakeholders do not want an improvement of reliability then reliability expenditure could be reduced.

Hazards

Assumption: It has been assumed that stakeholders want a network that does not cause an unacceptable level of hazard to the general public, staff, or animals. It is assumed that there will be no stepped inputs to significantly alter this plan.

Principle Sources of Information: The hazard assumption is based on people not wanting to get shocked or electrocuted and, if they do, the legal and emotional liabilities that stakeholders will face if this is caused by lack of renewal programmes, maintenance, and general failure to operate a network with acceptable levels of hazards. It is also assumed that the organisation complies with Electrical (Safety) Regulations. The assumption is also based on the liabilities associated with not taking all practicable steps to eliminate, isolate or minimise hazards.

Potential Effects of the Uncertainty: If stakeholders decide not to have a programme with projects that eliminate/minimise hazards, then the forward development expenditure would reduce by approximately \$1million p.a.
The present programme eliminates or minimises the worst of the hazards by about 2019. The annual spend would be reduced in the medium term if the programme were lengthened.

Pricing

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

Inflation

Assumption:	It has been assumed that inflation will continue through the planning period.
Principle Sources of Information:	The rate of inflation for cost increases has been based on recent CPI figures. The assumption is based on published CPI data.
Potential Effects of the Uncertainty:	An inflation factor of 1.77% to 2.15% has been built into expenditure forecasts for years 2 to 4. Years 5 onwards are set at 2.2%. The inflated figures hold most relevance in the short term (2-3 years). The current economy is gaining but slowly and it is likely this will continue to be the case short term.

Performance Measures

Assumption:	It has been assumed that stakeholders want development of performance measures that align with customer expectations.
Principle Sources of Information:	<ul style="list-style-type: none"> • Terms and Conditions of Supply • The connection code/standard • Customer surveys • Customer complaints and feedback • Commerce Commission performance measures • Measures that have been aligned and developed over time with the objective of making information more understandable to customers.
Potential Effects of the Uncertainty:	The performance measures are currently aligned with customer simplification needs, the asset management system and Commerce Commission criteria. Variation from these will lead to periods of uncertainty in terms of performance measurements. It will take time to set up systems to measure new indices.

Customers' Ability to Pay

Assumption:	It has been assumed that customers in the King Country are not affluent and have limited ability to pay increasing line and energy charges.
Principle Sources of Information:	The principal source of information suggesting customers have limited ability to pay includes things such as: <ul style="list-style-type: none"> • School decile ratings • Government "wealth information" associated with electorates • Customers and stakeholders feedback
Potential Effects of the Uncertainty:	There is little uncertainty associated with the limited ability of TLC's customers to pay ever increasing charges. The potential effect of this uncertainty/certainty will be an increased pressure for TLC to carry out its renewal work at the lowest possible cost.

Following the Asset Management Plan

Considerations:	If some sort of plan is not followed for maintenance, renewal and development, then the chance of adverse events substantially increases. The principal sources of information from which they have been derived include: <ul style="list-style-type: none"> • Legislation • Engineering industry experience • Industry papers and event information • PAS55 asset management standard
Likelihood Consequence Control:	This plan details the various policies and strategies that are in place to control the impact of adverse events. Adverse events have a high level of uncertainty. i.e. earthquakes, storms, floods, volcanic eruptions etc. Any of these events has a level of likelihood that flows through into this Plan and other disclosed information. The other variables include economic prosperity in the rural and tourism areas and the future regulatory climate.

Commerce Commission Allowed Revenue

Assumption:	It has been assumed that the current regulatory determination will remain until 2019 and that further determinations will allow TLC to have adequate funds to replace an aging network.
Principle Sources of Information:	The principle source of information is the published determination and associated documents.
Potential Effects of the Uncertainty:	There is little uncertainty associated with the Commerce Commission decision. However the current determination used a maximum capital increase of 20%. This was less than required at TLC due to aging assets. There is uncertainty how the next determination will approach maintenance and capital replacement spend.

Adequate Field Resources

Assumption:	It has been assumed that there will be enough skilled field resources to complete the work required on the network.
Principle Sources of Information:	The principle source of information is Labour Force immigration Long Term allowed occupations include Electricity Supply workforce.
Potential Effects of the Uncertainty:	While there is generally currently adequate contracting resources, parts of the TLC network are a long way from the home bases of all the contractors. This places added pressure on resources and could lead to a premium being required to attract the skilled resources required.

Legal Frameworks Continue to Allow Progressive Hazard minimisation

Assumption:	It has been assumed that the legal framework will allow progressive minimization and removal of hazards.
Principle Sources of Information:	The principle source of information is Health and Safety at Work Act.
Potential Effects of the Uncertainty:	If progressive minimisation of hazards was not possible over time, there would be a large one off cost, as well as a shortage of resources and diversion from higher value customer work.

Section 3

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3. Assets Covered

3.1 High Level Description of the Distribution Area

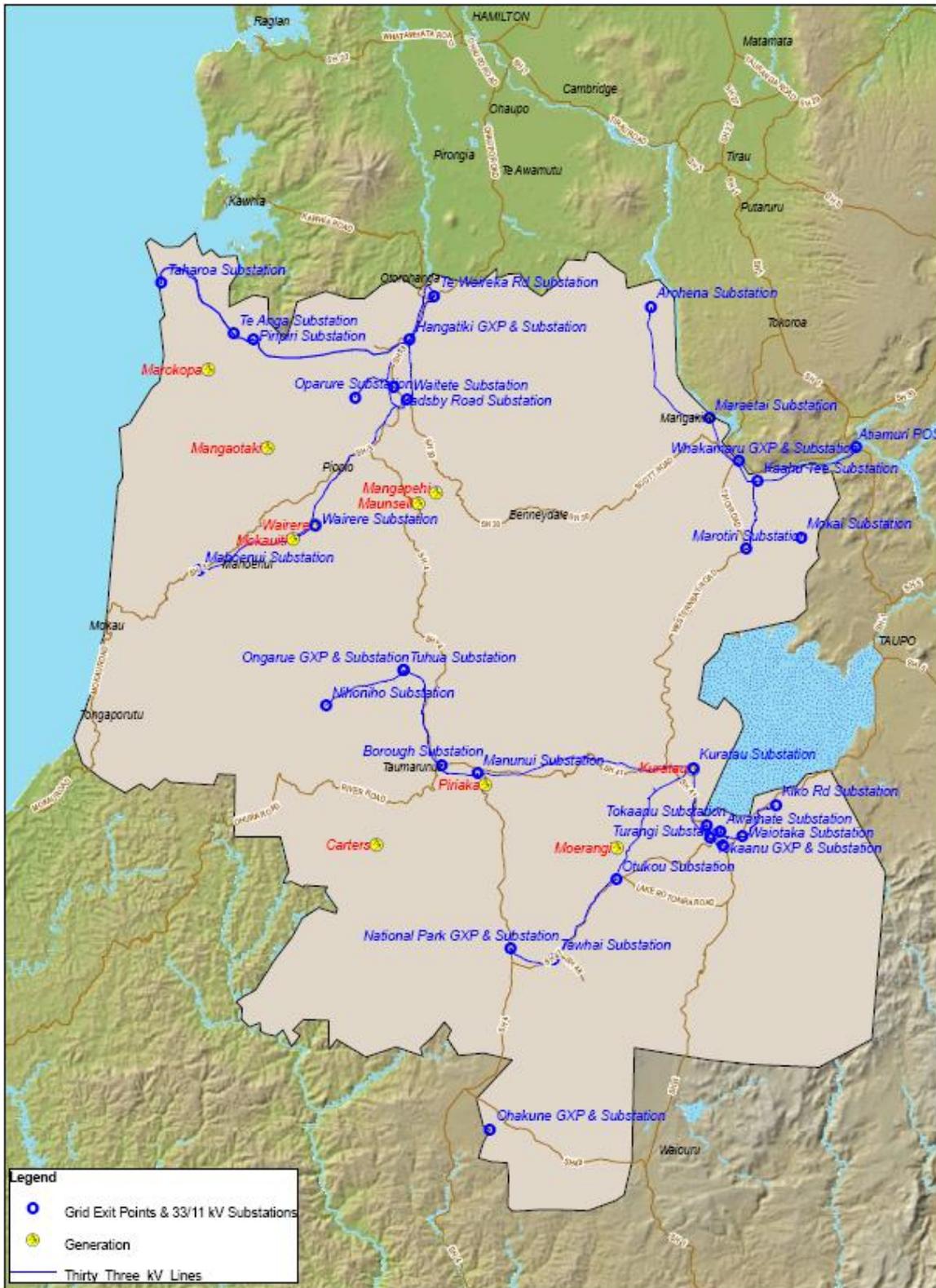


Figure 3.1: Distribution Area Covered by TLC Network showing Grid Exit Points, Generation and Subtransmission Network

3.1.1 Distribution Area Covered

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

The coastal western edge of the network starts on the south side of the Kawhia harbour and extends south to Mt Messenger. Heading south and east, the network includes Mt Ruapehu and the two large ski fields (Whakapapa and Turoa), Ohakune and most of the area around Lake Taupo excluding Kinloch and the town of Taupo. North from Lake Taupo, the area predominately follows the western bank of the Waikato River to Arohena, with a recent expansion north of Whakamaru straddling the river, then west back to the southern side of the Kawhia harbour. The area covers 13,729 km². Collectively (overhead and underground), the network length is 4,368km.

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:

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

3.1.3 Comparison with Other Distribution Businesses

Figure 3.2 below shows that The Lines Company (EDB21) is 20th out of 29 companies in terms of the number of customers (ICPs) and yet 12th out of 29 in terms of the length of network. TLC regulatory asset base valuation is 15th out of 29 showing an aging, but not particularly old, network. This illustrates the challenge with a long network and relatively few customers to fund necessary replacement expenditure.

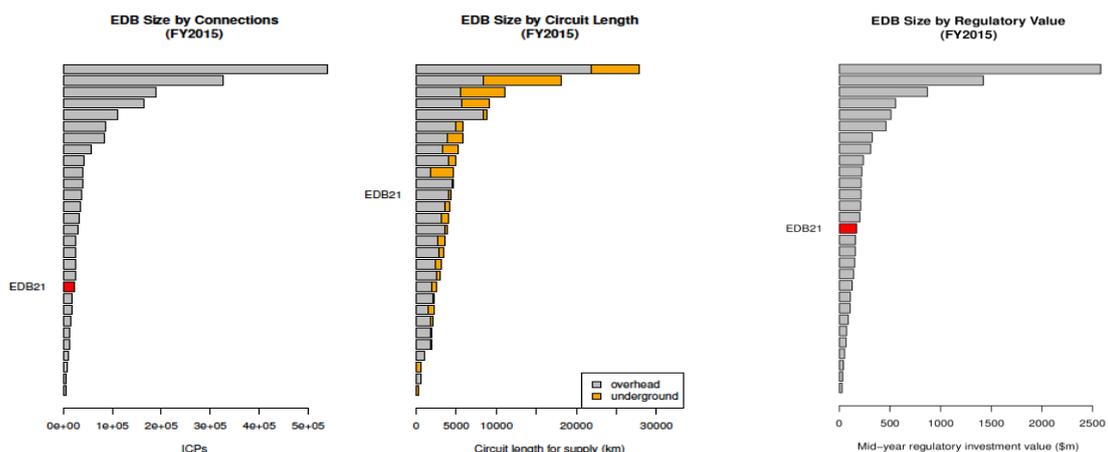


Figure 3.2: Comparison with Other Distribution Businesses

3.1.4 Demarcation and Ownership

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

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

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

Company policy is to regard any line that supplies a property owned by a single entity as private regardless of voltage. The private lines start at the Point of Connection to the network and then travel to individual properties. The 'Point of Connection' may or may not be the 'Point of Supply'. The 'Point of Supply' is defined in legislation and, in most cases, is the point where a line crosses the boundary to a property. If these lines were included in the assets owned by TLC, the likely line length increase would be a further 17% or approximately 730km.

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

3.1.5 Large Load Customers and the impact on network operations

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

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

3.1.5.1 Large load customers: description, impact and management

Iron Sands Extraction

Description:	Iron sands processing and ship loading at Taharoa
Impact on TLC Network:	<p>The plant has a steady mining load of about 4MW that increases to 15MW forecasted at interval of 2 to 3 weeks during ship loadings over a four day period. It is during these periods that the Hanganiki grid exit system peak loads occur.</p> <p>The amount of dedicated asset, including the Taharoa zone substation built on the West coast iron sand beach, means maintenance and renewal requirements for the site are high. The income received from this business, the size of peaks and ensuring the assets operate reliably have significant impact on network operations. Also, the plant has an impact on system losses.</p> <p>The customers' commitment to increase the quantity of bulk carrier shipments means that there will be a re-investment into the site over the next two years. The projected site load is expected to be in excess of 24MW from the end of 2016.</p>

Asset Management Priorities:	<p>The iron sand extraction process involves pumping product in undersea pipelines to about 3.5 km off shore onto large ships. Supply reliability is essential and work has been taking place to improve this.</p> <p>The economic downturn stalled plans for reinvestment at the site, however the plant has recently indicated that it is willing to fund reinvestment as a consequence of forward customer supply contracts as the NZ Steel owners look to expand production. The substation is in poor condition, and the need to eliminate/minimise hazards and other impacts of the Iron Sand's operation has been considered in this Asset Management Plan.</p>
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Ski Fields

Description:	Whakapapa and Turoa ski fields at Mt Ruapehu. Operators of chairlifts, ski field facilities and snow making equipment.
Impact on TLC Network:	An additional 3.5MW (approx.) of winter peak load is added to the TLC network. The installations are in extreme, very sensitive environments that require constant maintenance and renewal work. The owner and operator of the ski field are progressively investing in development of the ski field.
Asset Management Priorities:	<p>Both ski fields have some hazard related risk sites, which the operators are aware of. Most have been addressed with the installation of significant amounts of appropriately rated switchgear as part of a hazard minimisation/elimination program. Reliability to the Ski Fields has improved as a by-product. Included in this asset management plan are estimates for addressing the remaining hazards on both of the ski field sites.</p> <p>The ski fields operate in a World Heritage Park and TLC has developed a strong working relationship with DOC.</p> <p>TLC is also working with ski field owners to minimise peak-based charges by operating on-field generation into the network. The ski field and related accommodation use affect National Park and Ohakune grid exit peak loads. These loads are included in asset management planning.</p>

Corrections Department

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

Limestone Extraction and Processing

Description:	Six plants at various locations in the Te Kuiti district.
Impact on TLC Network:	The plants have a combined load of about 8 MVA. Operating loads tend to be seasonal and dependent on orders. Connected plant consists mainly of large motors that tend to reduce network power factor.
Asset Management Priorities:	<p>Owners of a number of these plants have concerns about voltage sags and reliability, which have led to a change in asset design approaches. Specifically, TLC is planning for smaller localised zone substations to fulfil these customers' needs.</p> <p>A number of the plants have hazards associated with the transformer enclosures and switchgear they own. Some have proposals to eliminate/minimise these hazards and issues.</p> <p>The peak lime processor loadings coincide in late summer. The timing of these loadings, coincident with increasing demand at the Iron Sands site, is 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.</p>

Meat Processors

Description:	Two plants on the Te Kuiti urban boundary and a third rural plant at the end of two, 40km long, 11kV feeders.
Impact on TLC Network:	<p>The 3 plants have a combined load of about 5 MVA.</p> <p>Plants on town boundaries are connected to 11kV feeders. Reclosers are located on these feeders just beyond the plant Point of Connection, with the objective of maintaining the supply to the plants by isolating the sections of rural line should a fault occur beyond the plant. These plants are sensitive to switching surges and early discussions were held to provide the plants with dedicated 33/11kV zone substations to reduce voltage sag.</p> <p>The rural plant at the end of two long 11kV 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.</p>
Asset Management Priorities:	<p>TLC is also working with Meat processor owners to minimise peak-based charges.</p> <p>Due to the impact of the load of the Crusader Meats plant TLC is looking at options for smaller localised zone substations to fulfil these customers' needs.</p>

Timber Processors

Description:	Two plants are on the Te Kuiti urban boundary. A third plant is located at Tangiwai and other smaller plants at Otorohanga.
Impact on TLC Network:	Two Te Kuiti plants have a combined load of about 3 MVA. The plants are connected to the 11kV network and are sensitive to feeder faults, auto recloses, and surges beyond the connection points. The Tangiwai plant is supplied from Tangiwai GXP. This plant only connected to the TLC network when the Tangiwai GXP is taken out of service for maintenance purposes. This is usually done during low load times.
Asset Management Priorities:	The improved reliability of the network in recent years has aided significantly for these operations. Even so, the owners at these plants are watchful for concerns with voltage. As demand patterns change, TLC has planned for smaller localised zone substations to fulfil these customers' needs.

Mokai Energy Park: Milk Plant: Glasshouses

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

3.1.6 Generation Customers and the impact on network operations

3.1.6.1 Distributed generation

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

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

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

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

ONGARUE GXP LOAD SUPPORT			HANGATI KI GXP LOAD SUPPORT		
Machine/Location	Nameplate size (kW)	Notes	Machine/Location	Nameplate size (kW)	Notes
Kuratau 1	3000	1	Wairere 4	3000	2
Kuratau 2	3000	1	Wairere 5	1190	2
Piriaka 1	1000	1	Mokauiti 1	1000	2
Piriaka 2	250	1	Mokauiti 2	600	2
Piriaka 3	250	1	Mangapehi 1	1500	2
			Mangapehi 2	1500	2
			Speedies Road	2200	3

Table 3.1: Generation ≥ 1 MW

Notes:

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

3.1.6.2 Distributed Generation \geq 1 MW

Mokauiti Energy Retailer Site

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

Kuratau Energy Retailer Site

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

Piriaka Energy Retailer Site

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

Wairere Falls Energy Retailer Site

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

Speedies Road, Te Anga

Description:	2.2 MW supporting Hangatiki. The single, synchronous plant is a subsidiary of TLC and Investor owned.
Impact on TLC Network:	The plant increases network voltages that have to be managed and causes a reduction in the Hangatiki grid exit power factor.
Asset Management Priorities:	Modify the current SCADA program so that real time data can be made available for network analysis on Hangatiki GXP. Currently the system records instantaneous KW data at half hourly periods.

Mangapehi

Description:	3 MW supporting Hangatiki GXP. The plant is a wholly owned subsidiary of TLC.
Impact on TLC Network:	<p>The generation is 'run of the river' and there is growing industrial load in the area.</p> <p>When water is available, regulators have to be used in reverse to reduce generation output voltage</p> <p>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.</p> <p>The plant increases network voltages and causes a reduction in the Hangatiki grid exit power factor.</p>
Asset Management Priorities:	Tuning of regulator, protection settings and adjustment of about 20 to 30 local transformer tap settings.

3.1.7 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.

3.1.7.1 Hangatiki area (north western region)

Regional Activities Affecting Load

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

Resulting Load Characteristics

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

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

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

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

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

Regional Activities Affecting Load

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

Resulting Load Characteristics

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

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

Regional Activities Affecting Load

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

Resulting Load Characteristics

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

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

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

3.1.7.4 Ohakune region

Regional Activities Affecting Load

- Ski season
- Carrot processing
- Increasing dairying load

Resulting Load Characteristics

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

3.2 A Description of Network Configuration

3.2.1 Identification of Bulk Electricity Supply Points

3.2.1.1 Arapuni to Bunnythorpe 110kV system

Figure 3.3 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.)

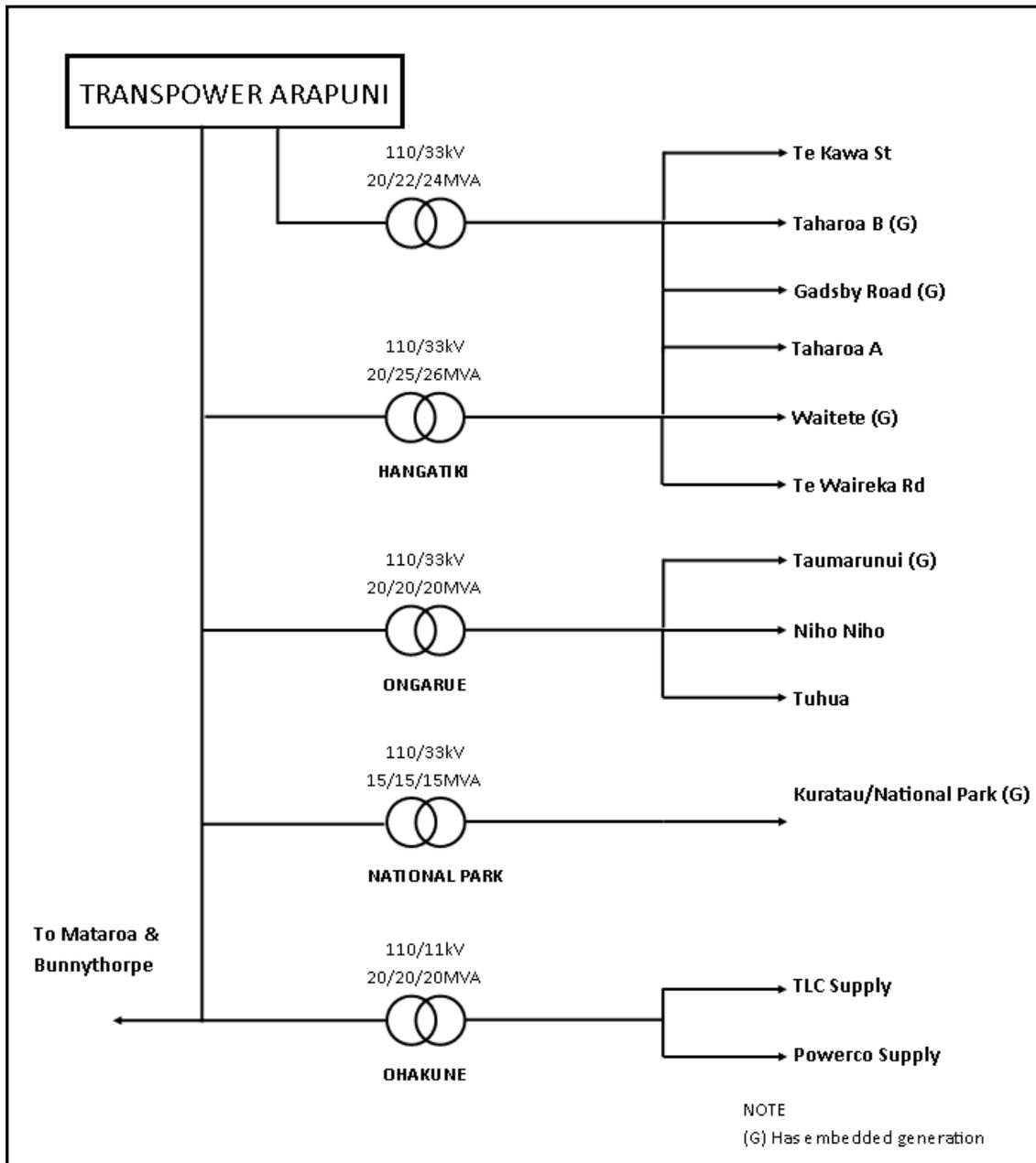


Figure 3.3: Simplified single-line diagram of the Hangatiki, Ongarue, National Park and Ohakune Grid Exit Points

Note: Transformer Ratings shown are Maximum Continuous/Summer/Winter (e.g. 10/10/10MVA). Both Ohakune and National Park have regulated transformer supply. The tee into Hangatiki from the circuit going south is about 13km from the substation.

3.2.1.2 Tokaanu

Figure 3.4 illustrates the arrangement at Tokaanu whereby TLC takes energy from Transpower via two 220/33kV transformers. These transformers are unregulated.

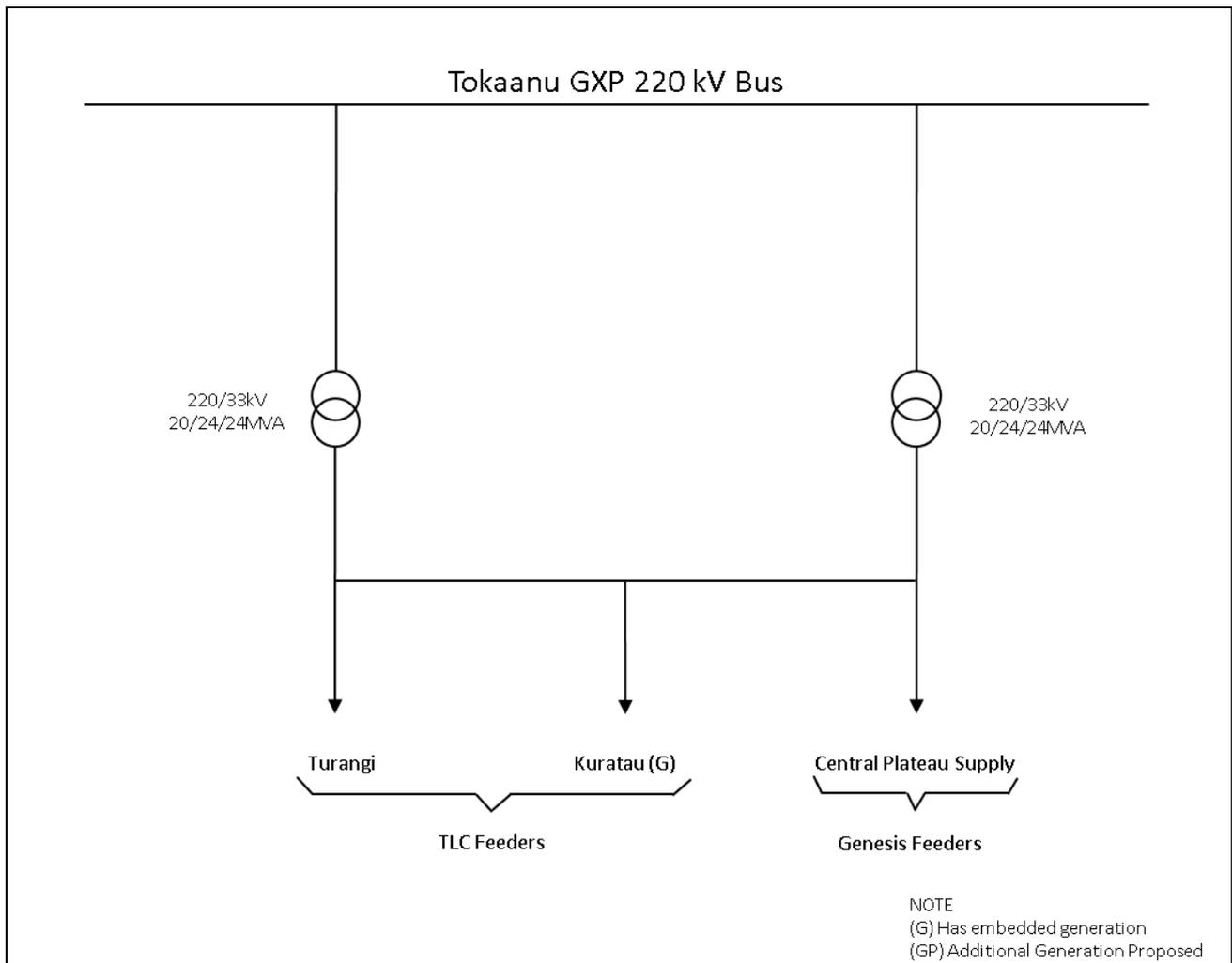


Figure 3.4: Tokaanu Connection Detail

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

3.2.1.3 Whakamaru and Atiamuri

Figure 3.5 illustrates the arrangement at Whakamaru where energy comes directly from either the Mokai investor owned geothermal station or Mighty River Power (MRP) G4 generator.

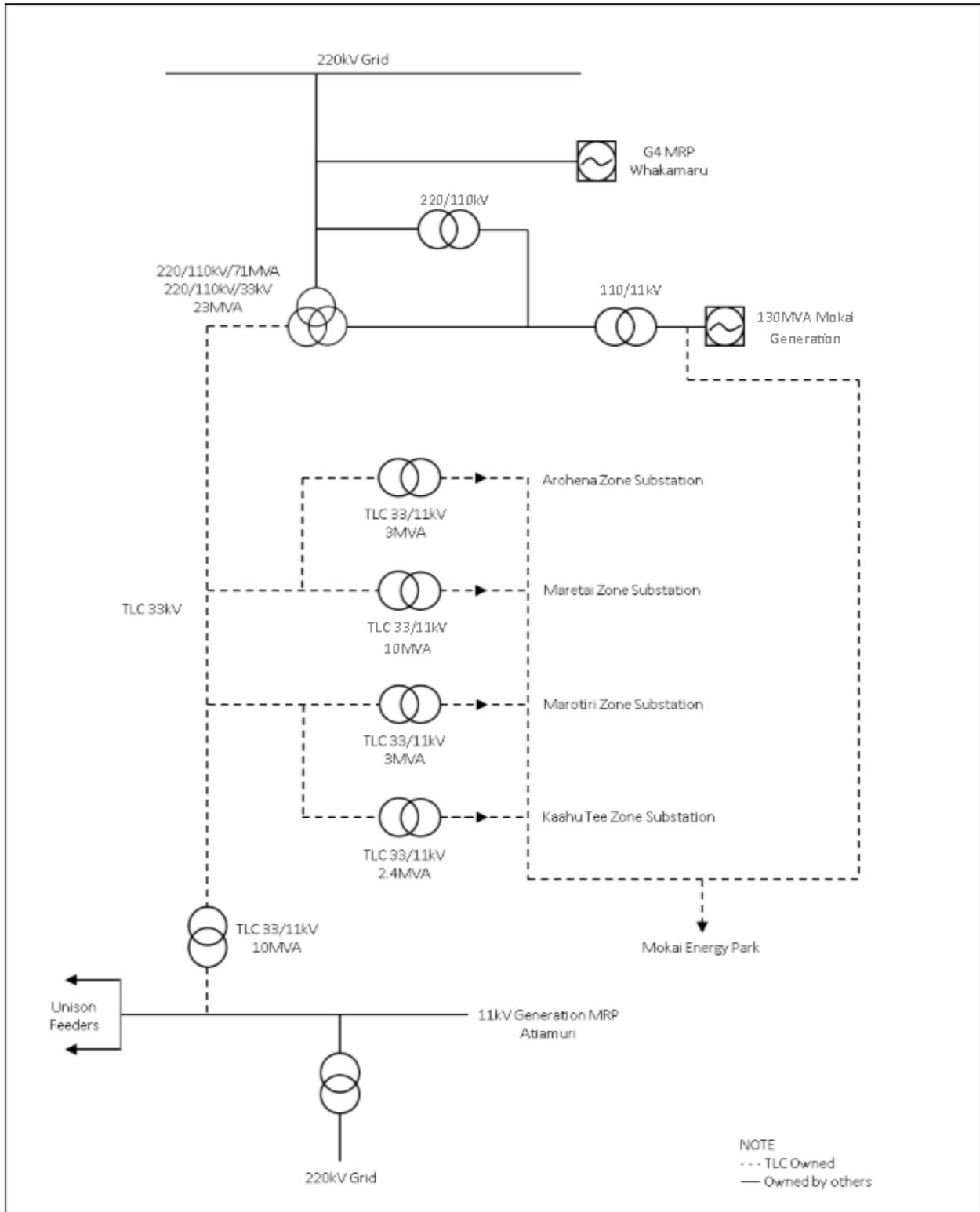


Figure 3.5: Whakamaru and Atiamuri Connection Detail

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

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

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

3.2.1.4 Ohakune emergency supply

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

This connection is used to:

- Supply Ohakune when the Transpower Ohakune grid exit point connection is out of service for planned and unplanned work. (The connection cannot supply the total Ohakune load during the winter period.)
- Supply the mill during maintenance periods when the 220/11kV 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 11kV line between the mill and Ohakune is not available, this supply can be used for the Whangaehu Valley area.

3.2.2 Assets at Locations not owned by TLC

Table 3.2 lists the locations where TLC own assets but not the site land.

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

Table 3.2: Assets at locations not owned by TLC

Note: Whakamaru is not a grid exit point as it is upstream of Transpower assets.

3.2.3 Subtransmission Distribution Network

3.2.3.1 Subtransmission Network Overview

Figure 3.6 below summarises the 33kV subtransmission network, from point of supply to zone substation. The geographical layout is illustrated in section 3.1.

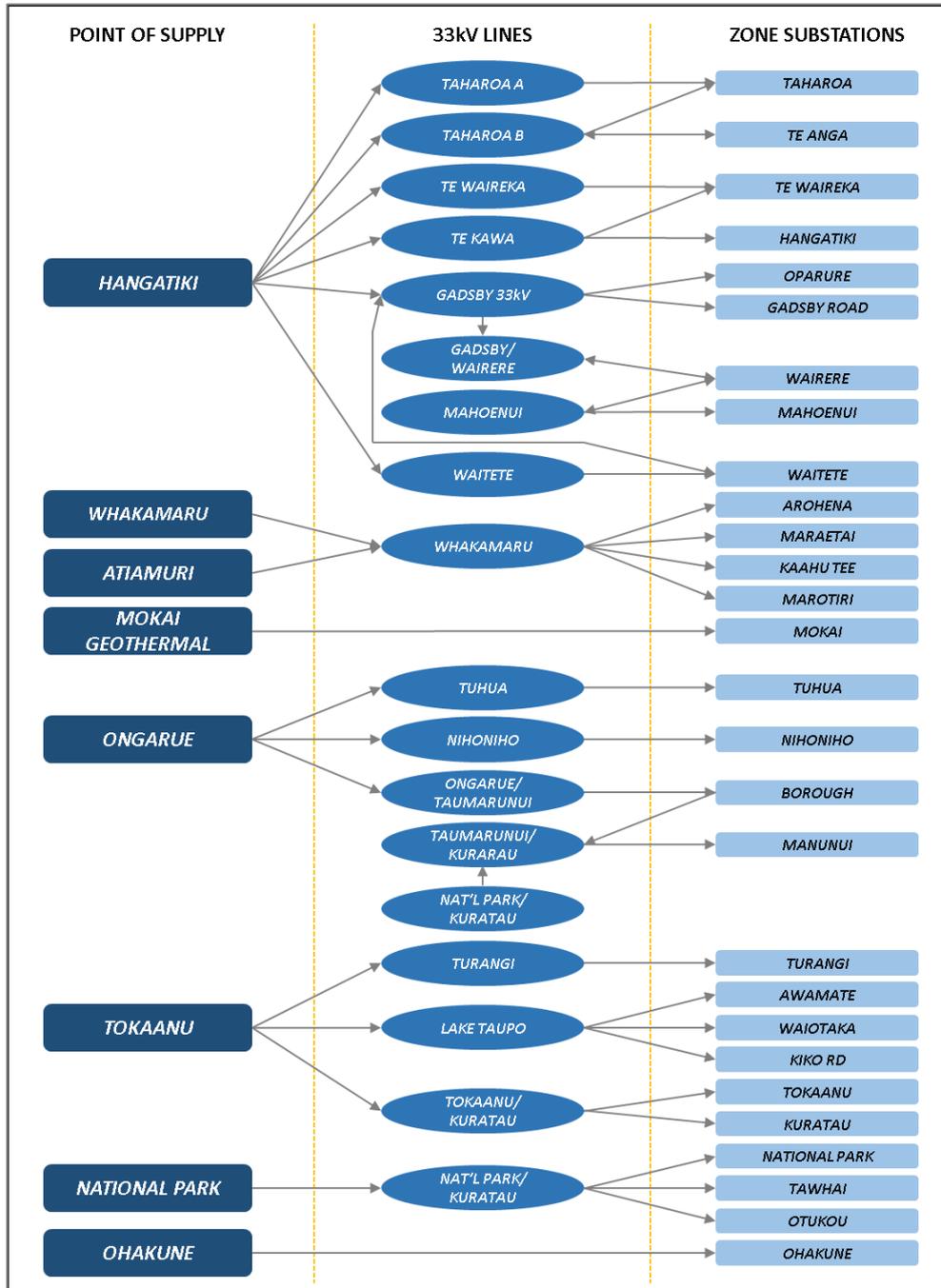


Figure 3.6: 33kV Subtransmission System

Note: Mokai Geothermal and Ohakune Points of Supply are 11kV.

3.2.3.2 Subtransmission 33kV Lines and Cable

The configuration description and backup security of subtransmission line assets is included in Table 3.3. The 33kV feeder assets are listed by supply point. Overall, TLC subtransmission network comprises 500 km of overhead line and 2.2 km of XLPE cable (primarily associated with zone substations).

SUBTRANSMISSION SUPPLY POINT / FEEDER CONFIGURATION	
Description	Configuration, Backup and Condition
HANGATIKI SUPPLY POINT	
Gadsby / Wairere (FED307) Length: 34.1km	<p>Part of ringed network linking Te Kuiti, Wairere generation and surrounding industrial areas to Hangatiki GXP.</p> <p>About 5% of the time it can be backed up by Wairere generation provided that generators are carefully controlled.</p> <p>Well-designed line that has been partly renewed over the last few years. Main problems generally involve trees, insulator failure due to fertiliser build-up and aged component failure. A substantial number of insulators have been changed from 33kV to 44kV ratings.</p>
Gadsby Rd (FED305) Length: 17.5km	<p>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. The Oparure Spur constitutes about 10km of this feeder, running through hill country to the limestone quarry.</p> <p>Backup from Waitete 33kV to about 75% of present full load. (Back up has difficulty when load is high and river flows are low).</p> <p>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 33kV to 44kV ratings.</p>
Taharoa A (FED301) Length: 57.6km	<p>Principally for supply to the iron sand extraction plant at Taharoa. Includes some local rural supply and Speedies Road Generation.</p> <p>Backed up to full load by Taharoa B line.</p> <p>A well designed line that over the last few years has been renewed in parts. Further renewal of poles and hardware is needed. Main problems over recent years have been trees, insulator failure due to fertiliser build-up and aged component failure.</p> <p>A substantial number of insulators have been changed from 33kV to 44kV ratings. Further renewal will have to be funded by the customer if they require an improved level of reliability.</p>
Taharoa B (FED302) Length: 47.9km	<p>Supply to the iron sand extraction plant at Taharoa. Includes some local rural supply. The line is not roadside and travels through hill country. Operated in closed ring.</p> <p>Backed up to present full load from Taharoa A line.</p> <p>Well-designed line that over the last few years has been extensively renewed in parts. Main problems over recent years have been trees, insulator failure due to fertiliser build-up and aged component failure. A substantial number of insulators have been changed from 33kV to 44kV ratings. Removal and renewal of hazardous equipment on the Taharoa B line is included in this plan.</p>
Te Kawa St (FED304) Length: 12.0km	<p>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.</p> <p>Te Waireka 33kV line. Backed up to present full load.</p> <p>A well designed line that over the last few years has been renewed for most of length. Main problems over recent years have been insulator failure due to fertiliser build-up and aged component failure. A substantial number of insulators have been changed from 33kV to 44kV ratings.</p>

SUBTRANSMISSION SUPPLY POINT / FEEDER CONFIGURATION	
Description	Configuration, Backup and Condition
Te Waireka Rd (FED303) Length: 9.9km	One of two lines supplying north from Hangatiki to the Otorohanga area. Loadings and security requirements show that the line is needed. Travels through hill country. Operated in closed ring. Te Kawa 33kV line. Backed up to present full load. A well designed line that over the last few years has been extensively renewed for most of length. Main problems over recent year have been insulator failure due to fertiliser build-up and aged component failure. A substantial number of insulators have been changed from 33kV to 44kV ratings. Has been strengthened for part of length to overcome fireball problems from conjoint 11kV circuits below.
Wairere / Mahoenui (FED309) Length: 22.6km	Spur line between Mahoenui and Wairere. Supplies long 11kV spur lines after transformation at Mahoenui. Considerable DG resource in area that is under investigation. Travels through hill country. 11kV backup for about 15% of time when light loads exist. Lighter construction than other 33kV feeders. Main problems over recent years have been trees, insulator failure due to fertiliser build up and aged component failure. A substantial number of insulators have been changed from 33kV to 44kV ratings. An extension to this feeder is planned as development and demand in the Mokau area continues to grow.
Waitete (FED306) Length: 10.8km	Part of ringed network linking Te Kuiti, Wairere generation and surrounding industrial areas to Hangatiki GXP. Gadsby Road. Backed up to about 75% of present max loading. Well designed line that over the last few years has been renewed for most of length. Main problems over recent years have been insulator failure due to fertiliser build-up and aged component failure. A substantial number of insulators have been changed from 33kV to 44kV ratings to overcome the fertiliser problem.
NATIONAL PARK SUPPLY POINT	
National Park / Kuratau (FED609) Length: 59.7km	Interconnecting line between the National Park GXP and Kuratau switchyard site. Normal load on line is the Whakapapa ski field and Central Plateau rural area including supply to the Whanganui river diversion race controls. The line travels across difficult access country and sensitive Maori land. Backup from Kuratau up to about 25% load. In practical terms this means (n-1) except for ski season. The line has been split into two sections. The section between National Park and the Tawhai Substation supplies the Chateau and Whakapapa ski fields and is in good condition. The second section between Tawhai and Kuratau Substation is a secondary link and has been patched at known trouble spots. This line is under ideal design strength and frequently trips when wind speeds exceed about 60km/hr.
ONGARUE SUPPLY POINT	
Nihoniho (FED603) Length: 14.6km	Spur line connecting Ongarue GXP to Nihoniho Zone Substation. Line runs through very hilly and remote country with poor access. 50% load backup on 11kV from Tuhua. (Voltage drop causes issues.) Aged low strength line based on a low cost design. Has had problems with magpies, hardware failure and insulator flashover due to fertiliser build-up.
Ongarue / Taumarunui (FED604) Length: 20.4km	Main line supplying Taumarunui from the Ongarue GXP. Line runs through extremely hilly country. 50% load backup from Tokaanu provided Kuratau and Piriaka generation running. Originally built to a low strength design and upgraded in 2014. Much of the line is in very steep hill country with difficult access. Has had problems with magpies, hardware failure and insulator flashover due to fertiliser build-up.

SUBTRANSMISSION SUPPLY POINT / FEEDER CONFIGURATION	
Description	Configuration, Backup and Condition
Taumarunui / Kuratau (FED608) Length: 44.0km	Interconnecting line between the Ongarue GXP and the Kuratau marshalling site. Normally loaded with output of Kuratau area Distributed Generation back into the Ongarue GXP. If Kuratau DG did not exist or was not paying a fair portion of this line, options for continuing renewal, maintenance and ownership will need further evaluation. The line travels across difficult access country. Backup from National park GXP and Tokaanu (n-1) depending on generation and ski season. The line has adequate size conductor but the poles are well under strength for today's environment. The poles are also very short and the line has a number of ground to conductor clearance issues. Renewal work on this feeder has been put on hold due to the fact that alternative options to maintaining this feeder are currently being assessed
Tuhua (FED602) Length: 0.1km	Few metres of spur line connecting Ongarue GXP to Tuhua Zone Substation. 50% load backup from Nihoniho on 11kV network. The line is in average condition and not prone to faults.
TOKAANU SUPPLY POINT	
Lake Taupo (FED606) Length: 47.4km	Spur line connecting Tokaanu GXP to the Kiko Road, Awamate Road and Waiotaka substations. Crosses many plots of extremely sensitive Maori land. No fixed backup available, generators are used when back up is required. Line has been rebuilt to withstand the fault current capacity of the Tokaanu Grid Exit. Earlier parts of the rebuild were completed to a low cost design and do not have a high inherent strength. The line crossing the sensitive Tongariro River is of less than ideal design and presents a risk to trout fishermen who use conductive fishing lines. Work to mitigate this hazard is included in the plan.
Tokaanu / Kuratau (FED607) Length: 16.3km	Interconnecting line between the Tokaanu GXP and Kuratau. The line travels across difficult access country and extremely sensitive Maori land. Normally supplies Kuratau Zone Substation and is a backup for the connection of the Kuratau area distributed generation to the grid. Backup from National Park GXP and Ongarue via Taumarunui. (n-1) depending on generation and ski season. Line has adequate size conductor and recent upgrade work has addressed many pole strength and ground clearance issues.
Turangi (FED605) Length: 3.4km	Spur line connecting Tokaanu GXP to the Turangi Zone Substation. The line crosses sensitive Maori land. There is 30% back up for the Turangi 33kV line from Awamate and Waiotaka. The line includes a number of iron rail poles. Some renewal work was done in 2011.
WHAKAMARU SUPPLY POINT	
Whakamaru (FED310) Length: 113.2km	The line travels through hill country to connect Atiamuri and Whakamaru supply points to Arohena, Maraetai, Kaahu Tee and Marotiri Zone Substations: <ul style="list-style-type: none"> » Atiamuri – Kaahu Tee: 20km of forestry, hill country and river flats » Kaahu Tee – Marotiri: 15km of farmed hill country » Kaahu Tee – Whakamaru: 20km of mostly hill country » Whakamaru – Maraetai: 10km of farmland » Maraetai – Arohena: 30km of bush and farmed hill country Very limited backup capacity (about 10%) through the 11kV network. The line was originally constructed as a 50kV transmission line. It was purchased by TLC in 2002 and has since been operated at 33kV. As part of the conversion process, aged conductor was changed and smaller 33kV insulators fitted.

Table 3.3: Subtransmission Assets Configuration Description

Figures 3.7 And 3.8 Illustrate age profiles for subtransmission spans and poles respectively.

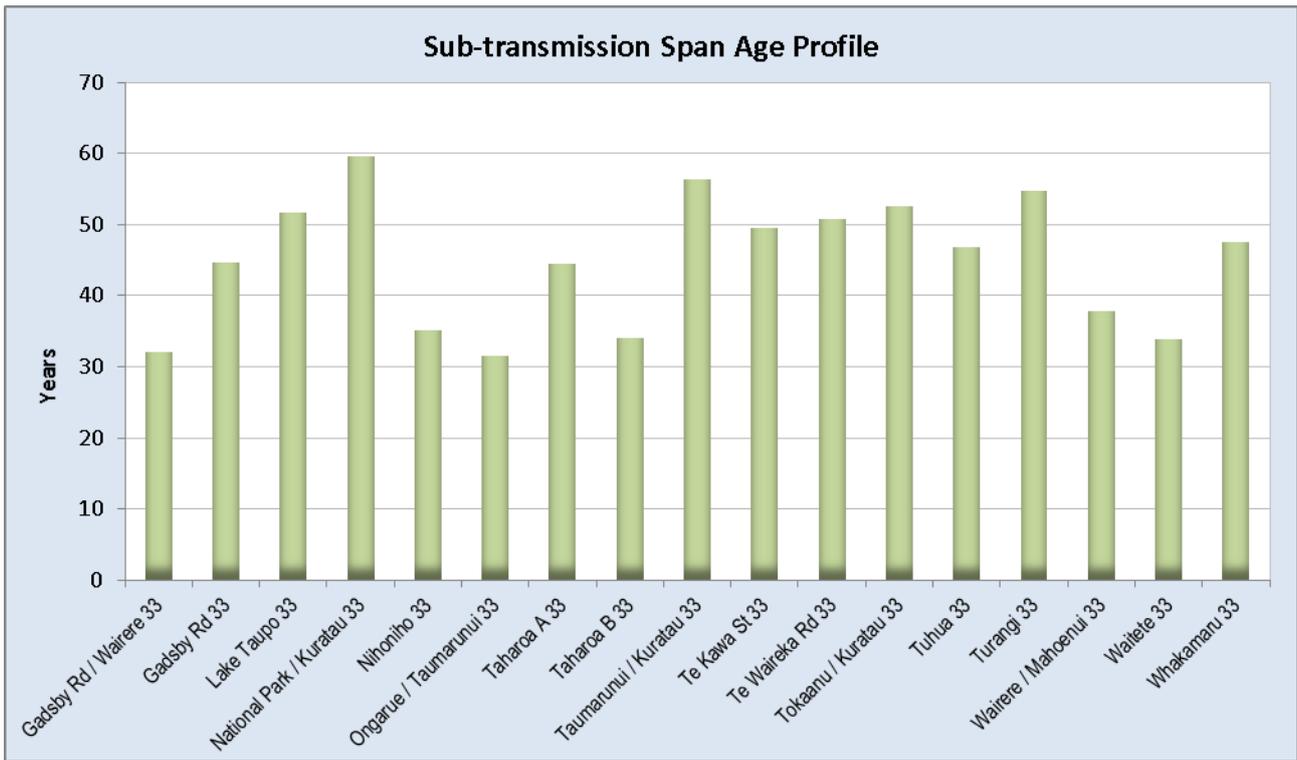


Figure 3.7: Subtransmission Conductor Average Age Profile

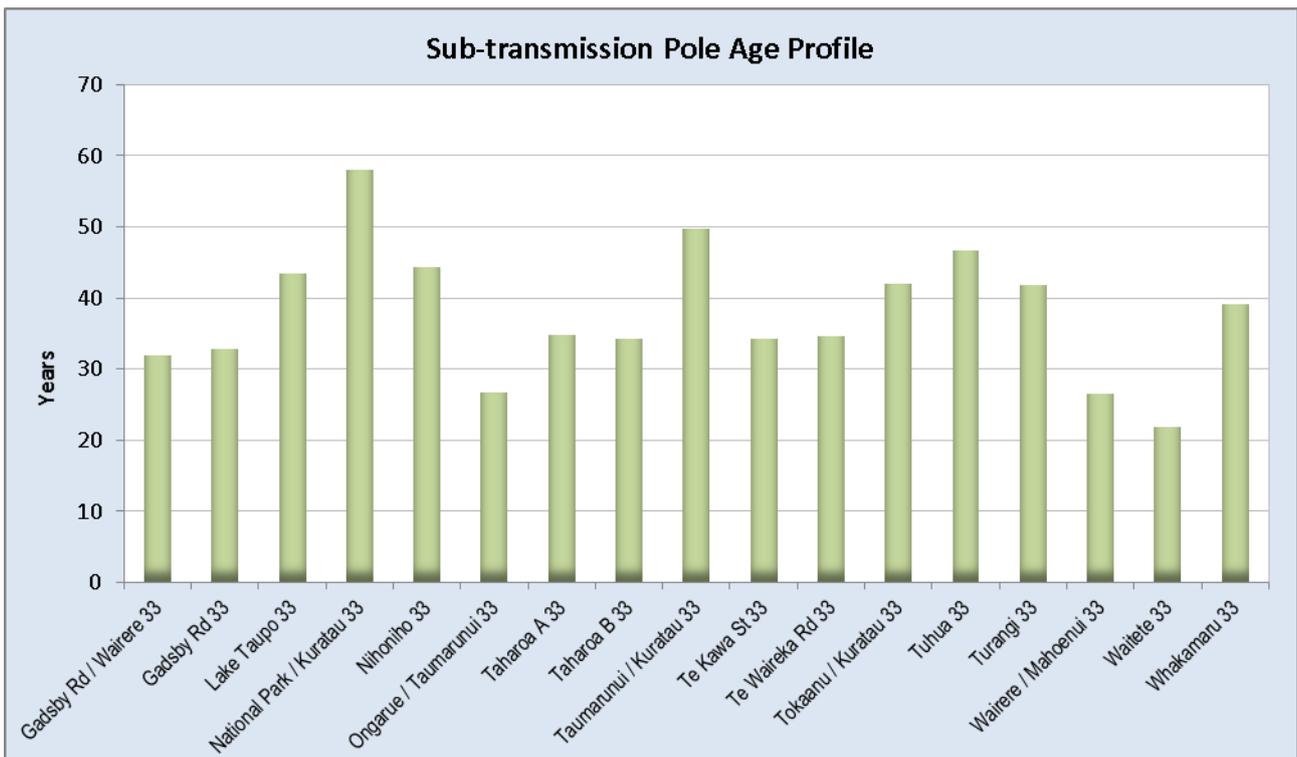


Figure 3.8: Subtransmission Pole Average Age Profile

3.2.3.4 Zone Substations, Switchyards and Power Transformers

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

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

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

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

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

Table 3.4 details each of the zone substations, switchyards and power transformers in the TLC network.

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

ZONE SUBSTATIONS, SWITCHYARDS AND POWER TRANSFORMERS	
Site/Transformers	Description / Security / Condition
Borough (ZSub508) 2 @ 5000 kVA	Two unit, 33kV to 11kV zone substation that is able to supply light load on one unit. Two 33kV supplies are available. The transformers were both commissioned in 1965 and since been refurbished. Tests show the condition of one unit as acceptable and the other marginal. The 33kV switchgear has been renewed and new transformer bunding has been installed. Two of the four feeder breakers are currently enclosed in a concrete block building and the remaining 2 feeders are in a container. An upgrade of the oil separation system has been included in this plan. Housed assets are currently enclosed in a concrete block building. Capacitors have been installed to support backfeed from Tokaanu should the Ongarue supply be unavailable. Upgrades – including relocating and containerising - are included in the plan. Site is not fully backed up as 1x5MVA will not support all load at peak times. Limited light load backup is available from 11kV network with some transfer and embedded generation. In practical terms this means limited (N-1) transformers.
Gadsby Road (ZSub205) 1 @ 5000 kVA	Single unit, 33kV to 11kV zone substation on the north side of Te Kuiti. The site has two alternative 33kV supplies running as a closed ring. The refurbished transformer was commissioned in 2006. Tests show the condition of the unit as acceptable. The site is well built and in reasonable condition. It has bunding and oil separation but not earthquake constraints. Housed assets are enclosed in a concrete block building. Medium load backup is available from the 11kV network. In practical terms this means (N).
Hangatiki (ZSub204) 1 @ 5000 kVA	Single unit, 33kV to 11kV zone substation at the Transpower point of supply. There are two alternatives for 33kV supply running as closed ring with a very short spur to substation bus. The transformer was commissioned in 1992 and tests show the condition of the unit as acceptable. A well-built site in reasonable condition. The site includes concrete block transformer housing. It has bunding and oil separation. Medium load backup is available from the 11kV network. In practical terms this means (N).
Kaahu Tee (ZSub216) 1 @ 2400 kVA	Single unit, 33kV to 11kV zone substation embedded in the Marotiri / Maraetai network. The transformer was commissioned in 2009 and oil tests show the condition of the unit as acceptable. A containerised asset in good condition. Backup is available from Marotiri/Maraetai. Cannot be taken out of service during heavy load times. In practical terms this means (N).
Kiko Road (ZSub518) 1 @ 3000 kVA	Single unit, 33kV to 11kV zone substation. Single 33kV line supply with no 11kV alternatives. The transformer was commissioned in 2001 and oil tests show that high gas discharging is occurring in the transformer, this is currently being addressed by the transformer manufacturer. The site is in good condition and has automatic Aqua Sentry Device bunding. No backup available other than bypassing the substation and injecting 11kV from Turangi into the 33kV line. This is light load backup only. In practical terms this means (N).
Kuratau (Switchyard)	Switchyard site is at the Kuratau Power Station, with various structures and switchgear. Some of the switchgear has been renewed.
Kuratau (ZSub509) 1 @ 3000 kVA 1 @ 1500 kVA	Two unit, 33kV to 11kV zone substation. Three 33kV supplies are available; there are no 11kV alternatives. Local embedded generation exists when there is sufficient water available. The 3 MVA transformer was commissioned in 1955, is aged and returns poor test results. The 1.5 MVA unit was commissioned in 2009 and it is in good condition. The site is generally in average condition and banded with an automatic outlet valve. The setup provides backup on site however it will not cover full load situations. The backup is not able to be phased so an outage is needed to transfer load. In practical terms this means (N) for emergency use only.
Mahoenui (ZSub209) 1 @ 3000 kVA	Single unit, 33kV to 11kV zone substation supplied from a single 33kV line. The transformer was commissioned in 1966 and tests show the condition of the unit as acceptable. The site bunding and separation unit is in the process of being renewed. The installation of an incoming 33kV breaker for reliability purposes has been included in this plan. Light load backup is available from the 11kV network. In practical terms this means (N).

ZONE SUBSTATIONS, SWITCHYARDS AND POWER TRANSFORMERS	
Site/Transformers	Description / Security / Condition
Manunui (ZSub510) 1 @ 5000 kVA	Single unit, 33kV to 11kV zone substation. Two 33kV supplies are available. The transformer was commissioned in 1965 and tests show the condition of the unit as acceptable. The site was upgraded in 2013. The oil separation now includes an extended sump and additional alarms. Light to medium load backup is available from the 11kV network. In practical terms this means (N).
Maraetai (ZSub210) 1 @ 10000 kVA	10 MVA single unit, 33kV to 11kV zone substation supplied from a single 33kV line. (The previous 5 MVA transformer failed during 2015 and has been replaced.) The site is ex Transpower and has oil separation and bunding. The incoming 33kV breaker was renewed in 2014. Light load backup is available from the 11kV network, however it will not support the milking load in the area. In practical terms this means (N).
Marotiri (ZSub212) 1 @ 3000 kVA	Single unit, 33kV to 11kV zone substation supplied from a single 33kV line. The transformer was commissioned in 2001 and tests show the condition of the unit as acceptable. A well maintained ex Transpower site in good condition with oil separation and bunding. Loading is at full or greater than rating. Housed assets are enclosed in a weatherboard building. Light load backup from the 11kV network. This backup will not support the milking and industrial load in the area. In practical terms this means (N).
Mokai (ZSub3358) 1 @ 7500 kVA	Single unit, 11kV to 11kV zone substation with a fault reducing transformer. The transformer was commissioned in 2011 and tests show the condition of the unit as acceptable. The substation is semi containerised - the regulator and switchgear is containerised but not the transformer. The site is in good condition and has oil separation and bunding. Light load backup from the 11kV network. In practical terms this means (N).
National Park (ZSub501) 1 @ 3000 kVA	Single unit, 33kV to 11kV zone substation with two 33kV supplies. A new containerised site commissioned in 2014. Test results on the new transformer show some abnormalities this is currently under investigation. The site has bunding and oil separation. Light load backup available from 11kV network. In practical terms this means (N).
Nihoniho (ZSub503) 1 @ 1500 kVA	Single unit, 33kV to 11kV zone substation supplied from a single 33kV line. The transformer was commissioned in 2010 and tests show the condition of the unit as acceptable. Improvements are currently underway on the site to mitigate hazard constraints and incorporate bunding and oil separation. Light to medium load backup is available from the 11kV system. In practical terms this means (N).
Oparure (ZSub208) 1 @ 3000 kVA	Single unit, 33kV to 11kV zone substation mostly supplying a limestone processing plant. Supply is via a 33kV line spurred off a closed ring. The transformer was commissioned in 1994 and tests show the condition of the unit as acceptable. The site is in good condition despite operating in a harsh environment. The installation of bunding and an oil separation unit are included in this plan. Light load backup is available. In practical terms this means (N).
Otukou (ZSub512) 1 @ 500 kVA	Single unit, 33kV to 11kV zone substation with two 33/11kV supplies. The transformer was commissioned in 2010 and tests show the condition of the unit as acceptable. Average condition site with no bunding or oil separation. Improvements for the site are included in this plan. No backup or alternative feed security. In practical terms this means (N).
Piripiri (Switchyard)	Switchyard only, with load in area picked up by Te Anga substation. The switchyard was constructed for Speedies Road Hydro and replaced the Piripiri Zone Substation which was decommissioned in 2010.

ZONE SUBSTATIONS, SWITCHYARDS AND POWER TRANSFORMERS	
Site/Transformers	Description / Security / Condition
Taharoa (ZSub201) 3 @ 5000 kVA	Three unit, 33kV to 11kV zone substation supplying iron sand extraction and local load. Supply is from two 33kV lines operating as closed ring. Two transformers were commissioned in 1971 and the other in 1979. Tests show the condition of all units as acceptable. The site is in poor condition, operating in a harsh environment on the beach and has hazard issues. Extensive upgrade work is included in this plan - as requested and funded by the industrial customer. Medium load backup available from 11kV network. In practical terms this means (N-1).
Tawhai (ZSub513) 1 @ 5000 kVA	Single unit, 33kV to 11kV zone substation with two 33kV supplies. The transformer was commissioned in 1966 and tests show the condition of the unit as acceptable following its refurbishment in 2013 as part of an extensive site rebuild. The site is in good condition with oil separation and bunding. Light to medium load backup is available from the 11kV network. In practical terms this means (N).
Te Anga (ZSub520) 1 @ 2000 kVA	Single unit, 33kV to 11kV zone substation. The transformer was commissioned in 2012 and tests show that high gas discharging is occurring in the transformer. This is currently being addressed by the transformer manufacturer. New containerised asset. The site has a single 11kV bus with no bus coupler and may be backed up from Taharoa. In practical terms this means (N).
Te Waireka (ZSub203) 2 @ 10000 kVA	Two unit, 33kV to 11kV zone substation supplied by two 33kV lines operating as closed ring. Each unit is able to carry full load. The transformers were commissioned in 1996 & 2001 and return acceptable test results. Recent upgrade work included oil separation and bunding and replacing aged, oil filled switchgear and protection. The site is now in good condition. Feeder loadings are high. Funding for diversity of the busbar arrangement is included in this plan. The zone substation includes brick housing. Firm transformer capacity feeding a single 11kV bus with no bus coupler. Limited light load backup available from 11kV network. In practical terms this means (N-1) transformers.
Tokaanu Village (ZSub507) 1 @ 1250 kVA	Single unit, 33kV to 11kV zone substation supplied by a single 33kV line. The transformer was commissioned in 1996 and tests show the condition of the unit as acceptable. The site is in good condition with further improvements included in plan. Limited backup via 33kV to 400V which is then stepped-up to 11kV. No transformer or 11kV backup. In practical terms this means (N).
Tuhua (ZSub502) 1 @ 1500 kVA	Single unit, 33kV to 11kV zone substation supplied by a single 33kV line. The transformer was commissioned in 1962 and tests show the condition of the unit as acceptable. The tap changer for the transformer is mechanically weak and is due for replacement. The site overall is in poor condition with no bunding or oil separation and has hazard constraints. Full load backup from 11kV system. In practical terms this means (N-1) transformers.
Turangi (ZSub505) 2 @ 5000 kVA	Two unit, 33kV to 11kV zone substation supplied by a single 33kV line. The transformers were commissioned in 1961 and 1964. Tests show the condition of both units as acceptable. The site is in improved condition with work continuing to upgrade protection and addressing hazards. Site has firm transformer capacity but the 33kV supply and 11kV outgoing configuration is weak. There is no 11kV backup available. In practical terms this means (N-1) transformers.
Waiotaka (ZSub511) 1 @ 1500 kVA	Single unit, 33kV to 11kV zone substation supplied by a single 33kV line. The transformer was commissioned in 2006 and tests show that high gas discharging is occurring in the transformer. This is currently being addressed by the transformer manufacturer. A new, containerised asset operating efficiently. 75% back up is available from Turangi 11kV. In practical terms this means (N).

ZONE SUBSTATIONS, SWITCHYARDS AND POWER TRANSFORMERS	
Site/Transformers	Description / Security / Condition
Wairere (ZSub207) 2 @ 2500 kVA	Two unit, 33kV to 11kV zone substation with embedded generation. The transformers were built in 1963, purchased second hand and commissioned on site in 1980. Tests show the condition of both units as acceptable. The site is in average condition, banded with a manual outlet valve. Protection and 33kV bus arrangement needs reviewing and are addressed in this plan, as is transformer refurbishment. The switch room is enclosed in a brick building. One transformer capacity and 11kV network connections will support connected load customers but not generation customers. Supply will island. In practical terms this means (N-1) transformers.
Waitete (ZSub206) 3 @ 5000 kVA	Three unit. 33kV to 11kV zone substation. Able to supply full load with some 11kV transfer and embedded generation. Two 33kV lines run in a closed ring. Two transformers were commissioned in 1961, the other in 1955. Routine tests show the condition of all units as acceptable. The site is in good condition, with recent modifications including new bunding, oil separation and earthquake restraints. Housed assets are enclosed in a brick building. Normal operating loads are in the 6 to 7 MVA range. The site has firm capacity in its present configuration with limited backup from the 11kV network. In practical terms this means (N-1) transformers.
Whakamaru (Point of Supply)	This is a non-standard arrangement put in place to avoid Transpower charges for this area. Under the arrangement, TLC use the tertiary winding on a Mighty River Power owned transformer. Backed up from Atiamuri. In practical terms this means (N).

Table 3.4: Zone Substation (N-x) Subtransmission Security

Figure 3.9 illustrates the age profile of subtransmission zone substations, based on commissioning date. Figure 3.10 Illustrates the age profiles for subtransmission power transformers.

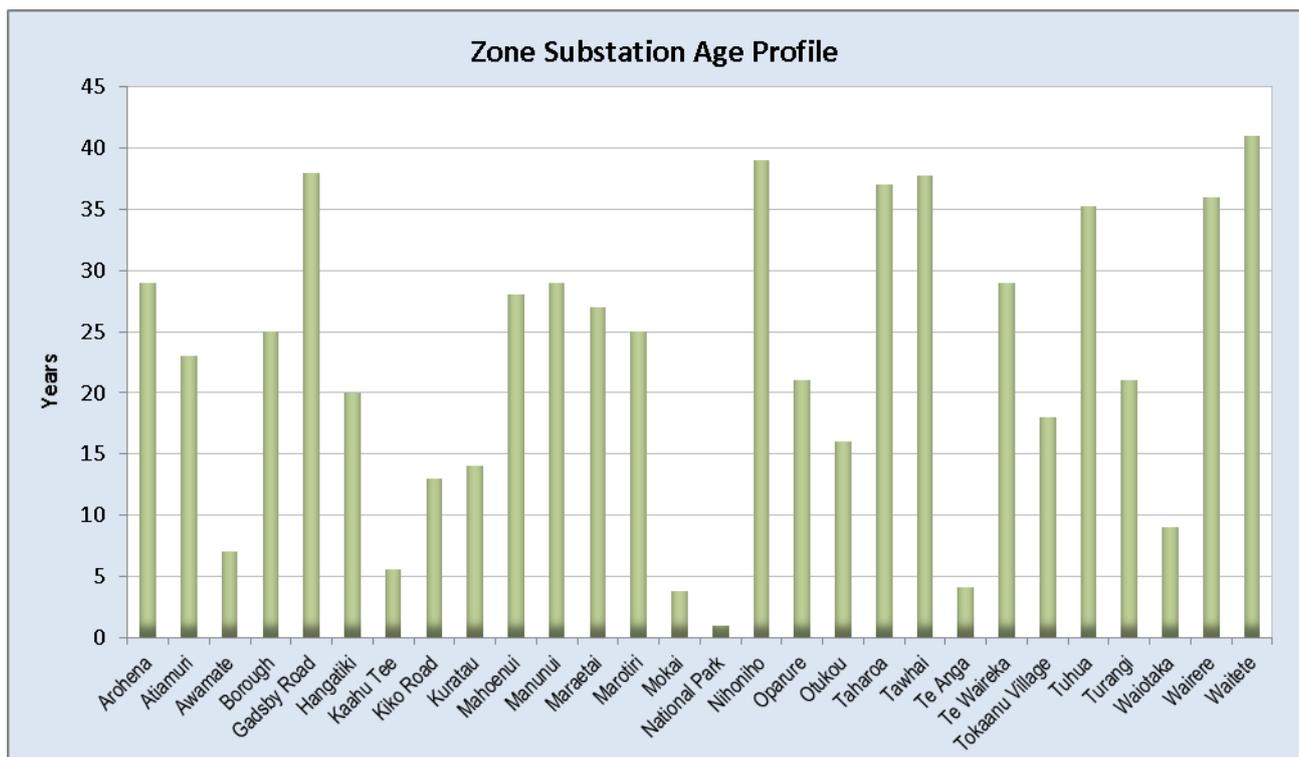


Figure 3.9: Age Profile of Zone Substations – based on year of commissioning

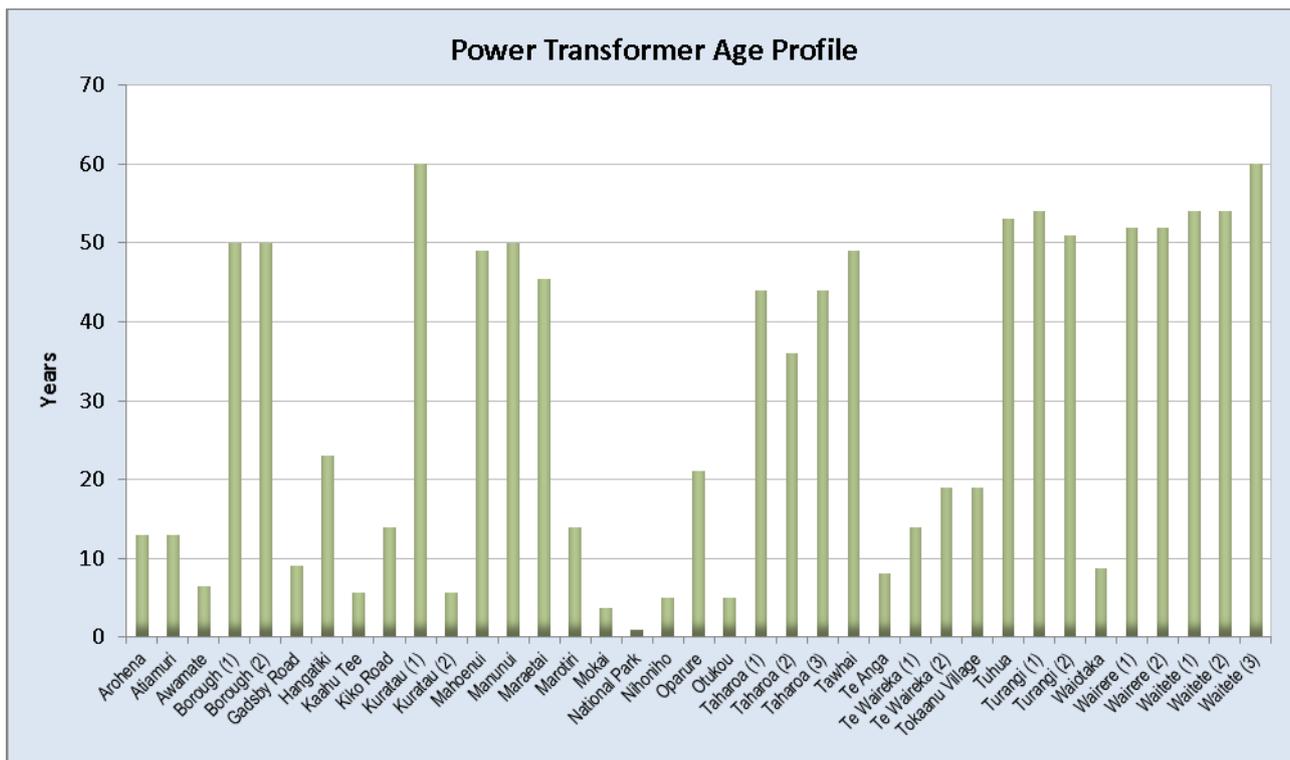


Figure 3.10: Power Transformer Age Profile

3.2.3.5 Subtransmission Switchgear

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

Table 3.5 lists the quantity, location and condition of the subtransmission (33kV) switchgear assets. As per the figures shown, some of the assets are located in zone substations and others are in the field on subtransmission lines. The switch ages and condition vary; they are renewed when no longer serviceable.

33kV SWITCHGEAR ASSETS			
Description	Field	Zone Subs	Total
Air Break Switches	68	60	128
Circuit Breakers	5	49	54
Fault Throwers		1	1
Fused Links	6	4	10
Load Break Switches		1	1
Reclosers	7	3	10
Solid Links	30	12	42
Transformer Fuses		3	3
Total	116	133	249

Table 3.5: Subtransmission Switchgear Assets and Location

Figures 3.11 and 3.12 give an indication of the age profile of subtransmission switchgear for both field and zone substation assets.

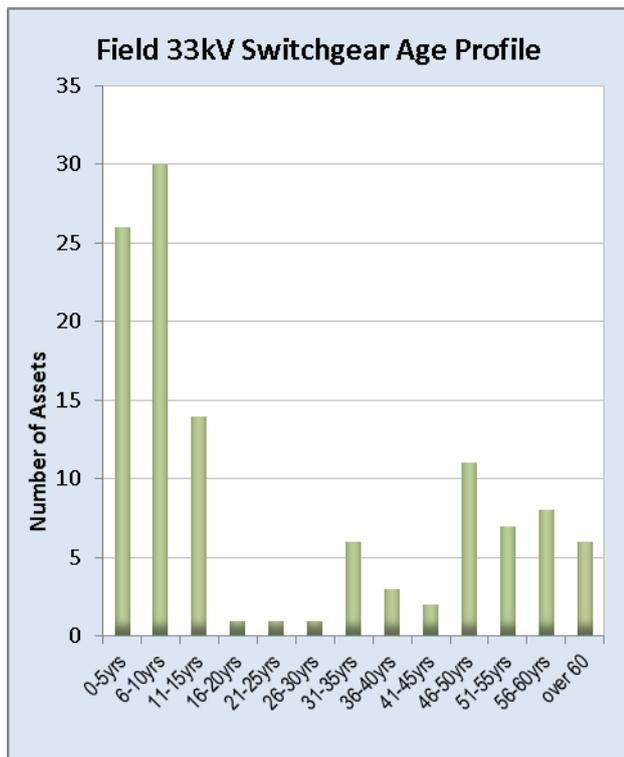


Figure 3.11: Age Profile of 33kV Subtransmission Switchgear located in the field

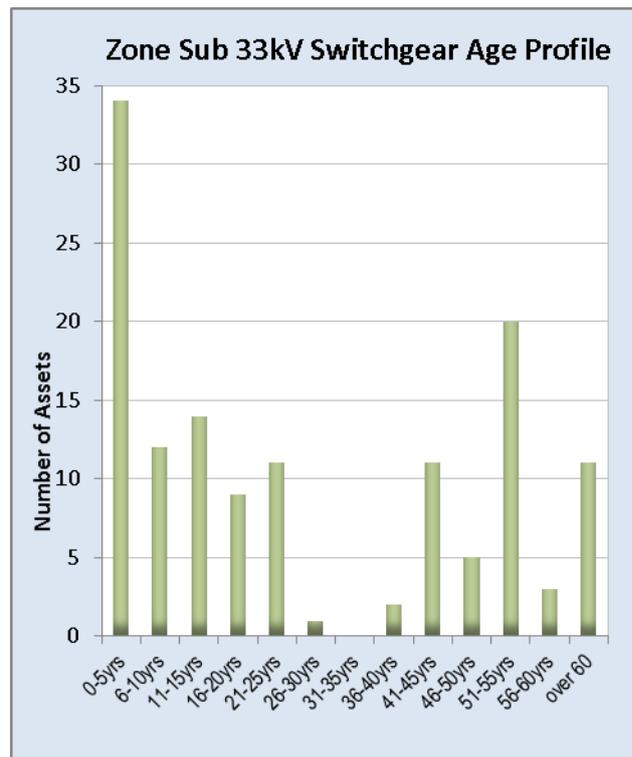


Figure 3.12: Age Profile of 33kV Subtransmission Switchgear located in Zone Substations

3.2.3.6 Subtransmission Systemic Issues

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

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

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

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

3.2.4 11kV Distribution Network

3.2.4.1 11kV Feeder Lines and Cable

The 11kV feeder network comprises overhead line, SWER systems and cable. Table 3.6 summarises these assets.

11kV DISTRIBUTION NETWORK SUMMARY	
Description	Length (km)
Overhead line : 1, 2 and 3 Phase	2,244
Overhead line : SWER	892
Underground Cable	124

Table 3.6: 11kV Distribution Network Summary

Note: These lengths do not include privately owned 11kV lines. It is estimated that there are 777 km of privately owned lines connected to TLC owned assets.

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

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

Table 3.7 documents the 11kV distribution network and includes information regarding location, length, ICP connections and general condition.

11kV DISTRIBUTION NETWORK	
Feeder/Length	Description
Aria (FED114) O/H 74.3; U/G 0.0 km	Aria rural area servicing 257 ICPs. The feeder is in average condition and constructed predominantly on 10/2kN concrete poles. Problems have been experienced in recent times with aged insulator issues. Some renewal work has been completed. Feeder includes Kumara Road SWER system.
Benneydale (FED103) O/H 130.9; U/G 0.1 km	A long rural feeder servicing south east of Te Kuiti, Benneydale, Mangapehi Generation and Crusader Meats. It has 473 ICPs. The feeder carries four regulators in series - being run to the maximum - and has been substantially renewed. Travels through moderate hill country and includes many long spans with some close conductor phase spacings. There is a short span of cable out of the zone substation. Feeder includes Waimiha and Kopaki Road SWER systems.
Caves (FED101) O/H 59.7; U/G 0.6 km	Waitomo village and rural area to the west, servicing 321 ICPs. Rebuilt to Waitomo Caves. Beyond this there are long spans with light low strength conductor that is prone to failure. Poles are predominantly 10/2kN concretes and iron rails with aged insulator issues. Cable out of the zone substation. Feeder includes Kokakoroa Road SWER system.

11kV DISTRIBUTION NETWORK	
Feeder/Length	Description
Chateau (FED419) O/H 0.0; U/G 29.0 km	Whakapapa Ski field and village supply, servicing 137 ICPs. The feeder is all cable, 60% of which is heavy armoured. About half of the network 11kV cable is associated with the ski field supply. Much of this cabling has been laid directly on solid rock and does not comply with codes. The long-term strategy is to improve these installations whenever customers or other events such as emergent work and hazard elimination/minimisation projects trigger alterations in the vicinity.
Coast (FED125) O/H 85.1; U/G 0.1 km	Remote rural area around Marokopa servicing 322 ICPs. Generally aging rural feeder with parts exposed to severe coastal conditions. Several sections have been renewed. Mostly small ACSR conductor that is showing corrosion problems in some areas. Poles predominantly 10/2KN concretes and iron rails with aged insulator issues. A difficult feeder to automate due to lack of communication signals from existing repeaters. Feeder includes Mangatoa Road SWER system.
Gravel Scoop (FED109) O/H 92.9; U/G 0.2 km	South east of Otorohanga, servicing 530 ICPs. Average condition rural feeder supported by a mixture of wooden poles and 10/2KN concretes. Sections have been renewed. Cable out of the zone substation.
Hakiaha (FED401) O/H 3.8; U/G 1.9 km	Supplies central area of Taumarunui and rural areas on the town boundary. 286 ICPs. Cable in Taumarunui CBD. Rural part is small ACSR conductor and pole types are mixed with some wooden, 10/2KN concretes and iron rails. Insulators mostly low creepage distance. Some renewal work completed.
Hangatiki East (FED102) O/H 18.7; U/G 0.1 km	Area east of Hangatiki servicing 69 ICPs. Average condition rural feeder with two large limestone processing plants connected. Conductor size is less than ideal in places. Pole strengths should ideally be higher given the span lengths and conductor size. Some renewal work completed. Cable out of the zone substation.
Hirangi SWER (FED405) O/H 1.0; U/G 0.1 km	SWER feeder to semi residential area around Turangi. 370 ICPs. Average condition with some renewal work completed. Cable into substation.
Huirimu (FED121) O/H 46.7; U/G 0.0 km	Supply to rural area south of Arohena, servicing 153 ICPs. Average condition in dairying and dry stock area. Most of the feeder is constructed of light conductor and supported on iron poles. The insulators are mostly of the 1950's short creepage distance type. Some renewal work completed.
Kuratau (FED406) O/H 51.4; U/G 3.6 km	Supply to Kuratau Village area, servicing 1316 ICPs. Extensive renewal and strengthening completed. Cable in parts of the township. Feeder includes multiple SWER systems.
Mahoenui (FED113) O/H 98.0; U/G 0.1 km	Supply to Mahoenui and surrounding rural areas. 280 ICPs. Average condition. Most of feeder is supported on 10/2KN concrete poles. Some renewal work completed. Cable to ground mount transformers in Mokau and Awakino. Feeder includes multiple SWER systems.
Maihihi (FED111) O/H 105.74; U/G 1.1 km	Rural area north east of Otorohanga servicing 897 ICPs. Rural feeder supplying dairying load that has been mostly renewed. Average to good condition. Cable runs out of the zone substation. Feeder includes Waituhi, Ngapuke and Kirton Road SWER systems.
Mangakino (FED118) O/H 20.3; U/G 2.2 km	Supply to Mangakino, servicing 480 ICPs. Average condition overall with a mixture of poles. Some asset groups have been renewed. Cable runs out of the zone substation.

11kV DISTRIBUTION NETWORK	
Feeder/Length	Description
Manunui (FED408) O/H 84.5; U/G 0.8 km	Rural area to south and east of Taumarunui and Manunui village. 565 ICPs. Generally in reasonable condition but design is inherently light. Poles mainly 10/2KN concrete and iron rails. Renewal work and some upgrading is planned. Cable to ground mount transformers in Manunui.
Matapuna (FED404) O/H 14.8; U/G 2.0 km	Supply to western side of Taumarunui, servicing 1036 ICPs. Good condition, mostly supported by concrete poles with 10/2KN strength ratings. Cable in the Taumarunui urban area.
McDonalds (FED110) O/H 38.7; U/G 0.9 km	Rural area to the south of Otorohanga servicing 449 ICPs. Cable to ground mount transformers
Miraka (FED131) O/H 0.2; U/G 0.7 km	Supply to Mokai Energy Park and Miraka Milk Plant area. 2 ICPs. Cable to new subdivision
Mokai (FED123) O/H 71.1; U/G 1.9 km	Mokai rural area including western bays area of Lake Taupo. 310 ICPs. Average condition, mostly supported on mixture of hardwood and concrete 10/2kn poles. Consists of some long spans with close conductor spacings that can clash in wind and has aged insulator issues. Some renewal work completed; more planned. Cable to new subdivision.
Mokau (FED128) O/H 134.3; U/G 0.0 km	Mokau coastal area, servicing 635 ICPs. Long coastal 11kV feeder in very harsh environment. Gives problems with drop-out fuse connections and insulator failures. Has inherent line design weakness in the Awakino Gorge. Some renewal work completed. Feeder includes multiple SWER systems.
Mokauiti (FED115) O/H 69.5; U/G 0.0 km	Rural area south east of Piopio servicing 170 ICPs. Average condition, mostly supported on mixture of hardwood and concrete 10/2KN poles. Some long spans with close conductor spacings that can clash in wind and has aged insulator issues. Some asset groups have been renewed. Feeder includes Mokauiti Road SWER system.
Motuoapa (FED425) O/H 1.9; U/G 0.6 km	Supply to Motuoapa area on the eastern side of Lake Taupo. 422 ICPs. Overall average condition – parts have been renewed and parts very old construction. Cable to new subdivision.
National Park (FED411) O/H 44.4; U/G 0.2 km	Supply to the National park area including the village. 365 ICPs. Part renewed, part in very poor condition with long spans of light conductor on 10/2KN concrete and iron rails. Overall in average condition. Cable to ground mount transformers in village.
Nihoniho (FED412) O/H 28.0; U/G 0.0 km	Supply to the Nihoniho and Matiere areas. 60 ICPs. Remote lightly constructed rural feeder in poor to average condition with few customers. Will be renewed with some strengthening in key places as part of 15-year programme. (Some of this work has been completed.) Feeder includes Nihoniho SWER system.
Northern (FED402) O/H 106.9; U/G 3.0 km	Area north of Taumarunui servicing 1207 ICPs. A long feeder in average condition. Some renewal work has been completed. Most of the feeder is supported by 10/2KN concrete poles and iron rails. There are also two large SWER systems that can tie with other feeders attached to the end of the line. This feeder is the most heavily loaded out of Taumarunui. Cable exists in urban area of Taumarunui. Feeder includes Okahukura and Hikurangi SWER systems.
Ohakune Town (FED414) O/H 5.7; U/G 3.5 km	Ohakune town supply, servicing 902 ICPs. Generally in average condition. Several security improvement projects and renewal /strengthening work have been completed to bring feeder up to industry standard for a supply to a popular tourist area. Cable in Ohakune CBD.

11kV DISTRIBUTION NETWORK	
Feeder/Length	Description
Ohura (FED413) O/H 146.0; U/G 0.1 km	Ohura and surrounding remote rural areas. Services 363 ICPs. Lightly constructed feeder in average condition overall. The area covers a large section of a remote part of the King Country, with a low customer density and a declining population base. Designs associated with renewal have to focus on maximum improvement for spend. Supplies several interconnecting SWER systems. Cable to ground mount transformers. Feeder includes multiple SWER systems.
Ongarue (FED421) O/H 132.4; U/G 0.0 km	Large rural area around Ongarue. 258 ICPs. Lightly constructed feeder in a remote part of the King Country. Feeder overall is in average condition with some renewal work completed. Has low customer density and a declining population base. Designs associated with renewal have to focus on maximum improvement for spend. Supplies multiple interconnecting SWER systems.
Oparure (FED107) O/H 74.5; U/G 5.4 km	Supply to an area west of Te Kuiti servicing 929 ICPs. Rural feeder of light construction. Suffers from long spans of light conductor in a few places. Mostly supported by 10/2KN concrete and iron rails. Low creepage distance 1950's insulators have given trouble on this feeder. Some renewal work has been completed to address the worst of these problems. Cable in urban area of Te Kuiti.
Oruatua (FED417) O/H 14.2; U/G 1.7 km	Eastern side of Lake Taupo, north of Motuoapa. 390 ICPs. Part renewed and part very old construction. Cable to new subdivision. Feeder includes Waitetoko and Tauranga-Taupo SWER system.
Otorohanga (FED112) O/H 47.5; U/G 1.4 km	Supply to most of Otorohanga town plus rural area to the southwest. 1151 ICPs. Overhead urban/rural feeder. Urban area is in average condition. The rural section has been partly renewed. Fault current levels are high and connections are often destroyed when through fault currents occur. Pole population is mixed but predominantly 10/2KN concrete and iron rails. More renewal work is planned. Cable in CBD of Otorohanga and out of the zone substation.
Otukou (FED418) O/H 5.9; U/G 0.0 km	Area around Sir Edmund Hillary Outdoor Pursuits Centre. 82 ICPs. Relatively short feeder on Central Plateau with SWER systems attached. Light construction has trouble supporting the snow loadings it is exposed to on the Central Plateau. Some renewal completed. Mostly supported on 10/2KN concrete poles and iron rails. Average condition. Feeder includes Otukou and Mangatepopo Intake SWER systems.
Paerata (FED130) O/H 3.3; U/G 0.5 km	Supply to Mokai Energy Park, Glasshouse and other customers. 9 ICPs. Mostly new - constructed as part of energy park supply. It does include some older sections that were part of the Mokai feeder. Cable to the new subdivision.
Piopio (FED116) O/H 52.1; U/G 0.1 km	Supply to Piopio rural settlement and surrounding rural area to north. 455 ICPs. Good condition overall with some renewal completed. Feeder does have long spans with close conductor spacings. It is predominantly supported by 10/2KN concrete poles. Cable to ground mount transformers in village.
Pureora (FED119) O/H 52.1; U/G 0.1 km	West of Whakamaru including supply to Crusader Meats. 172 ICPs. Supplies dairying and industrial load and is in average condition with parts having been renewed. Medium size conductor on mix of wooden and 10/2KN concrete poles. Two more regulators and some upgrading are included in the plan to support voltage levels. Cable out of zone substation.
Rangipo / Hautu (FED424) O/H 28.9; U/G 6.1 km	Supply to areas east of Turangi, servicing 858 ICPs. Sections have been rebuilt in conjunction with work on East Taupo 33kV. Remainder is lightly constructed and in average condition. Some renewal has been completed. Cable across Tongariro River and at the prison. Feeder includes Tokaanu River and Korohe SWER systems.

11kV DISTRIBUTION NETWORK	
Feeder/Length	Description
Rangitoto (FED106) O/H 68.8; U/G 3.1 km	Area east of Te Kuiti servicing 722 ICPs. Average condition with some renewal work completed. Mixture of concrete 10/2KN, wooden and iron rail poles with some long spans and close conductor spacings. Cable in the urban area of Te Kuiti. Feeder includes Gardiner Road SWER system.
Raurimu (FED410) O/H 156.4; U/G 0.1 km	Raurimu village and rural areas to east, west and south. 285 ICPs. Average to poor condition and predominantly supported by iron rails. Limited income is available from this extremely rugged and remote area. Includes some major SWER lines that go deep into the King Country.
Rural (FED126) O/H 4.7; U/G 0.0 km	Rural area surrounding Taharoa. 109 ICPs. Average to poor condition rural feeder exposed to the harsh west coast seaside environment. Has a mixture of wooden, concrete and iron rail poles. Corroded hardware and conduction is an issue with this feeder. The feeder has small customer numbers and renewal is balanced against returns. Cable to ground mount transformers.
Southern (FED409) O/H 125.5; U/G 0.0 km	Area south of Manunui including connection for Piriaka distributed generation. 593 ICPs. Generally in good condition. The feeder is predominantly supported on 10/2KN concrete poles and has a number of long spans that are prone to clashing during periods of strong winds. Much of the feeder has conjoint SWER systems.
Tangiwai (FED416) O/H 84.3; U/G 1.9 km	Area east of Ohakune servicing 651 ICPs. Average condition with some renewal having been completed. This feeder is located in a moderate to heavy snow area and the inherent design has no allowance for ice loadings. The poles are either iron rails or 10/2KN concretes. Cable to subdivision.
Te Kuiti South (FED104) O/H 24.0; U/G 1.1 km	Part of Te Kuiti town and rural area to south. 575 ICPs. Average condition feeder principally supported on 10/2kN concrete poles. Has a number of long spans that are prone to clashing during periods of strong winds and aged insulators issues. Some renewal work completed. Cable from substation and in urban area of town.
Te Kuiti Town (FED105) O/H 2.0; U/G 0.8 km	Central area of Te Kuiti servicing 145 ICPs. Average condition with some renewal completed. Mostly supported by 10/2KN concrete poles and has a mix of AL and CU conductors. Suffers from joint failure when exposed to through fault currents. Cable from substation and in urban area of town.
Te Mapara (FED117) O/H 84.0; U/G 0.1 km	Area south east of Piopio servicing 230 ICPs. Rural feeder in good condition with some renewal complete. Mixture of wooden and concrete poles. Cable from substation. Feeder includes SWER systems.
Tihoi (FED124) O/H 65.6; U/G 0.0 km	Western bays area of Lake Taupo, servicing 206 ICPs. Average condition with some renewal completed. Parts of feeder have an on-going tree problem due to a large number of tree blocks owned by absentee landowners. Feeder includes Tihoi SWER system.
Tirohanga (FED129) O/H 68.8; U/G 5.1 km	Western bays area of Lake Taupo. 240 ICPs. Average condition with some renewal complete. Cable to subdivision.
Tokaanu (FED420) O/H 0.0; U/G 1.2 km	Tokaanu town and marina. 84 ICPs. Cable in urban area and supply to marina is mainly in good condition. Includes some SWER.
Tuhua (FED422) O/H 41.4; U/G 0.0 km	Remote rural area around Ongarue servicing 143 ICPs. Average condition with a number of SWER lines connected towards its ends. Supported by mostly 10/2KN concrete poles and iron rails.
Turangi (FED423) O/H 0.9; U/G 9.2 km	Supply to Turangi Town and surrounding area. 1097 ICPs. Mostly underground feeder. The overhead section that supplies the underground is has been changed from a double circuit to a single circuit. Cable in urban areas.

11kV DISTRIBUTION NETWORK	
Feeder/Length	Description
Turoa (FED415) O/H 34.6; U/G 24.2 km	Turoa ski field and urban rural area to bottom of mountain. 444 ICPS. Main purpose is supply to Turoa ski field. The feeder is constructed with heavy conductor on moderate strength poles. There are a few long spans with inadequate conductor spacing. The overall condition is good but the line is generally constructed under strength for the heavy snow area it is in. Cable in urban area and at ski field.
Waihaha (FED426) O/H 77.2; U/G 2.3 km	Area around the south western edge of Lake Taupo. Services 317 ICPS. A feeder in mixed condition with a significant length of SWER. The lines are mostly supported on 10/2KN concrete poles and iron rails. Spans are long and conductor sizes are small. Some renewal has been completed however the expenditure needed is hard to justify. Cable to the Whareroa holiday area.
Waiotaka (FED427) O/H 9.4; U/G 1.2 km	Supply to prison and area east of Turangi. 8 ICPS. This feeder was originally part of the Rangipo / Hautu feeder. It was split off and renamed Waiotaka in conjunction with the new container substation (commissioned in 2007) to provide security of supply to prison and surrounding area. Average condition with some renewal work having been completed. Cable at the prison. Feeder includes Hautu SWER system.
Waitomo (FED108) O/H 10.5; U/G 0.70 km	Northern Te Kuiti area. Includes town, rural and industrial sites. 432 ICPS. Average condition, predominately rural feeder supplying part of Te Kuiti town, rural areas to the north and a major lime plant. Medium size conductor mostly supported on 10/2KN concrete poles. Has some larger spans with close conductor spacing. Cable from the substation and in the Te Kuiti urban area.
Western (FED403) O/H 117.8; U/G 1.2 km	Rural area north west of Taumarunui. 438 ICPS. Supplies part of Taumarunui and travels west along the Whanganui River until breaking into a number of SWER systems. Generally in poor condition with lines being mainly supported by 10/2KN concrete poles and iron rails. Some renewal has commenced and security has been increased by establishing a link to the Northern feeder. Cable from the substation and in urban areas of Taumarunui.
Whakamaru (FED120) O/H 81.9; U/G 1.2 km	Whakamaru village and surrounding area. 579 ICPS. Rural feeder supplying dairying area and Whakamaru Village. Overall feeder is in average condition with sections having been renewed. Cable from the substation.
Wharepapa (FED122) O/H 102.4; U/G 0.5 km	Large rural dairying area west of Arohena. 405 ICPS. A long rural feeder supplying dairying area and includes a large amount of 16sq.mm Cu conductor supported on iron rail and hardwood poles. Some renewal work has been recently completed. Further renewal, including some conductor, is included in this plan. Cable to transformer.
Winstones (FED428) O/H 0.1; U/G 0.0 km	East of Ohakune. 3 ICPS. Short feeder servicing Winstones industrial site at the end of the Tangiwai feeder. Good overall condition. Some cable within the industrial site.

Table 3.7: Distribution of 11kV Distribution Lines

3.2.4.2 Distribution Poles

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

The age profile of distribution poles by pole type is shown in Figure 3.13 below.

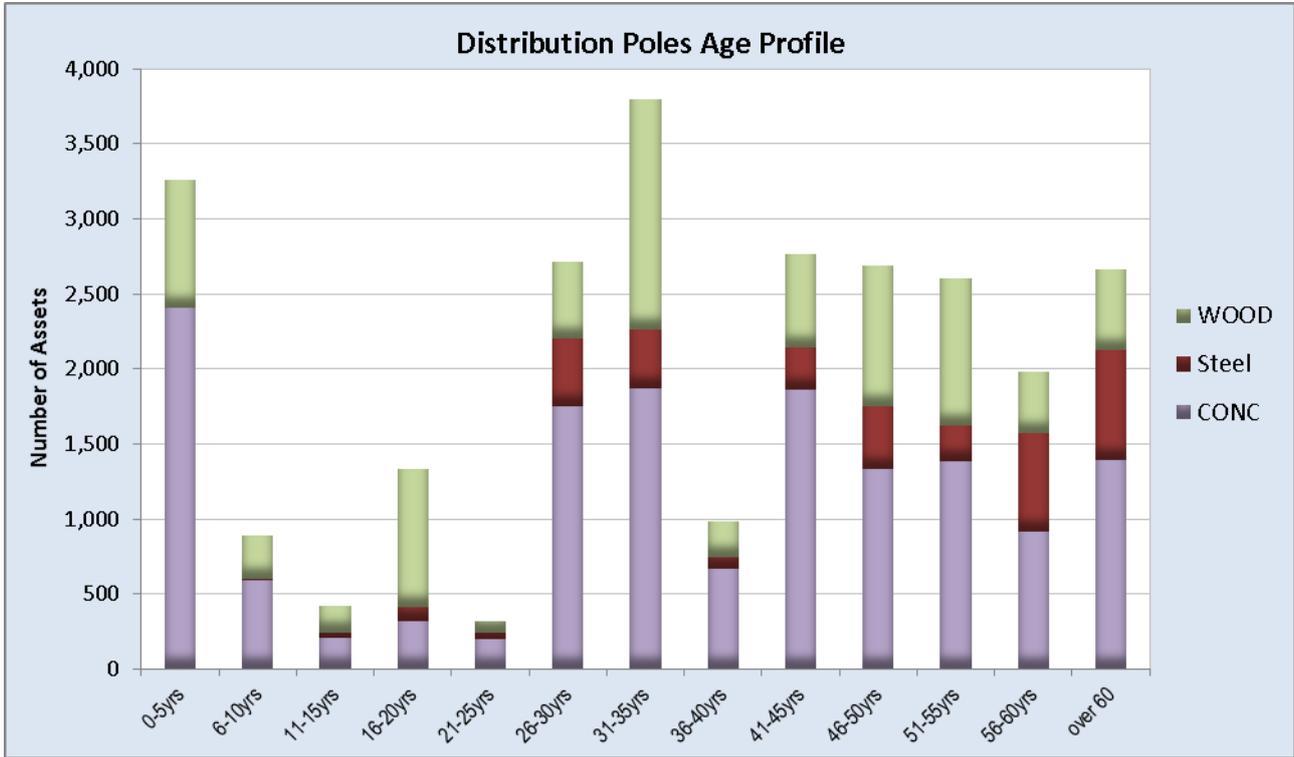


Figure 3.13: Age Profile of Distribution Network Poles by Pole Type

3.2.4.3 Distribution Cables

The age profile of distribution cable is shown in Figure 3.14

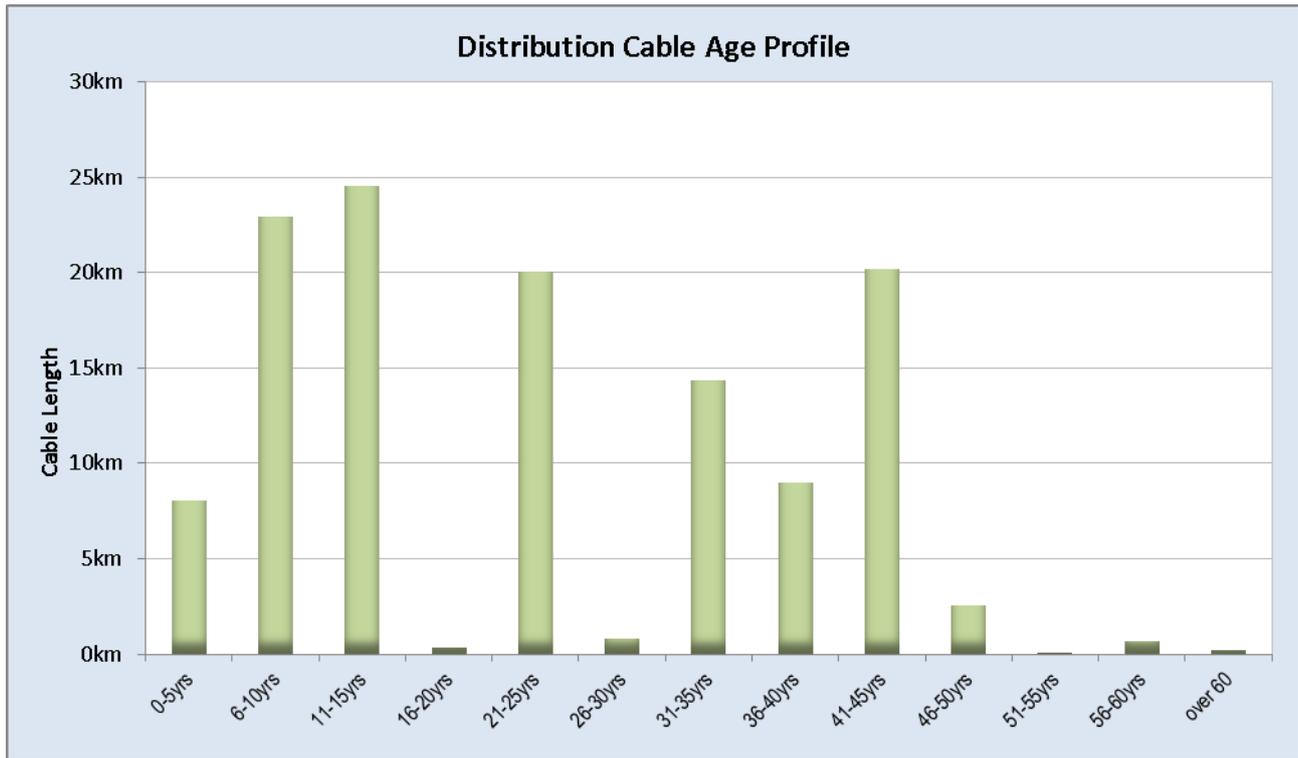


Figure 3.14: Age Profile of Distribution Network Cable

3.2.4.4 Inherent 11kV Distribution Issues

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

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

3.2.4.5 SWER Configuration

Isolation transformers feed all Single Wire Earth Return (SWER) systems. The revised code of practice for ECP41 SWER operation is now in use. It has moved away from the 8.0 amp limit for return current to a risk based approach to voltages on the earth of isolating transformers. TLC continues to monitor loads on the network SWER isolating transformers.

3.2.5 11kV Distribution Switchgear

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

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

Table 3.8 summarises the identified distribution switchgear and control assets. The figures include 236 switchgear assets contained in the 76 Ring Main Units on the distribution network. Figure 3.15 illustrates the age profile of these assets. A significant number of the assets between 31-35 years are assets of unknown age and carry a default installation date of 1/7/1974.

11kV DISTRIBUTION SWITCHGEAR	
Asset Type	Number
11kV Air Break Switches	650
11kV Circuit Breakers	136
11kV Fused Switches/Fused Links	972
11kV Load Break Switches	183
11kV Reclosers	113
11kV RTE Integrated Transformer Switches	67
11kV Sectionalisers	81
11kV Solid Links	470
11kV Transformer/Tap-off Fuses	5407
Total	8079

Table 3.8: 11kV Distribution Switchgear and Control Assets

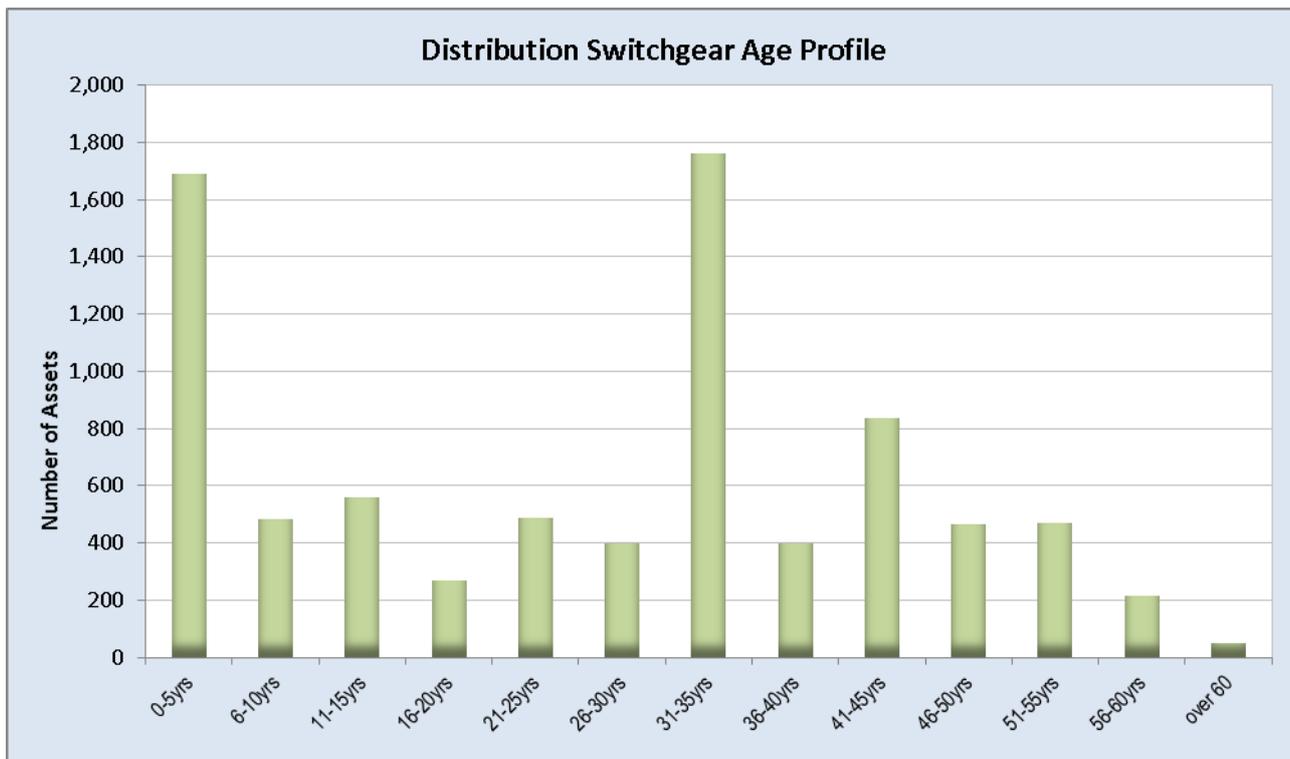


Figure 3.15: Age Profile of 11kV Switchgear Assets

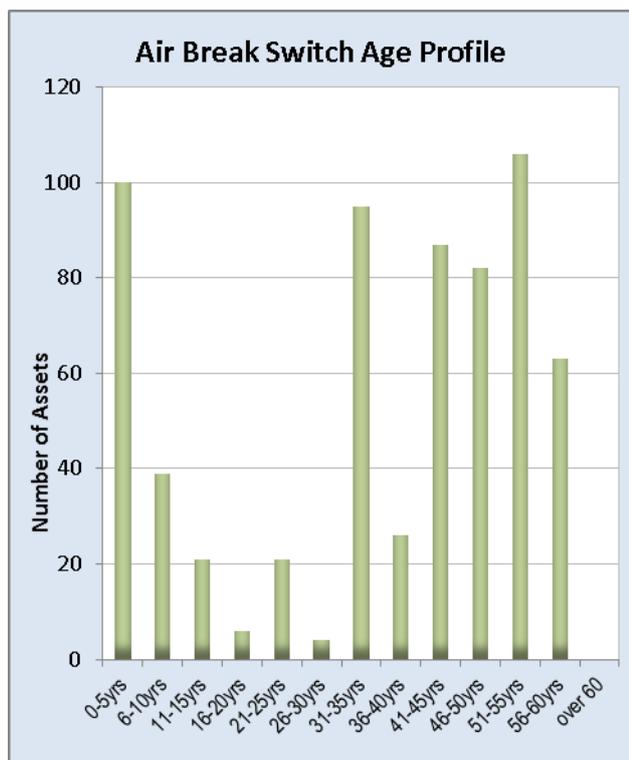


Figure 3.16: Age Profile of 11kV Air Break Switches

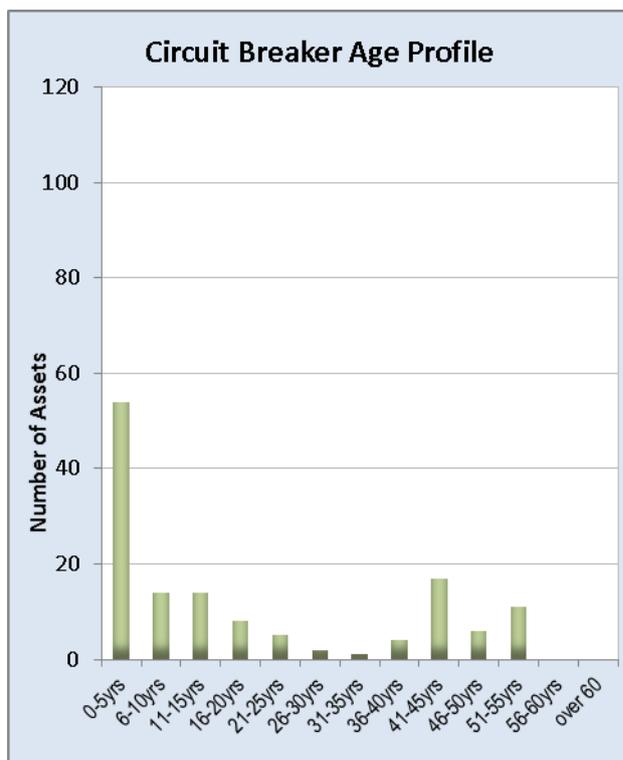


Figure 3.17: Age Profile of 11kV Circuit Breakers

Figures 3.16 and 3.17 show the age profile of distribution Air Break Switches and Circuit Breakers respectively.

3.2.6 Distribution Substation/Transformers

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

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

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

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

Table 3.9 summarises TLC's distribution transformer assets by mounting, phasing and kVA.

DISTRIBUTION TRANSFORMER SUMMARY									
Pole Mount	<=15	30	50	100	200	300	500	>500	Total
Single Phase	2527	366	33	2	1				2930
Two Phase	154	32	9						195
Three Phase	401	576	273	194	23	4		1	1471
Ground Mount									
Single Phase	8	6	3	1					21
Three Phase	6	15	22	57	191	125	34	35	482
Total	3096	995	340	254	215	129	34	36	5099

Table 3.9: Distribution Transformer Summary

Figure 3.18 illustrates the age profile and quantity by transformer mounting. A significant number of the assets between 31-35 years are assets of unknown age and carry a default installation date of 1/7/1974.

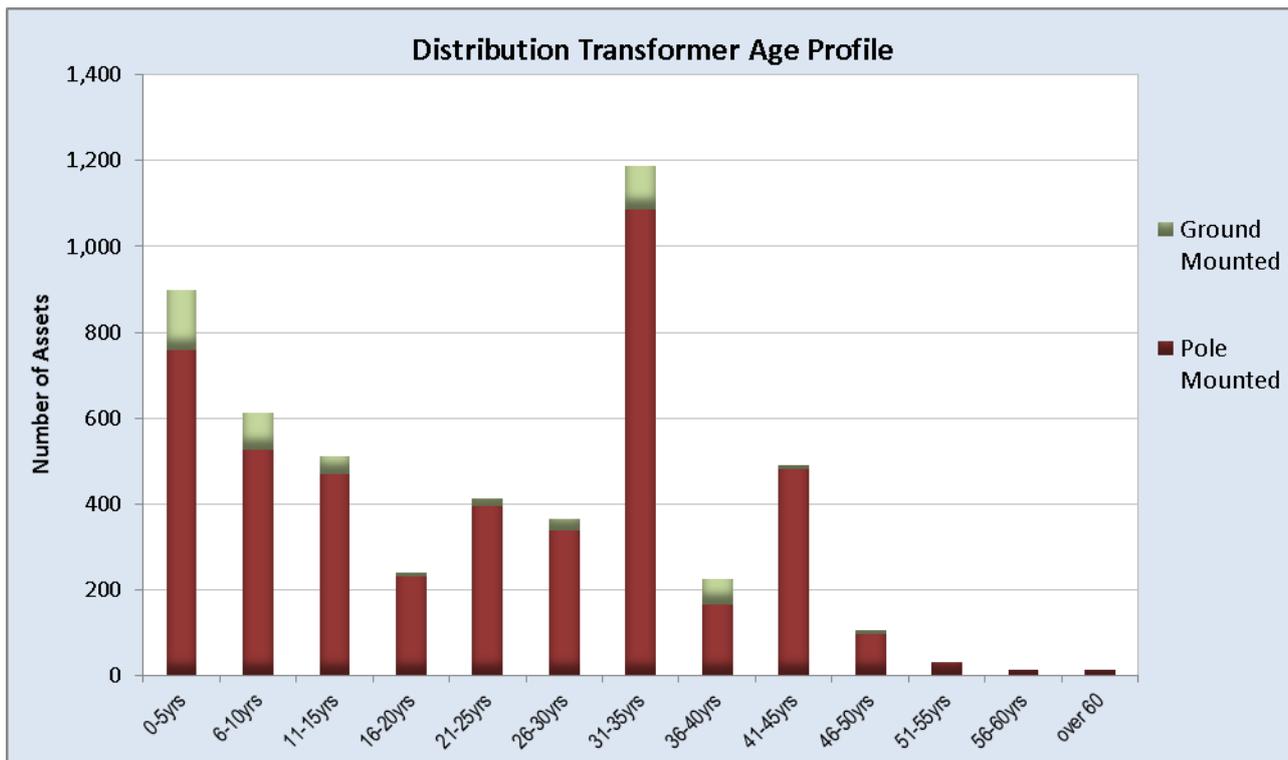


Figure 3.18: Distribution Transformer Age Profile

3.2.7 Low Voltage Distribution Network

3.2.7.1 Low Voltage (LV) Assets

The LV network operates at 400/230V and is mostly overhead line. LV assets include poles, conductor, cable and pillar boxes. The LV assets are aging with a focus on the 33 and 11kV due to its condition and impact on reliability.

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

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

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

The LV data held about the network is limited but improving as inspections continue. A simplified breakdown of known LV assets is shown in Table 3.10

LOW VOLTAGE NETWORK ASSETS			
Assets	Units	LV Circuit	km
Poles – Concrete (inc Steel)	852	Overhead Circuit	427
Poles – Wood.....	4128	Underground Circuit	130
Pillar Boxes	4055	Streetlight Circuit	48

Table 3.10: Breakdown of LV Assets

The age profiles of LV poles (by type) and cables (by length) are shown in Figures 3.19 and 3.20. A significant number of the assets between 31-35 years are assets of unknown age and carry a default installation date of 1/7/1974.

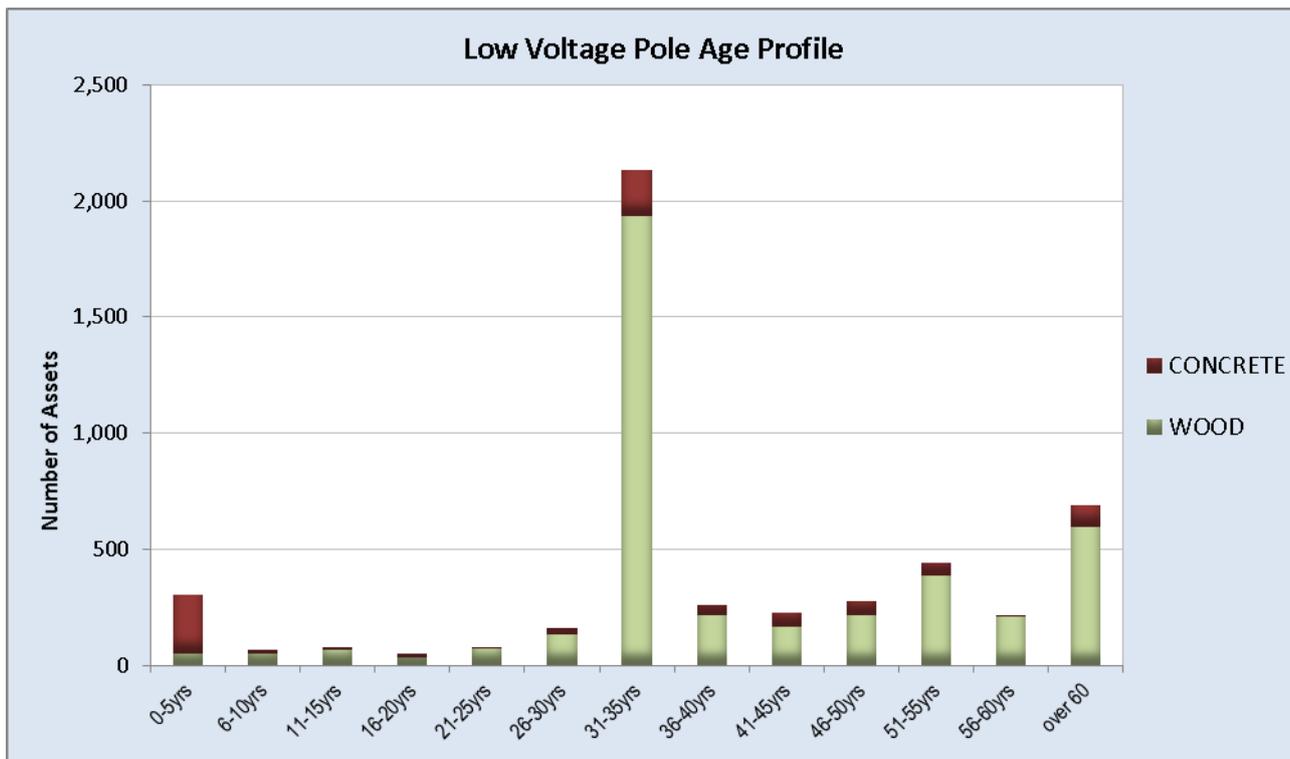


Figure 3.19: Age Profile of Low Voltage Poles

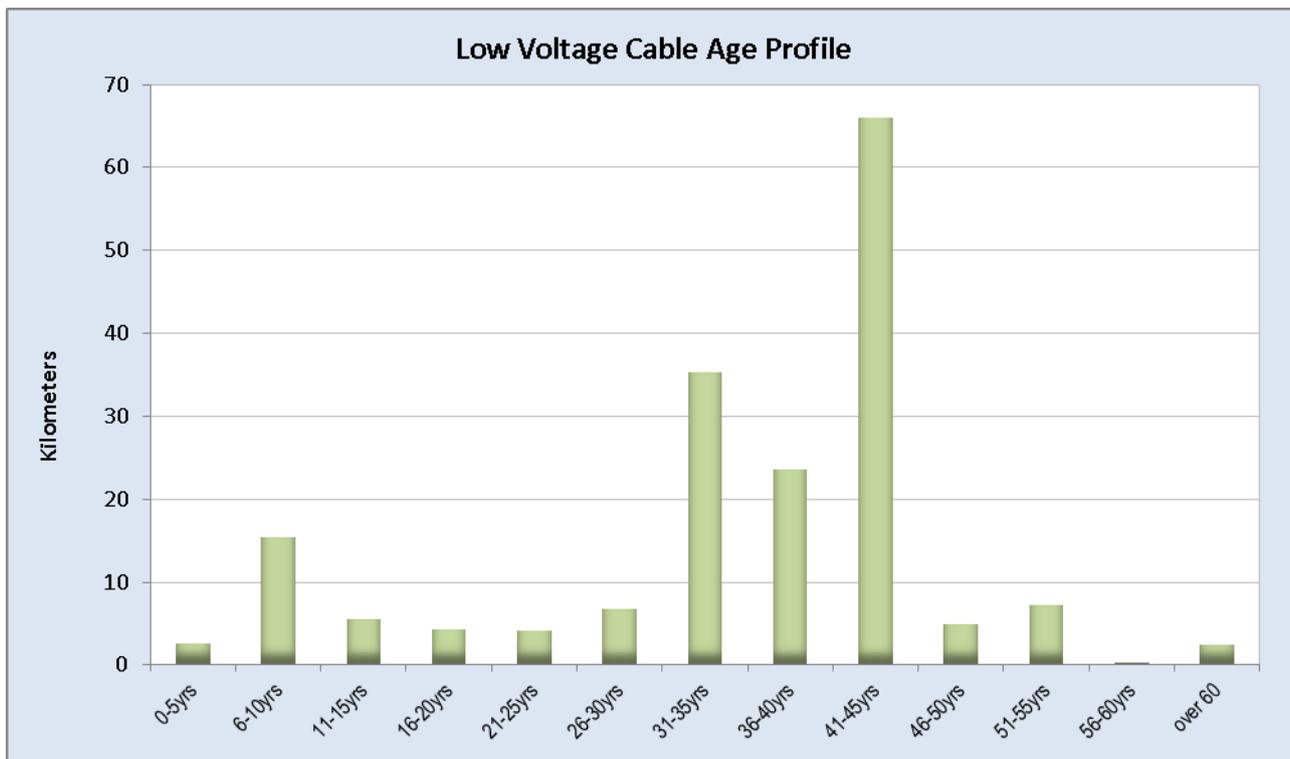


Figure 3.20: Age Profile of LV Cable (including Streetlight)

3.2.7.2 Customer Service Connection Points

The identified customer service connection points (ICPs) on the network total 24,423. This figure does not include meters and relay assets. Figure 3.21 illustrates the location of ICP sites across the network based on the source Grid Exit Point.

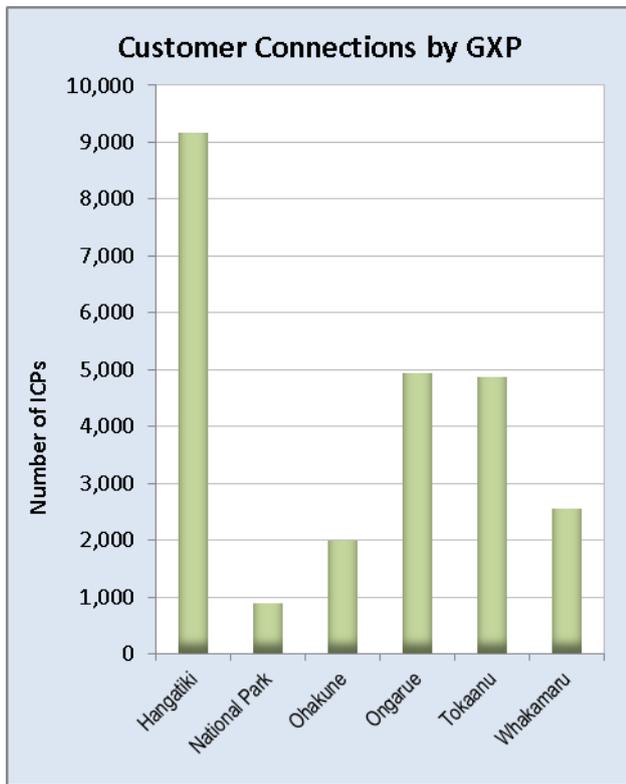


Figure 3.21: ICPs by Grid Exit Point

3.2.8 Secondary Assets

3.2.8.1 Voltage Regulators

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

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

Systemic issues leading to the premature replacement of regulators include:

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

Table 3.11 provides a summary of voltage regulators. Figure 3.22 illustrates the age profile of these assets.

VOLTAGE REGULATOR UNITS					
Regulator Units	<=100 Amp	150 Amp	200 Amp	300 Amp	Total
Single Phase	6	20	33	8	67
Three Phase	2	1		1	4
Total	8	21	33	9	71

Table 3.11: Voltage Regulator Summary

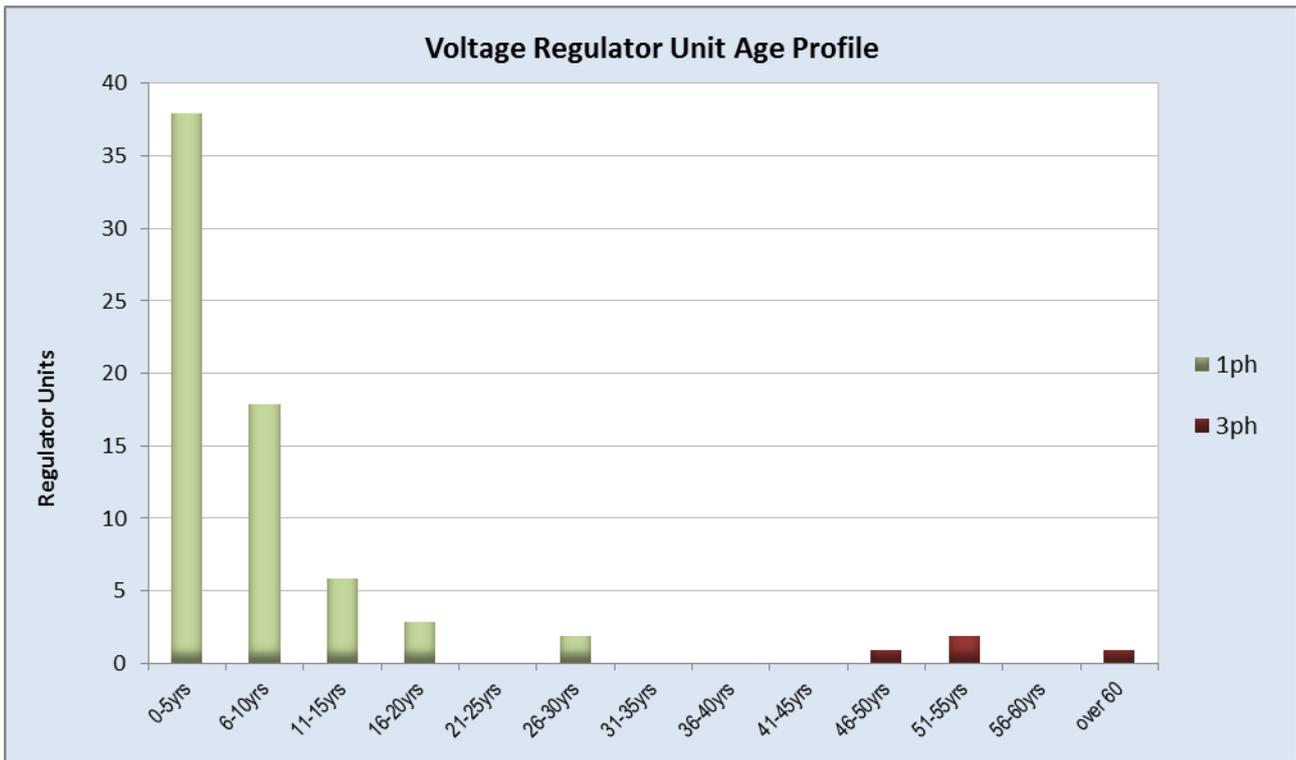


Figure 3.22: Regulator Age Profile

3.2.8.2 Ripple Injection Systems

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

Table 3.12 lists the injection plants, frequencies, and injection voltages.

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

Table 3.12: Ripple Injection Plants

The exchange from the 725 Hz relays with 317 Hz devices has been modified to allow the deployment of advanced meters incorporating a relay across the entire network so that customer demands can be fully measured. It is expected that the advanced meter deployment will be completed within the next 18 months. The priorities for this deployment have 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 two new 33kV injection plants at Hangatiki and Whakamaru are physically enclosed in 40 foot containers to ensure they are modular and have adequate security. The old Landis and Gyr plants will be decommissioned once the advanced meters have been installed. (The Maraetai unit was decommissioned in early 2015.)

The southern system injects into the 33kV network, which has the advantage of removing any difficulty of adding 33/11kV zone substations. The 317 Hz system also has the advantage of enabling good signal propagation throughout the downstream network. The present plant controllers and relays are not set up to allow load to be switched if the frequency begins to fall. There are little known harmonic interference problems with the southern plants. The northern regions are supplied by old 11kV 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 33/11kV transformers and create new zone substations without the loss of load control signals. Figure 3.23 indicates the age of load control plants.

The TLC owned ripple relays are 80% modern programmable electronic type. The remainder are old, electro-mechanical relays. The controlled load is spread across 10 channels, which is mainly water heater load but does include other customer designated loads. This spread of channels allows for close control of load without step changes that can affect voltage on feeders.

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

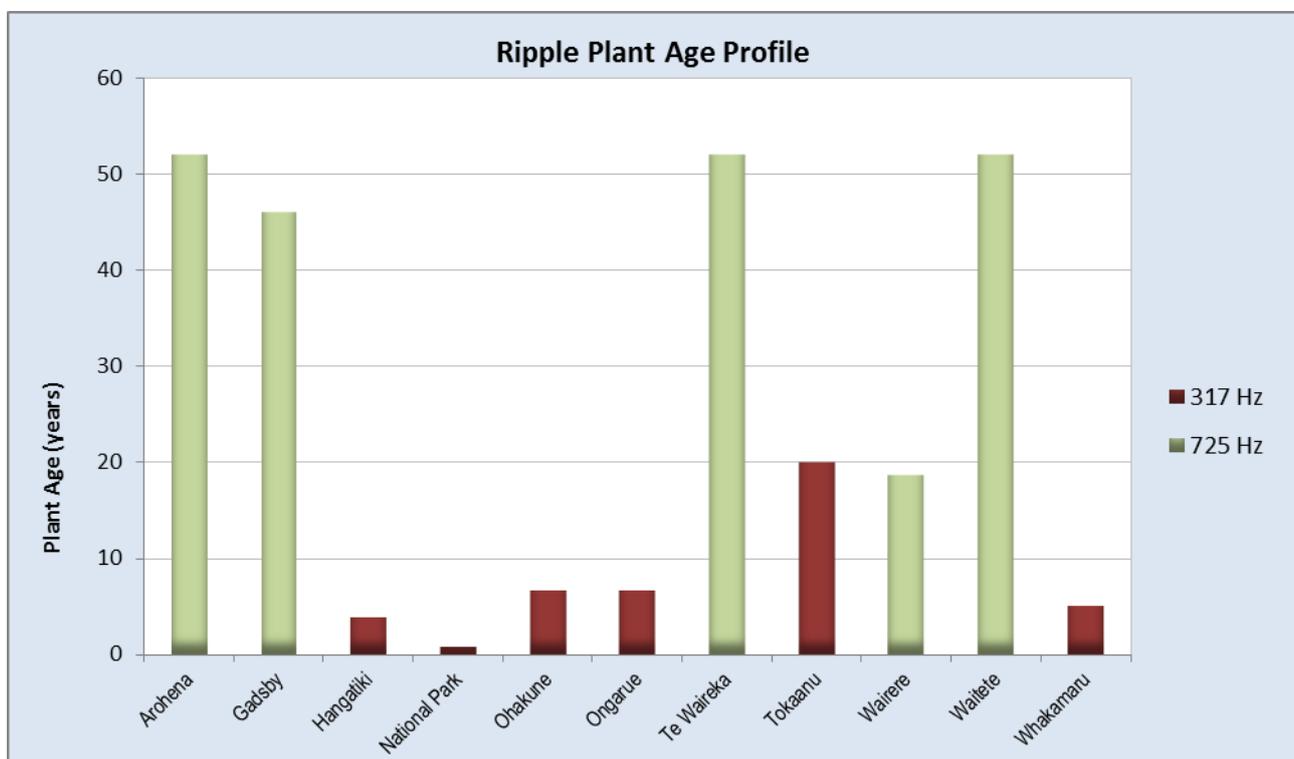


Figure 3.23: Age Profiles of Ripple (Load Control) Plants

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

There is no redundancy in any of the load control systems. A failure will result in loss of signal until a unit is repaired, i.e. there are no n-1 components in any of the plants. Maintenance contracts with suppliers guarantee the holding of spare parts up to 10 years of service age. After this supply is not guaranteed but parts generally remain available for the following 5 years. Installation of parts takes 12-30 hours once received.

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

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

3.2.8.3 SCADA and Voice Radio

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

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

The network incorporates six E-Band (150 – 155 MHz), radio repeaters providing voice communication throughout the operational area. Given the terrain and limited cell phone coverage this is often the only available communications. A further eight repeaters divided across three sub communication networks provide a complimentary low speed (1200bps) SCADA transmission platform to access the 100 plus remote terminal units.

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

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

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

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

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

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

3.2.8.3.1 Data Communication

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

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

The SCADA and Voice Radio Equipment summary shown in Table 3.13 includes the site locations. Each site comprises radio componentry – all in good condition - and other ancillaries. The age of communication equipment will remain relatively constant.

3.2.8.3.2 Voice Radio Equipment

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

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

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

Table 3.13: SCADA and Voice Radio Equipment Summary

The SCADA and Voice Radio Age Profile shown in Figure 3.24 shows the average asset age at key sites. Network diagrams for these are shown in Figures 3.25 TLC SCADA Radio Network and 3.26 TLC Voice Radio Network respectively.

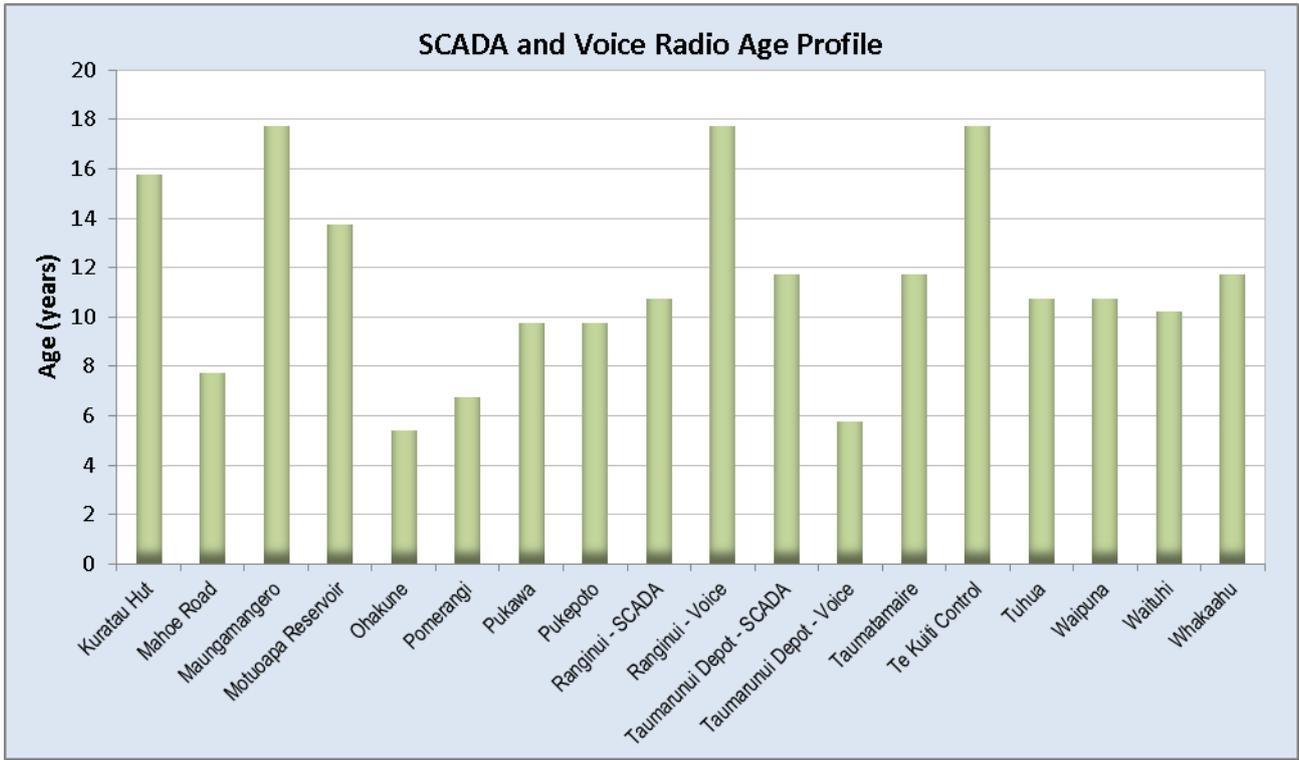


Figure 3.24: SCADA and Voice Radio Age Profile

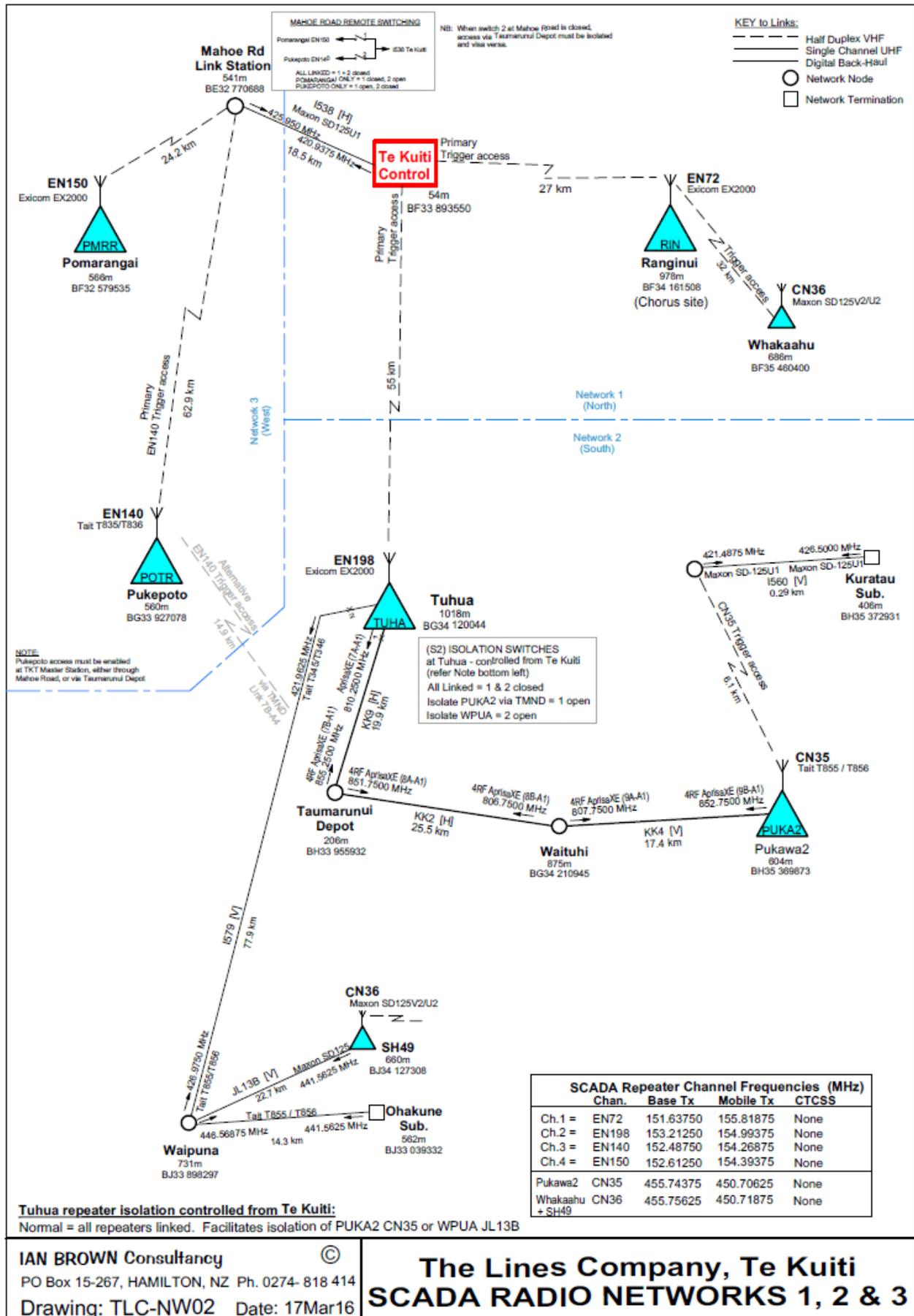


Figure 3.25: TLC SCADA Radio Network

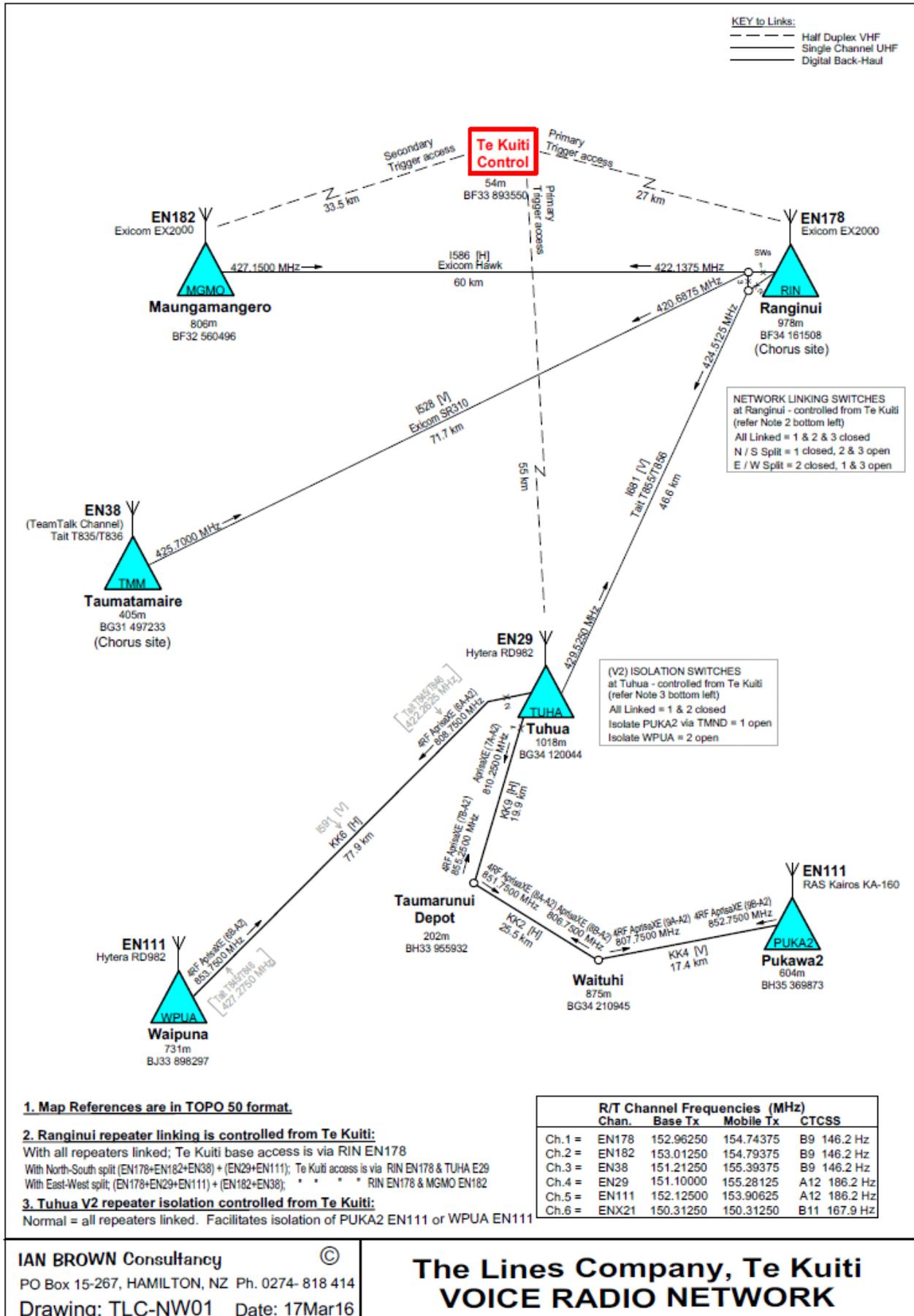


Figure 3.26: TLC Voice Radio Network

3.2.8.4 Mobile Emergency Generator and Injection Transformer

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

The interconnection between the 11kV 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 Mobile Capacitor Banks

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

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

The 3 of the fixed capacitor banks are located on the Wharepapa, Huirimu and Pureora feeder. There are also fixed capacitor banks at the Tuhua and Borough zone substations.

3.2.8.6 Metering Assets

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

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

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

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

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4. *Targets and Performance*

To ensure that TLC is providing a service in line with customers' expectations, TLC has consulted with customers through surveys, customer clinics, focus groups and other consultation meetings. TLC also consults with stakeholders and researches other industry performance.

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

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

The key performance targets are:

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

The service performance targets in this section are used to:

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

4.1 Historical Reliability Performance

The performance of the TLC network has been steadily improving, as the renewal programmes started in the mid-2000's takes effect on SAIDI performance, Figure 4.1. Transpower related outages are not included. Outage performance has stabilised around the target of 307 SAIDI minutes.

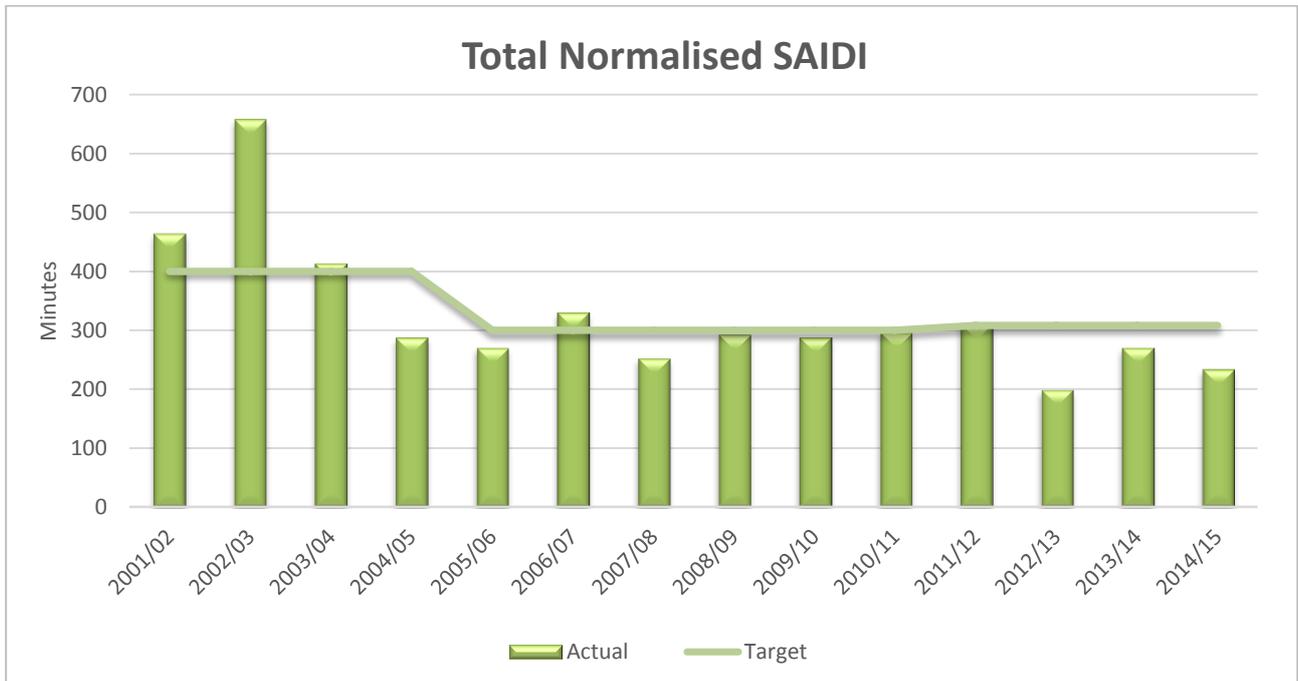


Figure 4.1: 2002-2015 Total SAIDI (excluding Transpower)

Figure 4.2 shows the historical data for SAIFI along with TLCs performance target. While SAIDI is relatively stable, there is concern that SAIFI may be increasing and at best is flat.

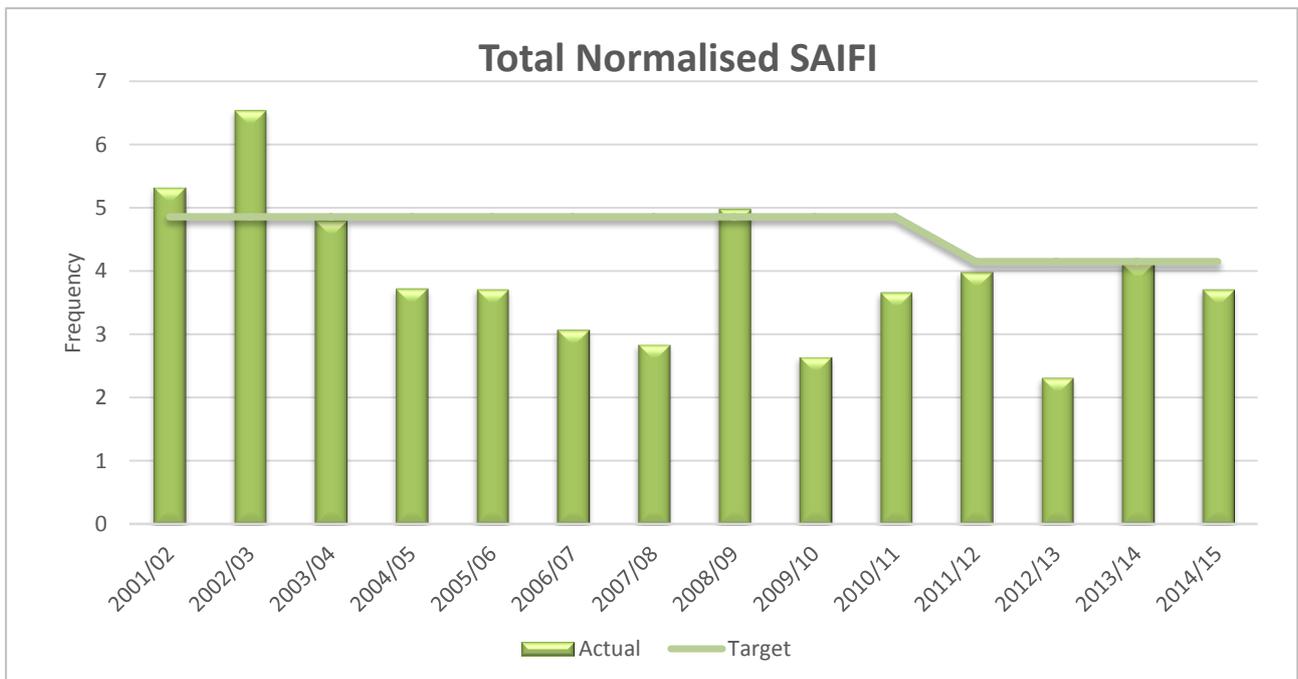


Figure 4.2: 2002-2015 Total SAIFI (excluding Transpower)

4.2 Regulatory Standards

4.2.1 2015-2020 Regulatory Changes

4.2.1.1 Overview

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

The SAIDI and SAIFI limits from 2015/16 are set at one standard deviation above the 10-year historical average, which is the same for the SAIDI and SAIFI caps under the quality incentive scheme. The new regulatory SAIDI and SAIFI targets and incentive limits are outlined in Table 4.1 below. These SAIDI and SAIFI totals emphasise unplanned outages, with planned outages being weighted at 50%. To limit the impact of severe weather events on the annual reliability measures, the maximum daily SAIDI or SAIFI figures are limited to normalised values of 10.97 SAIDI minutes and 0.144 SAIFI.

REGULATORY TARGETS AS AT 1ST APRIL 2015			
	Collar	Target	Cap
SAIDI	183.40	208.80	234.20
SAIFI	2.67	3.07	3.47

Table 4.1: Regulatory Targets as at 1st April 2015

The revenue linked incentive scheme is linked to the cap and collar limits outlined above. Under this scheme future revenue is adjusted linearly, based above or below the target reliability level. If reliability is better than the target, then future revenues will be increased. Likewise, if reliability is worse than the target, then future revenue will be reduced. If the cap is breached for either SAIDI or SAIFI in two-out-of-three consecutive years then TLC would be deemed non-compliant and subject to investigation as to the cause and possible penalties under section 87 of the Commerce Act.

4.2.1.2 Planned/Unplanned Targets

As discussed in the preceding overview, the target figures are all based on normalised values. Table 4.2 lists the SAIDI targets by outage type and Table 4.3 the SAIFI targets. The 2015/16 targets apply for the 2015-2020 regulatory period and reflect the 50% weighting given to planned outages.

PLANNED/UNPLANNED SAIDI TARGETS			
	Planned	Unplanned	Total
2014/15 Target	90.7	217.0	307.7
2015/16 Target (Weighted)	39.5	169.3	208.8

Table 4.2: Planned/Unplanned SAIDI Targets

PLANNED/UNPLANNED SAIFI TARGETS			
	Planned	Unplanned	Total
2014/15 Target	0.70	3.45	4.15
2015/16 Target (Weighted)	0.25	2.82	3.07

Table 4.3: Planned/Unplanned SAIFI Targets

4.2.2 2014/15 Network Performance

4.2.2.1 Targets and Performance by Outage Type

Table 4.4 shows the SAIDI and SAIFI targets, performance and variance by outage type for the 2014/15 reporting period. Figure 4.3 illustrates these figures in a graphical format.

2014/15 SAIDI/SAIFI TARGETS AND PERFORMANCE BY OUTAGE TYPE			
	Planned	Unplanned	Total
SAIDI Target	90.7	217.0	307.7
SAIDI Performance	75.1	203.9	279.0
SAIDI Variance	17.2% (F)	6.0% (F)	9.3% (F)
SAIFI Target	0.70	3.45	4.15
SAIFI Performance	0.42	3.64	4.06
SAIFI Variance	40.0% (F)	5.5% (U)	2.2% (F)

Table 4.4: 2014/15 Targets and Performance by Outage Type

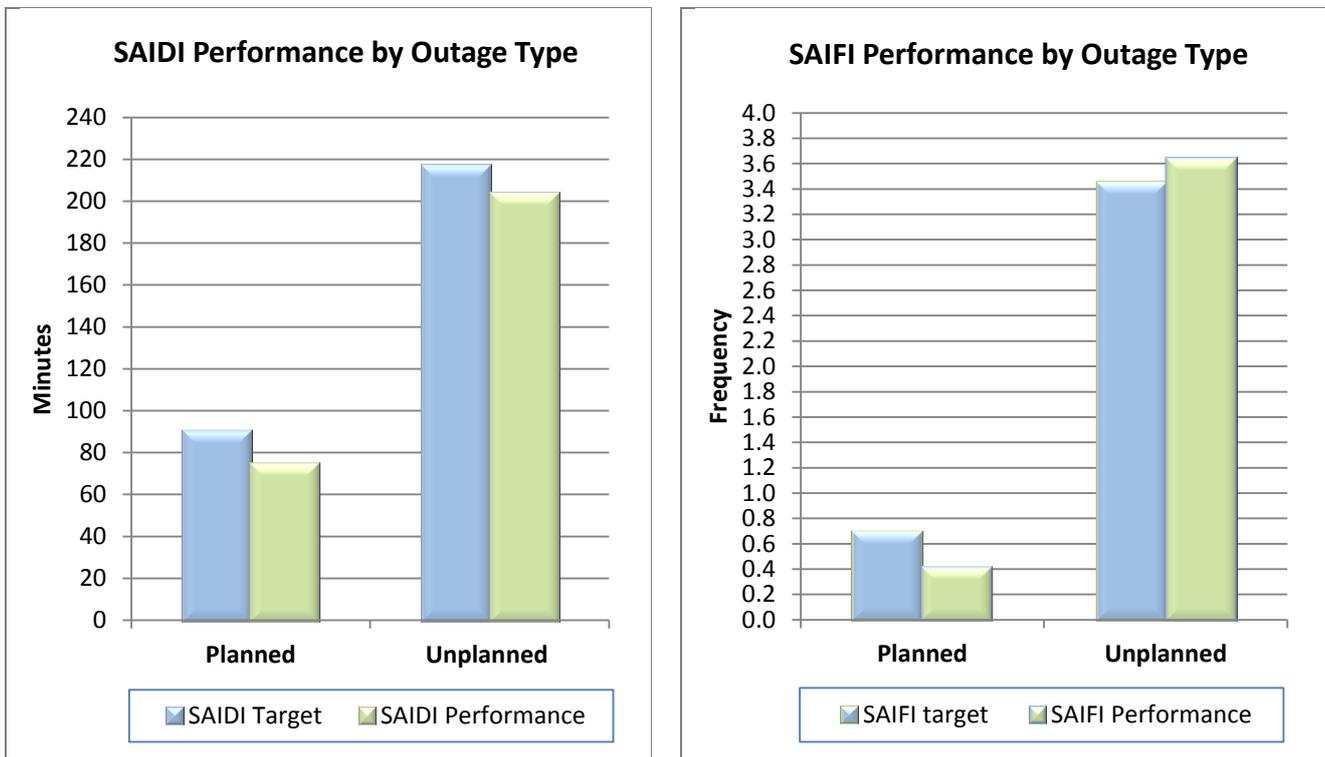


Figure 4.3: SAIDI and SAIFI Performance by Outage Type

2014/15 SAIDI performance was within target for both Planned and Unplanned outages.

The SAIFI performance was within target for planned outages but 5.5% unfavourable for unplanned outages. This was mainly due to an increase in generator use and an increase in unplanned interruptions during extreme storm events in April and October.

4.3 Customer Oriented Performance

TLC saw the need for a modular asset management system where there is correlation between assets and service levels. To meet this, a system was created where assets are grouped and these groups are then aggregated up into service level areas. 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 may be divided into 6 asset groups.

Costs, reliability, valuations etc. can be attributed 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; Figure 4.4 illustrates the areas in geographical layout.

- Urban Service Level A
- Rural Service Levels B, C and D
- Remote Rural Service Levels E and F

The TLC Pricing Methodology (available on the TLC web site) completes the 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 at focus group meetings by stakeholders and other interested parties. They were originally set in 2003 and were reviewed in 2008.

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

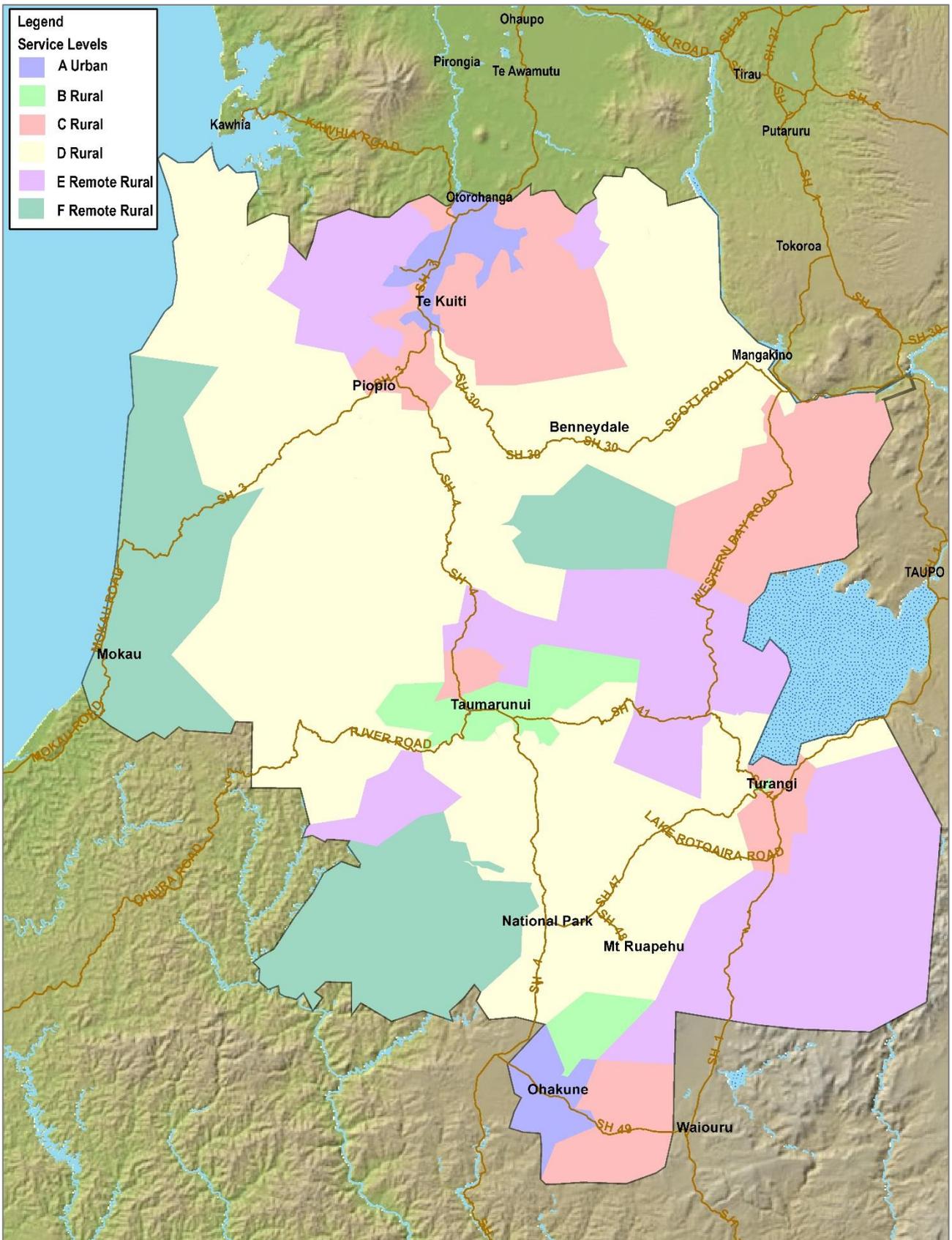


Figure 4.4: Geographical Layout of Service Level Areas

4.3.1 Customer Oriented Performance: Asset Related

The following customer oriented performance targets (asset related) are used. These are set for each of the 6 service levels.

- SAIDI
- Time to restore supply after an unplanned outage
- Maximum number of planned shutdowns per year
- Maximum number of long and short faults per year

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

4.3.1.1 SAIDI Targets and Performance

Table 4.5 documents the SAIDI 2014/15 targets, performance and variance by service level. Figure 4.5 presents this data in a graphical format.

SAIDI 2014/15 TARGETS AND PERFORMANCE BY SERVICE LEVEL							
Service Level Region	Urban A	Rural B	Rural C	Rural D	Remote Rural E	Remote Rural F	Total
SAIDI Target	41.0	36.0	51.0	123.0	20.7	36.0	307.7
SAIDI Performance	50.8	26.1	27.5	133.2	16.7	24.8	279.0
Variance	-27.0% (U)	26.0% (F)	45.0% (F)	-11.0% (U)	16.0% (F)	29.0% (F)	9.3% (F)

Table 4.5: SAIDI Targets and Performance by Service Level

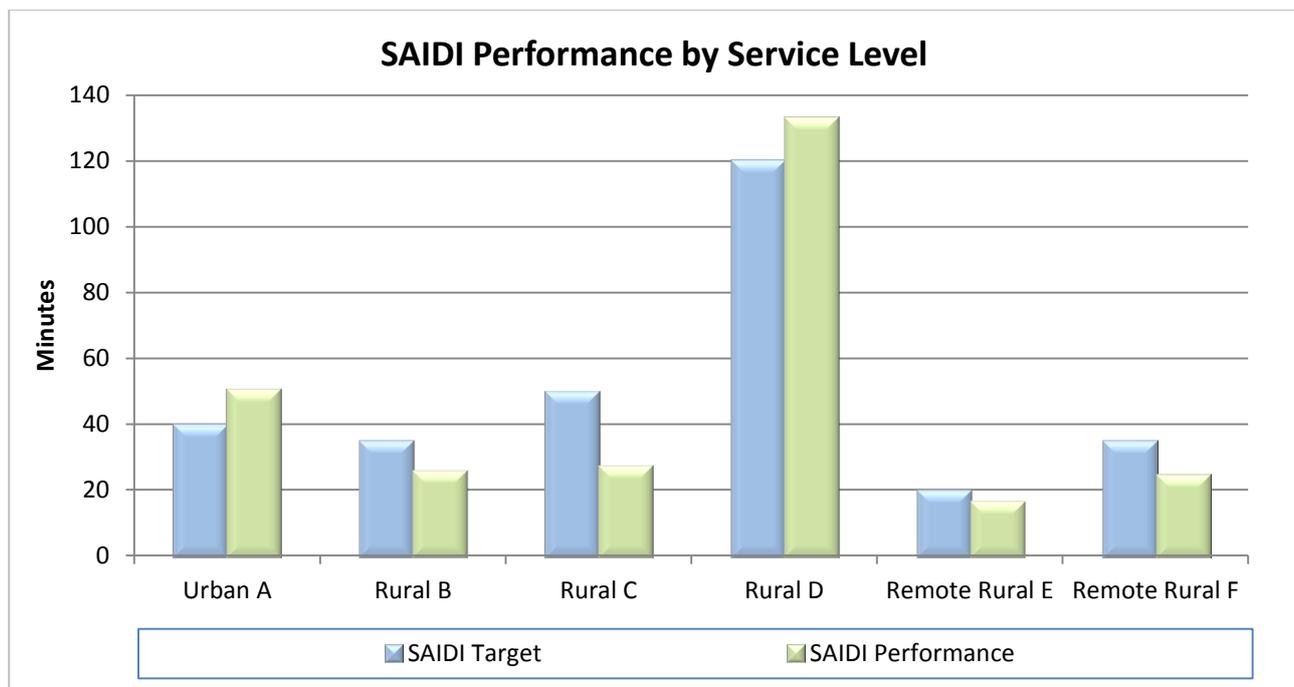


Figure 4.5: SAIDI Performance 2014/15 by Service Level

The main driver in the variances is the storm events in May, September, October and November months. The wind and lightning strikes in these months significantly delayed the restoration of supply to both urban and some rural areas. A number of faults occurred in urban areas when staff were working on rural line renewals; in cases like this it takes time for them to mobilise back into urban areas.

TLC's on-going objective is to continue to target the rural service level regions through the planning period. A number of urban and rural areas are also being targeted for switch automation. This is described in more detail in section 5.

4.3.1.2 Time to Restore Supply

Table 4.6 lists the target and performance figures for maximum times to restore supply by service level. The measuring index of this target is based on the percentage of events that do not exceed the target time.

MAXIMIUM TIME TO RESTORE SUPPLY AFTER AN UNPLANNED OUTAGE (HOURS)						
Service Level Region	Urban A	Rural B	Rural C	Rural D	Remote Rural E	Remote Rural F
Number of Asset Groups	90	16	56	128	23	16
Target Time (Hrs)	3	6	6	6	12	12
Total Number of Unplanned Events	149	58	179	442	101	76
Number of Events where Target Time was Not Met	41	12	26	101	3	5
Target Compliance %	95.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Actual Performance %	72.5% (U)	79.3% (U)	85.5% (U)	77.1% (U)	97.0% (F)	93.4% (F)

Table 4.6: Targets and Performance for Maximum Time to Restore Supply

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

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

- Additional training is taking place on the use of generator by-pass.
- Further automation is being deployed, i.e. automation of a number of key ring main sites.
- Mobile capacitor banks are set up to increase the capacity of back feeds.

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

4.3.1.3 Maximum Number of Planned Shutdowns

Table 4.7 lists the target and performance figures for the Maximum planned shutdowns per year by service level. Achieving this in all cases is not possible because of an extensive renewal programme and a large number of aged hazardous assets. Shutdowns are necessary to complete this work, especially when old hazardous assets are involved. The measuring index of this is based on the percentage of events that complied with this target.

PERFORMANCE TARGETS AND VARIANCES OF THE NUMBER OF PLANNED SHUTDOWNS PER YEAR						
Service Level Region	Urban A	Rural B	Rural C	Rural D	Remote Rural E	Remote Rural F
Number of Asset Groups	90	16	56	128	23	16
Target Number of Shutdowns per Asset Group	2	4	6	6	8	10
Number of Asset Groups where Target was Exceeded	3	2	3	8	1	0
Target Compliance %	95.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Actual Performance %	96.7% (F)	87.5% (U)	94.6% (F)	93.8% (F)	95.7% (F)	100.0% (F)

Table 4.7: Targets and Performance for Maximum Planned Shutdowns

The variances were within expected levels. Only the Rural B region was below the target.

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

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

4.3.1.4 Maximum Number of Unplanned Shutdowns per Year

Table 4.8 lists the target and performance figures for the maximum number of short and long faults per year by service level. The measuring index of this is based on the percentage of events that complied with the target.

PERFORMANCE TARGETS AND VARIANCES OF THE NUMBER OF SHORT AND LONG FAULTS PER YEAR						
Service Level Region	Urban A	Rural B	Rural C	Rural D	Remote Rural E	Remote Rural F
Number of Asset Groups	90	16	56	128	23	16
Target Max Number of Long Faults (> 1 minute)	5	15	15	15	25	25
Number of Asset Groups that Did Not Meet Criteria	3	0	0	0	0	0
Target Compliance %	95.0%	90.0%	90.0%	90.0%	90.0%	90.0%
2014/15 Performance %	96.7% (F)	100.0% (F)	100.0% (F)	100.0% (F)	100.0% (F)	100.0% (F)
Target Max number of Short Faults (< 1 minute)	20	20	60	60	60	160
Number of Asset Groups that Did Not Meet Criteria	1	0	0	0	0	0
Target Compliance %	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%
2014/15 Performance %	98.9% (F)	100.0% (F)	100.0% (F)	100.0% (F)	100.0% (F)	100.0% (F)

Table 4.8: Maximum Number of Short and Long Faults per Year

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

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

Other more general strategies to address this include:

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

4.3.2 Customer Oriented Performance – Service Related

The following customer oriented service related targets are used:

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

4.3.2.1 Telephone Calls Coming into the Organisation

The number of telephone calls TLC receives is a measure of the ability of the organisation to provide information and education to our customers. Experience has shown us that rather than attempt to minimise the number of calls into the organisation we should welcome customer contact and use this opportunity to provide demand response and energy efficiency advice.

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

Table 4.9 list the target and average number of telephone calls coming into the organisation per month.

COMPARISON OF ACTUAL TELEPHONE CALLS AGAINST TARGET (Average per Month)							
Item	2010/11	2011/12	2012/13	2013/14	2014/15	Target	Variation
Monthly Incoming Calls	4098	3932	4854	4798	4525	<4500	0.6% (U)

Table 4.9: Comparison of Monthly Average Telephone Calls against Target

4.3.2.2 Unresolved Complaints

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

Table 4.10 lists the target and actual number of unresolved complaints annually investigated by the EGCC.

COMPARISON OF UNRESOLVED COMPLAINTS AGAINST TARGET							
Item	2010/11	2011/12	2012/13	2013/14	2014/15	Target	Variance
Unresolved Complaints	40	9	41	20	24	20	20% (U)

Table 4.10: Comparison of Unresolved Complaints against Target

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 causes some confusion for customers. The difference between meter measured load and formula loads has contributed to this.
- iii. There was a very active lobby group using the EGCC scheme requirements very effectively.

4.3.2.3 Community Group Meetings

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

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

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

The target was increased in 2014/15 to at least 10 meetings per year, taking into account the addition of regional public meetings. This target is measured by collating reports on meetings presented at the Board of Director's meetings. The target has been set based on the number of meetings that TLC can realistically handle given its present staffing levels.

Table 4.11 lists the target and number of Community Group Meetings.

COMPARISON OF COMMUNITY GROUP MEETINGS AGAINST TARGET							
Item	2010/11	2011/12	2012/13	2013/14	2014/15	Target	Variance
Community Group Meetings	11	6	8	7	10	10	0% (F)

Table 4.11: Comparison of Community Group Meetings against Target

Community Group Meetings met the revised target. These focused on responding to customer queries regarding TLC's pricing methodology, landlord/tenant and vacant installations, and the meter rollout programme.

4.3.2.4 Customer Clinics

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

As shown in Table 4.12, the target is to have 12 customer clinics offered annually. This target is measured by logging the clinics into a database.

COMPARISON OF CUSTOMER CLINICS AGAINST TARGET							
Item	2010/11	2011/12	2012/13	2013/14	2014/15	Target	Variance
Customer Clinics	26	19	17	53	36	12	200% (F)

Table 4.12: Comparison of Customer Clinics against Target

Following a successful year of clinics in 2013/14, the number of clinics in 2014/15 reduced due to decreased demand from customers for face to face clinics. TLC plan to continue to seek clear and simple ways to communicate what we do and why to our customers.

4.3.3 Justification of Customer Oriented Performance Targets

Table 4.13 summarises the justification for customer oriented performance targets.

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

Table 4.13: Justification of Customer Oriented Performance Targets

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

4.4.1 Asset Performance Targets

The following targets are used to measure asset performance:

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

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

4.4.1.1 Power Quality

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

4.4.1.2 Voltage Complaints

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

4.4.1.3 Voltage Studies: Legacy Issues

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

Table 4.14 lists the targets and performance for voltage complaints and Legacy voltage issues.

COMPARISON OF VOLTAGE PERFORMANCE ACTUALS AND TARGETS							
Item	2010/11	2011/12	2012/13	2013/14	2014/15	Target	Variance
Voltage Complaints	10	1	2	2	6	10	40.0% (F)
Resolved Legacy Voltage Issues	1	3	2	1	2	2	0.0% (F)

Table 4.14: Asset Performance: Comparison of Quality Targets versus Actuals

2014/15 voltage complaints were higher than the previous year but remain within target, and two legacy voltage issues were resolved.

The need to target legacy voltage issues is on-going and one of the drivers behind network constraints and load controller settings. Two voltage regulators were installed in 2014/15 to overcome legacy voltage problems.

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

4.4.1.4 Voltage Surge Complaints

Voltage surges can destroy appliances which cause inconvenience, nuisance and cost to customers. TLC has implemented a system of measuring the complaints and the related letters it has to send to customers when they claim this damage against their insurance policies. TLC has set a performance target to benchmark and measure these complaints. TLC has set a target to not exceed 80 voltage surge complaints per year. Table 4.15 lists the voltage surge targets and performance. (These are measured from the number of complaints and resulting insurance claim letters).

VOLTAGE SURGE PERFORMANCE ACTUALS AND TARGET					
Item	2012/13	2013/14	2014/15	Target	Variance
Number of surge events (Measured and compared to numbers of customers)	52	42	45	80	44.0% (F)

Table 4.15: Voltage Surge Performance

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

4.4.1.5 Harmonic Levels in Various Key Locations

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

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

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

Table 4.16 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 over time, and ensure that levels are stable. While the number of instances where the 3-Wire System target was exceeded has increased over the previous years it is still within the expected annual variance of 5%.

HARMONIC DISTORTION: ACTUALS AND TARGETS					
System	Description	2012/13	2013/14	2014/15	2015/16
Harmonic Levels 3-Wire Systems Target is 10%	Measured Sites	87	N/A	87	85
	Instance where target exceeded	6.9% (F)	N/A	2.3% (F)	7.1% (F)
Harmonic Levels SWER Systems Target is 30%	Measured Sites	60	N/A	62	50
	Instance where target exceeded	0.0% (F)	N/A	1.6% (F)	0.0% (F)

Table 4.16: Asset Performance: Harmonic Distortion Targets and Actual

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

4.4.1.6 System Component Performance: Failures

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

The renewal programme should reduce the number of component failures that lead to faults. Previous performance and future targets are shown in Figure 4.6 below.

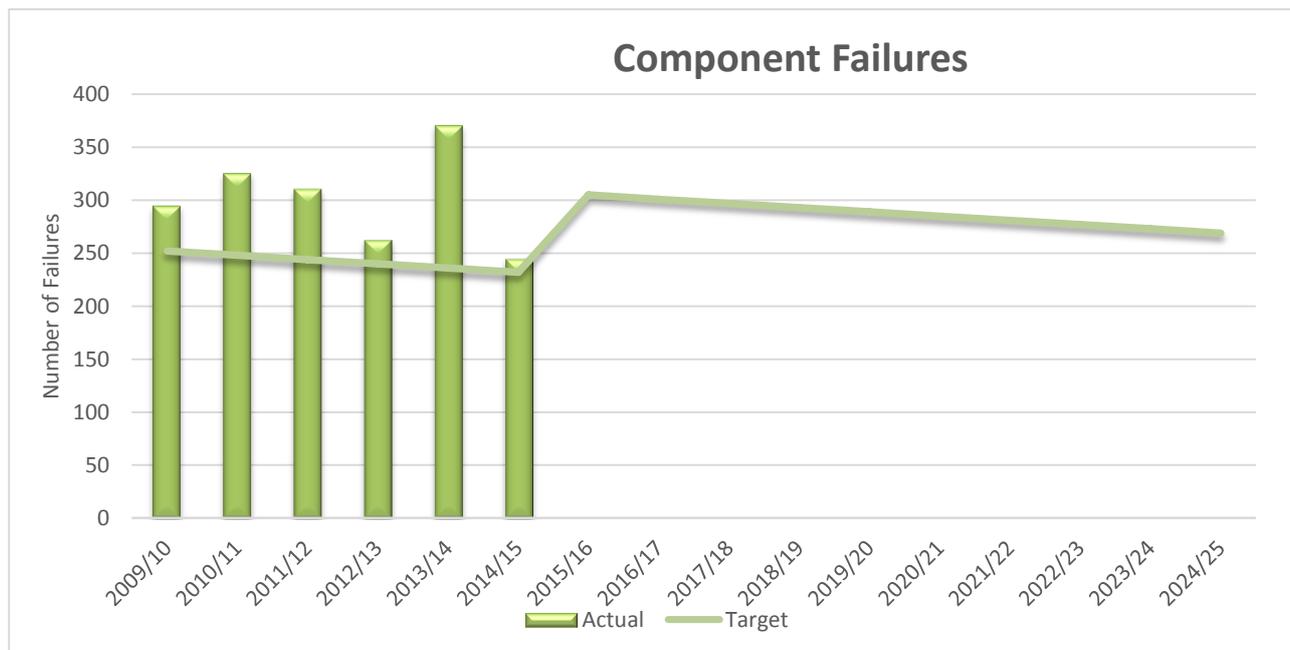


Figure 4.6: Component failures performance and targets

The system component failure performance was higher than the target by 3.81%; this is mainly due to better recording of outage causes in the outage reporting system.

TLC has a renewal programme in place that over the long term will address component failures due to age. TLC is continuing with a strategy of trying to follow up fault “warning signs” (such as auto recloses) before situations deteriorate to failure and renew assets that are in poor condition. TLC is also very focused on the quality of components that are used on the network. However the Commerce Commission reduced the allowed capital expenditure by around \$2m per year. This restricts TLC's ability to maintain or improve customer service.

4.4.1.7 Environmental Performance

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

There was one prosecution in 2015 regarding an oil spill that occurred in TLC's Waitete Depot. Following an investigation it was found that the bunded area where the transformer oil was being stored was of insufficient capacity to contain the oil from the tank. Following this a full environmental compliance review of the Waitete depot was conducted. 13 recommendations from this review are currently being implemented.

Table 4.17 lists the environmental impact targets for the next two years. There is no environmental impact work currently planned over the remainder of the planning period.

ENVIRONMENTAL PERFORMANCE TARGETS	
Year	Environmental Impact Works Due For Completion
2016/17	2
2017/18	1

Table 4.17: Environmental Performance Targets

4.4.2 Asset Efficiency Targets

The following targets are used to measure asset efficiency:

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

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

4.4.2.1 Network Losses: Technical

The technical losses in comparison with other EDBs are shown in Figure 4.7 below. TLC has high losses due to the distance of major loads to Points of Supply and Zone substations. Section 5 contains a discussion on minimising losses over time.

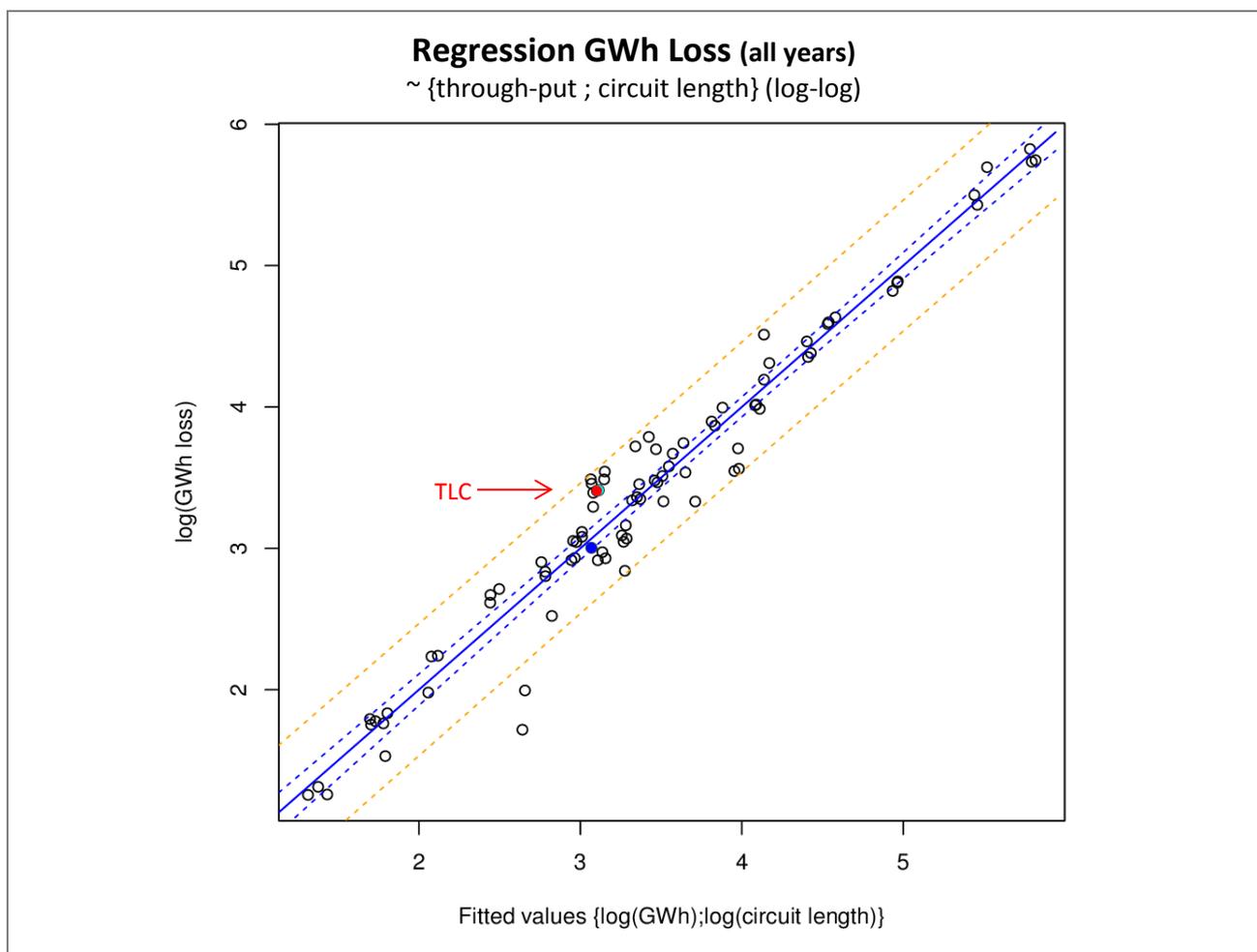


Figure 4.7: Losses Compared with Other EDBs

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

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

Table 4.18 lists the targets and performance for technical losses for contiguous network regions under heavy and light loads with the generation injecting at expected levels throughout the planning period.

COMPARISON OF MODELLED TECHNICAL LOSS STUDIES BASED ON NETWORK REGION										
Region	2012/13		2013/14		2014/15		Target		Variance	
	Heavy	Light	Heavy	Light	Heavy	Light	Heavy	Light	Heavy	Light
North	5.19%	1.61%	5.29%	1.84%	5.81%	1.56%	7.00%	2.00%	1.19% (F)	0.44% (F)
Central	11.40%	1.90%	10.27%	1.74%	8.55%	1.45%	8.00%	5.00%	0.55% (U)	3.55% (F)
Ohakune	11.75%	0.81%	8.60%	0.61%	9.17%	0.69%	9.00%	2.00%	0.17% (U)	1.31% (F)

Table 4.18: Modelled Technical Loss Targets and Performance by Region

TOTAL ACTUAL TECHNICAL AND NON-TECHNICAL LOSSES	
2014/15	9.18%

Table 4.19: Total Actual Losses Across the Network for 2014/15

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

Long term, TLC is focusing on reducing losses by:

- Demand side management initiatives by the use of load control systems and charges.
- Upgrading metering technology to achieve compliance and improve accuracy.
- Designing to minimise losses.
- Increasing conductor sizes where this is economic
- Considering the location and configuration of transmission Points of Supply.
- Requiring distributed generators to set plants to minimise losses and maximise power factor during RCPD periods.
- More innovative load control and network automation schemes.
- When necessary and practical, deployment of capacitors to reduce reactive power flows.
- In the case of Ohakune; upgrading of the network and the use of mobile capacitors during ski weekend times.

4.4.2.2 Network Power Factor

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

Table 4.20 lists the power factor targets and performance at grid exit supply points during regional peak periods. The target is based on 2010 national data set by the Electricity Authority and that the existing power flow is maintained.

COMPARISON OF GRID EXIT POWER FACTOR TARGETS AND ACTUAL					
Grid Exit	2012/13	2013/14	2014/15	Power Factor Target	Variance
Hangatiki	0.922	0.924	0.882	0.912	3.29% (U)
Ongarue	0.794	0.975	0.813	0.916	11.24% (U)
Tokaanu	0.996	0.997	0.999	0.992	0.71% (F)
National Park	0.998	0.994	0.983	0.990	0.71% (U)
Ohakune	0.990	0.993	0.987	0.991	0.40% (U)

Table 4.20: Targets and Performance for Power Factor by GXP during RCPD Period

Note: The Ohakune grid exit is shared with Powerco.

The Hangatiki power factor is lower than the target and is as a result of the large industrial loads supplied from this site, notably New Zealand Steel has the most influence. TLC has been granted by Transpower an exemption from power factor during RCPD periods for the Hangatiki GXP. Transpower has granted this request via a variation agreement. Due to high distributed generation output supplied into the Ongarue GXP the power factor was well below the target. There are ongoing discussions with generators to provide reactive power during RCPD periods to improve GXP power factor.

4.4.2.3 Network Load Factor

Load factor is an indicator of network investment efficiency; the higher the load factor the more efficient the utilisation is of the assets. Nationally over recent years load factor has been reducing as peak demand has been growing faster than the energy transported. An objective of TLC's demand based billing is to hold load and ideally improve load factor. The target is to maintain or improve on the current load factor of 60%. The target has been determined by historic data. The main driver of the increase is industrial and dairy loading on Hangatiki that increases total energy delivered while not occurring in the winter when the co-incident network demand peak occurs.

Figure 4.8 shows the historic load factor performance and the load factor target.

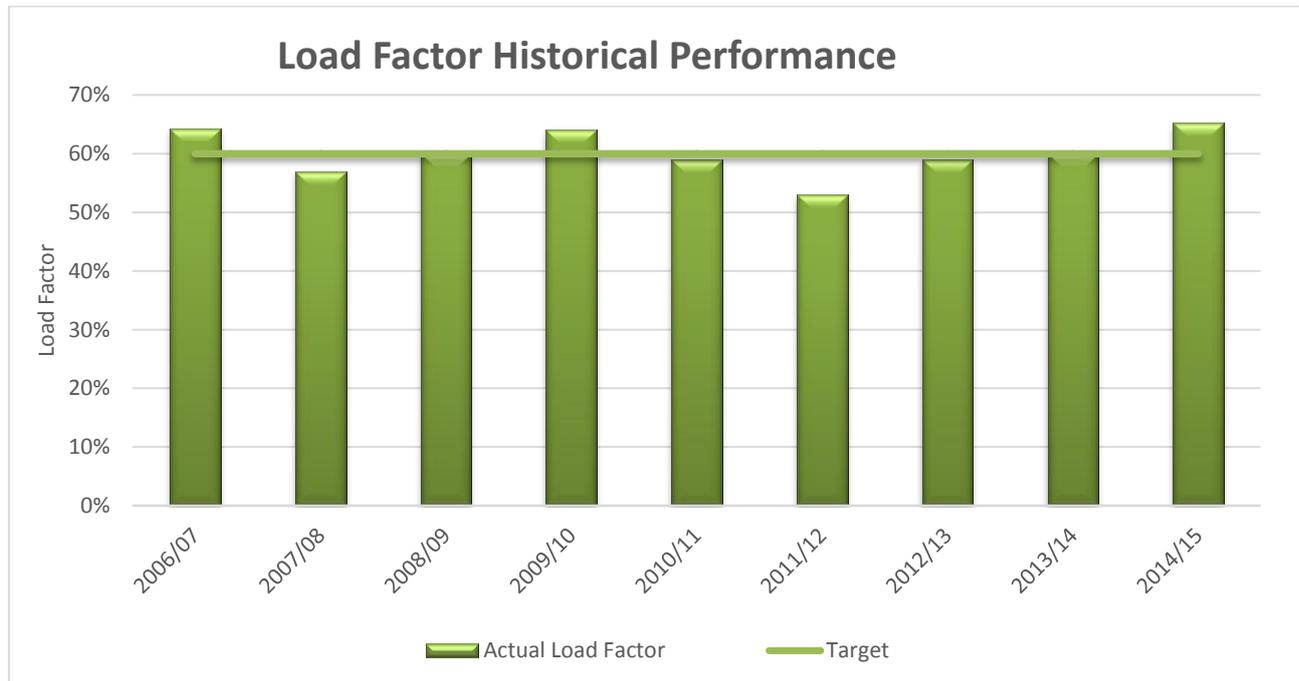


Figure 4.8: Target and Performance for Network Load Factor

The load factor is seen as an important network effectiveness indicator and the long term objective of demand charging is to improve the load factor over time.

4.4.3 Asset Effectiveness Targets (Accidents, Hazards, Diversity and Trees)

The following targets are used to measure asset effectiveness:

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

4.4.3.1 Accidents/Incidents Involving TLC Network Assets

TLC's objective is to minimise the accidents and incidents that are caused by or are associated with its network assets. Table 4.21 lists the targets and performance for accidents/incidents involving TLC network assets for the last 3 years.

ACCIDENT/INCIDENT PERFORMANCE: ACTUAL COMPARED TO TARGET					
Event	2012/13	2013/14	2014/15	Target	Variance
Lost time - injuries involving Staff or Contractors	0	1	13	5	160% (U)
Average hours lost (per employee)	1.68	4.07	3.15	<2.5	26% (U)
Number of DOL notifiable accidents	0	0	0	0	100% (F)
Number of public injuries involving a TLC facility	0	0	5	0	100% (U)

Table 4.21: Accident/Incident Performance: Actual compared to Target

The targets have been set based on historical data. The number of lost time injuries and average hours lost per employee are above the target; this is due to employee injuries such as back and shoulder injuries.

There were four reported incidents of public injury involving a TLC facility that resulted in 5 injuries. The most serious incident occurred when two members of the public were injured when scaffolding that they were installing made contact with live 11kV lines. This incident highlighted the importance of keeping the public informed of the safety requirements when working around power lines. The other 3 incidents were minor shocks resulting from faulty connections causing a slight potential rise in nearby metal work.

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

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

4.4.3.2 Asset Hazards that are Eliminated/Minimised Annually

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

Table 4.22 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	Two Pole Structures	GMT	Switching Equipment	Total Hazards Eliminated/Minimised
2016/17	5	3	1	9
2017/18	4	0	3	7
2018/19	5	1	1	7
2019/20	5	3	2	10
2020/21	4	4	6	14
2021/22	5	2	2	9
2022/23	3	2	1	6
2023/24	3	3	5	11
2024/25	0	3	2	5
2025/26	0	2	0	2

Table 4.22: Targets for Removing Hazardous Equipment Sites during the Plan Period

Table 4.23 shows asset hazard elimination/minimisation targets and compares to actual.

ASSET HAZARDS ELIMINATED/MINIMISED: ACTUAL COMPARED TO TARGET			
Hazard Category	Actual 2014/15	Target 2014/15	Variance
Pillar Boxes	77	50	54.0% (F)
Two Pole Structures	9	9	0.0% (F)
Ground Mount Transformer	3	4	25.0% (U)
Switching equipment	7	7	0.0% (F)
Total Hazard Control	96	70	37.1% (F)

Table 4.23: Asset Hazards Eliminated/Minimised: Actual Compared to Target

Most of the hazard elimination/minimisation projects for 2014/15 achieved target, and the pillar box project was completed. Continuous improvement of the work management systems is taking place to ensure focus throughout the year is maintained on priority hazard renewals. Faults, customer demands and the need to complete other priority emergent work can quickly take the focus away.

4.4.3.3 Diversity Factor

Diversity Factor is the probability that a particular piece of equipment will come on at the time of the facility's peak load. It is also a measure of how effective TLC's demand billing programme has been. It is an indication that customers have spread their load more effectively. Higher diversity means the individual maximum demands are less likely to occur at the same instants, which means a more efficient network asset utilisation. Diversity Factor target is set at 1.35. Table 4.24 lists the target and performance for diversity factor.

DIVERSITY FACTOR						
2010/11	2011/12	2012/13	2013/14	2014/15	Target	Variation
1.36	1.32	1.38	1.33	1.39	1.35	0.04 (F)

Table 4.24: Diversity Factor: Actual Compared to Target

The performance is above the target due to the increased demand at Hangatiki that occurs outside of the typical winter peak.

4.4.3.4 Tree Management

Vegetation control is TLC’s greatest operating cost. Figure 4.9 below, on a managed tree length basis, indicates that TLC is spending below other EDBs. Felling trees as opposed to trimming gives the best permanent solution, this however costs more per km until a full cut cycle has been performed. If the funds are not adequate to fell/cut all the trees needed then the backlog will cause reliability issues placing pressure to use a more short term approach with longer term increased costs. Section 6 on the Lifecycle Plan will discuss that the funds currently spent are inadequate to finish the full tree removal cycle.

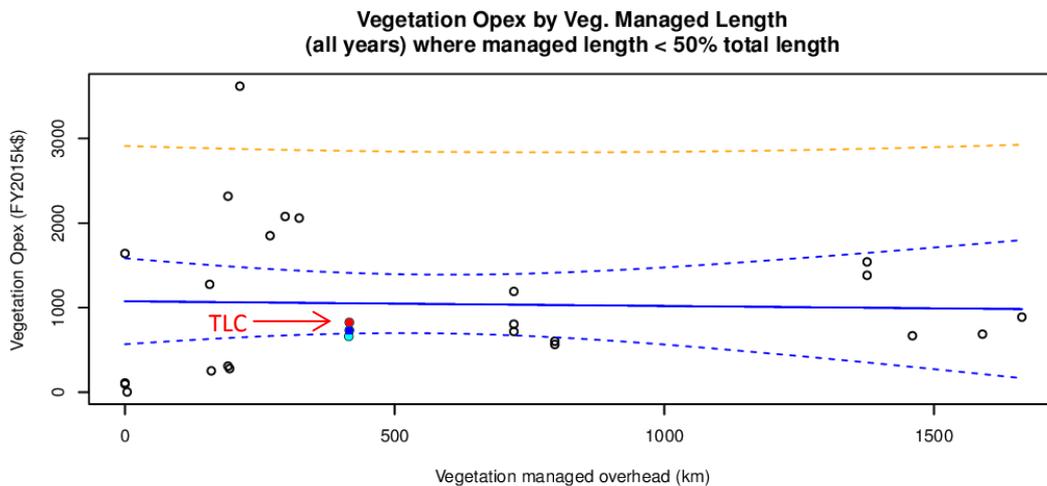


Figure 4.9: Comparative Tree Spend

The target for the planning period is to keep the fell ratio above 70%, i.e. 70% or more of all trees are felled as opposed to being trimmed throughout the planning period.

Table 4.25 lists the annual ratio between the number of trees felled to the number of trees worked on.

RATIO OF TREES FELLED TO TREES TRIMMED (FELL RATIO)							
	2010/11	2011/12	2012/13	2013/14	2014/15	Target	Variance
Fell Ratio	80%	77%	81%	88%	84%	70%	20% (F)

Table 4.25: Ratio of Trees Felled to Trees Trimmed

The fell rate above target, with the variation within expectations. Customers’ understanding of the importance of allowing trees close to power lines to be removed to improve reliability and minimise costs is increasing. TLC is constantly striving to increase the fell rate to try and minimise its long term vegetation control costs and improve reliability. The key challenge remains convincing plantation owners to participate.

4.5 Performance Against the Plan

This section discusses the comparison between planned and actual expenditure, including the reasons for any variances. Table 4.26 outlines overall capital expenditure compared with the forecast for 2014/15.

2014/15 CAPITAL EXPENDITURE			
Category	Actual \$	Forecast \$	Variance
Consumer Connection	365,221	618,050	59% (F)
System Growth	568,586	219,471	259% (U)
Asset Replacement and Renewal	7,761,267	7,102,139	109% (U)
Asset Relocations	-	10,500	0%
Quality of Supply	181,309	812,256	22% (F)
Other Reliability, Safety and Environment	1,121,297	1,419,732	79% (F)
Non System Fixed Assets - Routine	618,345	197,400	313% (U)
Total	10,616,025	10,379,548	102% (U)

Table 4.26: Comparison of Actual and Forecast Capital Expenditure

Carry over expenditure from the 2013/14 Borough capacitor project constitutes 50% of the System Growth spend. The Quality of Supply underspend relates primarily to the reassessment of the Mokai backup transformer project. Non System actual figures includes TLC costs not included in the AMP forecast.

Figure 4.10 compares historical network expenditure with the forecast expenditure for the corresponding year and includes both Capital and Maintenance figures. Non-network expenditure is excluded. The anticipated rise in forecast capital around 2018-2019 is largely attributed to a \$2.5m allowance for Taharoa expansion coinciding with major supply upgrade work in the Atiamuri area. Other factors include increases to meet customer load growth and security of supply requirements.

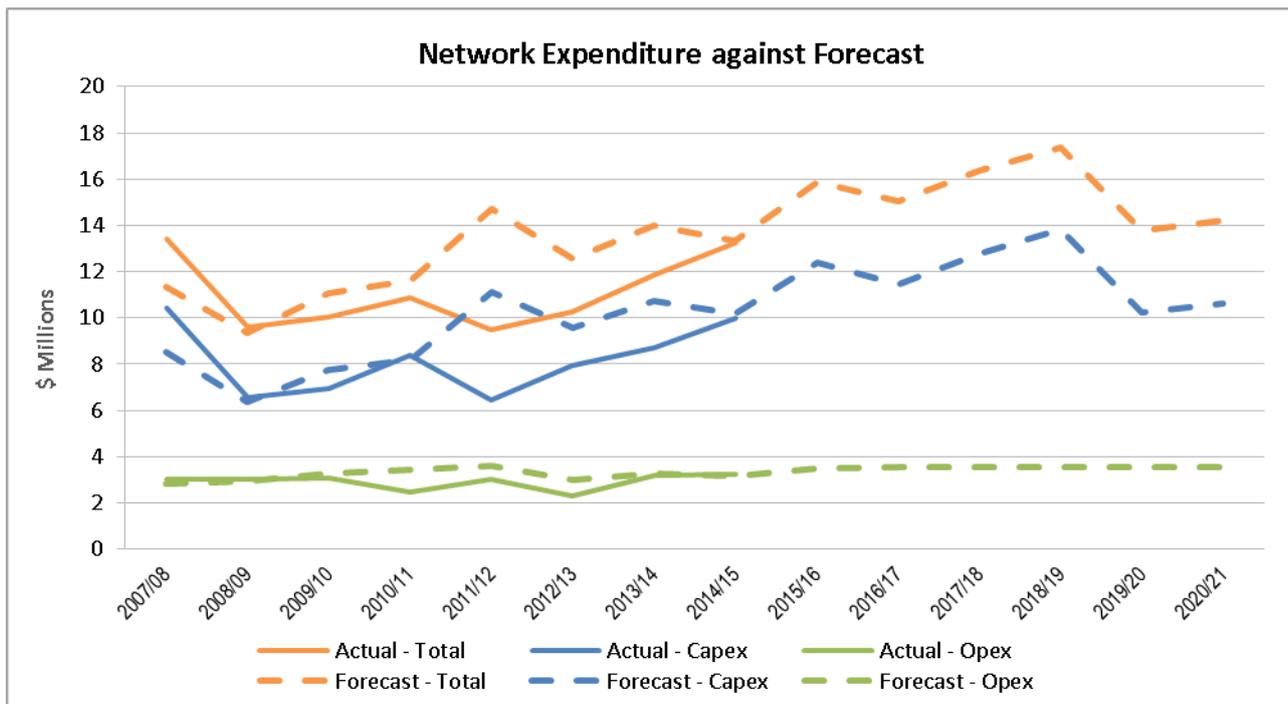


Figure 4.10: Comparison between Historical Actual and Forecast Expenditure

2014/15 saw forecast and actual expenditure closely aligned. While this reflects a high level of planned work implementation, it should be noted over 20% of the total spent related to work planned for prior years. This in turn means a similar amount of work planned for 2014/15 was not achieved and will carry into the 2015/16 financial year. Resource limitations were a primary factor in the carry over work and this is forecast to be caught up by the end of 2015/16.

4.6 Performance Benchmarking

During 2015 TLC engaged with Southwest Consulting Group and Hyland McQueen Ltd to conduct a review of reliability and capital expenditure. This section outlines the findings of these reviews. The review has been compiled using information published by all EDB's under the required disclosure rules. Given these rules have only been in place for a few years, the sample size is relatively narrow. It has still proven to be a worthwhile exercise to gauge relative performance and insight.

It is also important to gauge the outcomes against the considered customer-focused strategy employed by TLC through recent years of network reinvestment. Reliability was such that the renewals program embarked upon was unavoidable and wouldn't necessarily fit with some of the modelling outcomes depicted below. The other significant context for the results is the level of funding, and therefore income, which would be required from customers to meet indicated levels. TLC has a stated strategy of managing its assets cost effectively which also includes being cost conscious of behalf of our customers.

4.6.1 Regulatory Asset Base

The regulatory asset base comparative performance in Figure 4.11 shows TLC at just above the regression line. It demonstrates that TLC can consider ageing its assets, as there are companies with considerably older assets around the TLC density. This needs to be considered with the current need for reliability improvement.

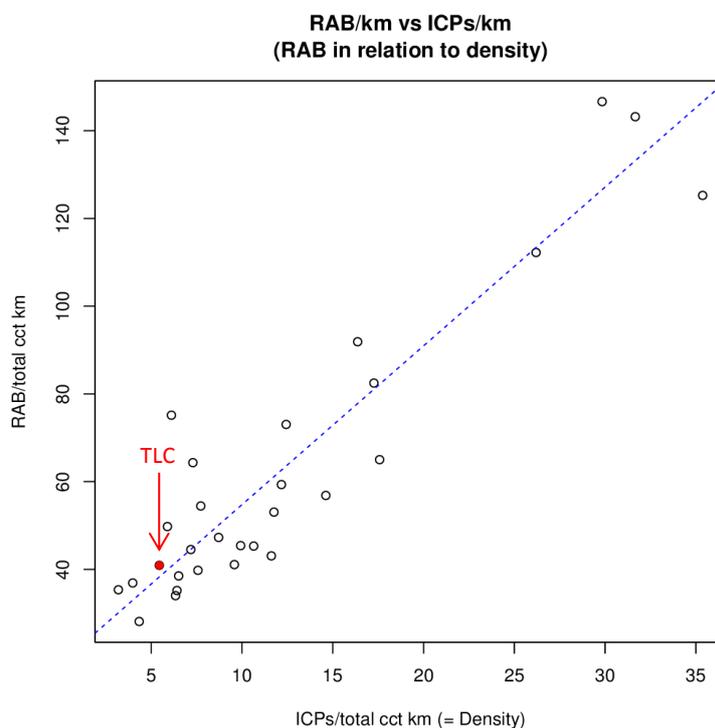


Figure 4.11: Comparative RAB in Terms of Density of Customers

Figure 4.12 below indicates, in comparison with its cohort, that TLC has more invested in distribution switchgear and distribution transformers and less invested in zone substations. This does not necessarily indicate areas of over investment and potential to let assets age, or under investment needing more replacement. Zone substations asset value is likely to indicate a focused approach to value and cost innovation with package substations. Existing distribution transformers have a low life and replacement has been necessary. TLC is also reducing it's in service stock with pricing mechanisms to encourage multiple customer use and increasing utilisation. Over time with appropriate quality of replacement assets this should revert to industry cohort levels. It may be worth confirming this strategy will lead to a lowering of transformer asset value over time. It may be worth investigating switchgear lives, as the asset value appears inconsistent with the lives stated. This could however be as simple as a previous investment cycle. In terms of subtransmission lines, TLC has 6 points of supply and this enables a lower length and RAB for this asset.

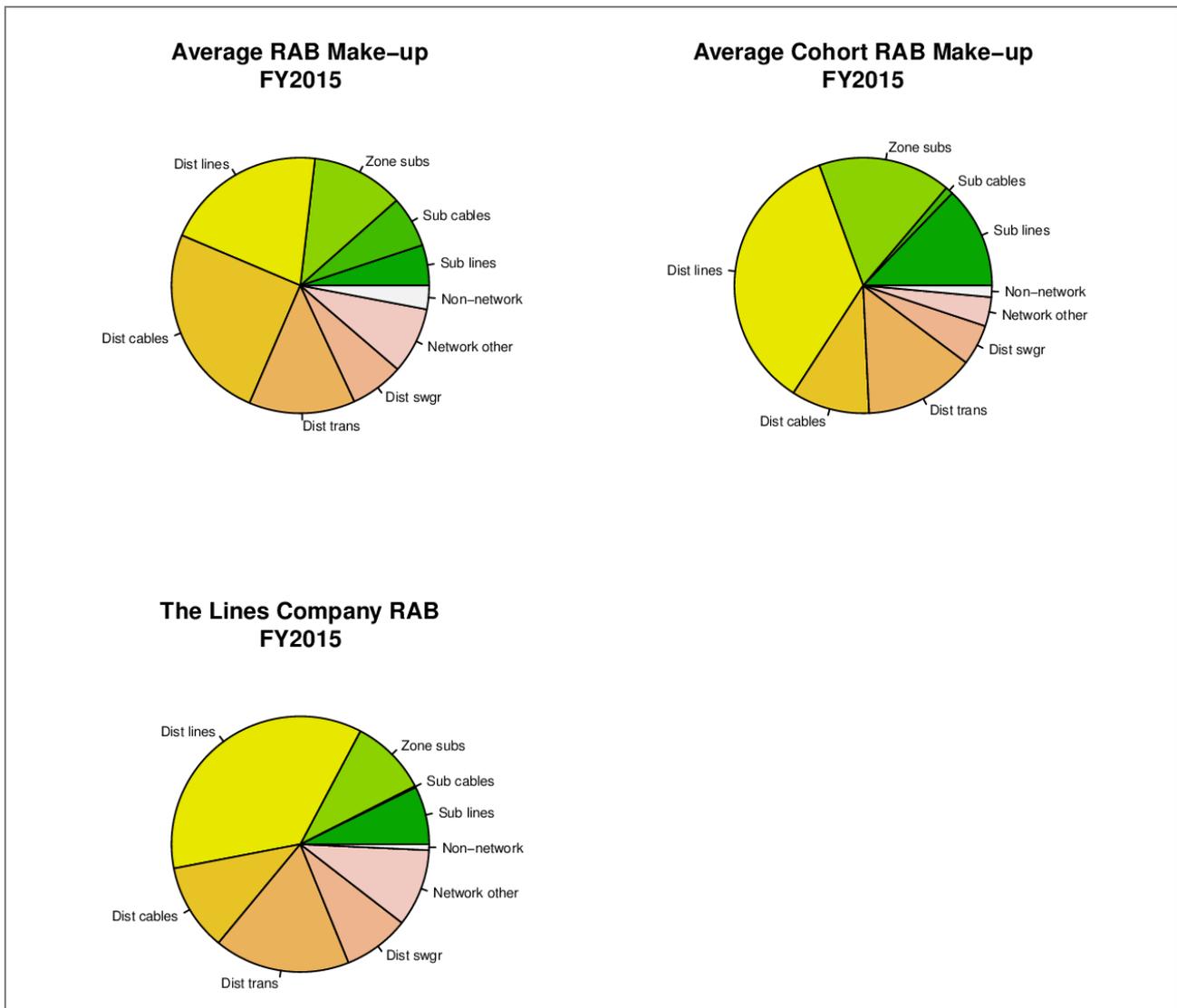


Figure 4.12: Comparative Performance of RAB Make-up

Figure 4.13 below shows that TLC has average lives except for distribution transformers that are lower quartile and distribution switchgear that is upper quartile. After the survival work done this year that shows TLC lines are lasting 60 years, not the 56 years currently used, and transformers 58 years not the current 55 years, this will change and show lines close to the top quartile and transformers close to the average.

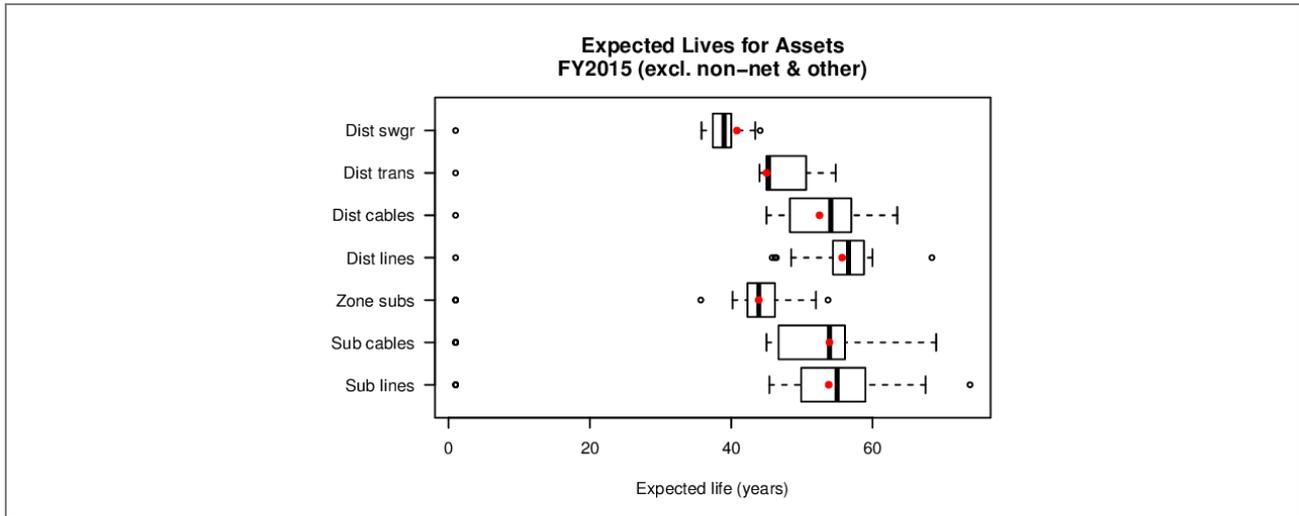


Figure 4.13: Comparison with the Lives of Other EDBs

4.6.2 OPEX

The OPEX regression in Figure 4.14 shows TLC as over the regression line by approximately \$1m. In a previous section the benchmarking indicated that TLC was under funding tree management by circa \$0.5m. Reliability is not at the benchmark level, which suggests tree management could be funded to a higher level. Reliability is highly valued by some segments of the TLC customer base, and besides difficult trade-offs in expenditure TLC is considering refining it's investment into areas where reliability is valued highly such as the dairy regions.

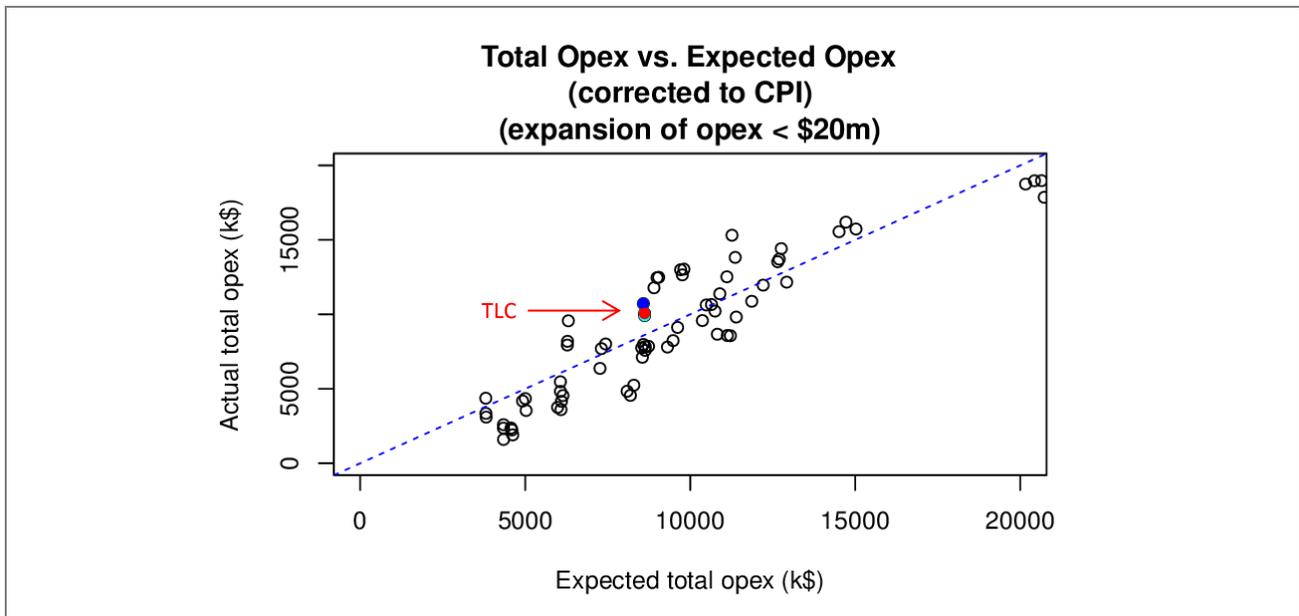


Figure 4.14: Comparison of Actual to Expected Opex

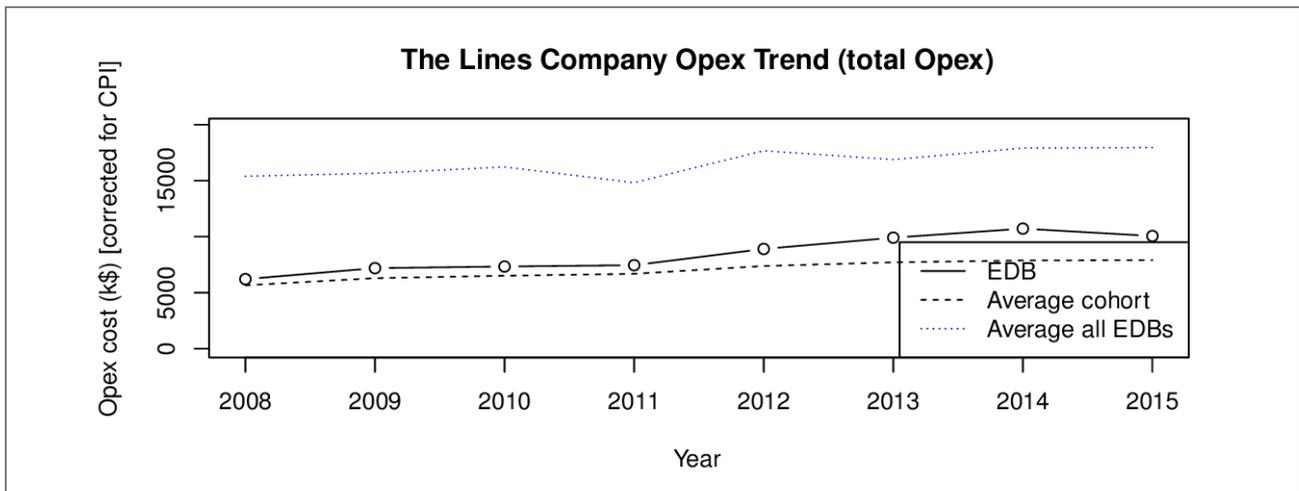


Figure 4.15: Comparison of TLC Opex with Cohort Opex

Figure 4.16 below demonstrates that TLC business costs are over its cohort, with lower renewal costs and vegetation. Routine costs are also under the cohort. Fault costs are over the cohort in 2015 and have been increasing over the last three years. With increasing tree faults it is possible this will continue to rise. TLC will investigate its routine maintenance as well as trees to determine if the lower levels are contributing to worsening SAIFI and increasing fault costs. This years budget has allowed increased vegetation maintenance spending.



Figure 4.16: Comparison of TLC Opex Make -up with Industry and Cohort Opex

4.6.3 Reliability

4.6.3.1 SAIFI

Figure 4.17 below indicates at best a flat SAIFI trend for TLC and possibly an increasing one. In most years TLC is well over the cohort values. In the early 2000s a substantial improvement in SAIFI was made and the community acknowledge this. The TLC staff also acknowledge that the levels of callout and overtime to fix faults has considerably reduced. This indicates TLC needs to consider its targeting and possibly its investment level in reliability that would increase value to customers. TLC has revisited its capital programme and introduced more automated switching and reclosers as initial steps to start addressing SAIFI. This has been achieved within the reduced capital envelope allowed by the Commerce Commission for the 2015-2019 regulatory period.

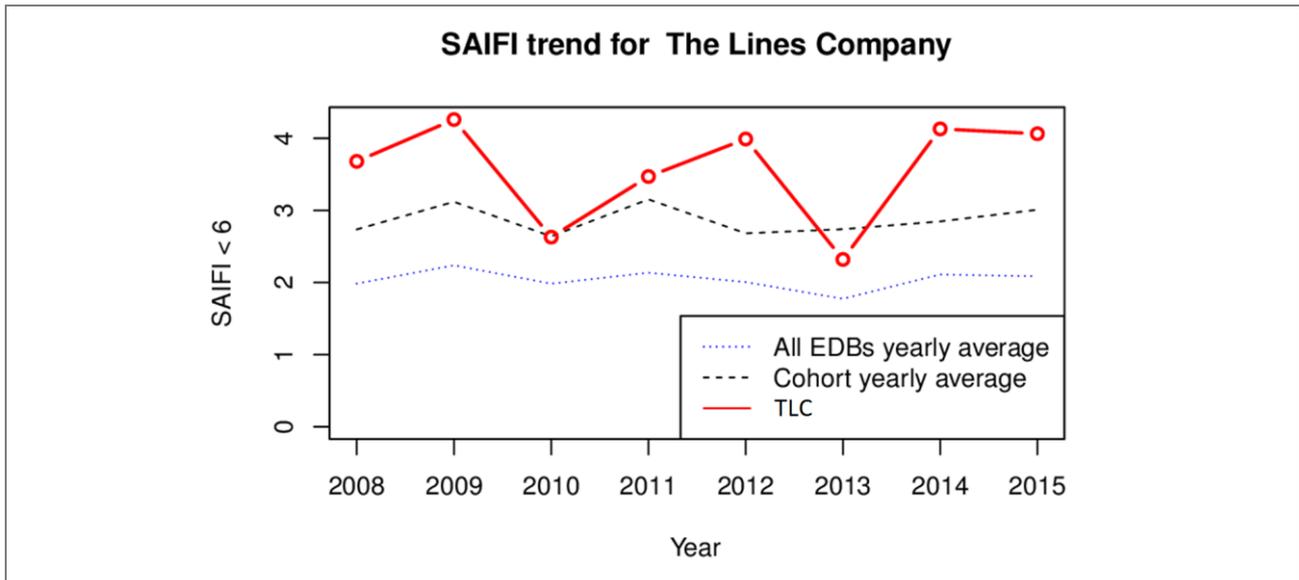


Figure 4.17: SAIFI Compared with TLC Cohort and NZ Average

Figure 4.18 below indicates that TLC has a higher ratio of defective equipment and tree faults to the cohort. This is confirmed in the next section with fault counts. While weather and unknown are not high compared with the industry, they are large enough to be masking other controllable causes such as clashing, bird and tree faults. It may be sensible to increase the guidance for coding faults, to set a wind speed for instance, below which faults are considered within design codes and not due to the wind, and therefore open to solutions.



Figure 4.18: Comparison of SAIFI Make-up with Cohort and All EDBS

Figure 4.19 below indicates an increasing trend of SAIDI from vegetation. The 2013/14 and 2014/15 data is more accurate than the historical data as faults classified as weather with a secondary cause as trees were reclassified to trees. A plan to address this issue is underway.

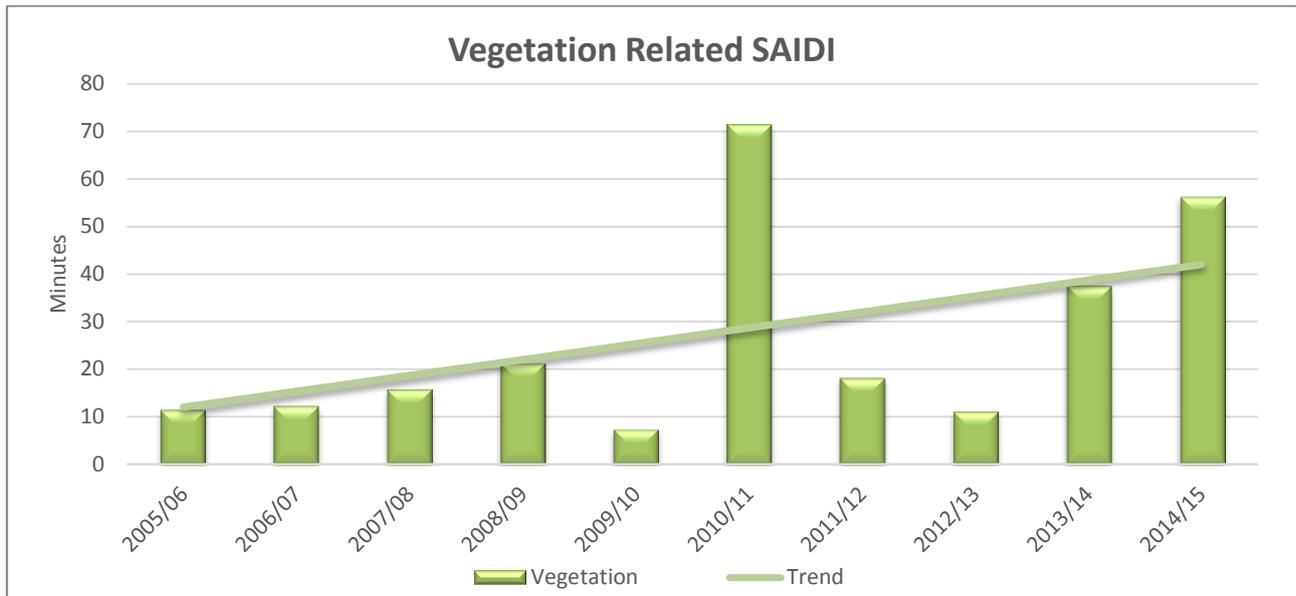


Figure 4.19: Outages Caused by Vegetation

Figure 4.20 confirms from industry regression - that considers the nature and terrain of the TLC network - that SAIFI is over industry norms.

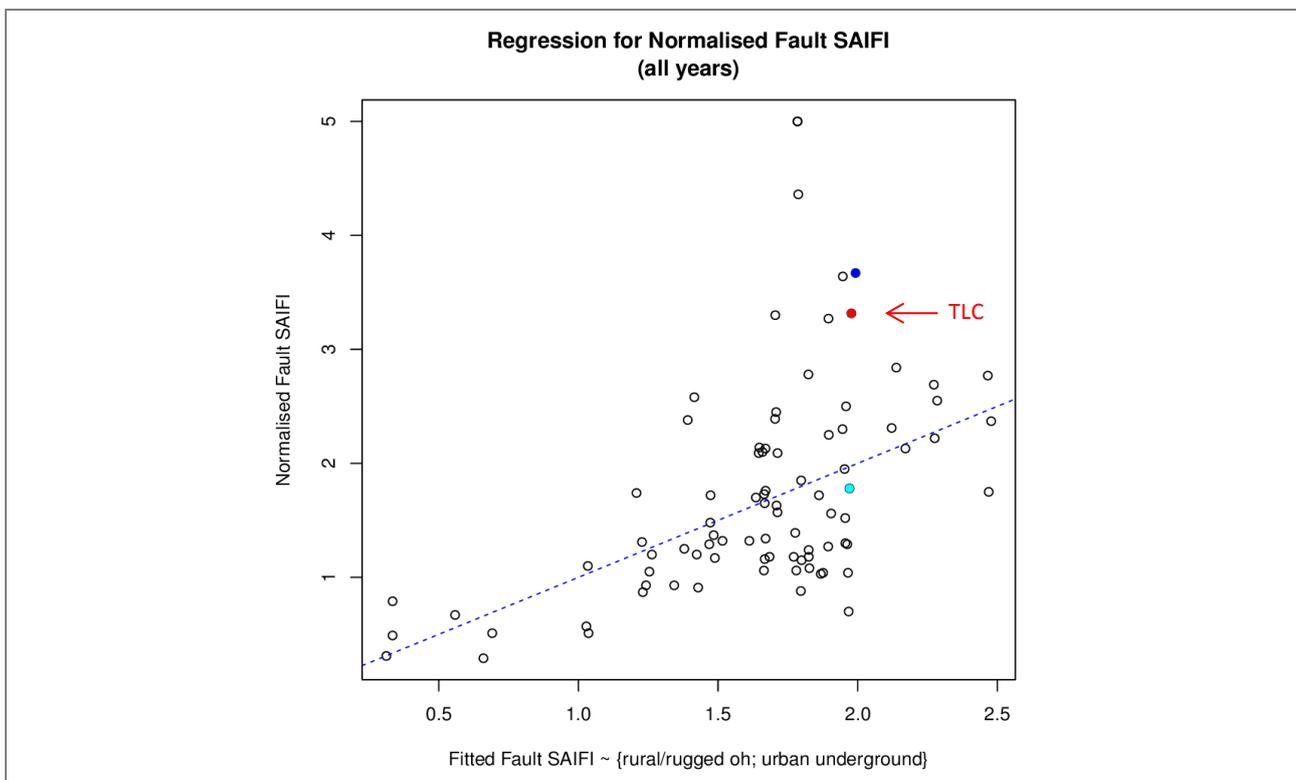


Figure 4.20: TLC Normalised SAIFI Compared with Fitted Compared to all EDBS

Figure 4.21 shows the breakdown of defective equipment SAIDI over time. It shows that cross arm faults are reducing. Conductor SAIDI is over double the level of cross arms and poles combined. Many conductor faults are jumpers and connections and this is being checked in all line outages for other equipment replacement. Budget has also been allocated to conductor replacement and an investigation to determine the root causes and target areas for replacement is budgeted.

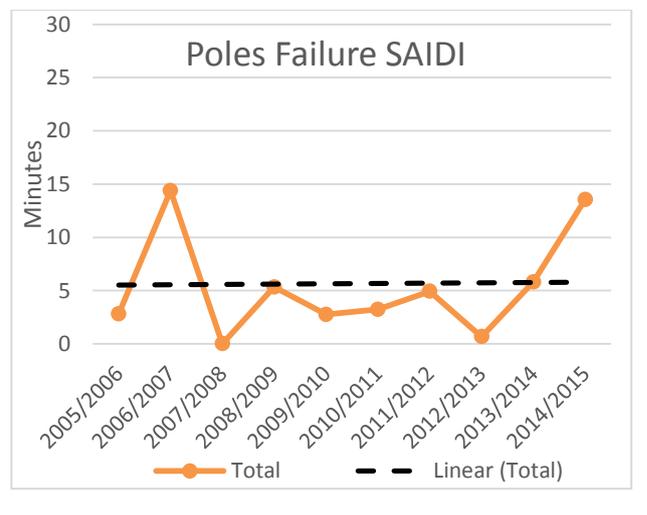
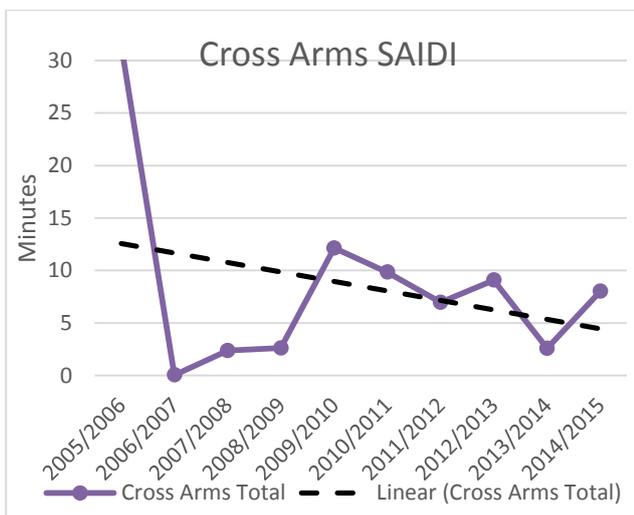
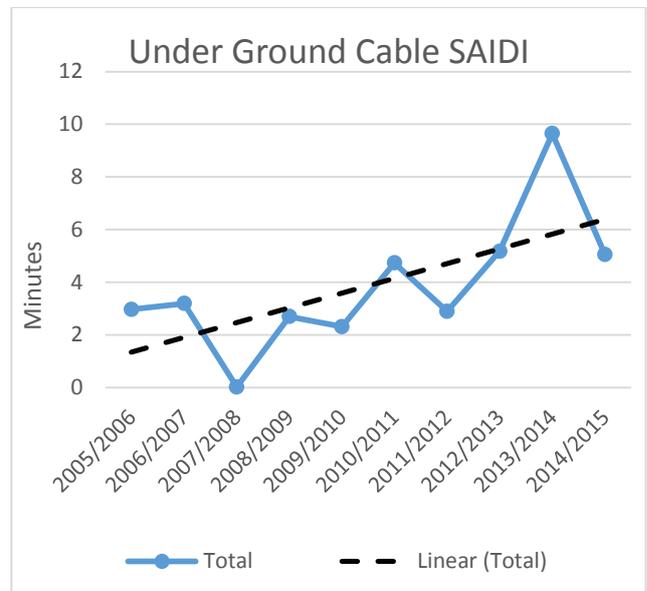
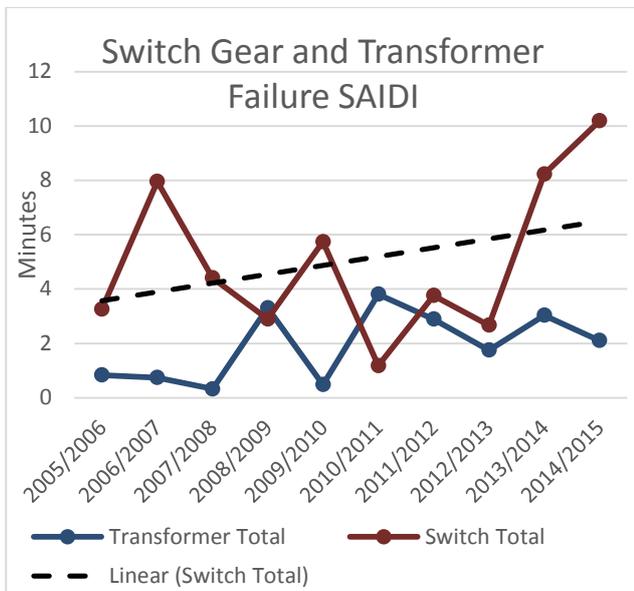
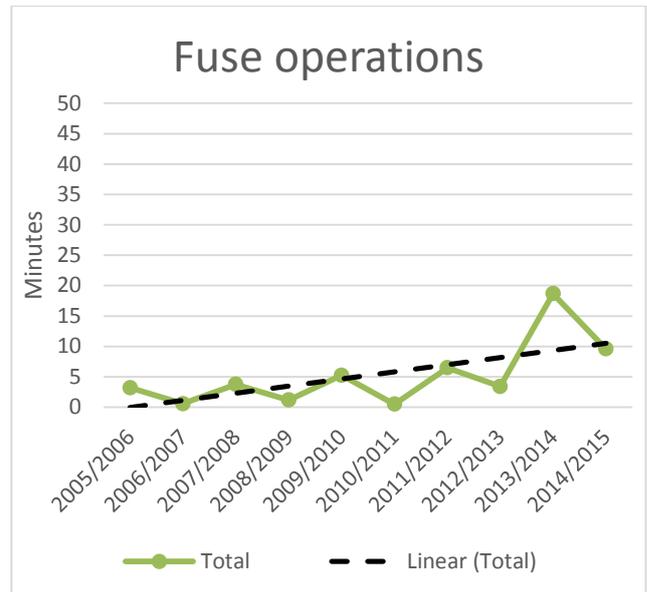
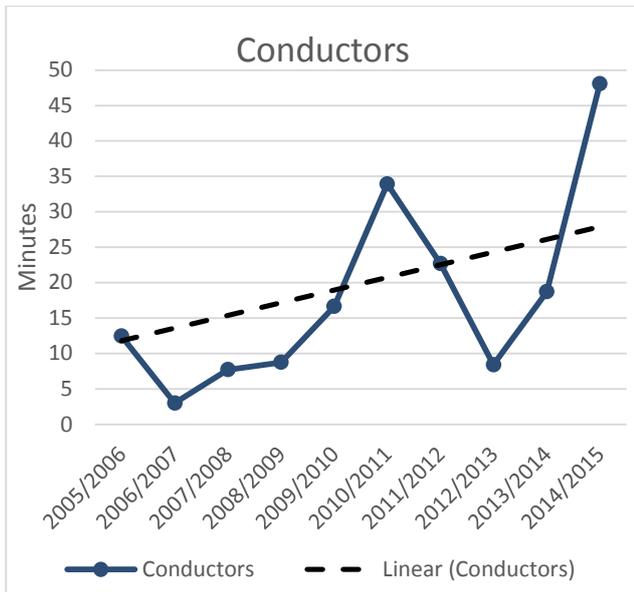


Figure 4.21: Breakdown of Equipment Defect Faults

Figure 4.22 below shows that planned SAIFI is over the industry regression line. TLC extensively use mobile generators to reduce the duration of planned outages. It may be possible for TLC to consider live line installation and synchronising of the generation to reduce planned SAIFI.

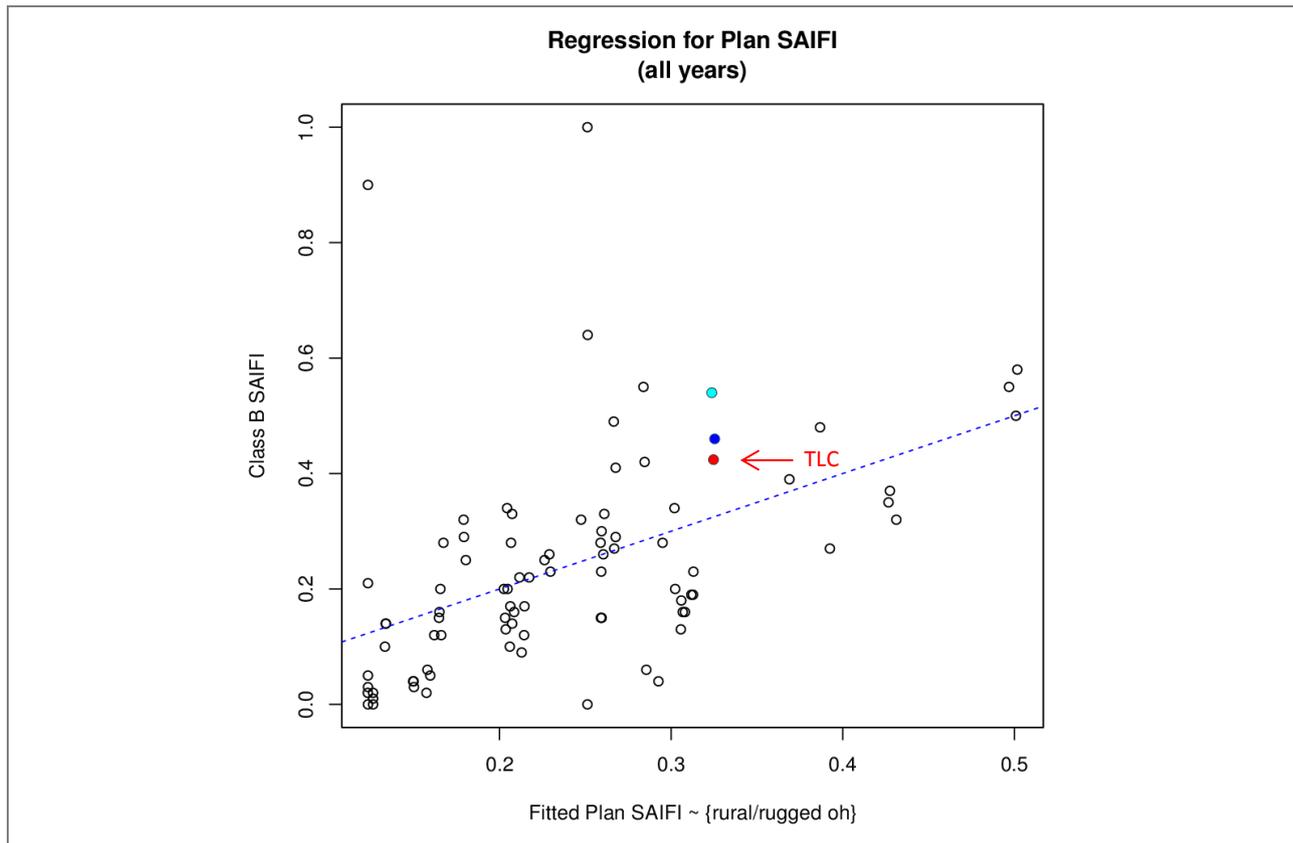


Figure 4.22: Planned Outage SAIFI Regression

4.6.3.2 Fault Rates

The decreasing fault count shown in Figure 4.23 indicates that maintenance and replacement strategies are reducing fault numbers over time. It may be that the current concentration of resources on feeder groups further out on the network is resulting in groups closer to the zone substations having increasing fault numbers. This would be consistent with these feeder groups having been inspected some 6 and 7 years ago and where non urgent poles and cross arms were not able to be replaced due to funding constraints. TLC has a 15 year cycle of inspection but this relies on funding replacement assets that were due to be replaced between 5 and 15 years after the initial inspection. It may be worth selectively reinspecting these assets to focus resources on assets with high numbers of customers.

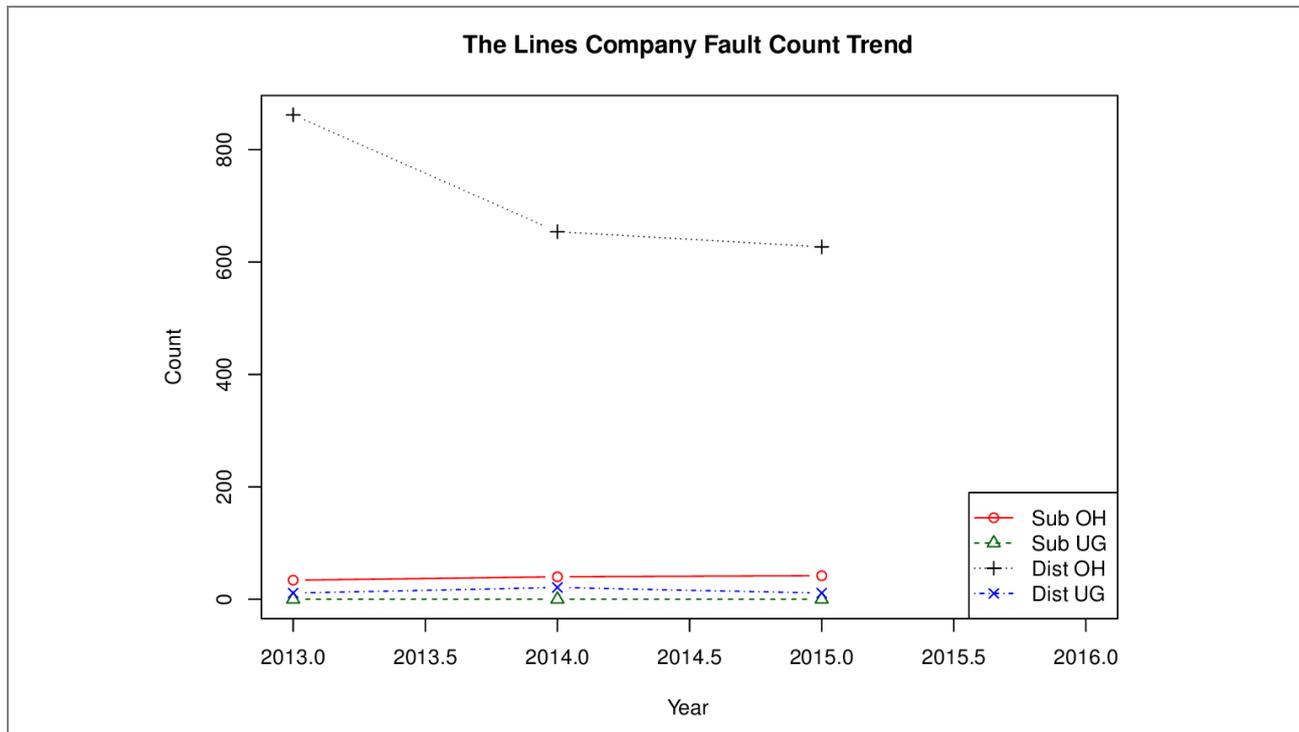


Figure 4.23: TLC Fault Count Trend

Figure 4.24 indicates that while the overall fault count trend is decreasing, TLC fault rates are around double the cohort rate per km. This would indicate that targeting of funding is not optimal. This is another indication of the need to concentrate on non-pole and cross arm faults. The constraints of a long rural network are reinforced in this comparison.

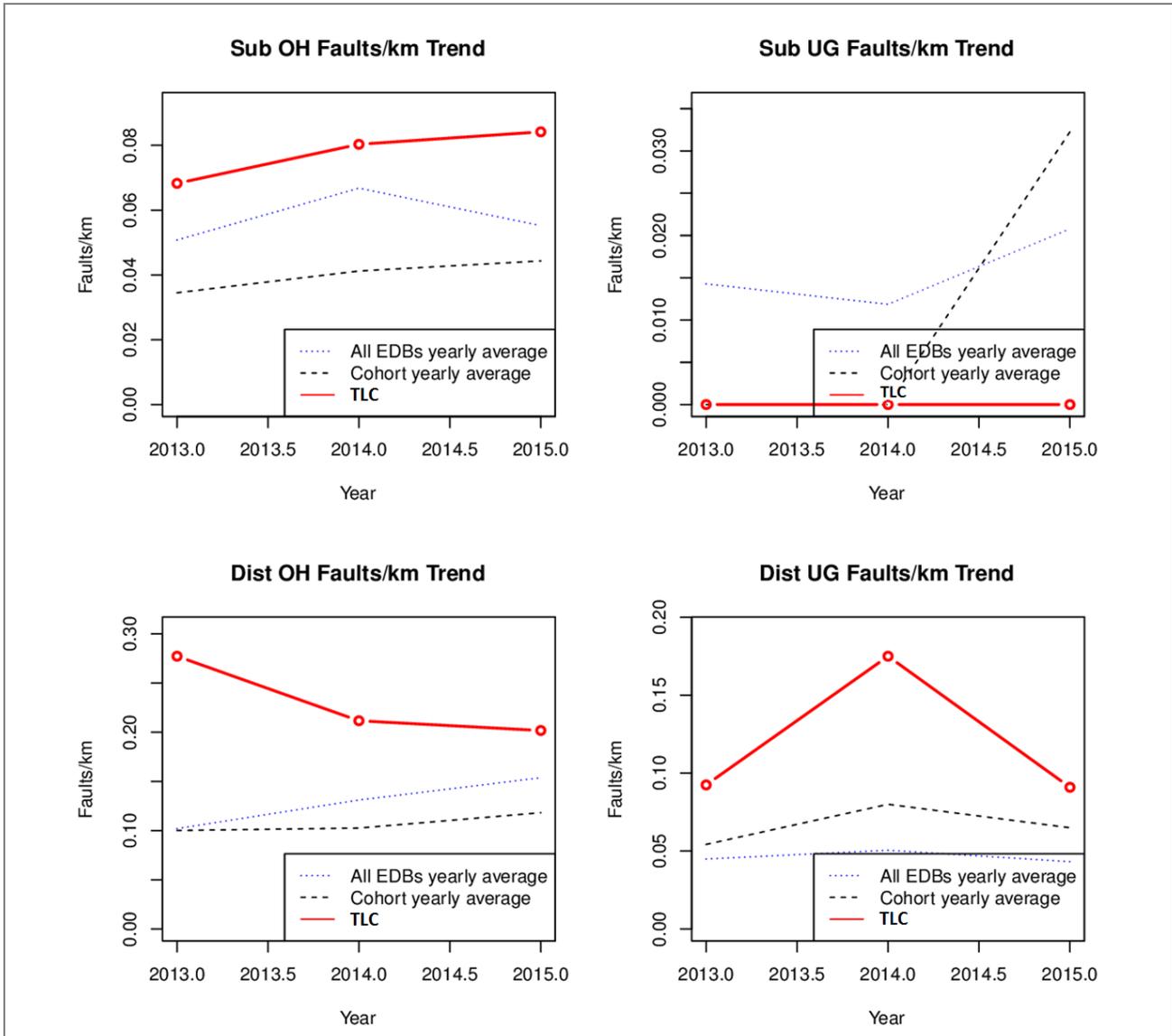


Figure 4.24: Fault Count Trends Compared with Cohort and NZ Average

4.6.3.3 CAIDI

Figure 4.25 below of CAIDI shows a reducing value for TLC. This is the opposite trend for companies managing reliability well, as they reduce faults that affect larger numbers of customers and yet may be of short duration, such as tree outages. They also install remote controlled switches and reclosers to reduce the impact of outages. This again reinforces the need to examine maintenance and reliability strategy to target efforts in the most effective areas. Reducing CAIDI can also be a result of increased labour applied and may also be contributing to the increasing fault costs.

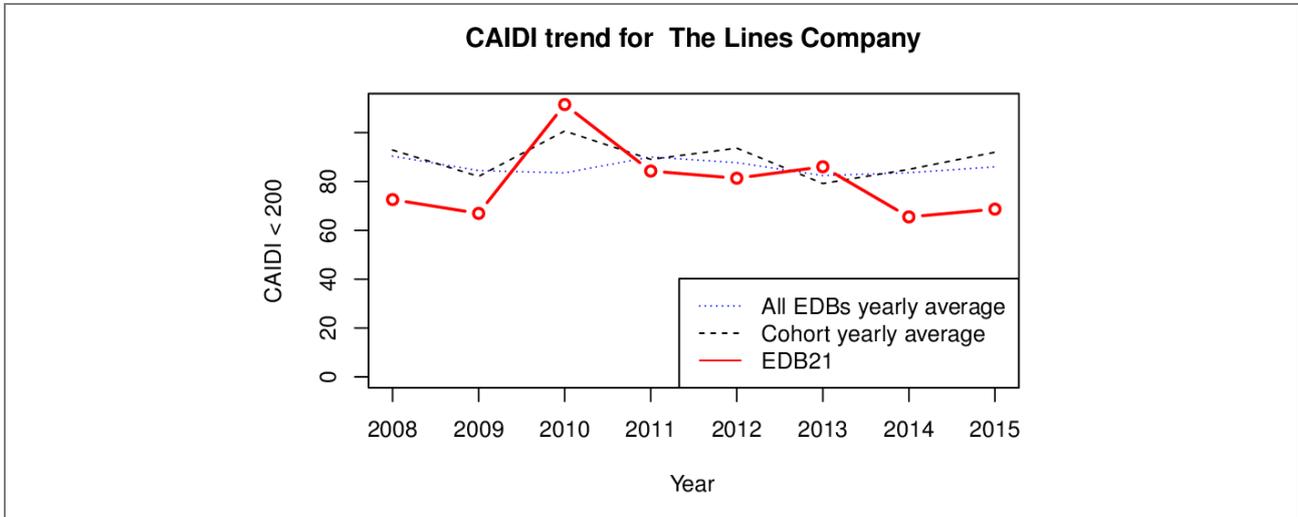


Figure 4.25: TLC CAIDI Trend

In comparison to other EDB's TLC have around mid-range CAIDI for unplanned work but very low planned CAIDI. The low planned CAIDI is a result of a targeted plan to minimise the duration that customers are without supply using generators

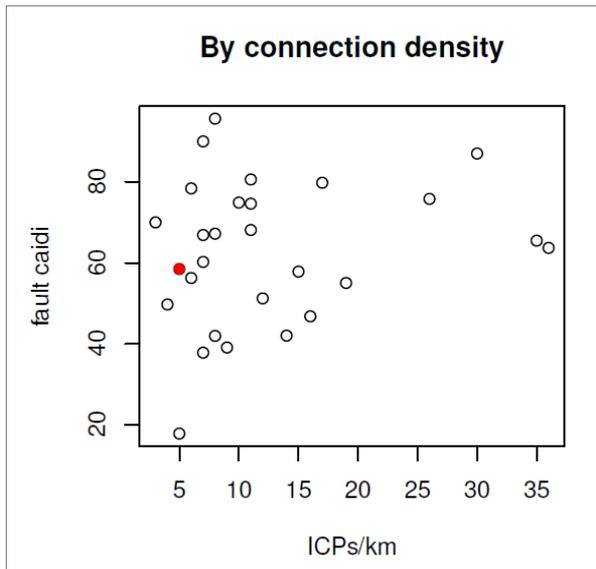


Figure 4.26: Fault CAIDI by Network Connection Density

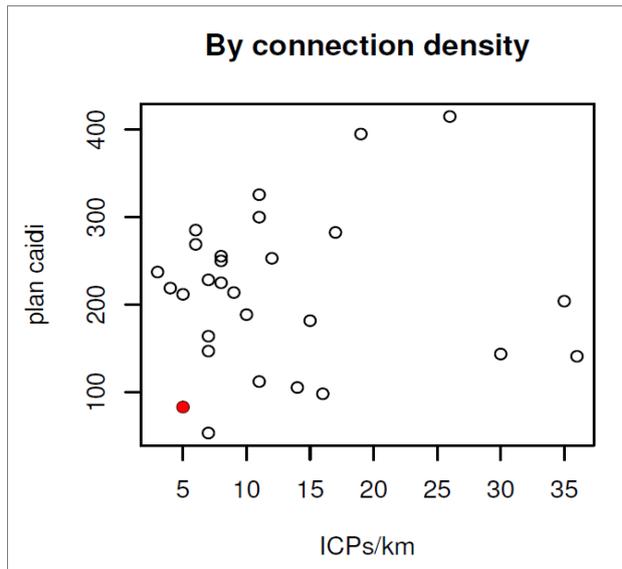


Figure 4.27: Planned CAIDI by Network Connection Density

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5. Development Planning

5.1 Description of Network Planning Criteria and Assumptions

5.1.1 Introduction

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

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

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

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

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

5.1.2 Planning Assumptions

5.1.2.1 Performance Assumptions

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

5.1.2.2 Economic Assumptions

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

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

5.1.2.3 Customer Load Growth Assumptions

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

5.1.2.4 Business Environment Assumptions

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

5.1.2.5 Asset Assumptions

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

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

5.1.2.6 Data and Network Analysis Assumptions

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

5.1.2.7 Grid Exit Power Factor Assumptions

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

5.1.2.8 Equipment End of Life Assumptions

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

5.1.3 Planning Criteria

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

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

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

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

5.1.3.1 Planning Criteria: Customer Connections

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

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

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

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

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

5.1.3.1.1 Planning Criteria: Customer Connections: Subdivisions

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

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

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

The key criteria include:

- Fuses at the point of connection to individual customers.
- Cabling to industry codes using industry preferred sizes.
- Low voltage protection on each circuit heading away from transformers.
- Links between low voltage circuit ends if practical.
- Low voltage panels to be insulated and to have transformer isolation and maximum demand indicators.
- High voltage switchgear (ring main type) should be fitted to all but the last spurred transformer. Each transformer and/or spur should be individually protected against over-current.
- Where practical and economic the high voltage cable network will be ringed.
- 11kV 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 4 and hazards are controlled to acceptable standards.

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

5.1.3.1.2 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 11kV or 33kV points of connection (11kV – 9kV, SWER 11kV – 18kV and 33kV – 27kV arrestors respectively).

Experience has shown that designs to these criteria will meet network performance targets. (As outlined in Section 4 and in the assumptions above)

5.1.3.1.3 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 11.2kV on 11kV system and depends on the tapping range of 33kV zone substation transformers on the 33kV 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 $\pm 10\%$.
- Frequency: Frequency protection set to trip slightly outside the reach of national automatic under frequency load shedding (AUFLS) relays.
- Fault levels: Additional generation must not cause combined network fault levels that exceed the rating of existing equipment.
- Harmonics: Compliance with NZECP 36.
- Voltage flicker: Use of guidelines as in AS/NZS 61000 series.
- Reliability: Customers have to accept the reliability of existing lines. If they require a better level of reliability or security they have to fund this.

- Auto-reclosing: Connections have to be engineered to be able to withstand line auto-reclosing.
- Charges: In compliance with the Electricity (Distributed Generation) Regulations.

5.1.3.2 Planning Criteria: System Growth

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

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

5.1.3.2.1 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.

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

5.1.3.2.2 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, there is a capacity charge added to every new connection to the Network.)

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

5.1.3.2.3 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 11kV 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 4.

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

5.1.3.2.4 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 4 for power quality in maintaining regulatory requirements for voltage levels and ensuring current ratings of existing assets are not compromised.

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. The harmonic levels recorded from these checks 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

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.

5.1.3.3 Planning Criteria: Quality of Supply

5.1.3.3.1 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 4.

The criterion is to increase automation of network tie points and the installation of reclosers or sectionalisers 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 is also analysed and problem areas targeted.

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

5.1.3.3.2 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 4 are targeted specifically at hazard elimination by removing and replacing hazardous equipment and consequently minimising and eliminating accidents. Details of plans to achieve this are included later in this section.

5.1.3.3.3 Planning Criteria: Other Environmental

The planning criteria for environment projects are:

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

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

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

Thermal areas, such as Tokaanu, require components that can be installed in hot ground. In one case TLC obtained special dispensation to not follow Taupo District Council District plan for underground

reticulations in urban areas, as the ground was too hot for an underground cable. TLC also had to install wooden poles due to the corrosive nature of the gases in the thermal area that reduce the life of concrete poles.

5.1.3.4 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.
- Reinststate the asset with similar capacity as previously.
- Secure funds from road controlling authorities in compliance with acts and regulations.
- Obtain land access easements for relocated works.

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

5.1.3.5 Planning Criteria: Asset Replacement and Renewal

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

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

5.2 Prioritisation Methodology Adopted for Development Projects

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

This includes:

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

Figure 5.1 illustrates the process for prioritising risk driven needs.

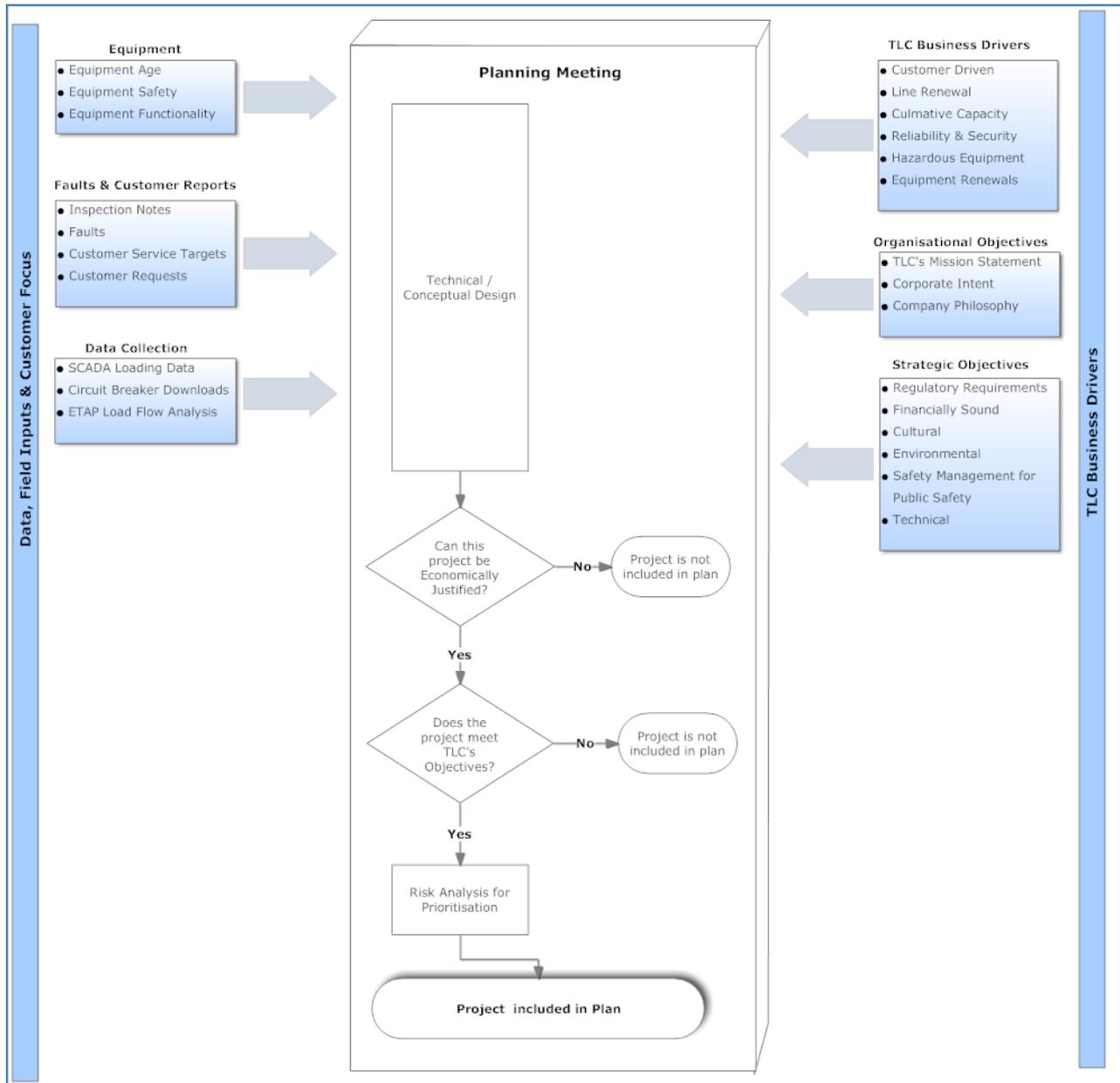


Figure 5.1: Planning Methodology

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

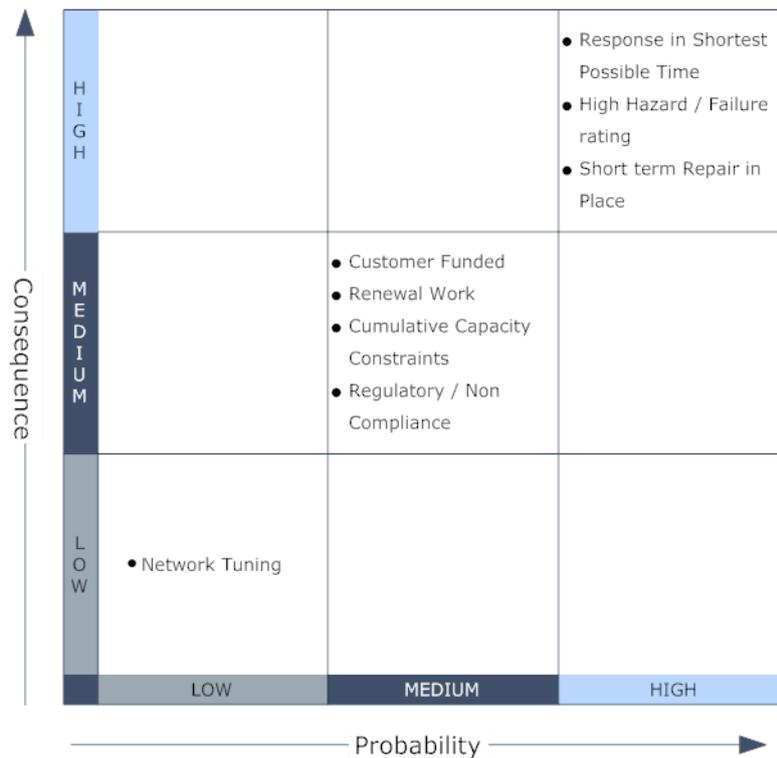


Figure 5.2: Prioritisation Matrix for Risk Driven Needs

The guidelines that are used in applying this approach include:

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

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

SUBJECTIVE/OBJECTIVE ANALYSIS GUIDELINES		
Ranking	Guidelines	Alignment with Company Objectives
High Consequence High Probability	<ul style="list-style-type: none"> » Response required in a shortest possible time to mitigate catastrophic failure. » High probability of hazard control breaches and or issues. 	Renew, develop and maintain a network that does not exceed 208.8 SAIDI minutes or 3.07 SAIFI interrupts.
	<ul style="list-style-type: none"> » 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	<ul style="list-style-type: none"> » Customer funded work that is needed for business or lifestyle activities. 	Objectives above plus:
	<ul style="list-style-type: none"> » 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.
	<ul style="list-style-type: none"> » Equipment with legacy legal and statutory non-compliance issues. » Medium risk of equipment failure. (For example lines that are on a slow moving slip). » The overall renewal programme work. » DSM programmes. » Reliability improvement projects. 	Renew, develop and maintain a network that fulfils stakeholders' value expectations including their ability to pay and long term tenure, social and environmental responsibilities.
Low Consequence Low Probability	<ul style="list-style-type: none"> » Network tuning for long term sustainability i.e. regulator settings, distributed generation settings, phase loadings etc. » Harmonic and power factor control programmes » Other non time dependant projects that have been present for many years. (For example reducing current levels on overloaded SWER systems). 	Minimising costs and improving efficiency through innovation

Table 5.1 Subjective/Objective Analysis Guideline For Priority Setting

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

5.2.1.1 System growth

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

This includes:

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

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

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

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

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

5.2.1.2 Customer connections

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

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

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

5.2.1.3 Reliability, Safety (Hazard Control) and Environment

5.2.1.3.1 Reliability

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

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

5.2.1.3.2 Hazard Elimination/Minimisation

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

1. Hazard elimination/minimisation
2. Environmental
3. System security/capacity and reliability
4. SMS impact.

This is aligned with the requirement to own and operate a hazard controlled and compliant network. (It also needs to be recognised that hazard elimination/minimisation projects enhance environmental, system security, capacity and reliability issues and vice versa.)

The network was originally constructed under budgetary constraints and less rigorous hazard control regulations leading to inherited hazard issues. The slow development of the area has meant that many of these sites have not been upgraded as part of evolutionary network development.

Contributors to identification and evaluation of hazards include:

- Simple obvious problems with equipment.
- Industry accident reports.
- The various acts, regulations, codes etc. that control the industry.
- The application of engineering principles on how equipment operates, and the associated risks.

The experience from investigating and being involved in various industry incidents is used to add a practical aspect to the outcomes of the initial analysis. Over 400 sites have been assessed for hazards by a qualified engineer and electrical inspector/technician as part of the preparation of this plan. Priority has been assigned to those works that remedy hazards and these have been included in the forward renewal and maintenance projections in the plan.

This priority is aligned to the business objective for a hazard controlled, sustainable network and SMS compliant.

5.2.1.3.3 Environmental

Substation inspection data highlights pending environmental risks and concerns. This data is used to prioritise environmental issues such as the likelihood of an oil leak and the impact it will have. Where issues are found, the risks are assessed and improvements programmed in accordance with the prioritising methodology and guidelines.

The long term plan includes a number of environmental projects with medium priority. High priority issues such as oil leaks in sensitive areas are addressed sooner than the medium term projects. This aligns with the objective to fulfil stakeholders' value expectations, including their ability to pay, long term tenure, social and environmental responsibilities.

The long-term renewal programmes include projects to improve oil separation and other environmental facilities. Oil separation and earthquake restraints are also brought up to modern standards when other major work at a site is undertaken.

Environmental factors are considered with most projects. These include:

- End of life disposal issues. The use of SF6 gas insulated equipment is avoided where possible. Recyclable materials and equipment are given priority.
- Compliance with Resource Management Act.
- Minimal cutting of natural vegetation.
- Solutions to minimise environmental impacts, particularly in the National Parks and on sensitive Maori land.
- Impact of natural events on assets.

5.3 Network Demand Forecasts

5.3.1 Introduction

To ensure optimal efficiency, security and stability of the network TLC has forecasted the following:

- Loadings on TLC's Network.
- Demand imposed on each busbar from which it takes supply, or proposes to take supply, from Transpower's Network.
- The effects of proposed generation on TLC's Network.

The forecasts are used extensively in the planning and prioritisation of work proposed on the Network.

5.3.2 Typical factors considered when adjusting growth forecasts

5.3.2.1 Peak Demands

Figure 5.3 shows the peak demand trends for each of the six supply areas in the network. Demands do fluctuate from year to year and the figure below indicates the trends from 2005. These are the instantaneous peaks in MW. The main base data used for load forecasts is the peak demand figures.

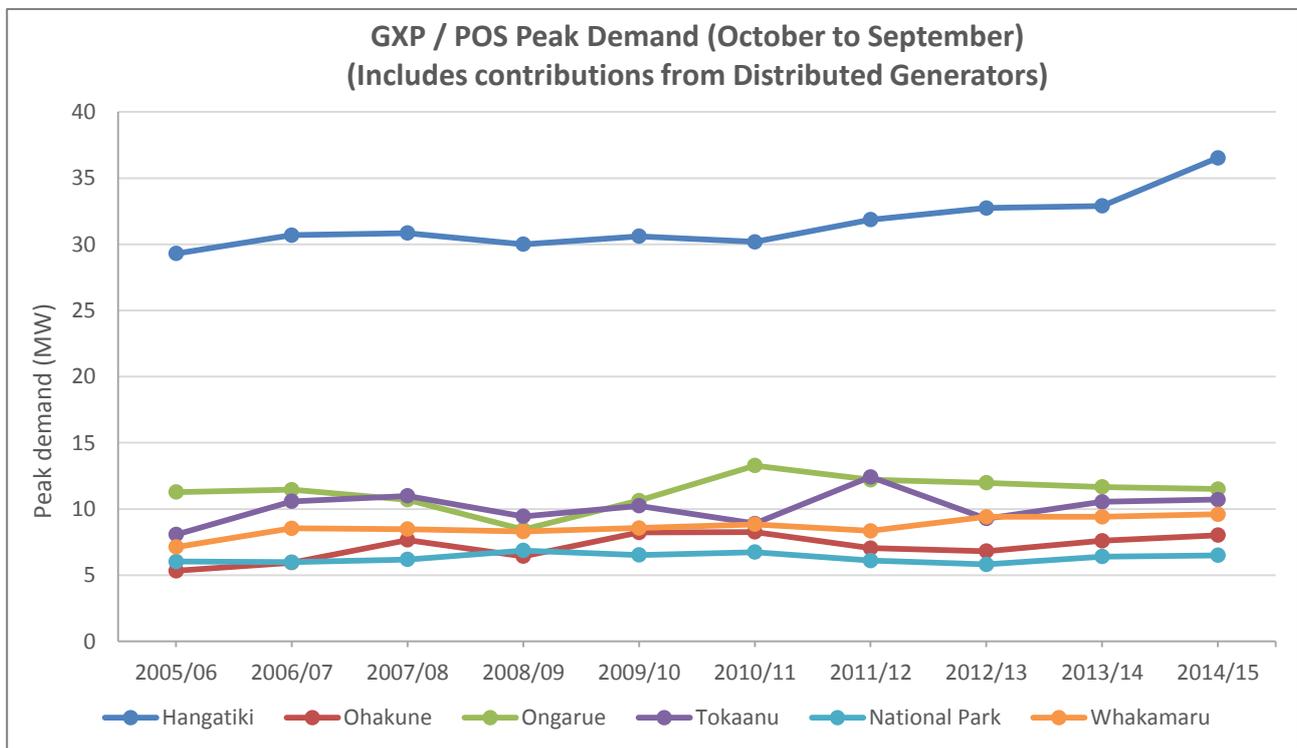


Figure 5.3: Instantaneous Peak Demand Trends from 2005/06 to 2014/15

Peak demand has been stable across all points of supply except Hangatiki which has shown a steady increase on previous years.

- Hangatiki continues to climb due to further dairy growth and increased industrial load.
- Ongarue demand continues to fall back to historic levels.
- Tokaanu has remained stable close to its 10 year average.
- Ohakune and National Park remain stable within annual variations around tourism and weather factors.
- Whakamaru maximum demand has remained consistent with the previous year's peak.

5.3.2.2 Energy Transported

Figure 5.4 shows the trends for the total energy transported for each of the six supply areas in the network.

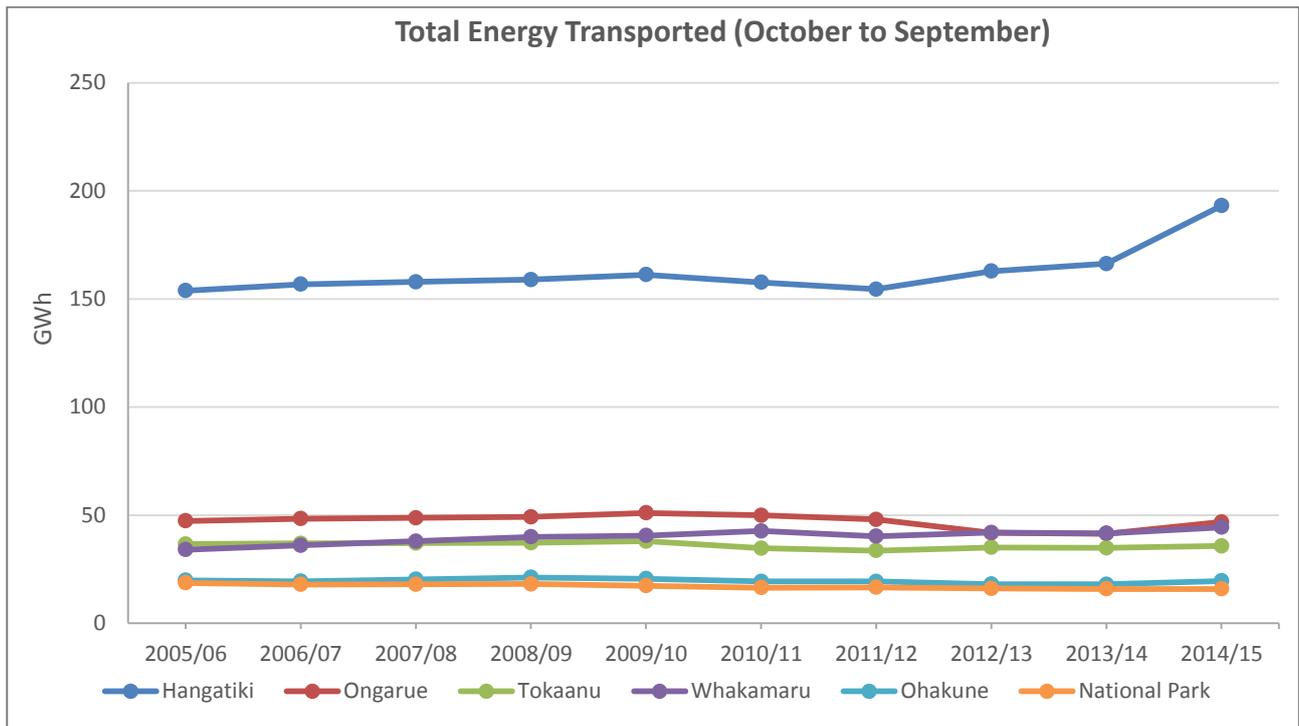


Figure 5.4 Total Energy Transported from 2005/06 to 2014/15

Hangatiki has seen a large increase in energy transported mostly due to increasing intensity of iron sands mining in the area. All other supply areas have shown relatively small movements in total energy transported over the last year. These small movements have not caused any significant changes from the current planning.

5.3.2.3 Applications for Load

Figure 5.5 illustrates the trend in applications for load development. Residential housing, businesses and holiday homes have shown a great downturn since the global financial crisis. However there are some signs of turnaround in both farming and particularly residential applications.

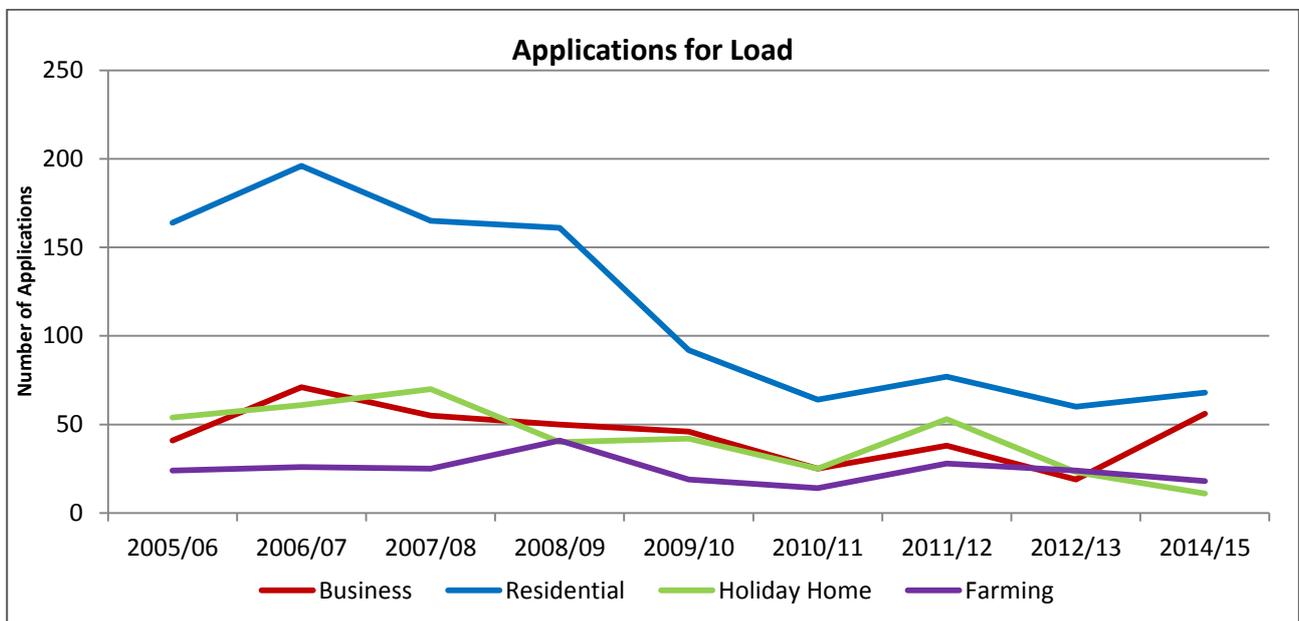


Figure 5.5: Applications for Connecting Load onto TLC's Network

Further information that provides an indication of possible load growth changes include:

- Records of applications regarding electricity availability and subdivision information as required by councils for resource consent provision.
- Building consents.
- Pillar box records.
- Feeder and GXP loadings.

5.3.2.4 Effect of Embedded Generation

There are eight existing distributed generators of significance (about 28 machines) connected to the TLC network.

The factors taken into account when modelling generation includes:

- Output during periods of peak network loads.
- Output during periods of minimum network loads.
- Output during typical summer and winter network loadings.
- Expected operating power factors during the above periods.

It is anticipated that embedded generation output will remain relatively steady over the planning period.

5.3.2.5 Effect of Solar Installation

There are slowly increasing numbers of solar installations on the network. Currently only approximately 20kW of solar is installed across the network annually (averaging 3kW per installation). However with the affordability of solar rapidly improving, it is expected that there will be increasing numbers of solar installations over the planning period.

Due to the timing of solar production there is very little impact on network demand (or revenue) but there is an increasing effect on the volume of energy transported.

5.3.2.6 Effect of Construction of a New Zone Substation

Forward estimates have included the effects of additional modular zone substations and the resulting feeder breakup. This will reduce the loading on the feeders that currently supply these areas.

5.3.3 Load Forecasting over the 10 Year Planning Period

Detailed below are the specific load forecasts and the associated reasons for the forecast, based on the methodologies and data included in Section 5.2 that details how TLC prioritises projects.

5.3.3.1 Supply Area Projected Demands

Figure 5.6 illustrates the forecast growth rate for the planning period in each supply area inclusive of existing generation. The grid exit loads are less than the system loads for the areas that are inclusive of distributed generation. The figures take into account the poor power factor at grid exits due to the effects of distributed generation.

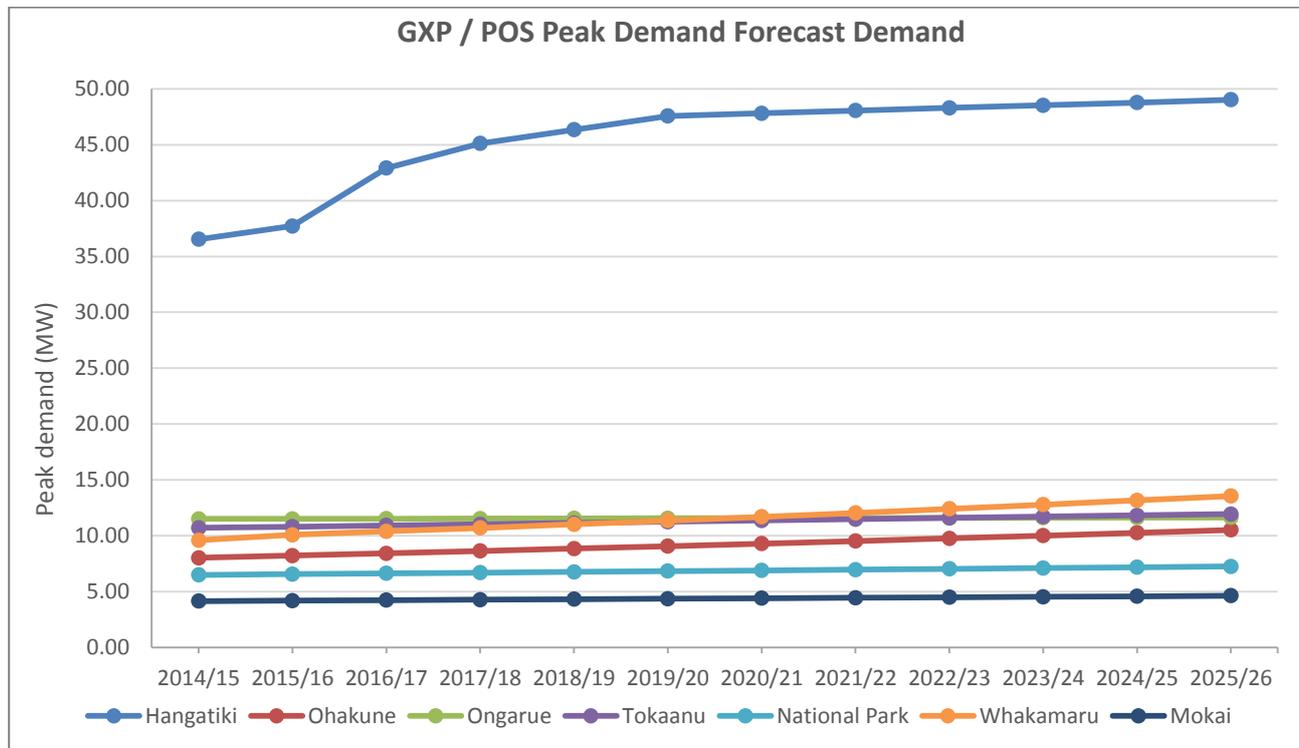


Figure 5.6: Projected Supply Point actual and 10 Year Forecasted Loads

Uncertainties associated with these projections:

- If the effects of demand billing and the demand side management initiatives encourage constrained demand growth then further “head room” will be achieved at Hangatiki.
- Ohakune estimates assume no stepped changes to ski fields or holiday home developments. The grid exit transformer has historically reached 95% of its capacity initially but with demand billing and demand side management, load has stayed within the transformers capacity. Transpower have completed upgrading the GXP transformer to avoid further overloading, increasing the supply from 10MVA to 20MVA.
- Tokaanu estimates assume continued but slow development in Turangi area. A prison expansion or other development associated with recreational activities will change this.
- There is adequate capacity at the Tokaanu supply point to provide for further growth unless there is an exceptional amount of development.
- National Park estimates assume no stepped growth on the Whakapapa ski field or National Park Village. The World Heritage Park plan controls growth in this area and as a consequence it is highly unlikely there will be stepped changes. In 2015 Transpower upgraded the supply from a 10MVA to a 15MVA.

- Ongarue estimates assume a small amount of growth in the Taumarunui area associated with dairy farming and lifestyle development surrounding the township. Continued increase in heat pump loads could affect these assumptions.
- A new 10MVA substation (Point of Supply) is proposed for the Whakamaru area in year 2017/18 to accommodate increasing growth of local dairy farming and irrigation pumps along Waikato River. Furthermore, Atiamuri Zone transformer will be constrained in this planning period and a new substation will remove this constraint. There are a number of alternative options to address backup supply into this area. The main options are to install extra capacity at Atiamuri or to take supply directly from one of the nearby hydro generators (Maraetai or Whakamaru). This will require in depth analysis to determine the optimal solution.
- Hangatiki shows a significant increase early in the planning periods, due to proposed expansion at the NZ Steel iron sand extraction at Taharoa. At the time of writing, negotiations were well advanced to confirm this as proceeding but it is dependent on a number of factors.

5.3.3.2 Zone Substation Projected Demands

The forecasts (Table 5.2 and Table 5.3) assume the adoption of the development plan included in later sections and the upstream projects described in other sections taking place. Green boxes indicate a change in system operating conditions. Orange boxes indicate a potential overloading of the transformers.

Site	Rating (MVA)	Number of Transformers (MVA)	Forecast MD's (MVA) for year ending March 31										
			2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Arohena	3.0	1 x 3.0	2.78	2.80	2.81	2.82	2.84	2.85	2.87	2.88	2.89	2.91	2.92
Atiamuri	10.0	1 x 10.0	9.40	9.68	9.97	10.27	10.58	10.90	11.22	11.56	11.91	12.27	12.63
Gadsby Rd	5.0	1 x 5.0	3.41	3.44	3.48	3.51	3.55	1.58	1.60	1.62	1.63	1.65	1.66
Omya	2.4	1 x 2.4						2.00	2.01	2.02	2.03	2.04	2.05
Hangatiki	5.0	1 x 5.0	3.56	3.60	3.63	3.67	3.71	3.74	3.78	3.82	3.86	3.90	3.94
Kaahu Tee	2.4	1 x 2.4	1.52	1.55	1.57	1.59	1.62	1.64	1.67	1.69	1.72	1.74	1.77
Mahoenui	3.0	1 x 3.0	0.93	0.94	0.95	0.96	0.98	0.99	1.00	1.01	1.02	1.03	1.04
Maraetai ¹	10.0	1 x 10.0	5.01	5.26	5.31	5.37	5.42	4.97	5.02	3.93	3.97	4.01	4.05
Ranginui Road ²	2.0	1 x 2.0						1.50	1.51	1.53	1.54	1.56	1.58
Sandel Road ²	2.0	1 x 2.0								1.14	1.15	1.17	1.18
Marotiri	3.0	1 x 3.0	2.46	2.48	2.51	2.54	2.57	2.60	2.62	2.65	2.68	2.71	2.74
Miraka	7.5	1 x 7.5	2.93	2.99	3.05	3.11	3.18	3.24	3.30	3.37	3.44	3.51	3.58
Oparure	3.0	1 x 3.0	1.52	1.54	1.56	1.58	1.59	1.61	1.63	1.65	1.66	1.68	1.70
Taharoa	15.0	3 x 5.0	14.19	15.00	20.00	22.00	23.00	24.00	24.00	24.00	24.00	24.00	24.00
Te Anga	2.4	1 x 2.4	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20	2.20
Te Waireka Rd	20.0	2 x 10.0	11.15	11.68	11.82	11.96	12.11	12.25	12.40	12.55	12.70	12.85	13.00
Wairere	5.0	2 x 2.5	3.03	3.06	3.10	3.13	3.16	3.20	3.23	3.27	3.31	3.34	3.38
Waitete	15.0	3 x 5.0	9.18	9.28	9.39	9.49	9.59	9.20	9.30	9.40	9.51	9.61	9.72

Table 5.2 Northern Zone Substation forecast maximum demands

Note

1. 10MVA Transformer installed during fault
2. Installation dependant on transformer capacity at Maraetai zone substation

Site	Rating (MVA)	Number of Transformers (MVA)	Forecast MD's (MVA) for year ending March 31										
			2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Awamate Road	2.00	1 x 2.0	0.48	0.48	0.48	0.48	0.49	0.49	0.49	0.49	0.50	0.50	0.50
Borough	10.00	2 x 5.0	7.79	7.87	7.95	8.03	8.11	8.19	6.77	6.84	6.91	6.98	7.05
Northern	2.00	1 x 2.0							1.50	1.51	1.53	1.54	1.56
Kiko Rd	3.00	1 x 3.0	1.41	1.42	1.43	1.44	1.45	1.46	1.47	1.48	1.49	1.50	1.51
Kuratau ¹	3.00	1 x 3.0, 1x1.5	2.46	2.47	2.48	2.49	2.51	2.52	2.53	2.55	2.56	2.57	2.58
Manunui	5.00	1 x 5.0	2.13	2.16	2.18	2.20	2.22	2.24	2.27	2.29	2.31	2.33	2.36
National Park	3.00	1 x 3.0	1.81	1.83	1.85	1.86	1.88	1.90	1.92	1.94	1.96	1.98	2.00
Nihoniho	1.50	1 x 1.5	0.61	0.62	0.63	0.64	0.65	0.66	0.67	0.68	0.69	0.70	0.71
Ohakune ²	20.00	1 x 20.0	6.81	6.90	6.99	7.08	7.17	7.27	7.36	7.46	7.55	7.65	7.75
Otukou	0.50	1 x 0.5	0.25	0.25	0.25	0.25	0.25	0.25	0.26	0.26	0.26	0.26	0.26
Tawhai	5.00	1 x 5.0	3.92	4.00	4.08	4.17	2.12	2.17	2.21	2.25	2.30	2.35	2.39
Tawhai 2nd Tx	5.00	1 x 5.0 (2019)					2.12	2.17	2.21	2.25	2.30	2.35	2.39
Tokaanu	1.25	1 x 1.25	0.17	0.17	0.18	0.18	0.19	0.19	0.19	0.20	0.20	0.20	0.21
Tuhua	1.50	1 x 1.5	0.78	0.79	0.79	0.79	0.80	0.80	0.80	0.81	0.81	0.82	0.82
Turangi	10.00	2 x 5.0	4.61	4.62	4.62	4.62	4.13	4.13	4.14	4.14	4.15	4.15	4.15
Waiotaka	1.50	1 x 1.5	0.51	0.52	0.52	0.53	1.04	1.05	1.06	1.07	1.08	1.09	1.10

Table 5.3 Southern Zone Substation Forecast maximum Demands

Note

1. 1.5MVA backup transformer on site, this cannot be run in parallel with the 3MVA transformer
2. Transpower GXP transformer

5.3.3.2.1 Zone Substation Demand assumptions

- **Tawhai** – Load at Whakapapa slowly developing such that an additional transformer is needed at Tawhai in 2019/20. If the development of the ski field does not eventuate there will be little impact other than an additional transformer will not be required. (Existing transformer is proposed to be run into overload due to low ambient temperatures when loading is greatest.)
- **Sandal Road** - It is assumed a substation will be needed in Sandal Road about 2022/23 to service increasing dairy development in the Whakamaru area.
- **Ranginui Road** – It is assumed a substation will be needed in Ranginui Road about 2020/21 to service increasing development at the Crusader Meat Plant. (This will be needed to reduce loading on the Maraetai transformer, voltage drop on the Pureora feeder and conductor loadings.) The greatest demand is from the dairying in the area and from the meat processing plant whose peak time is through the summer months. If the Crusader Meat Plant were to reduce in size and farm development in the area were to stop then the need for an additional modular substation would not be alleviated due to the cumulative increasing load on the Maraetai zone substation. It would however, be likely that the project would be delayed beyond the planning period as it presently exists. Alternatively a new 33kV line could be built from Waitete substation out to a substation closer to Crusader Meats yard.
- **Lime Processor Industrial** – Lime processors in Te Kuiti/Otorohanga area opting for a modular substation in 2020/21 to improve plant reliability and increase capacity. If the Te Kuiti industrials choose not to expand and fund this project then the status quo would exist. The 11kV feeders would be under pressure at times and this pressure would have to be alleviated by demand side initiatives such as power factor improvement.
- **Okahukaru** – An additional container sub north of Taumarunui in 2021/22. This is to minimise the flood risk at the Borough substation. The loading on the Northern feeder is expected to continue to increase as more heat pumps displace log fires in the northern part of Taumarunui.
- **Taharoa** – Planned development occurs at New Zealand Steels iron sands mine.
- Transformer replacement as proposed in the forward plan does occur.

5.3.3.3 11kV Distribution Feeder Projected Demands

The significant events that could affect distribution feeder forecasts include:

- The changes to the sub transmission network as described in earlier sections.
- The existing TLC network configuration will largely remain unchanged.
- Lime processors partially funding modular substation to create new 11kV feeder in Old Te Kuiti Road. If this does not take place, the existing network will remain in place until there is some form of external trigger point. It is likely to be when industrial load growth coupled with demand side management (mostly power factor control) is no longer able to provide the quality and security of supply that customers require.
- Distributed generation projects that are not included in forecasts and likely to proceed in the planning period.
- A change in the historical growth patterns in the Taumarunui area. If this takes place there will be pressure on sub transmission and distribution assets. A solution will be more modular substations and a point of supply out of the Transpower Taumarunui substation. If this were to occur the existing Ongarue grid supply point would likely be decommissioned.
- Continued growth in ski fields. Any sudden additional growth to be partly covered by demand side generation on ski fields. The cost of upgrading and supplying extra capacity to the ski fields will be substantial. As a result of this, it is likely that all the capacity in the present system will be used and then demand side generation used for peak control during the planning period.
- Continuing industrial load growth for areas around Te Kuiti. This is dependent on the demand for the primary products (meat, timber and lime) that the industrial processors produce.
- Continued dairying expansion in the Whakamaru and Mangakino area.

Table 5.4 and Table 5.5 outline the projected maximum demand forecasts for 11kV distribution feeders.

FORECAST MD'S (A) FOR YEAR ENDING MARCH 31												
FEEDER	REFERENCE	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
McDonalds	110	211	234	237	241	244	247	250	253	257	260	263
Gravel Scoop	109	112	112	113	113	113	113	114	114	114	114	114
Otorohanga	112	200	202	205	207	209	211	214	216	218	221	223
Maihihi	111	210	213	216	220	223	226	230	233	237	240	244
Coast \ Te Anga	125	115	115	115	115	115	115	115	115	115	115	115
Mokauiti	115	45	45	45	45	45	45	45	45	45	45	45
Mahoenui	113	24	24	24	24	24	24	24	24	24	24	24
Piopio	116	66	66	67	68	69	69	70	71	72	73	73
Te Mapara	117	41	42	42	43	43	44	44	45	45	46	46
Aria	114	27	27	28	28	28	28	29	29	29	29	29
Benneydale	103	290	293	297	300	303	306	310	313	317	320	324
Te Kuiti Town	105	51	51	52	52	53	53	54	55	55	56	56
Te Kuiti South	104	41	42	42	43	43	44	44	45	45	46	46
Rangitoto	106	143	144	145	146	147	148	149	150	151	152	153
Hangatiki East	102	152	153	155	157	158	56	57	110	111	112	114
Proposed Limestone industrial							104	105	105	106	106	107
Caves	101	49	49	50	50	51	51	52	52	53	54	54
Oparure	107	167	169	171	172	174	176	178	180	182	184	186
Waitomo	108	123	125	126	127	129	130	132	133	135	136	138
Mangakino	118	44	45	45	46	46	47	48	48	49	49	50
Huirimu	121	37	37	37	37	37	37	37	37	37	37	37
Wharepapa	122	129	131	133	135	137	139	141	143	145	147	150
Pureora	119	123	125	127	128	130	106	108	49	50	51	51
Whakamaru	120	112	112	112	112	113	86	86	87	87	87	87
Proposed Ranginui Road							79	80	81	83	84	85
Proposed Sandel Road									60	61	61	62
Tirohanga	129	105	106	108	109	111	113	114	116	118	120	121
Mokai	123	69	70	71	72	73	74	75	77	78	79	80
Tihoi	124	50	50	51	51	52	52	53	53	54	55	55
Rural	126	20	20	20	20	21	21	21	21	21	21	21
Mokau	128	51	51	52	52	53	53	54	55	55	56	56
Paerata	130	33	34	34	34	35	35	35	36	36	36	37
Miraka	131	139	140	142	144	145	147	149	151	153	154	156

Table 5.4 Feeder Load Forecast for Northern Feeders

FORECAST MD'S (A) FOR YEAR ENDING MARCH 31												
FEEDER	REFERENCE	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Hakiaha	401	94	94	94	94	94	95	95	95	95	95	95
Northern	402	162	163	164	166	167	168	90	91	91	92	93
Proposed Okahukaru								79	80	81	82	83
Western	403	65	66	67	68	69	70	71	72	73	74	75
Matapuna	404	149	151	154	156	158	161	163	166	168	171	173
Motuoapa	425	36	37	37	37	37	38	38	38	38	39	39
Oruatua	417	33	33	34	34	34	34	35	35	35	35	36
Hirangi	405	41	41	42	42	42	42	42	43	43	43	43
Turangi	423	150	150	150	151	151	151	151	151	151	152	152
Rangipo-Hautu	424	142	142	142	143	117	117	117	117	117	117	117
Waiotaka	427	26	27	27	27	53	54	55	55	56	56	57
Manunui	408	68	68	69	70	71	72	72	73	74	75	76
Southern	409	61	61	62	62	63	64	64	65	66	66	67
Ongarue	421	26	26	26	27	27	27	27	27	27	27	27
Tuhua	422	18	18	18	18	18	19	19	19	19	19	19
National Park	411	71	72	72	73	74	75	76	76	77	78	79
Raurimu	410	26	27	27	27	27	28	28	28	28	29	29
Otukou	418	16	16	16	16	16	16	17	17	17	17	17
Turoa	415	239	242	246	249	253	257	261	265	269	273	277
Tangiwai	416	109	110	112	113	114	115	117	118	119	120	122
Ohakune	414	170	172	174	176	177	179	181	183	185	187	189
Waihaha	426	33	33	33	34	34	34	34	34	35	35	35
Kuratau	406	111	111	112	112	113	113	114	114	115	116	116
Chateau	419	248	253	258	263	268	274	279	285	290	296	302
Tokaanu	420	11	11	12	12	12	12	13	13	13	13	14
Nihoniho	412	4	4	4	4	4	4	4	4	4	4	4
Ohura	413	27	27	27	28	28	28	28	28	28	28	29

Table 5.5 Feeder Load Forecast for Southern Feeders

5.3.4 The Impact of Uncertain but Substantial Individual Projects on Load Forecasts

5.3.4.1 Wind Farm Projects

The effects of the wind farm generation have not been included in the forecasts due to no activity on the current two large proposed wind farm projects that TLC has received applications for. It is anticipated that in the short to medium term there is a low likelihood of wind generation growth.

5.3.4.2 Hydro Generation

Distributed generation has a dynamic effect on the network and there is a lot of uncertainty as to where and when developments will take place. As a consequence it is not practical to factor into future load predictions all possible effects. Currently there are no new projects being developed that will have an effect on the network.

5.3.4.3 Industrial Site Expansions

A number of industrial sites have approached TLC with upgrade and expansion plans. For those sites near a 33kV line, TLC has programmed into the forecasts a modular substation that will allow the industrials the capacity to expand.

These include:

- A lime works where a modular substation will reduce the demand on Hangatiki East feeder and the transformer at the Hangatiki zone substation.
- A meat works where a modular substation will reduce the demand on Pureora and Benneydale feeders and the transformers at the Maraetai and Waitete zone substations.
- An iron sands mine that would require the upgrading of transformers at the Taharoa zone substation and the upgrading of the Hangatiki GXP transformers.

If these industrial developments do not occur the modular substations proposed for the industrial sites will be removed from the plan.

5.3.4.4 Dairy Farming & Irrigation

TLC has two modular substation planned for rural areas where irrigation has taken place. If the development continues with increase in demand then the proposed modular substation can be brought forward to avoid any voltage constraints.

There is an expected increase in load due to more stringent milk refrigeration requirements that are expected to come into effect in 2016. The effect of these changes are already coming in to effect with a number of increased load applications from dairy farms for milk chilling.

5.3.4.5 Effects of Electric Vehicles

It is recognised that the introduction of electric vehicles has the potential to have a significant effect on the TLC network. In the longer term it may be that the energy transported to charge these vehicles will increase as they become more main-stream.

The demand effects, if this were to occur, would likely be significant. If the vehicle batteries were set up to assist demand side management by supplying power in peak times and absorbing power in off peak times, there could be a decline in peak growth. Alternatively, if no demand side management is implemented, peak demand could increase rapidly. It is hoped that demand billing would strongly encourage the former option. If the batteries assist demand management by supplying power directly from their reserves, the network fault level within the system could rise due to the additional sources of energy that would feed into network faults when they occur.

The timing of these vehicles turning up and the extent of penetration into the rural TLC environment is unknown. There are several penetration timing scenarios prompted by various motoring experts. A common theme amongst them is that electric vehicles are more likely to be adopted in urban areas as

opposed to rural. Many of these writers suggest that electric vehicle penetration into rural areas will take a long time to develop given the current technological status of the batteries.

For example, the most likely vehicles that will be suitable for rural use are hybrids that use a combination of petrol/diesel and electric motors with some battery storage.

For the purposes of this plan, the effects of electric vehicle penetration on the network have not been included.

5.3.5 Equipment or Network Constraints Anticipated in the planning period

TLC uses Electrical Transient Analyser program (ETAP) to predict where constraints will occur if the forecast load growth occurs. The network is modelled with the projected loadings and the program produces reports that highlight the assets within TLC's network that are likely to have unacceptable voltage levels; similarly, ETAP reports can be used for current constraints.

The report can be used to highlight sections of the network that are below or close to the minimum supply of 94% of rated voltage. Areas identified with low voltage are slated for voltage regulators or conductor upgrades in the planning period.

Current constraints are identified in the report by comparing the maximum load current with the conductor's current rating.

TLC uses these reports to assist in planning and identifying areas of constraint. An analysis of the network constraints is summarised in the following sections, given the predicted system demands listed in the sections above.

5.3.5.1 Supply Points Constraints

Hangatiki - The constraining factor on the present load off-take from Hangatiki is the capacity of the two 110kV/33kV banks. These have a summer/winter rating of 22/24 MVA for one unit and 25/26 MVA for the other. It is often difficult during day light hours to reduce load to the 22/24 MVA level to allow Transpower to remove a unit from service to carry out maintenance. A failure or a fault in a unit will mean that a number of dairy farmers, meat processors, and lime processors will have to stop production.

If the load increase at Taharoa goes ahead then the capacity will have to be upgraded in the first half of the planning period to accommodate the extra load. Transpower in conjunction with TLC, have commenced planning for this replacement.

Waipa Networks are currently constructing an 110kV line out of Hangatiki. This will add to the load requirements at Hangatiki and it will also aid in the cost reduction of GXP charges. Further impacts of this new 110kV line are being investigated through continued engagement with Transpower.

A modern ripple injection plant has been installed at Hangatiki. However, it is expected that the change out of all the customer load control relays will take another 2 years and the present plants will be decommissioned in 2017 or a little later, (dependent on the rollout of advanced meters). In addition to historic load control, signals are essential for customer demand side management under TLC's charging structures.

Ohakune – In 2015 the Ohakune GXP transformer (shared with PowerCo) was upgraded to 20MVA. The new transformer has double the capacity and improved reliability associated with modern power transformers at negligible extra cost.

Tokaanu - There are no capacity constraints at the Tokaanu point of supply.

National Park – In 2015 the GXP transformer was upgraded to a unit with increased capacity (15MVA) and the benefit of improved reliability due to a modern power transformer. Continued development at the Whakapapa ski field and National Park village will drive load demands at this grid exit point. Models are saying that the grid exit transformer capacity will be adequate to the end of the planning period. It is likely a non-asset solution in conjunction with the development of the ski field will be pursued when its

transformer capacity is fully utilised. There are a number of potential hydro sites in the area that, if developed, would alter the National Park grid exit loads.

At the beginning of 2014 the new containerised zone substation and ripple injection plant were commissioned at National Park, this has allowed for the removal of one Transpower circuit breaker which will reduce annual costs from this site.

Ongarue - The Ongarue point of supply has sufficient capacity for all likely development during the planning period. This may change towards the end of the planning period if potential hydro in the region is developed. The connection charges for the site are high and it is possible to reduce these by rationalising the number of outgoing feeder circuit breakers. As with other sites above, Transpower has agreed to work with TLC to modernise and rationalise the site to better produce outcomes that both organisations require. These will be addressed in planning work following the completion of Ohakune and National Park projects.

Whakamaru / Atiamuri – The capacity of the 10 MVA backup supply out of Atiamuri will be at its upper limit during this planning period. There is a plan for either a new point of supply at Whakamaru, an increase in capacity at Atiamuri or a new supply directly from a hydro generator in 2018/19 that will provide an improved backup supply.

More planning and thinking is required in this area as we get to understand developments in and around the Mokai Energy Park and changes in dairying load in the region.

The present primary load control system for the area downstream of the Whakamaru/Atiamuri supply is old and based on an injection frequency of 725 Hz. The plants themselves inject at 11kV. 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 modern ripple injection plant has been installed at Whakamaru GXP. It is expected that the present plants will be decommissioned in 2016 following completion of the advanced metering rollouts in the area. In addition to historic load control, signals are essential for customer demand side management under TLC's charging structures.

5.3.5.2 Zone Substation Constraints

There are transformers at two zone substations that will be constrained due to capacity in this planning period. Atiamuri supply transformer will be at capacity during this planning period. There is planned work for 2018/19 that will alleviate this constraint. With the planned increase in load at the iron sands mine an upgrade of the existing transformer arrangement at Taharoa is planned for 2016/17.

Oil tests on the Kuratau transformer indicate that it is in a deteriorated condition. This will be replaced with a refurbished transformer that is being swapped out of Mahoenui.

There is an environmental constraint due to a potential flood risk at the Borough zone substation. This will be mitigated with the establishment of a new modular zone substation that can back up supply to Taumarunui.

5.3.5.3 33kV Line Constraints

TLC's subtransmission network will not encounter any capacity constraints within this planning period. Assuming that the existing network configuration will be maintained in the Taumarunui and Kuratau areas. The Nihoniho 33 and the Kuratau/ National Park lines have reliability and hazard constraints caused by their age and inherent low strength design.

If the load increase at Taharoa goes ahead then the Taharoa A and B line will be running at full capacity and future upgrades on the line are being considered.

Included in the plan is the relocation and undergrounding of the Lake Taupo 33kV which runs through Turangi Town. The primary reasons for this are that the line runs through the main street of Turangi and it is susceptible to damage from surrounding trees.

5.3.5.4 Distribution Feeder Constraints

Current and Access Constraints

Current constraints are determined by using the network analysis program to forecast the expected currents on conductors. These are then checked against the existing conductors rating. The constraint priorities in Table 5.6 to Table 5.7 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 11kV Feeders for predicted loads over 10 year planning period
1	Current below 100% of a section conductor rating (Unconstrained).
2	Current of 110% of a section conductor rating.
3	Current of 120% of a section conductor rating.
4	Current of 130% of a section conductor rating.
5	Current of 140% or greater of a section conductor rating.

Table 5.6 Current Constraints

Access constraints are determined from the line inspection information and local knowledge.

ACCESS CONSTRAINTS	
Constraint Grade	Access Constraints on 11kV Feeders
1	Up to 20% of the feeder must be fault patrolled and accessed with a helicopter.
2	Up to 40% of the feeder must be fault patrolled and accessed with a helicopter.
3	Up to 60% of the feeder must be fault patrolled and accessed with a helicopter.
4	Up to 80% of the feeder must be fault patrolled and accessed with a helicopter.
5	Up to 100% of the feeder must be fault patrolled and accessed with a helicopter.

Table 5.7 Access Constraints

Reliability Constraints

Reliability problems due to age, construction, span lengths, tree numbers, numbers of alternative feeds, numbers of reclosers, other automated controls, known fault current problems, distances from depots, amount of feeder that is a radial feeder, local terrain, i.e. how rugged and remote the area is, previous history and likely problems have been considered to assign a reliability constraint.

The severity of these constraints is listed as in Table 5.8.

RELIABILITY CONSTRAINTS	
Constraint Grade	Reliability Constraints on 11kV Feeders
1	Above issues are expected to cause problems or likely to cause problems every 2 years.
2	Above issues are expected to cause problems or likely to cause problems every 12 months.
3	Above issues are expected to cause problems or likely to cause problems every 6 months.
4	Above issues are expected to cause problems or likely to cause problems every 3 months.
5	Above issues are expected to cause problems or likely to cause problems monthly.

Table 5.8 Reliability Constraints

Extreme Weather Constraints

Constraints due to extreme weather conditions rise as wind speed accelerates (Table 5.9). 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 11kV feeders.

EXTREME WEATHER CONSTRAINTS	
Constraint Grade	Extreme Weather Constraints on 11kV Feeders
1	Winds greater than 40 km/hr.
2	Winds greater than 60 km/hr.
3	Winds greater than 80 km/hr.
4	Winds greater than 100 km/hr.
5	Winds greater than 120 km/hr.

Table 5.9: Extreme Weather Constraints

Table 5.10 to Table 5.16 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	1	3	2	3	None within this planning period.	Rural feeder. Reliability constrained by long spans and polluted insulators. SWER lines.
Benneydale	1	4	3	2	There are 4 regulators on this feeder and distributed generation. Without generation the voltage can dip at the end of the feeder.	Distributed generation. Very long feeder with some large industrial and rural customers. SWER lines.
Caves	1	3	3	3	Due to the small conductor size, ends of long rural spurs are constrained.	Long spans towards end. SWER lines. Voltage regulator proposed for the end of the planning period.
Coast	1	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	1	1	4	2	Gravel Scoop constraints towards the end of the planning period.	Rural supply with dairying load. High fault currents near zone substation. Regulator is proposed for year 2024/25.
Hangatiki East	1	1	2	2	Due to a large lime industrial site this feeder is at its upper limits.	Industrial & dairying load.
Mahoenui	1	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.
Maihihi	1	3	4	2	Two regulators on this feeder providing voltage support. Mangaorongo and Maihihi Road junction is at upper limits.	Long urban and rural feeder with mainly dairy farming load. High fault currents near zone substation. Conductor renewal planned in 2016/17 and 2017/18.
McDonalds	1	1	4	2	None within this planning period.	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	1	4	4	4	Two regulators on this feeder.	Significant amount of overhead line in exposed coastal environment. Conductor renewal is planned for 2016/17. Four separate SWER systems into the remote rural areas.
Mokauti	1	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	1	3	4	2	Ends of long rural spurs are constrained.	Long rural feeder with fertiliser polluted insulators.
Otorohanga	1	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	1	3	3	3	None within this planning period.	Rural feeder. Reliability constrained by long spans and polluted insulators.
Rangitoto	1	4	3	2	Reconductoring at the beginning of the period will alleviate voltage constraints before the first regulator on the feeder.	Long feeder with industrial and rural loads. Has one small SWER system. Reconductoring near start of feeder to improve fault rating and strengthen feeder.
Rural	1	4	4	3	None within this planning period.	Small coastal feeder.
Te Kuiti South	1	3	2	2	None within this planning period.	Urban and rural supply with a number of ground mounted transformers.
Te Kuiti Town	1	1	1	1	None within this planning period.	Mostly urban supply with number of ground mounted transformers.
Te Mapara	1	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	1	1	3	1	None within this planning period.	Urban and rural supply. Has large sawmill connected.

Table 5.10 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	1	4	3	2	Voltage constraint at end of feeder at the end of this planning period.	Rural feeder supplying dairy load.
Mangakino	1	1	2	2	None within this planning period.	Ex dam construction town. Low 2 pole structures and low voltage in poor condition.
Mokai	1	4	3	3	Voltage constraint along Whangamata and Karangahape Road.	Rural feeder with dairying, subdivision and industrial load growth. Regulator proposed in 2015/16 year.
Pureora	1	5	3	2	Two regulators on this feeder and capacitors to provide voltage support. Load increase for Crusader Meats constrains the feeder.	Long rural feeder with meat processor on end. Regulator proposed in 2022/23.
Tihoi	2 (SWER)	4	3	3	Western Bay Road constraints before and after SWER sub.	Long rural feeder with growth. SWER system.
Whakamaru	1	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	1	4	3	4	This feeder has three regulators.	Long rural feeder supplying dairy load. Conductor renewals planned in 2016/17 to support growth.
Tirohanga	1	3	3	2	None within this planning period.	Rural feeder with many trees along route.

Table 5.11 Constraints on Feeders Supplied By Whakamaru POS

MOKAI POINT OF SUPPLY						
Feeder	Current Constraint	Access Constraint	Reliability Constraint	Extreme Weather Constraint	Voltage Constraint	Hazard Constraints and Comments
Miraka	1	1	2	2	Short underground feeder with no constraints.	High fault current from Mokai Station.
Paerata	1	1	2	2	Short overhead feeder with no constraints.	High fault current from Mokai Station.

Table 5.12 Constraints on Feeders Supplied By Mokai Station

ONGARUE POINT OF SUPPLY						
Feeder	Current Constraint	Access Constraint	Reliability Constraint	Extreme Weather Constraint	Voltage Constraint	Hazard Constraints and Comments
Hakiaha	1	OK	3	3	None within this planning period.	Mostly urban feeder in Taumarunui with many GMT substations.
Manunui	2 (SWER)	4	3	3	Long small conductor SWER lines.	Rural feeder with a number of SWER systems.
Matapuna	1	2	3	3	Due to small cable sizes this feeder is nearing its upper limits.	Mostly urban feeder in Taumarunui. Small cable.
Nihoniho	1	5	4	4	None within this planning period.	Old feeder into very remote rugged country with SWER.
Northern	1	4	4	3	Voltage constrains in rural areas.	Long rural feeder SWER systems. Old switchgear.
Ohura	1	5	4	4	None within this planning period.	Old feeder into very remote rugged country. Five separate SWER systems.
Ongarue	4 (SWER)	5	3	3	Due to small conductor voltage drops South of Tangitu. SWER systems also at upper limits.	Rural feeder in rugged remote country with high current SWER systems.
Southern	1	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	1	5	3	3	None within this planning period.	Rural feeder in rugged remote country. High current SWER systems.
Western	1	4	4	4	Growth of lifestyle blocks close to Taumarunui may see this feeder with voltage constraints at the end of the planning period.	Long rural feeder with high current SWER systems. Regulator is proposed if load growth occurs.

Table 5.13 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	1	1	1	1	None within this planning period.	SWER feeder close to Turangi.
Kuratau	1	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	1	2	2	2	None within this planning period.	Low structures & LV systems. Many improvements to minimise/eliminate hazards, more needed.
Oruatua	1	3	2	2	None within this planning period.	SWER systems. Low structures. Improvements required minimising hazards.
Rangipo / Hautu	1	2	2	3	None within this planning period.	Many improvements to eliminate/minimise hazards; more needed.
Tokaanu	1	1	2	1	None within this planning period.	Many improvements to minimise/eliminate hazards.
Turangi	1	1	4	2	None within this planning period.	Ground mounted transformers (GMT) in inadequate enclosures and old switchgear. Underground cabling reaching end of life.
Waihaha	1	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	1	1	1	1	None within this planning period.	Short feeder supplying Hautu Prison and SWER system to a Māori incorporation farm.

Table 5.14 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	1	3	3	4	Remote lines with small conductor south of National Park.	Hazard concerns include long spans of single phase along SH4. Environmental concern in World Heritage Park.
Otukou	1	3	3	3	None within this planning period.	Heavily forested, most of feeder is SWER.
Raurimu	2 (SWER)	5	3	3	None within this planning period.	Feeder with three very long SWER systems into remote rugged country. These systems have high current loadings.

Table 5.15 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	1	1	3	4	The small conductor and heavy loads over the ski season have put this feeder at its upper limits.	Work needed to remove hazard constraints with LV and switchgear and to meet growth. Conductor size small in some areas.
Tangiwai	3	3	3	3	One regulator installed at Tangiwai. At heavy loading this feeder constrains from the town's boundary.	Renewal work over the last few years to improve pole strengths. Snow area.
Turoa	1	3	3	2	Four regulators installed on this feeder.	Supply to ski fields. Has old switchgear.

Table 5.16 Constraints on Feeders Supplied By Ohakune POS

5.3.6 Impact of Distributed Generation on Forecasts

Post the global financial crisis, the national demand and supply position has changed considerably. Completion of significant geothermal power plant construction in the Central North Island and reducing demand has meant an uplift in the supply side of electricity. This has resulted in considerable downward sliding of wholesale energy prices. Developers of distributed generation and major retailers, have shelved the majority of any further generation projects. Additionally, older thermal stations are being signalled to the market as ready for closure; ie Southdown, Otahuhu and Huntly coal units.

As such, activity in the distributed generation market has subsided. While we are aware of the majority of potential distributed generation projects, none are anticipated to come on-stream within the planning period.

5.3.7 Impact of Demand Management Initiatives on Forecasts

5.3.7.1 Effect of Auxiliary Generation on Peak Demand Reduction

Ruapehu Alpine Lifts (RAL) has installed a generator to bolster the supply during peak load periods such as snow making on a winter's night on its Turoa ski field. The company is also proposing another similar installation at Whakapapa.

The Turoa installation has only been used occasionally to reduce peaks due to the practical issues associated with getting enough fuel up to the ski field to the site. There are also clauses in the World Heritage Park Plan that will make running this plant for extended periods difficult. There is still an amount of capacity in the existing supply to both ski fields and demand side management savings via power factor improvements are potentially possible.

As a consequence of this the forward models have assumed expansion of loads on the ski fields until all of the existing capacity is used and then loads have been seen to not increase further. It has been assumed that by this time the current difficulties with the auxiliary generation will be overcome and it will be used to constrain load for the remainder of the planning period.

Auxiliary generation over peak periods on the ski fields has been assumed to delay the need to upgrade the Tawhai transformer.

A number of smaller businesses in the Ohakune area also operate generators to reduce peak demand. Due to the small size of the generators they have a negligible effect on the network.

5.3.7.2 Effect of Load Control on Peak Demand Reduction

TLC uses a load control system to reduce loading during peak periods. The load control targets are set to align as best as possible with Transpower's regional peaks and network constraints.

Customers have a ripple relay that controls hot water and other assigned loads. Each ripple relay is assigned a channel and, TLC's SCADA system is programmed to automatically shed load based on the forecast loadings at peak times.

Load control through peak times delays the need to upgrade system capacity. Comparisons of loads in the network analysis program indicate that a number of assets would be constrained at peak loading time much earlier in the planning period, which would lead to the need for earlier investment than necessary.

5.3.7.3 Effect of Peak Demand Billing on Peak Demand Reduction

TLC utilises a Demand Billing methodology to influence customer energy usage, in particular network peak demand. The methodology is explained in detail in the Pricing Methodology document available online at www.thelinescompany.co.nz/disclosures/pricing-methodology.

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 will complete rolling out advanced meters to all customers over the next 2 years.

Initial calculations have shown that peak demand will have increased at a rate of 0.2% to 1.3% greater than if financially driven demand side management had not been introduced. These percentages have been included in the growth rates and trend lines have been adjusted accordingly.

5.3.7.4 The Implications of Demand Side Management Initiatives

5.3.7.4.1 On Supply Points

5.3.7.4.1.1 General Discussion on Demand Side Management Effects on Substations

Figure 5.7 shows the estimated reduction in peak demand as a result of demand side management.

Hangatiki - Demand side management creates capacity 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 TLC have been able to delay the upgrade of the Hangatiki transformers.

Ohakune – Demand growth is driven by the ski season. Demand charging has delayed any further investment by Transpower or TLC due to capacity constraints.

Tokaanu and Ongarue - It is predicted that if present growth in demand figures continue, then growth will be delayed by six and seven years respectively at these two sites. There are no supply point constraints on the planning horizon for either of these two sites.

National Park - Demand growth is being driven by the ski field. Similarly to Ohakune demand charging has delayed any further investment by Transpower or TLC due to capacity constraints. Again, as with Ohakune, it is likely that without demand charging, growth would have been greater. It is known that the ski lodges for example have become more focused on demand control.

Whakamaru/Atiamuri/Mokai – Without demand side management the Atiamuri supply transformer that backs this area up will be operating beyond acceptable loadings about one to two years sooner.

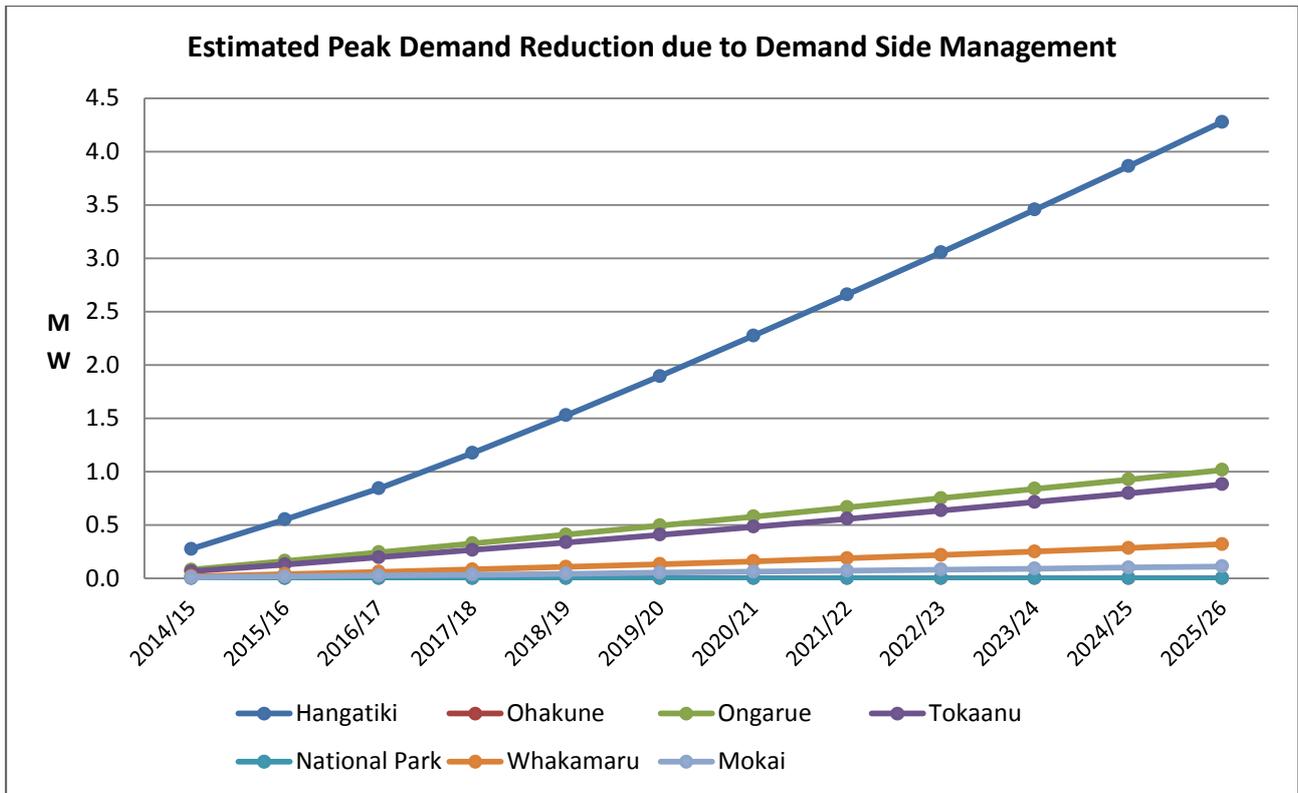


Figure 5.7 Effects of Demand Side Management on System Estimated Peak Demands

5.3.7.4.1.2 The Effect of Maximum Demand Tariff's on Supply Point Loadings

The following are cost reductions that are handed on to customers as a result of maximum demand billing:

- A reduction in Transpower charges. TLC is able to reduce its loading during the Lower North Island electricity peaks thus reducing the transmission charges imposed on it.
- By reducing the peak loading on network assets this will increase life expectancy and reduce failures caused by electrical deterioration, which is aggravated by excess heating. Thereby asset replacement is pushed further out.
- Benefits may be gained through the deferral of capacity upgrades. These occur at all levels from transmission through to distribution. For example, TLC is outgrowing several National Grid assets that will cost several million to replace such as the Hangatiki 110/33kV transformer bank. These assets have not yet reached their life expectancy and could be replaced prematurely due to overloading. Their replacement will be expensive to both TLC and its customers.

Load factor is used to estimate the effects of TLC's maximum demand pricing options.

The load factor is the ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. It is a percentage derived using the following formula.

$$\text{Load Factor} = \frac{\text{Actual Energy Consumed}}{\text{Maximum Demand} \times \text{Time in hours of period}}$$

Figure 5.8 outlines the change in load factors for each of the different systems in the network. The figures used are from 1st October to the 30th September for every year and includes the most recent winter.

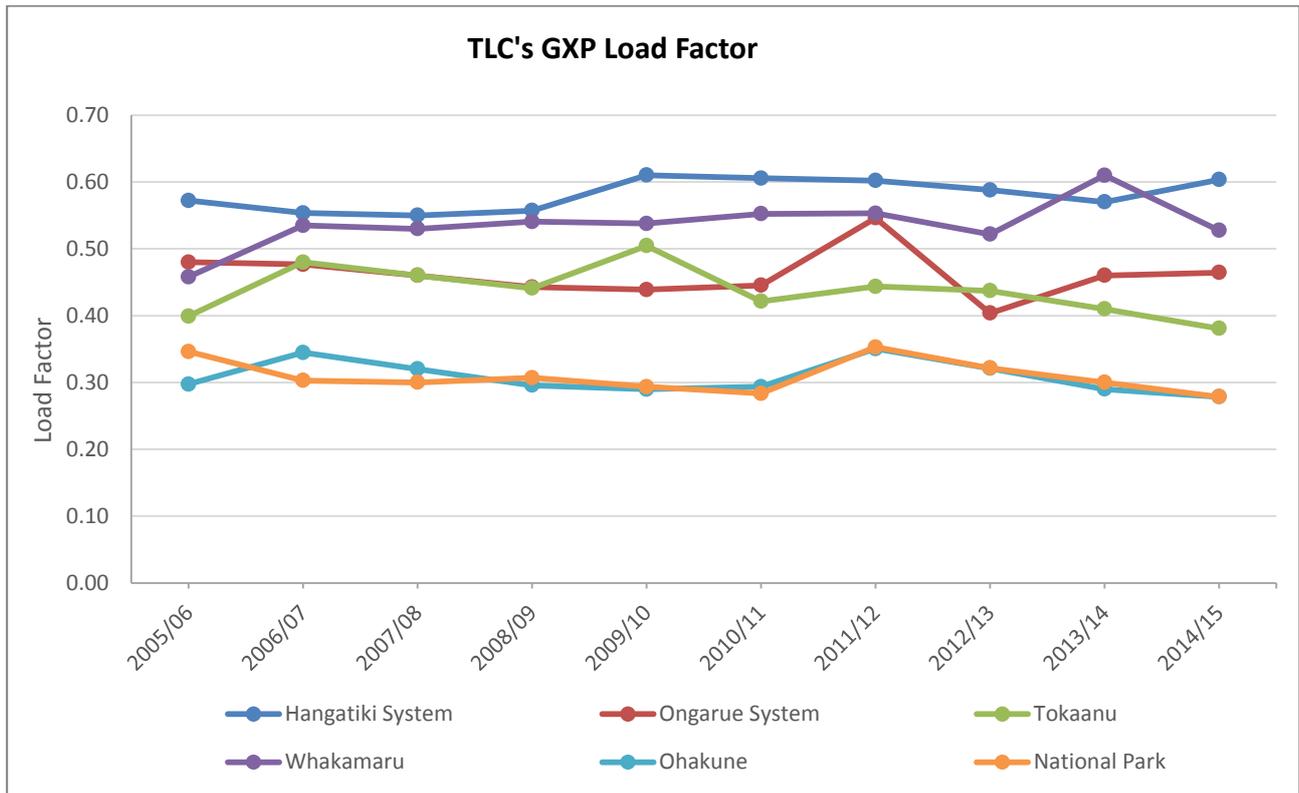


Figure 5.8: Load Factor at each Supply Point for the TLC Network

A load factor that is improving indicates that there is better utilisation of the systems assets in moving peak demand from the peak times. Ideal is a load factor of 1.

5.3.7.4.2 On 33kV Lines

Without demand side management, the conductors would be approaching their rated capacity at the end of the planning period.

5.3.7.4.3 On Zone Substations

Table 5.17 and Table 5.18 show the estimated reduction in forecast zone substation loadings due to the effects of demand side management. The following assumptions can be made about the impact of demand side management initiatives:

- The Atiamuri transformer is forecast to exceed full load at the end of the planning period but with demand side management realistic operating capacity limits are just being reached. The Plan includes an additional supply from Whakamaru in years 2016/17 which will alleviate this constraint.
- Taharoa and Te Anga show no effects from demand side management as the maximum demands on these substations are effected by a growing industrial load and distributed generation respectively.
- Due to the small peak demands at Otukou and Tokaanu it is difficult to discern the impact of demand side management on these zone substations.

FORECAST MD'S (MVA) FOR YEAR ENDING MARCH 31													
Site	Rating (MVA)	Number of Transformers (MVA)	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Arohena	3.0	1 x 3.0	0.03	0.04	0.05	0.05	0.06	0.06	0.07	0.08	0.08	0.09	0.09
Atiamuri	10.0	1 x 10.0	0.35	0.38	0.41	0.44	0.48	0.52	0.55	0.59	0.64	0.68	0.73
Gadsby Rd	5.0	1 x 5.0	0.11	0.16	0.21	0.26	0.31	0.35	0.38	0.41	0.44	0.47	0.51
Omya	2.4	1 x 2.4						0.01	0.01	0.02	0.02	0.03	0.03
Hangatiki	5.0	1 x 5.0	0.12	0.17	0.22	0.27	0.32	0.38	0.44	0.50	0.56	0.62	0.69
Kaahu Tee	2.4	1 x 2.4	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.08	0.08	0.09	0.09
Mahoenui	3.0	1 x 3.0	0.03	0.05	0.06	0.07	0.09	0.10	0.12	0.13	0.15	0.17	0.18
Maraetai	10.0	1 x 10.0	0.11	0.12	0.13	0.15	0.16	0.17	0.18	0.18	0.19	0.20	0.21
Ranginui Road	2.0	1 x 2.0						0.01	0.03	0.06	0.08	0.10	0.12
Sandel Road	2.0	1 x 2.0								0.01	0.02	0.03	0.04
Marotiri	3.0	1 x 3.0	0.06	0.07	0.07	0.08	0.08	0.09	0.10	0.10	0.11	0.12	0.12
Miraka	7.5	1 x 7.5	0.21	0.31	0.41	0.52	0.64	0.77	0.91	1.05	1.21	1.37	1.54
Oparure	3.0	1 x 3.0	0.05	0.07	0.10	0.12	0.14	0.17	0.19	0.22	0.24	0.27	0.30
Taharoa	15.0	3 x 5.0	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Te Anga	2.4	1 x 2.4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Te Waireka Rd	20.0	2 x 10.0	0.30	0.34	0.38	0.42	0.46	0.51	0.55	0.60	0.64	0.69	0.74
Wairere	5.0	2 x 2.5	0.09	0.12	0.15	0.19	0.22	0.26	0.30	0.34	0.38	0.42	0.46
Waitete	15.0	3 x 5.0	0.32	0.45	0.58	0.72	0.86	1.00	1.14	1.29	1.44	1.60	1.77

Table 5.17 Northern Zone Substation Estimated Maximum Demands Reduction Through Demand Side Management

FORECAST MD'S (MVA) FOR YEAR ENDING MARCH 31													
Site	Rating (MVA)	Number of Transformers (MVA)	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Awamate Road	2.0	1 x 2.0	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.03	0.03	0.03
Borough	10.0	2 x 5.0	0.20	0.25	0.31	0.36	0.41	0.47	0.52	0.56	0.61	0.67	0.72
Northern	2.0	1 x 2.0							0.01	0.01	0.01	0.01	0.01
Kiko Rd	3.0	1 x 3.0	0.03	0.04	0.05	0.06	0.06	0.07	0.08	0.09	0.10	0.11	0.12
Kuratau	3.0	1 x 3.0	0.04	0.05	0.07	0.09	0.10	0.12	0.13	0.15	0.17	0.19	0.20
Manunui	5.0	1 x 5.0	0.06	0.07	0.09	0.11	0.12	0.14	0.16	0.18	0.20	0.22	0.24
National Park	3.0	1 x 3.0	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Nihoniho	1.5	1 x 1.5	0.02	0.03	0.03	0.04	0.04	0.05	0.05	0.06	0.07	0.07	0.08
Ohakune	10.0	1 x 10.0	0.18	0.18	0.18	0.19	0.19	0.19	0.19	0.20	0.20	0.20	0.20
Otukou	0.5	1 x 0.5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tawhai	5.0	1 x 5.0	0.19	0.22	0.25	0.29	0.16	0.18	0.20	0.22	0.24	0.27	0.29
Tawhai 2nd Tx	5.0	1 x 5.0 (2019)					0.16	0.18	0.20	0.22	0.24	0.27	0.29
Tokaanu	1.3	1 x 1.25	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02
Tuhua	1.5	1 x 1.5	0.01	0.02	0.02	0.03	0.04	0.04	0.05	0.05	0.06	0.07	0.07
Turangi	10.0	2 x 5.0	0.04	0.06	0.09	0.12	0.15	0.18	0.20	0.23	0.25	0.28	0.31
Waiotaka	1.5	1 x 1.5	0.01	0.02	0.02	0.02	0.03	0.53	0.55	0.56	0.58	0.59	0.61

Table 5.18 Southern Zone Substation Estimated Maximum Demands Reduction Through Demand Side Management

5.4 Analysis of Network Development Options Available

The solutions listed below are after consideration of non-asset solutions including the gains made by demand billing and distributed generation.

5.4.1 Point of Supply Upgrade Considerations

With the planned increased load out of Hangatiki GXP options are being considered for taking additional supply from this GXP. This involves a series of complex negotiations to be undertaken with the customer and Transpower.

5.4.2 Voltage Regulator Installs in the Development Plan to Counteract Voltage Constraints

As stated in other sections TLC's network analysis package has been analysed to loadings expected at the end of the planning cycle. 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.

11kV REGULATORS (CUMULATIVE CAPACITY ALLOCATION)			
Supply Point	Feeder	Planning Notes for Voltage & Quality of Supply Improvements	Year
HANGATIKI	Gravel Scoop	Install regulator after switch 622 to support Lurman Rd area and for back feeding Maihihi.	2019/20
	Gravel Scoop	Install regulator on Otewa road just before Barber Rd. Will mainly be used when tying to Rangitoto and Maihihi.	2024/25
	Mahoenui	Mainly for backup of Mokau Feeder when 33kV is out.	2018/19
	Mahoenui	Improved back feeding of Mokau Feeder when 33kV is out.	2020/21
	Rangitoto	Install regulator near Switch112, to boost voltages before regulator 30.	2022/23
WHAKAMARU	Pureora	Close to Crusaders Meats for improved voltage at peak times.	2022/23

Table 5.19 Voltage Regulators For Voltage Constraints

5.4.3 Upgrades of conductor sizes in the Development Plan

The overhead conductor upgrades listed in Table 5.20 are cumulative capacity upgrades. Additional conductor renewal pertaining to line replacement (as opposed to upgrade) have been included in the line renewal programme.

CONDUCTOR UPGRADE PROJECTS (EXCLUDING LINE RENEWALS)						
Feeder	Asset	Conductor Size	Year	Constraint	Estimated Length	Estimated Cost (\$)
Rangitoto	106-04	Mink	2016/17	Fault Rating & Voltage	5.95km	221k
Maihihi	111-08	Mink	2016/17	Voltage	6.00km	189k
Maihihi	111-10	Mink	2016/17	Voltage	5.00km	158k
Wharepapa	122-01	Mink	2016/17	Voltage	3.00km	95k
Wharepapa	122-02	Mink	2016/17	Voltage	4.00km	126k
Ohakune Town	414-01	Dog	2016/17	Voltage & Current	0.30km	82k
Maihihi	111-12	Mink	2017/18	Voltage	3.20km	101k
Maihihi	111-01	Dingo	2017/18	Voltage & Current	0.50km	16k
Mokai	FED123	Mink	2018/19	Voltage & Current	7.00km	772k
Wharepapa	122-03	Mink	2018/19	Voltage	3.00km	95k
Manunui	408-01	Mink	2018/19	Voltage	4.00km	126k
Whakamaru	FED120	Dog	2019/20	Voltage	1.00km	105k
Turoa	415-04	Mink	2020/21	Voltage & Current	6.00km	616k
Wharepapa	122-08	Mink	2021/22	Voltage	6.20km	195k
Wharepapa	122-06	Mink	2021/22	Voltage	5.00km	158k

Table 5.20 Proposed Conductor Upgrades for Cumulative Capacity

5.4.4 Analysis of Distribution Transformers and Specific Locations where constraints are expected

The focus of the analysis of distribution transformers is hazard minimisation improvements. The results of this analysis have contributed to the lists of programmed work in the following sections.

5.4.4.1 Pole Mounted Transformers and Equipment (Distribution and SWER Isolation) Analysis

Historically, the structures for 2 pole distribution transformers and SWER isolation transformers were constructed low to the ground. All structures have been measured and assessed for hazards, including in particular, ground to live bare conductor clearances, and the ease of climbing up onto transformer mounting platforms. Other potential hazards such as the closeness of high voltage jumpers to low voltage fuse operating positions have also been considered.

The solutions include allowances for modifying the incoming and outgoing circuits to eliminate hazards and make the connections more straightforward and understandable by fault staff. The plan includes the on-going renewal of these structures starting from the worst. At this point TLC is about half way through the sites initially highlighted as hazardous. Each site has been assessed for its needs and estimates have been put together that sum into capital and maintenance plans for the planning period.

Sites were assessed for hazards using two independent parties. An electrical inspector viewed all photographs and prioritised. An engineer also went through the data and photographs allocating points based on the prioritisation policies described in this plan. The two approaches were reconciled and the plan finalised. This plan is reviewed annually to ensure it continues to align with safety objectives.

5.4.4.2 Ground Mount Distribution Transformer Analysis

The focus of the analysis of ground mounted transformers and enclosures, was to identify all security, operating, and potential points of contact with live terminal hazards. Each site has been assessed for its needs and estimates have been put together that sum into capital and maintenance plans for the planning period. Sites were assessed for hazards using two independent parties. An electrical inspector considered all photographs and prioritised. An engineer also went through the data and photographs, allocating points based on the prioritisation policies described in this plan. The two approaches were reconciled and the plan was finalised. This plan is reviewed annually to ensure it continues to align with safety objectives.

5.4.5 Low Voltage System Underground and Overhead

The low voltage lines in the TLC network are of the same vintage as the 11kV lines (old and in need of renewal). Many are well under current codes of practice height. The poles supporting many of these lines are often under strength and in poor condition. Most conductors are bare, and arcing, and clashing is common. This causes outages and the related surges may damage customers' equipment.

It is likely that aerial bundled conductor will be used for many of the renewals in rural villages. There are also poorly integrated underground and overhead systems that are creating hazards and require renewal to control these.

The design and planning process for each of these projects varies, being dependent on the local area issues. Low voltage renewal often involves customers' service lines and urban streets. As a consequence of this the design process involves discussions with landowners and road controlling authorities.

5.4.5.1 Underground Service Box Analysis

The constraint with low voltage service boxes is that they age and are subjected to vehicle and other damage. The result of this damage is that they often become insecure and the tops can be removed by members of the public. The damage is usually such that the service box needs to be renewed. The only other option is to leave them in a hazardous condition.

The option TLC chooses is to eliminate or minimise the hazard. An electrical inspector checks and tests service boxes on a five yearly cycle. Priorities are then set by this work.

5.4.6 Analysis of Related Systems (Load Control, SCADA, Communication) and Specific Locations where constraints are expected

All related systems have been analysed and predicted future needs to meet customer service levels have been included in spend plans.

The load control system in the northern area cannot provide the required customer service levels without renewal. New 317 kHz plants have been installed. A second communications path to each of the load control plants is being looked at using a GSM phone system.

The estimates assume continuation of present strategies with SCADA. On-going renewal and development of the SCADA equipment is included in forward estimates.

TLC is currently in the process of upgrading the radio network to meet new spectrum requirements. This includes adding new repeater sites to improve radio coverage.

5.5 Description and Identification of the Network Development Programme 2016/17

This section covers the planned expenditure for all non-renewal capital projects for the following 12 months. Renewal capital work can be found in Section 6.

CAPITAL EXPENDITURE SUMMARY 2016/17 EXCLUDING RENEWAL		
	Budget	Total
Consumer Connection		
Sub & 33 Dev - Substations	630,000	
Transformers - General Connections	279,120	
Transformers - Industrials	233,293	
Transformers - Subdivisions	134,924	1,277,337
System Growth		
11kV Fdr Dev - Feeder Development	1,089,900	1,089,900
Asset Relocations		
Equipment Relocations - Miscellaneous	10,871	10,871
Quality of Supply		
11kV Fdr Dev - Switch Automation and Renewal	274,496	
Sub & 33 Dev - Substations	105,000	379,496
Other Reliability, Safety and Environment		
11kV Fdr Dev - Switchgear for Safety	12,600	
Sub & 33 Dev - Substations	343,350	
Tx & Service Boxes - 2 Pole Structures	194,250	
Tx & Service Boxes - GMT	185,850	736,050
Non System Fixed Assets - Routine		
Eng & Asset Capital - Data Systems	26,250	
Eng & Asset Capital - Misc Equip	10,871	
Eng & Asset Capital - Office Area	21,741	
Eng & Asset Capital - Vehicle Replacements	69,274	128,136
Non System Fixed Assets - Atypical		
Eng & Asset Capital - Building Re-structure	3,200,000	3,200,000
Total		\$ 6,821,789

Table 5.21 Summary of Capital Expenditure for 2016/17 (excluding Line Renewals)

5.5.1 Customer Connection Development Programme – 2016/17

5.5.1.1 Customer Connection Project Details

Taharoa Expansion - \$630,000

The iron sands mine at Taharoa are expanding their operations and require increased security of supply and capacity to meet their needs. The focus will be upgrading of the supply transformers and switchgear at Taharoa zone substation. This project extends into the forecast year 2017/18 and 2018/19.

General New Connections Contributions - \$279,120

This allowance is to fund distribution equipment costs associated with new customer connections and includes transformers and fusing at the connection point and other costs. This amount covers the cost of TLC's contribution to new connections. Generally, TLC has a policy of supplying a transformer and substation (including earthing) as its economic contribution to a new connection. These items are included in TLC valuation registers.

The investment is recovered by each customer's low voltage capacity or dedicated transformer charges. The amount of the allowance expended is dependent on the number of new connections.

Industrial New Connection Contributions - \$233,293

TLC supplies various items and recovers these as part of on-going charges to customers when expansions and alterations are taking place. The amount of the allowance used is dependent on the level of industrial development.

The alternative options available to reduce this cost include installing the smallest transformer possible and supplementing with other energy options. The TLC charging structure means that customers have initial and on-going incentives to minimise capacity, reduce peaks and improve power factor. Alternative options for customers include providing energy requirements from alternative sources or providing their own transformers and earthing. Modular substation funded by the customer could be considered.

Subdivision New Connection Contributions - \$134,924

TLC supplies transformers and substation components as its capital contribution to new subdivisions. The developer funds the remainder. The substation components are those defined in the 2006 Valuation handbook. The amount of the allowance used is dependent on the number of new subdivisions and the allocation has been reduced due to the downturn in lifestyle and holiday home demand.

The alternative option available to reduce this cost is to install the smallest transformer possible. The TLC charging structure means that customers have initial and on-going incentives to minimise capacity and reduce peaks. The charging structure also encourages the connection of more than three ICPs per transformer.

5.5.2 System Growth Development Programme – 2016/17

Due to continued load growth out of the Hangatiki GXP initial planning and discussions are currently underway to look at options for increasing the capacity of the GXP.

Table 5.22 outlines the planned system growth capital projects for 2016/17.

SYSTEM GROWTH PROJECTS 2016/17				
Asset	Forecast	Scope	Justification	Alternative Options
Rangitoto 106-04	220,500	Reconductor with Mink along Rangitoto Road between switches 112 and 192.	The current fault levels on this feeder are near the fault rating of the current copper conductors.	Install fault reducing equipment at the zone substation.
Maihihi 111-08	189,000	Reconductor 6km with Mink to support network feeder tie project.	The current conductor is aging. Increasing the size of the conductor will improve the tie capacity between Maihihi and Wharepapa to improve security of supply to the growing load in the region.	Use generators to support load for back feeds. Risk failure due to aging conductor.
Maihihi 111-10	157,500	Reconductor 5km with Mink to support network feeder tie project.	The current conductor is aging. Increasing the size of the conductor will improve the tie capacity between Maihihi and Wharepapa to improve security of supply to the growing load in the region.	Use generators to support load for back feeds. Risk failure due to aging conductor.
Wharepapa 122-02	126,000	Reconductor 4km with Mink to support load growth and back feeding. Do in conjunction with 11kV line renewal.	The current conductor is aging and due to continued load growth in the region, power quality issues are expected if no changes are made.	Use generators to support load for back feeds. Risk failure due to aging conductor.
Wharepapa 122-01	94,500	Reconductor main feeder (3km) with Dog. This is to be done in conjunction with the 11kV line renewal.	The current conductor is aging and due to continued load growth in the region, power quality issues are expected if no changes are made.	Use generators to support load for back feeds. Risk failure due to aging conductor.
Ohakune Town 414-01	157,500	Insert RMU at the corner of Mangawhero Terrace and Foyle Street and cable along Foyle Street towards Transformer 20L35 to create 11kV link.	The current 11kV tie between Ohakune Town and Turoa Feeders is 16mm copper which is insufficient to safely backfeed at peak times.	Use generators to support load for back feeds.

SYSTEM GROWTH PROJECTS 2016/17				
Asset	Forecast	Scope	Justification	Alternative Options
Ohakune Town 414-01	81,900	Re-conductor from Ferret to Dog on Ayr Street between switches 6644 and 6444 due to the condition of existing conductor. Will also allow for increase in capacity.	The current conductor is in poor condition and causes a high voltage drop near the beginning of the feeder during peak loads that with the forecast increasing winter load will result in power quality issues at the end of the feeder.	Install voltage regulators to boost the voltage along the feeder.
Maihihi Feeder	63,000	Install 1 MVar of capacitors near Pukemapu Road switch 395 to support feeder tie voltage.	Improved feeder tie capacity between Maihihi and Wharepapa to accommodate load growth in the region.	Use generators to support load for back feeds.

Table 5.22 System Growth Forecast Capex Work for 2016/17

5.5.3 Asset Relocation Development Programme – 2016/17

This expenditure is primarily associated with relocating assets for road controlling authorities to carry out road works. The amount spent depends on the locations of road works. A contingency allowance of \$10,871 has been included in estimates for 2016/17.

Note: This expenditure may be varied due to the changing legislation for access to railway and road corridors.

5.5.4 Quality of Supply Development Programme – 2016/17

Programme Objective

The objective of the reliability improvement programme is to bolster reliability and reduce operating costs. Staffing rural depots is expensive and providing efficient workflows for periods when faults are not occurring is difficult. Increased skills specialisation is adding to this difficulty. Network automation speeds restoration and takes away the need to maintain high staffing levels in rural depots to service faults.

The risk assessment analysis indicated that the contingencies are needed for new and end of lifecycle equipment. The ability to support the network with a generator during fault conditions and maintenance projects improves the reliability of the supply to customers, reducing unacceptable outages and producing a saving in customer minutes. Mobile reactive power units are a lower cost way of doing this.

Automation Options

The automation of breakers improves network outage statistics, and has a hidden benefit in that it provides better data for on-going network analysis, including revenue reconciliation, and reduces operating costs.

Projects are aligned with the need to meet reliability objectives and service level standards as detailed in earlier sections. The last customer survey also highlighted customers' expectations of continuously improving supply reliability.

In recent times attracting staff to rural areas and meeting the costs of retaining these people to cover standby rosters have become difficult issues. Three of TLC's rural depots (Ohakune, Turangi and Whakamaru) no longer have enough staff to cover full rosters and the areas have to be covered on alternative week. This means at least a two hour mobilisation delay for the weeks when there is no local cover.

Sectionaliser Options

Sectionalisers are a low cost option for improving overall reliability. By targeting long spur lines the number of customers impacted by long outages due to faults on the spur line will greatly decrease down to only the customers directly connected to the faulted line. Sectionalisers are a cost effective solution that bridge the gap between simple fuses (that are not able to discriminate between transient and hard faults) and automated reclosers.

Outlined in Table 5.23 is the planned capital projects for 2016/17 to improve the quality of supply to customers.

QUALITY OF SUPPLY PROGRAMME				
Asset	Forecast	Scope	Justification	Alternative Options
Kuratau Zone Substation	105,000	Refurbish ex Mahoenui power transformer including new radiators before moving to Kuratau. Build new pad at Kuratau for transformer. The current 3MVA transformer will be kept as a backup.	The current transformer is nearing the end of its life. The current 1.5MVA backup transformer does not have sufficient capacity to fully back up the load out of Kuratau. This backup transformer will be freed up to be moved to Otukou.	None
Ground Mount Transformer 16N09	58,616	Install 4 bay ring main unit near transformer 16N09. Also included in the scope is to tidy up the aging Montrose distribution pillar box at this site.	Current RTE is very compact with multiple cables fitted to each leg. As a result all cables cannot be easily isolated from each other. Installing a ring main unit makes sectionalising more straight forward to isolate any faulty sections of cable.	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.
Recloser 474	42,630	Fit Modern style recloser capable of having multiple protection setting to provide protection in the normal network configuration and for when back feeding Miraka.	The current recloser is aged and is fitted with a very simple control relay that does not offer the full functionality required at this site.	Do nothing and have inadequate protection when back feeding Miraka.
Air Break Switch 242	42,000	Replace existing Hill Street ABS with automated ENTEC LBS to support Te Kuiti town feeder tie.	Automation of feeder ties allows for the reduction in time to both find the fault and restore power to customers not directly impacted by the fault.	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.

QUALITY OF SUPPLY PROGRAMME				
Asset	Forecast	Scope	Justification	Alternative Options
Solid Links 6557	42,000	Automate by replacing with ENTEC Sectionaliser with remote control.	Automated sectionalisers reduce the impact of long faults on the rest of the feeder and improve the time it takes to restore supply.	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.
Air Break Switch 5357	36,750	Automate to allow for Feeder change over point by fitting Entec type remote controlled switch.	Automation of feeder ties allows for the reduction in time to both find the fault and restore power to customers not directly impacted by the fault.	Continued manual operation of switches.
Air Break Switch 342	10,500	Install 3 phase sectionaliser at the start of Marongaronga Road to Scowns Road spur line under existing ABS.	This long spur is currently directly connected to the main feeder, as a result faults on this long spur line affect all customers on the feeder. Installing sectionalisers will limit any long outages to customers directly connected to the spur line. Sectionalisers offer a cost effective solution for spur lines without the need to install more costly reclosers.	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.
Fused Links 333	10,500	Replace fuse links with 3 phase Sectionaliser.	This long spur is currently directly connected to the main feeder, as a result faults on this long spur line affect all customers on the feeder. Installing sectionalisers will limit any long outages to customers directly connected to the spur line. Sectionalisers offer a cost effective solution for spur lines without the need to install more costly reclosers.	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.
Air Break Switch 522	10,500	Install 3 phase Sectionaliser under existing ABS.	This long spur is currently directly connected to the main feeder, as a result faults on this long spur line affect all customers on the feeder. Installing sectionalisers will limit any long outages to customers directly connected to the spur line. Sectionalisers offer a cost effective solution for spur lines without the need to install more costly reclosers.	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.

QUALITY OF SUPPLY PROGRAMME				
Asset	Forecast	Scope	Justification	Alternative Options
Air Break Switch 573	10,500	Install 3 phase sectionaliser at the start of Maihihi Road to Whibly Road spur line under existing ABS.	This long spur is currently directly connected to the main feeder, as a result faults on this long spur line affect all customers on the feeder. Installing sectionalisers will limit any long outages to customers directly connected to the spur line. Sectionalisers offer a cost effective solution for spur lines without the need to install more costly reclosers.	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.
Air Break Switch 574	10,500	Install 3 phase sectionaliser at the start of Maihihi Road to Ngahape spur line under existing ABS.	This long spur is currently directly connected to the main feeder, as a result faults on this long spur line affect all customers on the feeder. Installing sectionalisers will limit any long outages to customers directly connected to the spur line. Sectionalisers offer a cost effective solution for spur lines without the need to install more costly reclosers.	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.

Table 5.23 Quality of Supply Development Options for 2016/17

5.5.5 Other Reliability, Safety and Environment Development Program – 2016/17

Table 5.24 details all hazardous equipment and environmentally driven capital projects for 2016/17. Hazardous equipment renewals include renewals for reliability, safety and environmental reasons but does not cover line renewal.

OTHER RELIABILITY, SAFETY AND ENVIRONMENTAL DEVELOPMENT PROGRAM				
Asset	Forecast	Scope	Justification	Alternative Options
Turangi Zone Substation	105,000	Install 2nd set of switchgear Turangi sub to provide transformer incomer isolation. This is a continuation of the 2015/16 project to removed hazardous switches from Turangi Zone Substation and improve protection. This work will also include the upgrading of the existing transformer voltage control relay.	The present switchgear arrangement is complex, non-standard and consists of old components not designed for the job they are doing. This upgrade will minimise hazards and improve reliability.	Leave as is with confusing arrangement for field staff.
Otukou Zone Substation	94,500	Replace current 500 kVA transformer with a 1.5MVA ex Kuratau transformer. Install bunding and oil separation to fit the new transformer.	The voltage current transformer is fixed tap and the old voltage regulators at site have failed. As a result there is risk of low voltage when the 33kV line has to be back feed due to outages at the National Park GXP. The current site also has inadequate bunding for oil containment.	None
Te Waireka Zone Substation	94,500	Install 33kV line breaker and alter the position of Recloser 570 at Te Waireka Zone Substation. Complete upgrading protection on transformer T3.	Current protection does not guarantee faults will be cleared on the 33kV line due back livening of the line back through one of the transformers. This means a downed line with a high impedance fault will not trip due to the lack of earth reference.	None
ZSub508 - Borough Zone Substation	31,500	Raise the height of oil containment bunding and install oil separation system with oil/water sensors.	The current bund wall is low and while able to contain all the oil does not allow for any water that may collect in the bund. There is currently no oil separation as a result the bund fills up water that has to be manually removed.	No alternative to reducing the environmental risk of an oil spill.
ZSub207 - Wairere Zone Substation	17,850	Install oil separation system with oil/water sensors.	The zone substation is next to a river and currently has to be manually emptied to remove any water that it may fill up with.	No alternative to reducing the environmental risk of an oil spill.
Voltage Regulator 28	12,600	Install bypass protection fuse to Regulator 28.	There is currently a risk that the regulators will be damaged by circulating current if the bypass switch is closed while the regulators are not at a neutral tap setting.	None

OTHER RELIABILITY, SAFETY AND ENVIRONMENTAL DEVELOPMENT PROGRAM				
Asset	Forecast	Scope	Justification	Alternative Options
Pole Mount Transformer 08R09	47,250	Replace current pole mount transformer with standard ground mount.	Current transformer bushings are below regulation height.	No alternative to removing hazardous equipment.
Pole Mount Transformer 07D03	42,000	Replace current 2 pole structure with a new transformer on standard single pole design.	Current transformer bushings are below regulation height.	No alternative to removing hazardous equipment.
Pole Mount Transformer 09K50	42,000	Replace current 2 pole structure with a new transformer on standard single pole design.	Current transformer bushings are below regulation height.	No alternative to removing hazardous equipment.
Pole Mount Isolating Transformer T1453	31,500	Replace current 2 pole structure with a new transformer on standard single pole design.	Current transformer bushings are below regulation height.	No alternative to removing hazardous equipment.
Pole Mount Transformer T478	31,500	Replace current 2 pole structure with a new transformer on standard single pole design.	Current transformer bushings are below regulation height.	No alternative to removing hazardous equipment.
Ground Mount Transformer 10S26	105,000	Replace tin shed transformer and magnefix with standard ground mount and 5 bay Halo ring main unit.	The current transformer is a standard pole mount style transformer that is installed in a shed. The transformers exposed bushings and the aging magnefix switchgear present hazards to staff that have to work around this equipment.	No alternative to removing hazardous equipment.
Ground Mount Transformer 10S29	49,350	Replace tin shed transformer with standard ground mount.	The current transformer is an aged standard pole mount style transformer that is installed in a shed. The transformers exposed bushings and the low voltage rack has exposed bus bars which present a hazard to staff.	No alternative to removing hazardous equipment.
Ground Mount Transformer 01B20	31,500	Install modern low voltage rack and cover exposed transformer bushings.	The current transformer is a standard pole mount style transformer that is installed in a shed. The transformers exposed bushings and the low voltage rack has exposed bus bars which present a hazard to staff.	No alternative to removing hazardous equipment.

Table 5.24 Other Reliability, Safety and Environment Projects for 2016/17

5.5.6 Non-System Fixed Assets – 2016/17

5.5.6.1 Routine Non-system Fixed Assets – \$128,136

The scope of work for routine non-system fixed assets is associated with upgrade and procurement of the asset management systems, office equipment, motor vehicles, tools and plant.

5.5.6.2 Atypical Non-system Fixed Assets – \$3,200,000

A provision of \$4,070,000 (split over two years) has been made for establishing a new office building. The new building is planned as the cost of renovating the current building to meet the building code requirements is expected to exceed the cost of a new structure. The bulk of this expenditure is expected to occur in the 2016/17 financial year.

5.6 Summary Description of the Projects Planned for the next 4 years (2017/18 to 2020/21)

5.6.1 Unknowns

The unknowns that will affect plans are:

- Distributed generation development – if new schemes will be developed.
- Customer development – rural, residential, industrial and ski field.
- Network unknowns – An aged network will have unplanned and unexpected problems.
- Project unknowns – weather, landowners, resource shortage, access, and other factors will affect projects.
- Industry issues – compliance etc.
- Political and other influences such as economic cycles.
- Other events unknown at this time. (e.g. natural disasters)

The estimates will be influenced by levels of economic activity and future energy prices. For example, there are unknowns with the distributed generation proposals and the network upgrades that would be required to connect this plant.

5.6.2 Summary of Expenditure Predictions 2017/18 to 2020/21 in Disclosure Categories

A summary of the disclosure categories expenditure predictions (without inflation) is listed in Table 5.25.

NON-RENEWAL CAPITAL EXPENDITURE SUMMARY 2017/18 to 2020/21				
	2017/18	2018/19	2019/20	2020/21
Consumer Connection				
Sub & 33 Dev - Substations	2,625,000	1,995,000	-	-
Transformers - General Connections	279,120	279,120	279,120	279,120
Transformers - Industrials	233,293	233,293	233,293	233,293
Transformers - Subdivisions	134,924	134,924	134,924	134,924
	3,272,337	2,642,337	647,337	647,337
System Growth				
11kV Fdr Dev - Feeder Development	263,550	992,250	105,000	812,102
Regulators	-	106,575	106,575	106,575
Sub & 33 Dev - 33kV Lines	-	-	181,125	-
Sub & 33 Dev - Substation	630,000	462,000	735,368	484,916
Sub & 33 Dev - Supply Points	-	1,260,000	-	-
	893,550	2,820,825	1,128,068	1,403,593
Asset Relocations				
Equipment Relocations - Miscellaneous	10,871	10,871	10,871	10,871
	10,871	10,871	10,871	10,871
Quality of Supply				
11kV Fdr Dev - Feeder Development	-	63,000	-	-
11kV Fdr Dev - Switch Automation and Renewal	170,730	213,150	190,260	272,213
Sub & 33 Dev - Substations	-	63,000	-	-
Sub & 33 Dev - Supply Points	315,000	-	-	-
	485,730	339,150	190,260	272,213
Other Reliability, Safety and Environment				
11kV Fdr Dev - Switchgear for Safety	110,329	5,329	131,250	231,945
Sub & 33 Dev - Substations	47,959	-	-	63,000
Tx & Service Boxes - 2 Pole Structures	139,230	141,393	112,025	105,630
Tx & Service Boxes - GMT	-	42,630	147,074	133,061
	297,518	189,352	390,348	533,636
Non System Fixed Assets - Routine				
Eng & Asset Capital - Data Systems	26,250	131,250	183,750	183,750
Eng & Asset Capital - Misc Equip	10,871	10,871	10,871	10,871
Eng & Asset Capital - Office Area	21,741	21,741	21,741	21,741
Eng & Asset Capital - Vehicle Replacements	69,274	69,274	69,274	69,274
	128,136	233,136	285,636	285,636
Non System Fixed Assets - Atypical				
Eng & Asset Capital - Building Re-structure	870,000	-	-	-
	870,000	-	-	-
Total	\$ 5,958,140	\$ 6,235,670	\$ 2,652,518	\$ 3,153,284

Table 5.25 Summary of Capital Expenditure Forecast 2016/17 to 2019/20

5.6.2.1 Customer Connection Capital Expenditure Predictions

Taharoa Expansion – \$2,625,000 (2017/18) and 1,995,000 (2018/19)

The iron sands mine at Taharoa are expanding their operations and require increased security of supply and capacity to meet their needs. The focus will be upgrading of the supply transformers and switchgear at Taharoa zone substation. This project follows initial expenditure forecast for 2016/17.

This project is to meet customer expectations and will be funded in collaboration with the customer. There are two drivers for this; the first being that the iron sands require an increased supply. The second is that the Iron Sands will require an improved level of reliability. This upgrade will also remove hazards associated with the aged existing equipment.

5.6.2.1.1 General Connections, Industrials and Subdivisions

General, Subdivision and Industrial Connection Expenditure includes earthing, substations, points of connection, isolation/protection, transformers, switchgear and other items associated with general, subdivision and industrial new connections. The allocation for connections have been rolled forward at expected levels (\$647,337 per annum).

5.6.2.2 System Growth Capital Expenditure Predictions

Table 5.26 summaries the planned capital work to any system growth.

SYSTEM GROWTH CAPITAL EXPENDITURE PREDICTIONS 2017/18 to 2020/21			
Year	Asset	Forecast	Description
2017/18	Waitete Zone Substation	630,000	Purchase and install two 10MVA transformers at Waitete Zone Substation. This allows the existing three 5MVA transformers to be removed from Waitete Zone Substation. Two of these transformers would be moved to Maraetai Zone Substation to improve security of supply in this area. The remaining 5MVA transformer will be moved to Arohena to accommodate the increasing dairy load in the region. This project will be split over 2017/18 and 2018/19.
2018/19	Waitete Zone Substation	420,000	
2017/18	Maihihi 111-12	100,800	Reconductor 3.2km with Mink to support Network feeder tie project. This reconductoring will be done in conjunction with the 11kV line renewal. Reconductoring will improve the voltage profile in the area to accommodate increasing dairy loads and improve the intertie capacity between Maihihi feeder and Wharepapa.
2017/18	Turoa 415-04	90,300	Redesign of Low Voltage and High Voltage configuration for Rangataua to resolve voltage issues due to small conductor sizing and transformer capacity.
2017/18	Turoa 415-01	56,700	Upgrade Copper XLPE cable on Mangawhero River Road between Magnefix switch 6420 and transformer 20L18 to a feeder strength sized cable.
2017/18	Maihihi 111-01	15,750	Reconductor short section close to the substation that ties through to Gravel Scoop feeder with Dingo in conjunction with 11kV lines renewals. This greatly improves intertie capacity between Maihihi and Gravel Scoop feeders.

SYSTEM GROWTH CAPITAL EXPENDITURE PREDICTIONS 2017/18 to 2020/21			
Year	Asset	Forecast	Description
2018/19	Atiamuri Zone Substation	1,050,000	The back up to Whakamaru point of supply at Atiamuri is at capacity. There are three options that are currently being considered to overcome this constraint: <ol style="list-style-type: none"> 1. Upgrade Atiamuri 10MVA transformer to a 15MVA and reconductor around 20km of line to Kaahu Tee. 2. Take an 11kV supply out of Whakamaru Station. 3. Take an 11kV supply out of Maraetai station.
2018/19	Mokai Feeder	771,750	Reconductor Tirohanga Road / Okama Rd to improve back feed options and security of supply. Discussions with major industrial customers in the region are required in the coming years to refine the scope of the project.
2018/19	Mokai Zone Substation	210,000	Install 317Hz load control plant at Mokai. Investigations are currently underway to determine if the ex Ohakune plant meets the required specifications for this location. If this plant is used a new controller will still be required.
2018/19	Manunui 408-01	126,000	Reconductor main part of town to support back feed. Do in conjunction with Manunui 408-01 and 407-01 line renewals.
2018/19	Mahoenui Feeder	106,575	Install new regulator on Mahoenui feeder to support load when tied to the Mokau feeder. This is to improve the ability to pick up the load when Mahoenui zone substation is out of service.
2018/19	Wharepapa 122-03	94,500	Reconductor aging conductor with 3km of Mink to support load growth and improve back feeding. Do in conjunction with 11kV line renewal.
2018/19	Arohena Zone Substation	42,000	Relocate current Waitete T3 5MVA transformer to Arohena zone substation.
2019/20	Tawhai Zone Substation	735,368	Backup of Tawhai with either a second transformer or by upgrading National Park to 5 MVA. The chosen configuration will be heavily influenced by any planned load increases on the Whakapapa ski fields.
2019/20	Ohakune Point of Supply	181,125	Replace the 300mm ² Al cable between Transpower CB 38 and our 11kV bus. This single 11kV cable circuit from Transpower CB 38 supplies Ohakune. Increases in peak demand mean that this cable is nearing its rated capacity and increase the risk of failure and is the main constraint affecting supply.
2019/20	Gravel Scoop Feeder	106,575	Install regulator after switch 622 to support the Lurman Road area and for back feeding Maihihi. Capacitors may be an alternative solution to boost voltage in the area.
2019/20	Whakamaru Feeder	105,000	Reconductor from Maraetai zone substation to Regulator 31, opposite the entry to Mangakino Village.
2020/21	Turoa 415-04	616,004	Reconductor the feeder tie to Tangiwai between switch 5695 and 5680 to strengthen loop to Turoa feeder Ski field spur. To be undertaken in parallel to the 11kV line renewal.
2020/21	Maraetai Zone Substation	484,916	Additional modular substation near Ranginui Road to support meat works and regional growth.
2020/21	Ohakune Town Feeder	106,575	Install underground cable down Shannon Street from transformer 20L34 to transformer T4117 to create an additional feeder tie between Ohakune Town and Tangiwai feeders.
2020/21	Mahoenui Feeder	106,575	Install new voltage regulator on Mahoenui and Mokau Feeder tie for when Mahoenui out of service.
2020/21	Transformer 10S28	44,762	Replace existing transformer 10S28 with front access ground mount and LV generator connection point.
2020/21	Transformer 10S32	44,762	Replace existing transformer 10S32 with front access ground mount and LV generator connection point.

Table 5.26: System Growth Capital Projects for 2017/18 to 2020/21

5.6.2.3 Asset Relocation Capital Expenditure Predictions

The scope of works for asset relocations is associated with road re-alignments and relocations of lines when slips occur. TLC cannot forward plan for these. An allowance of \$10,871 p.a. has been included for the planning period.

There are usually no non-asset solutions that can be used for asset relocations. Projects are justified as part of compliance.

5.6.2.4 Quality of Supply Capital Expenditure Predictions

Table 5.27 outlines all automation and reliability capital projects for 2017/18 to 2020/21.

QUALITY OF SUPPLY EXPENDITURE FORECAST 2017/18 to 2020/21			
Year	Asset	Forecast	Description
2017/18	Ongarue Point of Supply	315,000	Rationalise the switchgear at Ongarue GXP. This will involve installing 33kV switch gear to reduce the number of Transpower breakers required to take a supply from Ongarue. This will allow for switching of Tuhua and Nihoniho quickly without relying on Transpower.
2017/18	Transformer 16N01	63,000	Replace the current transformer that supplies ski huts with refurbished ground mount and install ring main unit to allow 11kV cables to be safely and quickly isolated. The current transformer is a pole mount style installed in a shed with an exposed 11kV fuse rack.
2017/18	Fused Link 5688	44,100	Replace with automated ENTEC switch to reduce the impact of line faults on Kuratau customers.
2017/18	Air Break Switch 224	42,630	Replace air break switch with an automated recloser. This will prevent customers in town from experiencing outages when there is a fault on the rural 11kV line.
2017/18	Air Break Switch 316	21,000	Fit Fuse Savers with ABS bypass to the start of the spur down Ouruwhero Road.
2018/19	Maraetai Zone Substation	63,000	Relocate Waitete zone substation transformers T1 and T2 to Maraetai zone substation. This will improve security of supply to the area.
2018/19	Hakiaha Feeder	127,890	Install 11kV tie point between Matapuna and Hakiaha feeders adjacent to rail bridge where the feeders are in close proximity. This will involve installing a new ring main unit and a new feeder strength cable.
2018/19	Turangi 423-01	63,000	Transformers 10S41 and 10S42 are very close together. Tie low voltage lines together and replace with a single standard ground mount transformer. Both of these transformers are pole mount style installed in sheds with exposed bushings that present a hazard to staff working around them.
2018/19	Electronic Sectionaliser 5758	42,630	Replace sectionalisers on Taranui Road with an automated recloser to improve protection and provide remote switching.
2018/19	Air Break Switch 5146	42,630	Install automated Recloser to break up the long rural 11kV line and allow improved sectionalising of faults.
2019/20	Recloser 5119	42,630	Replace aging recloser on Golf Road with modern equivalent.
2019/20	Recloser with Bypass 5164	42,630	Replace aging recloser on Taringamotu Road with modern equivalent.
2019/20	Air Break Switch 5838	42,000	Install automated switch at feeder tie between Manunui and Matapuna feeders.
2019/20	Recloser 446	42,000	Replace aging recloser on Waihora Road with modern equivalent.

QUALITY OF SUPPLY EXPENDITURE FORECAST 2017/18 to 2020/21			
Year	Asset	Forecast	Description
2019/20	Sectionaliser 1626	21,000	Replace aging sectionaliser with modern three phase sectionaliser.
2020/21	Otorohanga Feeder	117,233	Upgrade LV links on East side of Maniapoto Street between transformers T1086, T1174 and T2417.
2020/21	Fused Link 6186	68,250	Replace Magnefix ring main unit with a motorised ring main unit to automate the tie point between Turangi and Awamate zone substations.
2020/21	Air Break Switch 320	44,100	Automate switch on Old Te Kuiti Road at the feeder half-way point to isolate faults.
2020/21	Air Break Switch 463	42,630	Automate feeder tie switch between Mangakino and Whakamaru feeders.

Table 5.27 Quality of Supply Capital Projects for 2017/18 to 2020/21

5.6.2.5 Other Reliability, Safety and Environmental Capital Expenditure Predictions

There are no non-asset alternatives to the network having to be hazard controlled for the public and staff. The following projects have very similar scopes and justifications to safety projects discussed earlier in this section. Table 5.28 details all safety and environmental hazard elimination or minimisation capital projects for 2017/18 to 2020/21.

OTHER RELIABILITY, SAFETY AND EXPENDITURE FORECAST 2017/18 to 2020/21			
Year	Asset	Forecast	Description
2017/18	Ground Mount Transformer 07R13	52,500	Install new 3 bay RMU next to transformer 07R13 in Whareroa Road to allow safe sectionalising and earthing of 11kV cable.
2017/18	Ground Mount Transformer 15L07	52,500	Install new RMU next to transformer 15L07 in McKenzie Street to allow for safe sectionalising and earthing of 11kV cable and transformer.
2017/18	Oparure Zone Substation	47,959	Install oil separation for transformer at Oparure zone substation.
2017/18	Pole Mount Isolating Transformer T2520	44,100	Raise the height of the transformer on the existing structure and replace the ageing recloser. The current structure is next to a public road and current heights of the bushings do not meet standards.
2017/18	Pole Mount Isolating Transformer T2177	42,630	Rebuild earth working structure on a standard single pole design. The current structure is next to a public road and current heights of the bushings do not meet standards.
2017/18	Pole Mount Isolating Transformer 08I21	26,250	Raise the height of the recloser on the structure to meet safety standards. Also replace sectionaliser with a recloser and reconfigure the structure so each SWER line away is feed through a recloser.
2017/18	Pole Mount Isolating Transformer 08H03	26,250	Raise the height of switchgear on the structure to meet safety standards.
2017/18	Voltage Regulator 4	5,329	Install bypass protection to regulator.
2018/19	Pole Mount Transformer 12N05	46,893	Rebuild the current 33kV to 400V transformer structure to improve safety or replace with standard ground mount transformer.

OTHER RELIABILITY, SAFETY AND EXPENDITURE FORECAST 2017/18 to 2020/21			
Year	Asset	Forecast	Description
2018/19	Ground Mount Transformer T9	42,630	Old ground mount with exposed cables that do not have sufficient mechanical protection. Replace with new front access transformer.
2018/19	Pole Mount Isolating Transformer T1865	31,500	Raise the platform on the two pole SWER structure to get bushings to a safe height. Fit a new vacuum recloser in conjunction with the structural work.
2018/19	Pole Mount Isolating Transformer 11K11	21,000	Raise the platform on the two pole SWER structure to get bushings to a safe height. Fit a new vacuum recloser in conjunction with the structural work.
2018/19	Pole Mount Isolating Transformer 06E01	21,000	Raise the platform on the two pole SWER structure to get bushings to a safe height. Fit a new vacuum recloser in conjunction with the structural work.
2018/19	Pole Mount Isolating Transformer T1777	21,000	Replace the platform on the two pole SWER structure and raise to get bushings to a safe height. Fit a new vacuum recloser in conjunction with the structural work.
2018/19	Voltage Regulator 25	5,329	Install by-pass protection on Regulator 25 on Whatauri Road.
2019/20	Ground Mount Transformer 16N28	84,000	National downhill ski hut has open bushing transformer in wooden enclosure inside building. Transformer needs to be moved outside building and new ring main unit installed.
2019/20	Ground Mount Transformer T4012	53,288	Old industrial transformer with exposed external tap and rusting cable boxes. Replace this transformer with a standard ground mount.
2019/20	Ground Mount Transformer T406	47,959	The current transformer is in a wooden enclosure that is in a deteriorating condition. Replace the existing transformer with a standard ground mount.
2019/20	Ground Mount Transformer 10S03	47,250	Install a new ring main unit next to transformer 10S03 to allow three phase switching and isolation of the cable.
2019/20	Ground Mount Transformer T1559	45,827	The current transformer is in a wooden enclosure that is in a deteriorating condition. Replace the existing transformer with a standard ground mount.
2019/20	Pole Mount Transformer 09R28	42,630	The current two pole structure does not meet safety guide lines. Replace the existing structure and transformer with a standard single pole structure.
2019/20	Pole Mount Isolating Transformer 09C05	21,000	The current two pole structure does not meet safety guide lines. Raise the transformer on the existing structure to meet requirements.
2019/20	Pole Mount Isolating Transformer 09K25	21,000	The current two pole structure does not meet safety guide lines. Raise the transformer on the existing structure to meet requirements.
2019/20	Pole Mount Isolating Transformer 08J07	21,000	The current two pole structure does not meet safety guide lines. Raise the transformer on the existing structure to meet requirements.
2019/20	Pole Mount Isolating Transformer T2194	6,395	Raise the platform on the two pole structure to get bushings to a safe height.
2020/21	Wairere Zone Substation	63,000	Replace existing aged circuit breaker 798 at the start of the Mahoenui 33kV line to a modern out door circuit breaker.
2020/21	Rangipo / Hautu Feeder	58,616	Rebuild structures each side of Genesis 33kV line crossing to mitigate potential line failure hazard.

OTHER RELIABILITY, SAFETY AND EXPENDITURE FORECAST 2017/18 to 2020/21			
Year	Asset	Forecast	Description
2020/21	Ground Mount Transformer 15N12	52,500	Install new four bay ring main unit to improve protection of transformers 15N11 and 15N12 and allow the 11kV cable to be more safely and quickly isolated and earthed.
2020/21	Ground Mount Transformer 15N11	52,500	
2020/21	Ground Mount Transformer 17N01	52,500	Install new four bay ring main unit and fault passage indicator to outgoing switch to transformer 17N01.
2020/21	Ground Mount Transformer T4025	47,959	The current transformer is pole mount style installed in a shed with low voltage laid out in a non-standard manner. Replace with a standard ground mount transformer.
2020/21	Ground Mount Transformer 10R20	42,630	Replace transformer and allow for a generation insertion point on the low voltage side.
2020/21	Pole Mount Isolating Transformer T1692	42,630	The current two pole structure does not meet safety standards. Rebuild as a standard single pole SWER structure with a new transformer.
2020/21	Ground Mount Transformer 07I12	31,973	The current transformer is in a tin shed with an open low voltage rack. This transformer will be replaced with a fount access transformer with a generator insertion point on the low voltage rack.
2020/21	Pole Mount Isolating Transformer 09R27	21,000	Raise the platform on the two pole SWER structure to get bushings to a safe height. Replace stainless steel pressed fittings with new polymer types.
2020/21	Pole Mount Isolating Transformer 12K08	21,000	Raise the platform on the two pole SWER structure to get bushings to a safe height.
2020/21	Pole Mount Isolating Transformer T4055	21,000	Raise the platform on the two pole SWER structure to get bushings to a safe height.
2020/21	Ground Mount Transformer 01A52	10,500	Wrap the low voltage board and cover the high voltage terminals on the transformer.
2020/21	Ground Mount Transformer 11S18	10,500	Add mechanical protection to exposed 11kV cable.
2020/21	Voltage Regulator 2	5,329	Install bypass protection on Tamatamaire Regulator 02.

Table 5.28 Capital Projects for the Improvement of Safety and Reduction of Environmental Risks for 2017/18 to 2020/21

5.6.2.6 Non-System Fixed Assets

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 \$128,136 p.a. has been included for 2017/18. This increases over the following 3 years in anticipation of expenditure required for data and GIS systems.

\$870,000 has been allocated in 2017/18 for the continuation of the office building replacement.

5.7 High Level Description of Projects Being Considered for Remainder of Planning Period

A detailed constraint analysis of the network is included in earlier sections of the Plan. These projects are modelled in detail for the 10 year planning period. Earlier sections provide in depth detail of this programme for the 2016/17 year and summary for the 2017/18 to 2020/21 years. The final years of the planning period are summarised in Table 5.29 below. Major projects for the final years of the planning period are outlined in the following sub sections. These are either financially significant projects (>\$400,000) or projects that will significantly affect network configuration or operation.

NON-RENEWAL CAPITAL EXPENDITURE SUMMARY 2021/22 TO 2025/26					
Capital Expenditure	2021/22	2022/23	2023/24	2024/25	2025/26
Capex Network1 NXC: Consumer Connection	1,073,637	647,337	647,337	647,337	940,418
Capex Network2 NXS: System Growth	720,484	790,650	52,500	106,575	1,281,368
Capex Network4 NXL: Asset Relocations	10,871	10,871	10,871	10,871	10,871
Capex Network5 NXEQ: Quality of Supply	349,178	269,404	218,479	58,616	566,528
Capex Network7 NXEO: Other Reliability, Safety and Environment	813,167	286,214	705,884	558,453	57,551
Capex Non-Network8 NXNR: Non System Fixed Assets - Routine	233,136	128,136	128,136	128,136	128,136
Total	\$3,200,471	\$2,132,611	\$1,763,205	\$1,509,987	\$2,984,870

Table 5.29 Summary of Capital Expenditure for 2021/22 to 2025/26

5.7.1 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:

5.7.1.1 Sub transmission Customer Connection Related Development

Significant projects and summary scopes of work allowed for in the planning period 2021/22 to 2025/26 include:

- Industrial modular substation in the Hangatiki area for customer to meet plant expansion. An alternative to this would be to install an additional 5MVA transformer at Hangatiki zone substation.

It is assumed that customers will use various technologies to reduce peaks and use non-asset solutions such as power factor correction.

5.7.1.2 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.

5.7.1.3 Subdivision Development

Assumes a continuing modest level of subdivision development. The scope of works includes supplying and installing new transformers, substations and fusing associated with subdivisions.

5.7.1.4 Industrial Development

Assumes a continuing level of industrial activity compared to previous years. It is assumed that customers will continue to consider peak reduction and on site non-asset solutions. The scope of works includes supplying and installing new transformers, substations, switchgear, cabling and fusing associated with industrial development.

5.7.2 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.

5.7.2.1 Sub Transmission System Growth Capital Expenditure

Significant projects and summary scope of works allowed for in the planning period 2021/22 to 2025/26 include:

- Build out 33kV line to Mokau to support growth in the region. Alternatives include converting to 22kV distribution and battery storage systems to boost supply during peaks.

It is assumed TLC will continue to promote demand side management and advise customers on non-asset solutions, such as power factor correction.

5.7.2.2 Voltage Support

We are continuing with the deployment of regulators, and capacitors, to support network voltage. Individual sites have been identified by network analysis models. It is assumed TLC will continue to promote demand side management and advise customers on non-asset solutions.

The scope of work for most of these installations involves installing a high strength pole and two single phase regulators. Depending on the changes that occur in customer needs and our increasing understanding of network performance it is likely there will be a number of sites where capacitors will be deployed for voltage support to complement regulators.

5.7.2.3 Feeder Development

Summary scope of works allowed for in the planning period 2021/22 to 2025/26 includes:

- Upgrade the conductor along the Rangataua Spur of the Turoa feeder to strengthen the feeder tie between Tangiwai and the Turoa ski field spur.
- Second cable from Tawhai Substation to Whakapapa Ski Field.
- Conversion of SWER systems to 3 phase lines as part of holiday home development in the Kuratau and Waihaha areas.

These projects assume increasing success of demand side management schemes by customers including the deployment of generators, (active and reactive power), for peak reduction.

5.7.3 Quality of Supply Projects

5.7.3.1 Quality of Supply

The projects allowed for in the planning period 2021/22 to 2025/26 include a continuing programme of increasing network automation at a rate of about five new items of equipment annually. The specific sites have been identified and are included in plans. High level designs, evaluations and justifications have been completed. The scope of works includes automating existing switches and reclosers. Major projects include adding low voltage ties in Taumarunui (2023/24) and Turangi (2025/26).

5.7.3.2 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 final 5 years of the planning period 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:

- Tongariro River 33kV crossing at Turangi.
- A modular substation to replace the aging equipment at Tuhua zone substation.

5.7.3.3 Environmental

The projects allowed for in the final 5 years of the planning period include working through the list of non-compliant equipment. The items of equipment are listed in the earlier constraints section.

The scope of work includes mostly the installation of oil bunding/separation and earthquake restraints.

The major project programmed for this period is a modular substation north of Taumarunui as the Borough substation is in a flood zone.

5.8 Distributed Generation

5.8.1 Policies for the Connection of Distributed Generation

5.8.1.1 General Policies

The policy on distributed generation is to allow the connection of distributed generation where it meets the costs of dedicated assets. The criteria for connection includes protection against the generation causing network hazards and impacting on network operating and other standards, including existing revenue flows.

TLC will encourage investors to provide network support by providing financial incentives aligned to the network savings that distribution generation produces.

All costs associated with collective and individual distributed generation connections shall be funded by the generators in accordance with the Electricity (Distributed Generation) Participation Code.

5.8.1.2 Capacity Policy

The capacity of generation that can be connected to any part of the network is determined by a number of factors. The most significant factor that affects capacity is the voltage rise when the network is in a normal state during an RCPD period with the plant operating at unity power factor. Policy is that the voltage rise should not exceed 2% (for 11kV and LV networks) above the normal voltage. TLC will follow the requirements of the Codes in implementing this policy.

5.8.1.3 Applications for Connection Policies

The processes for considering applications follow those detailed in the Electricity (Distributed Generation) Participation Code. The fees charged for considering applications are those prescribed in the distributed generation regulations. The generators have to fund the full costs associated with preparing and submitting their initial and final applications.

Much of the work for new connections involves investigating options for capital upgrades so that cost indications can be given to potential investors. These upgrades often go deep into the network and can be complex.

In at least two recent cases, several parties wish to connect to the existing lines that only have capacity for one plant. Issues such as this pose questions such as deciding which one should be connected or how costs should be allocated. TLC's experience is that distributed generation issues often absorb considerable engineering time. This input must be funded from charges on an on-going basis for the connection of distributed generation.

5.8.1.4 Charging Structure for Distributed Generation Policies

There are two possible options for generators if the requirements of the Electricity (Distributed Generation) Participation Code are followed. These are the default regulated terms as listed in the Electricity (Distributed Generation) Participation Code, or a fixed fee approach. The regulated terms result in uncertainty to generators by having the provision for an annual reset on pricing and no capacity rights. The fixed fee is a contract outside of the Participation Code whereby TLC, for a set fee, can give the generators more certainty in pricing and, for a fixed amount, take the uncertainties away from generators.

Most of the generators connected to, and wanting to connect to, the TLC network want the fixed fee approach provided the charges are realistic. The main reason for this is that the investor generators do not have technical knowledge and they want all of the complex electrical engineering taken off their hands while they focus on the environmental and mechanical issues associated with running plant.

TLC on the other hand is exposed to increased risk with this flat fee approach because of the uncertainty, for example, the possibility of complex grid exit power factor liabilities and the implications of operating outside the Electricity (Safety) Regulations.

The charging principle for the fixed fee and regulated approach is based on the following components:

A fixed fee for the capacity connected to cover the cost of administration, engineering and system operation associated with the connection of distributed generation.

A variable component with credits and charges associated with network benefits and non-benefits.

Credits are for:

- Transpower demand avoidance.
- Reduction in SAIDI minutes/SAIFI frequency. If plant is positioned in a place on the network, and has suitable controllers that will actually achieve SAIDI/SAIFI reduction, then TLC will pay a credit.
- Reduction in system losses (these payments will come from the market).
- Deferring of any capital expenditure by removing network constraints.

Charges are for:

- Inability to auto-reclose. TLC will instigate this charge if it cannot auto reclose within 5 seconds of a line tripping.
- Costs of power factor improvement required to be funded by TLC.
- Dedicated assets.
- Engineering time when a plant is modified, expanded or has an on-going operational problem.
- Any costs for destroyed appliances due to incorrect operation of the plant. (These will usually be direct claims from insurers or the owners of destroyed equipment.)

5.8.1.5 General Technical Issues with Distributed Generation that cause the need for Site Specific Conditions and Polices

As discussed in other sections of this plan, TLC has a long history of experience with distributed generation connected to the network. TLC's experience with distributed generation has highlighted the following issues:

Power Factor

The laws of physics are such that as power is transmitted through networks there are three components; active (kW) and reactive (kVAr) and apparent (kVA). Power factor is the ratio of real power flowing to the load to the apparent power of the network.

Whenever distributed generation is connected, active power is injected. In rural networks such as TLC's it is generally difficult to inject reactive power because of voltage rises. Figure 5.9 illustrates the impact of distributed generation on the network.

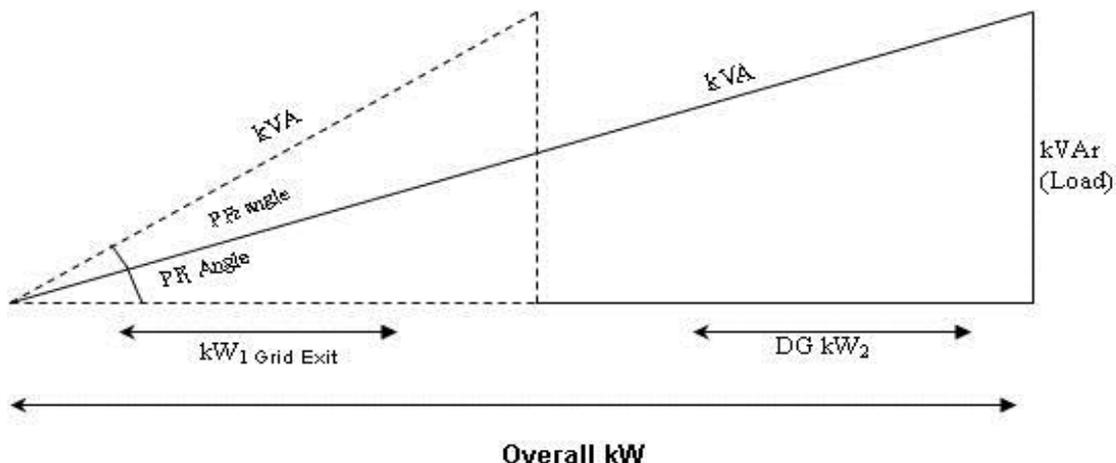


Figure 5.9 Illustration of Effect of Distributed Generation

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 11kV 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 Ferro resonance).

Islanding (Operate Isolated from Grid Connections)

Synchronous machines will island (or try to). When they island, TLC's experience is that frequency and voltage are not accurately maintained. This has destroyed electronic equipment and this has to be protected against.

Rules for Liability

Distributed generation and the interaction with the network is complex. When things do go wrong, electronic appliances can be destroyed. There are currently no rules for clearly determining these liabilities.

Loss Factors

Distributed generation connected to networks can reduce losses. They can also substantially increase losses and swing between the two extremes as network load changes. The electricity market requires a single figure for a loss factor. Calculating this is complex especially where there are a number of generators connected.

Self-Excitation

Rotating induction plant will self-excite when injecting into lightly loaded lines. It is important to get these machines quickly disconnected when they become isolated on a section of network.

Harmonics

At this time TLC is not experiencing any harmonic problems associated with distributed generation, but it is monitoring inverter sites. With the diverse TLC network, the risk potential for issues related to harmonics is high.

Voltage Flicker

As per the harmonics section above. TLC has to impose conditions and polices for applications to overcome these effects. These tend to be site specific.

Arc Flash

TLC has not experienced any serious arc flash incidents. However TLC is making steady progress in implementing arc flash policies for the safety of staff.

5.8.1.6 Effects of Power Factor Impeding Future Connections of Distributed Generation

Detail was included above on the theory associated with the effects on grid exit power factor of distributed generation. Figure 5.10 illustrates an example based on actual data from the Hangatiki grid exit.

Figure 5.10 Illustrates power factor every half hour during the year 1st April 2013 to 31st March 2014. Figure 5.11 shows the periods that Electricity Authority rules, Part F; say must be greater than 0.95 during RCPD periods.

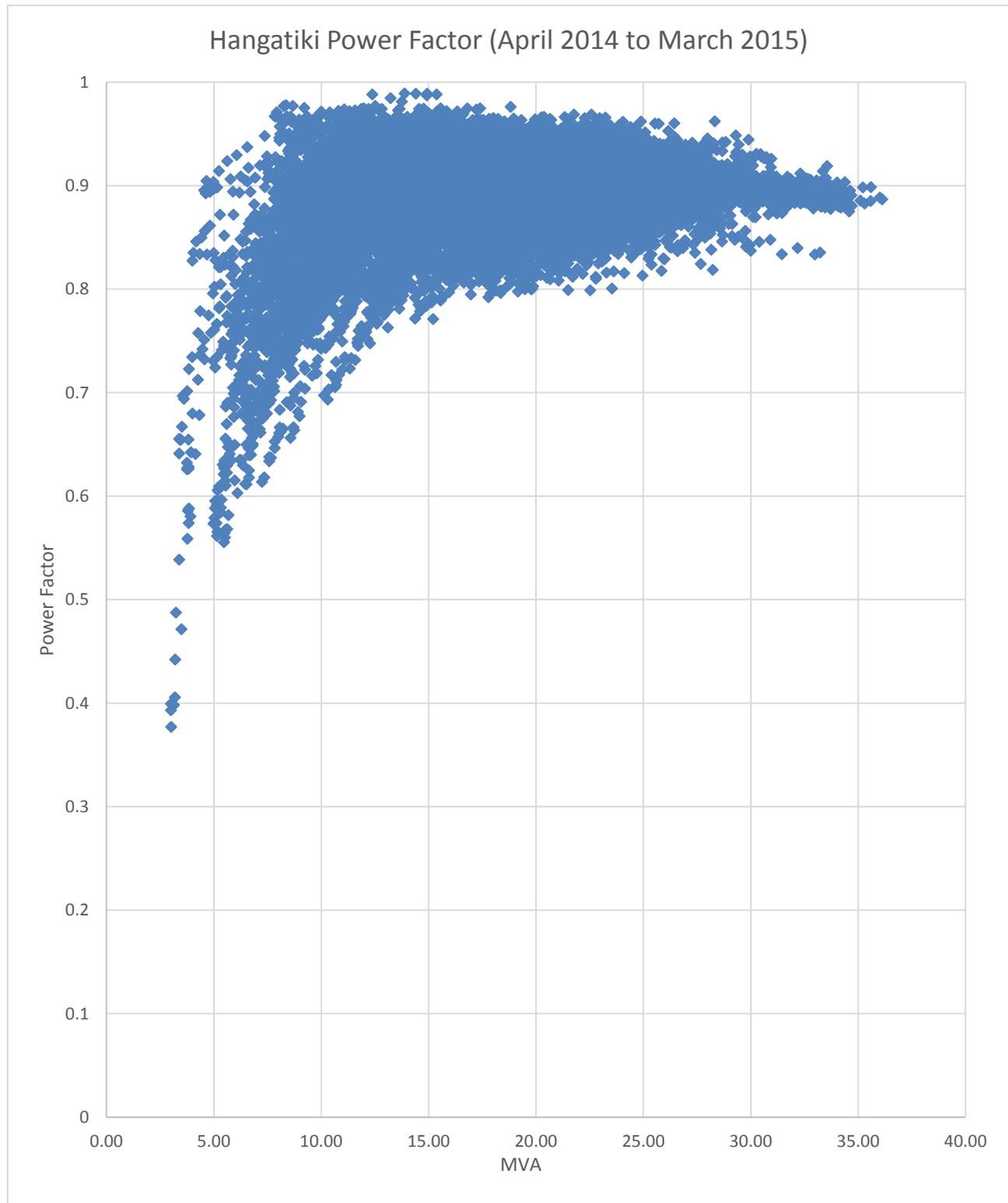


Figure 5.10 Hangatiki Power Factor

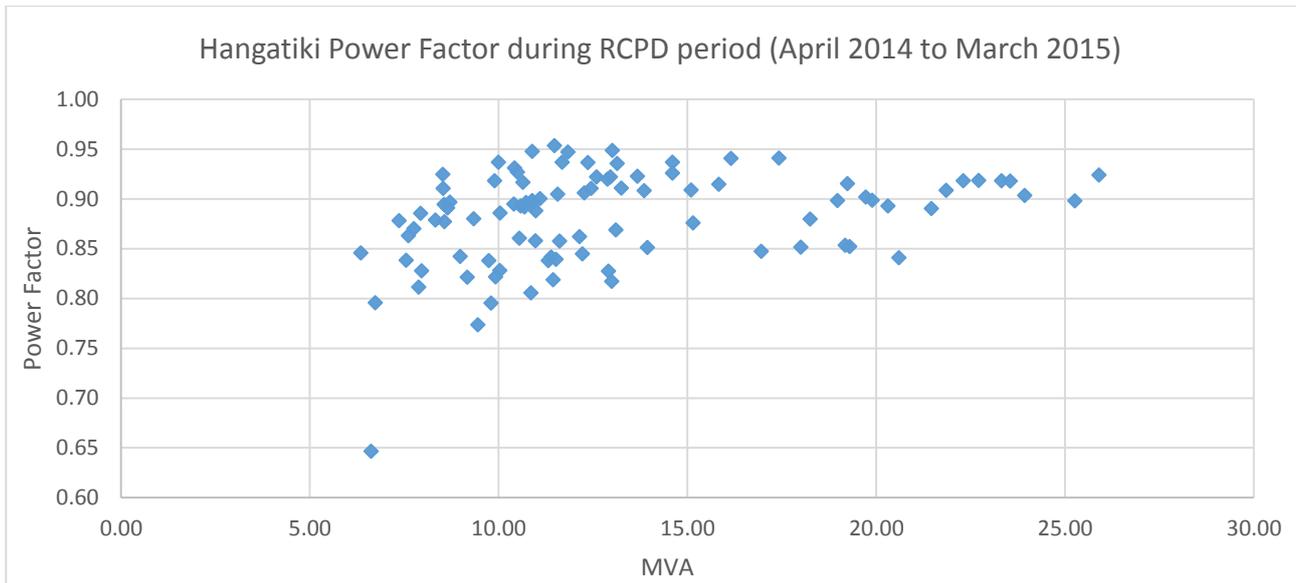


Figure 5.11 Hangatiki Power Factor during top 100 RCPD Peaks

Figure 5.11 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 as low as 0.65

As a comparison, Figure 5.12 shows the Ohakune power factor, which is above 0.95. Ohakune does not have distributed generation connected.

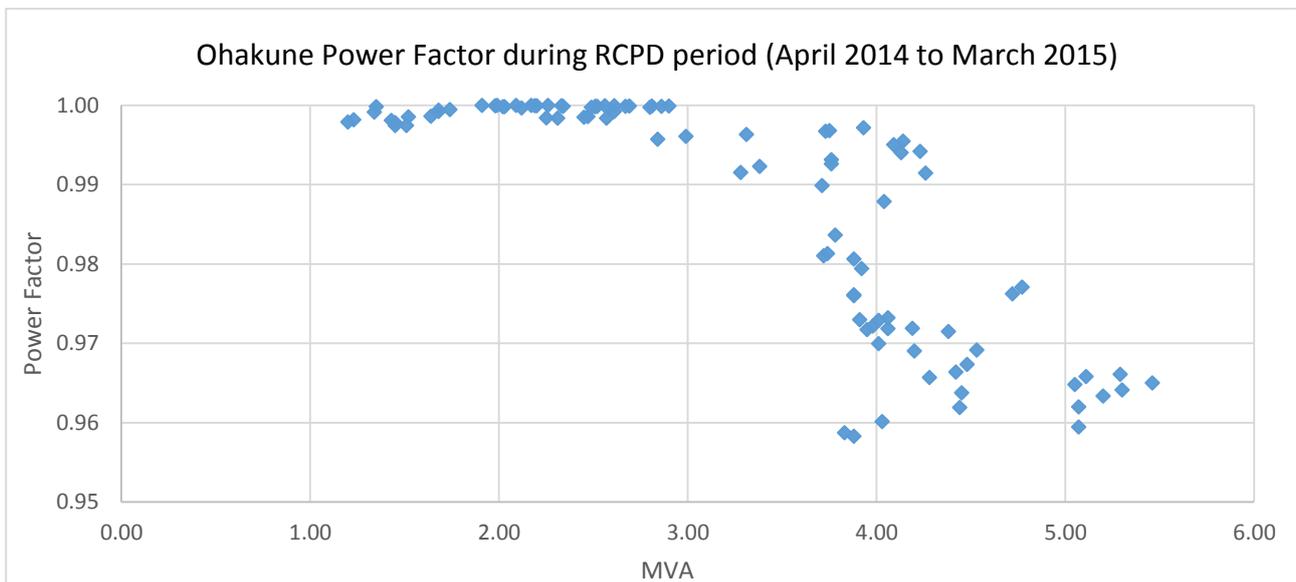


Figure 5.12 Ohakune Power Factor during top 100 RCPD Peaks

The intent of present documents produced by the Electricity Authority is to pass on the costs of correcting to 0.95 or unity at grid exits to network companies. Network companies have to recover this cost from somewhere. They have two choices: load taking customers or generators. Load taking customers are encouraged by TLC's demand based charges to correct power factor. Many do and are operating at 0.95 or better.

The generators could pay, but this will effectively penalise generators connected to distribution networks as opposed to the transmission grid. It also defies the intent of government policy to encourage distributed generation.

Given this difficult situation the solutions range from ignoring the power factor issue as has happened over the last eighty years or working towards a full reactive power market. The full reactive power market would be a good outcome as it would place a full value on reactive power. It would encourage the generation of

this and, in an ideal world, allow greater value to be placed on demand side active power generation. Customers would be free to generate reactive power similar to that for active power.

While this concept is good, the technical issues are not so straightforward. For example, resonance is always a possibility around capacitor sites, either from harmonics or at the fundamental frequency. Any such market would also be complex and add overall cost to the industry.

The capacity of generation that can be connected is heavily influenced by reactive power flows. The suggested solution to this issue is to focus on reactive power flows at grid exits, not power factor. The amount of reactive power that should be allowed at a grid exit should be that which would flow if no generation was present. The amount of generation capacity that could be connected would then be more defined, i.e. the amount that, if it operates at unity, would not cause excessive voltage rises on that part of the network.

5.8.2 Impact of Distributed Generation on Network Development Plans

5.8.2.1 Existing Generation

A summary significant existing distributed generation connected and injecting into the network can be found in section 3.

TLC also owns a mobile generator and injection transformer that is used to reduce planned and unplanned SAIDI events. The unit is also regularly used to support network voltage when only limited capacity back feeds are available.

5.8.2.2 Network Support

TLC has a mobile capacitor bank that is used to support network voltages during planned and unplanned events. Hire generators are also used from time to time to support the network or to provide supply during large outages.

TLC is also investing in the development of distributed generation through a wholly owned subsidiary called Clearwater Hydro.

5.8.2.3 Projects Directly Affected by Proposed Distributed Generation not going ahead

The following projects may be affected by distributed generation:

- Voltage regulators on the Wairere/ Gadsby 33kV line.
- Waihi modular substation is dependant of the re-development of the hydro site at Waihi near Kuratau.

5.8.2.4 Impact on Subtransmission Network by Distributed Generation

5.8.2.4.1 Grid Exits

The present transformers do not have n-1 capacity and are heavily loaded during peak demand periods without the availability of distributed generation. The problem with currently connected generation is that it is all run of the river and, as such, is rain dependent and is not necessarily available during periods of peak load.

5.8.2.4.2 33kV Lines

Distributed generation and demand side management has the potential to ease the loading on the Whakamaru 33kV, Taumarunui to Ongarue 33kV and Te Waireka/Te Kawa 33kV lines. Distributed generation proposals have the potential to cause upgrades of Te Kuiti and Mahoenui 33kV lines.

5.8.2.4.3 Zone Substations

Distributed generation and demand side management have the potential to ease the loading on the following zone substations and their transformers and prolong the period before an upgrade is required:

- | | | |
|------------|---------------|------------|
| • Marotiri | • Hangatiki | • Borough |
| • Kuratau | • Gadsby Road | • Waitete |
| • Tawhai | • Maraetai | • Atiamuri |

5.8.2.4.4 Distribution Feeders

Distributed generation can assist with supporting loadings on distribution feeders. However, during periods of light load on a relatively long and high impedance system it can push voltages high. Inductors or absorption of reactive power can be used to control this, but these actions can have a detrimental effect on overall network power factors and system stability.

5.9 Policies on Non-Network Solutions

5.9.1 Non-Network Solutions processes

The general processes that TLC applies to identify and pursue non-network alternatives to its plans include:

- Price to ensure customers are aware of the cost of their:
 - » Capacity;
 - » Peak demand;
 - » Dedicated assets.
- This ensures customers are financially motivated to look at options that drive their network and non-network decisions, i.e. generators versus grid connection: gas versus the use of electrical energy.
- A high-level look at the alternatives and advice to the customer on these. Where the work involves renewals, cumulative capacity, hazard control or reliability development, the options for both network and non-network options are looked at.
- The option selected is based on the criteria of optimum cost and planning risk.
- There are a number of customers who select alternative power supplies for new connections.
- Technologies that can provide the energy intensity required for activities such as continuous water pumping and dairying are often more complex and backed up by diesel generators.
- A number of customers use single phase to three phase converters or generators to milk and the existing supplies to cool milk when supply capacity is not available. This typically occurs when there is only a single phase supply in the area.
- Financial analysis based on regulatory asset values and Commerce Commission return guidelines are completed for most capacity upgrade proposals. This analysis may include several engineering solutions including non-asset approaches such as the use of generators to provide short term demand until growth provides a stable income platform to fund asset network upgrades.
- Encourage the development of distributed generation to alleviate capacity constraints. Part of this encouragement is mostly given by the pricing structures put in place.
- Any customer who has a critical load is encouraged to make provision for its own standby generation and/or install generation to meet peak demand. For example during power outages:
- Ruapehu Alpine Lifts (RAL) has generators installed so that in the case of a power failure they are able to run the lifts to clear people stranded on the chair lifts.
- A number of dairy farms have generators that they run from the tractor Power take off (PTO) which enables them to continue milking in times out power outages. See Figure 5.13, 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.



Figure 5.13 Generator Backup Installed at Cowshed

- Consideration of how automation and controls could be applied to minimise the asset investment for customer requests and network development.

For example: Is it possible to use intelligent control systems to control and distribute load to maximise the utilisation of existing assets? (TLC has implemented several schemes. The most complex solution pushes a connection back and forward across the end of two feeders from different supply points, one of which has a distributed generation connection.)

- Information is made available from models to customers and retailers to encourage energy efficiency and minimise losses.
- Network security and reliability information is considered for all network and customer solutions. Often these factors influence the ability to use non-asset solutions.
- Encourage large industrials with high load demand to consider the alternative of installing a modular substation supplied from TLC's extensive 33kV transmission network. This alleviates the capacity pressure on the 11kV 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 as when MRP has its maintenance shutdowns at Whakamaru.

Once the best solution option is identified, TLC pursues this. Often considerable discussion must be held with the stakeholder parties and extensive financial analysis of the options completed. Medium to longer term solutions for a particular part of the network or site are considered and included in plans. For example: TLC has developed long term solutions for the ski fields. Each time modifications are made they progress the long term plan. The final network configuration will take about ten years to achieve.

TLC is committed to encouraging non-network solutions and sees this as a key pricing strategy, both for peak demand management and power factor correction. Customer incentives and education are seen as the most effective tools to encourage solutions at the load, thereby maximising the utilisation of existing assets and deferring investment. TLC believes that non-network solutions to minimise electricity costs (both lines and energy) for the end customer are a key to its overall operation strategy and giving customers long term value.

The forecasting section discusses TLC's understanding of the impact of demand billing and its encouragement of demand side management non-asset solutions. The analysis in this section illustrates the impact of these initiatives. The CAPEX estimates also illustrate the difficulty TLC would have funding upgrades as well as its renewal programmes without demand side management. At this time no dedicated cost benefit analysis of the savings that demand (or load) based charges are achieving has been done.

5.9.2 Strategies Being Deployed to Promote Non-asset Solutions

5.9.2.1 Integration of Demand Side Management and Pricing Strategy

TLC encourages the implementation of policies and measures to reduce electricity demand, through the use of pricing strategy, high efficiency equipment and good operating practice. Over recent years, the demand on the TLC network has been growing at a faster rate than the energy transported. Peak demand is the defining factor for network upgrades and hence investment level. Controlling peak load is seen as an important initiative for TLC to minimise cumulative capacity network development and the escalation of customer charges.

TLC is the only lines company in New Zealand to introduce universal demand billing and to send separate bills to customers to ensure maximum impact of these pricing signals. This concept dates back to the 1950's when load control was extensively deployed in New Zealand. Demand and combined energy charges were passed down to large commercial customer level. In the past the demand measuring meters involved complex mechanical devices and it was likely that this did not allow the concept to be applied at a lower level during these times. The arrival of electronic time of use meters at lower cost has 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 detailed in the Pricing Methodology and available on the TLC web site.

5.9.2.1.1 Results

This structure has produced positive results amongst customers where demand meters have been installed. This has been attributed to:

- A TLC initiative to hire consultants to educate larger customers on how to reduce their demand and hence their costs.
- A push to get industrial customers to improve their operating power factor.
- PR campaigns and other customer education programmes.

TLC's programme of Customer Focus Groups and public meetings are beginning to show results through its domestic customers, and there is a greater understanding of load demand charging and why TLC has to build lines to take the maximum load, and that the infrastructure to carry that load has to be maintained to achieve the service levels that they, the customers, expect.

5.9.2.2 Generators Installed to Reduce Peak Demand

RAL has invested in a generator to bolster the supply in times of heavy use such as snow making on a winter's night on its Turoa ski field. Other large industrials that have critical load are encouraged to consider the same techniques.

Dairy farmers and small business are also encouraged to have a backup generator supply to enable them to carry on with their business in times of power outages.

TLC has two generators, the largest of which is 165 kVA, to allow it to supply areas that are disconnected by a fault or for maintenance where no back feed supply is available.

5.9.2.3 Distribution Network Capacitors

Three sets of 1.0MVAR capacitors have been installed on various feeder circuits. These are switched units that are used for voltage support as required. As more controlled load transfers over from the legacy 725Hz systems to the 317Hz load control system, the capacitors can be left in service for longer periods of time.

Consistent with its demand side management and pricing strategy, TLC believes that the most effective and efficient place for power factor correction is at the customer's load. Hence intelligent billing is used in lieu of capacitors as the preferred means of power factor correction at this time.

Industrial customers are provided with free engineering advice as how to best control their power factor and loads. They are also charged based on kVA demand rather than kW, which gives further incentive to improve their power factor. Pricing has been set at a level where power factor correction pay backs are typically in the 2 to 5 year range.

TLC, however, recognises that there are locations where the future use of capacitors on the network will likely be the most cost effective way of maintaining voltage and meeting the Electricity Commission grid exit power factor requirements. Deployment at the present time is complicated by the old high frequency ripple injection plants and has been avoided. Rising harmonic levels may also add future complexity. As a shorter term solution the mobile active and reactive power unit concept is being developed.

5.9.2.4 Use of Intelligent Systems and Network Tuning

TLC has in place the base data systems required to move to an intelligent network. The base data in the existing systems are now at a level of detail, consistency and correctness where the data can be incorporated with other data sets. The strategy has been to use systems that have accessible data formats that can be integrated with other products.

TLC is investigating an upgrade of network analysis program to include the Smart Grid and/or Real Time modules that will interact with the SCADA data. Some of the benefits from introducing this system could be to provide more intelligent load shedding, switching, advanced monitoring, demand-side management and advanced forecasting features. The system is modular and therefore the purchase of packages will depend on cost-benefit analysis of each package.

This philosophy is integrally related to work to automate remote switches and a focus on flexibility for new projects. This automation and improving in the SCADA system is taking TLC closer to be able to start introducing a self-healing network. In many instances security of supply for a customer also equates to operational flexibility for TLC. There are cases where savings can be made via the optimisation of:

- Load distribution.
- Reactive power flow.
- Losses.
- Voltage (higher voltages leading to lower losses).
- Phase balance.

TLC is currently using its network analysis software to understand and tune network power flows to minimise losses and maximise the benefits of distributed generation and existing asset capabilities (e.g. regulators). Some of these optimisations can be achieved by an intelligent SCADA system. Some are implemented/encouraged in the Distribution Connection Code and pricing strategy. For example, it is possible to maximise distributed generation impacts and minimise the negative power factor effects by optimising generator control. One generator connected to the TLC network replaced controllers and indications are that technical network losses can be reduced by tuning these settings. Implementation of these savings is a multifaceted task and will require engineering time to determine where and how policy, investment or operational intervention is most effective.

5.9.2.5 Advanced (Smart) networks and TLC's positioning

Elements of advanced networks are available now and these technologies will have a cumulative effect as time goes on.

At this time the potential cumulative effect is a vision for TLC, and the key elements that we have in place to build on include a firm base of data, network analysis, direct based charging and other initiatives. The challenge is to bring these together in a planned way to provide improved service at a price customers are willing to pay. These initiatives must align with the strategic objective of being the best supplier of capacity to remote rural areas.

5.9.2.5.1 Definition of Advanced or Smart Networks

The definition that was adopted by an Electricity Networks Association working group is "The application of real time information, communication and emerging trends in electricity delivery to improve capacity utilisation, asset management practices and reliability on the modern network thereby optimising network investment to the benefit of all stakeholders."

This group concluded that the elements of an advanced network can be usefully grouped into three distinct layers. Figure 5.14 (on the following page) illustrates these layers and what they are.

The group went on to explore the cost benefits and concluded that "cost/benefit assessments indicate that the benefits of advanced networks substantially outweigh the cost at a national level". It is also considered that industry-wide policy settings may impede the deployment of advanced network technologies and identified a range of regulatory policies that prevent EDBs from deploying these technologies.

It is also recognised there is "no such thing as a representative EDB. Every EDB's advanced network investment would be different. The technology deployed is changing quickly and the cost established today will likely be out of date very quickly."

These latter points are very pertinent to TLC given that TLC is in a unique position given its direct charging strategies and remote rural environment.

Referring to the diagram in Figure 5.14 each of the layers are outlined and expanded on in the following sections.

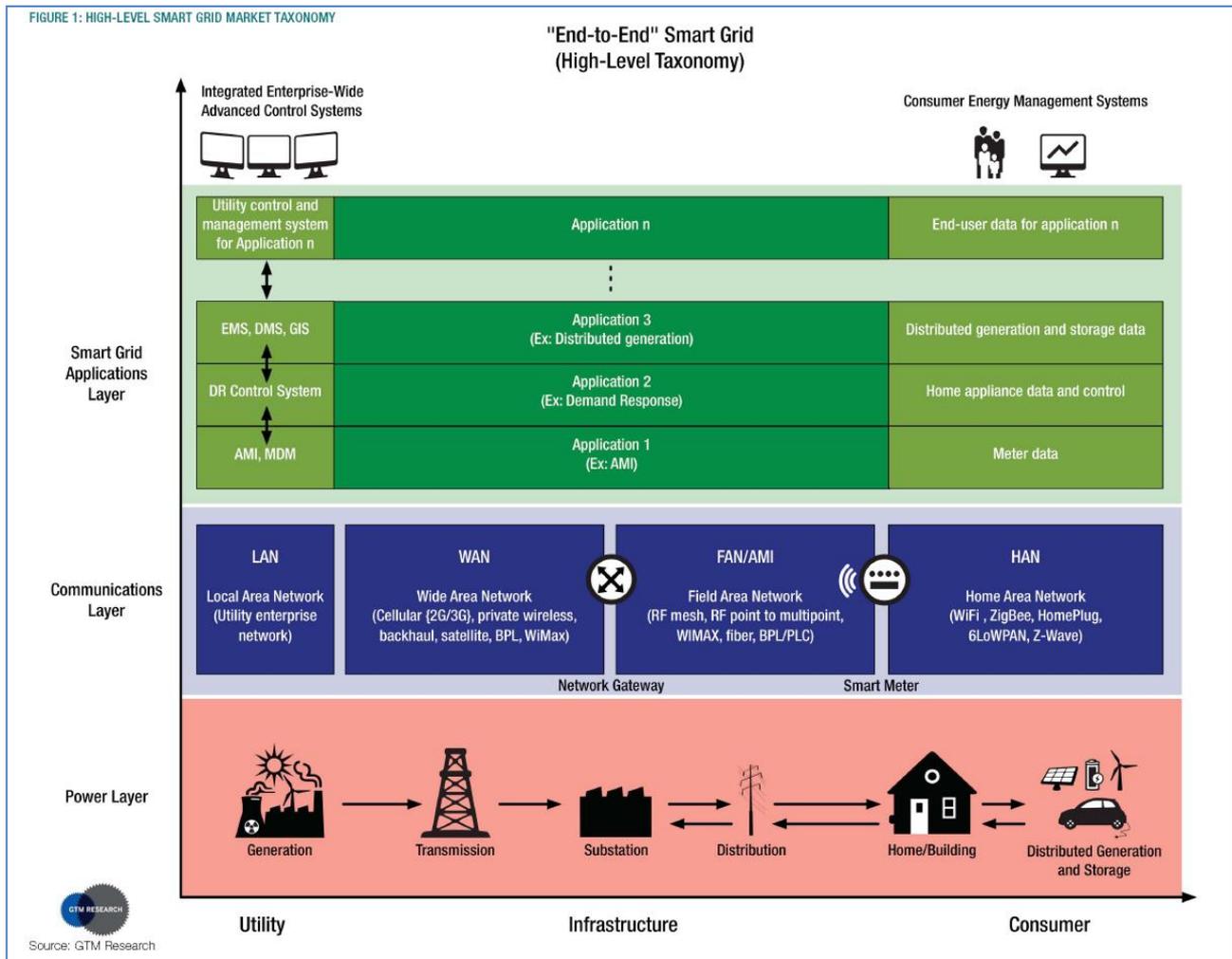


Figure 5.14 Three Distinct Layers Associated with an Advanced Network

5.9.2.5.2 Smart Grid Application Layer

At the heart of the applications layer lays a central element of an advanced network. It is the ability to:

- i. Monitor condition, consumption and injection across the network, preferably in real time.
- ii. Control the controllable functions in the way load control does now. However, this will become more complex and may include such things as charging for electric cars and signalling to smart appliances in a future smarter world.
- iii. Signal to customers the necessary information for them to make choices.
- iv. Recover the value of investments.

The communications layer covers the technologies and developments that facilitate a smart transformation. It includes metering developments, communications developments and information management.

The physical world may change as a result of more distributed generation, electric vehicles and other storage devices. The basic system will still deliver energy to load centres from large generating stations but the net demand from the network will be more volatile. The key physical impact of these developments will be greater two-way electricity flows on the distribution network and transmission grid. By itself this feature would necessitate a more active network operation approach.

Elaborating on these layers and relating them back to the TLC network: The strategies/tools and development vision TLC currently has for these are summarised in the following Table 5.30.

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	<p>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.</p> <p>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.</p> <p>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 than these amounts.</p>
SCADA Network Analysis, Asset Management, Technical Records, Billing and Accounting	<p>TLC presently has SCADA, network analysis, asset management, technical records, billing and accounting packages/systems as described in other sections.</p> <p>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.</p> <p>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.</p>

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	<p>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.)</p> <p>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.</p>
Automated: Self-healing Networks	TLC currently has not invested in automated self-healing networks. It has been focussing on getting the basic remote controlled equipment installed. Due to the radial nature of the network there are not as many potential options for the deployment of this technology as some other networks have. There are sites where the deployment may be useful and these will be researched and developed. As outlined in other sections it is a selection criteria for the equipment being purchased to have functions that will allow the deployment of some of these options. TLC's engineering structure is currently being adjusted to provide a level of additional resource to be able to carry out some additional research in this area. At this time there are no specific allowances in favour of estimates for the deployment of this technology; however, some of the contingency amounts in the communications and SCADA areas will likely go some way to achieving the "low hanging fruit" in this activity.
Reactive Power and Voltage Control	Over the last nine years TLC has been busy deploying modern technology assets (see Section 3) to ensure compliance with the electricity regulations. Similarly there are a number of deployments planned going forward. The recent upgrade of the injection plants in the Northern area has also meant that the deployment of capacitors is now an option. Also, as outlined in other sections, TLC is sending a message to customers via its charging to minimise reactive power flows. The intent is to increase the level of network tuning going forward. Forward expenditure predictions have been increased to cover off a level of increased engineering to research and develop more advanced schemes. The additional hardware and software investment is not included in forward estimates at this time.

POWER LAYER	
Item	Comments
Capacity	There are a number of things TLC could do to extract more capacity out of existing assets, particularly given the capability of things such as modern regulators, better information systems and reactive power flow initiatives. The implementation of these will likely be on an area-by-area basis. Such initiatives will require mostly technical labour type input plus some sensors and more advanced modelling.
Asset Management Information	The use of more advanced asset management information and the inter-relationships associated with this are perhaps part of the control layer but they also have a direct impact on the management of the power layer. An important part of running the power layer in a more advanced manner is to have individual, sectorised 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, Subtransmission and Substation Interfaces	Advanced networks will make use of a lot more data and information from transmission, subtransmission and substation interfaces. At this time no research has been done on the potential and how this information may be used.
Security	With the increasing value of copper, thefts and interference with power layer equipment is becoming more common. Advanced networks will likely have features that will increase security and related monitoring. This area is still to be researched.

COMMUNICATIONS LAYER	
Item	Comments
Ripple Signal	Ripple signal has the advantage that it reliably can send signals to large numbers of customers quickly and efficiently without involving a secondary communication system. This unique feature means that it has significant advantage. It cannot be used for 2-way network communication and as a consequence, given the hilly nature of the TLC network, it has been assumed it will be around for some time.
Voice Radio, Data Radio, Internet Protocols, Mesh Radio	The way the various communication mediums will be needed and develop as part of an advanced network is unknown at this time.

Table 5.30 Strategies, Tools and Development Visions TLC has for the layers associated with an Advanced Network

5.9.2.6 Large Industrial Customers Encouraged to Install Modular Substations

TLC has an extensive 33kV 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 33/11kV substation was installed by teeing in to an existing 33kV line and tying into the existing 11kV 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 11kV lines come from different points of supply, redundancy is achieved. The substation was customer funded, and lower cost than an 11kV 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 33kV network.

5.9.2.7 Ripple Control and Load Shedding

5.9.2.7.1 Peak Demand Load Shedding

TLC uses its ripple system to avoid RCPD peaks and reduce/signal network constraints. In 2010 the renewal of the old ripple system in the northern area operating on 725 Hz to a new system operating on 317 Hz began. The completion of replacement of customer relays within the next 2 years will see a significant improvement in the control TLC has over load at peak times.

As mentioned earlier, TLC is evaluating a package provided in conjunction with the network analysis program and will need to justify the initial cost against the proposed savings in reduced GXP costs, power factor penalties, MW and MVar losses, and avoidance of network upgrades.

A key to further enhancing demand side management will be to implement systems for load control at feeder level and below. This will require intelligent load control systems.

5.9.2.7.2 Under Frequency Load Shedding

TLC has Automatic Under Frequency Load Shedding (AUFLS) relays which is a requirement from the Electricity Authority to ensure that the national grid does not experience total system instability and fail. TLC has devised a system where, if an under frequency event should occur, blocks of load are disconnected from the system.

5.9.2.8 Alternative Supplies for Remote Rural Areas

Alternative supply solutions are now advanced enough to meet the needs of busy farmers who are focused on maximising the efficiency of their enterprises and low enough cost to be an alternative to uneconomic parts of the network. The concept of regulated off grid supplies will be explored in the next year to determine the value and practicality for the TLC network.

Most lifestyles require a supply reliably available on a 24 hours a day, seven days a week basis. This has been further cemented by the requirement for environmental reasons for farmers to fence water ways. A typical dry stock farm needs 4500 to 5500 stock units to be economic in today's trading environment. These stock numbers result in a daily water need of about 45,000 to 55,000 litres that has to be pumped. Alternative power supplies to cope with supplying the amount of energy to achieve this outcome are relatively large, however technology solutions now mean that the costs of off grid solutions are likely less than the replacement cost of the network.

The costs, particularly of solar cells, have reduced over the last few years; and, economic analysis shows that they are approaching competing against present energy rates (excluding lines charges). TLC is recommending them to customers when they are more economic and capable of producing similar lifestyle or enterprise outcomes. There is currently a cross subsidy from town, holiday and intensely farmed areas to sparsely populated areas often in rugged terrain. Given the cost reflective principles of TLC tariffs, if true costs were reflected to customers on some SWER parts of the network, it is expected the cheapest solution would be a standalone power supply. This is occurring in many remote parts of Australia. While the load profile is different in the TLC network with higher winter loads when solar is less effective, as remote parts of the network come up for replacement, alternatives to on grid supply need to be considered. TLC intends to report this in some detail in the next AMP.

Managing off grid regulatory supplies would require the same attention to reliability and service that are core parts of TLC culture.

5.9.2.9 Solar Panels and Domestic Wind Turbines

While TLC encourages customers to support their own power usage through the installation of photoelectric solar panels, solar hot water boosters and small wind turbines, TLC at this time does not have sufficient resources to assist in the development of these types of small business or domestic power supplies. TLC encourages customers to use the technical advisors associated with the distributors of these products. However, customers who do install alternative generation and can reduce their peaks may see benefit from lower network fees under the Demand Billing system.

5.9.2.10 Surge Arrestors and Surge Suppression

In order to minimise damage to customers' equipment connected to the network, surge arrestors are installed on the network. In addition to this a TLC promotion was run to issue vouchers for surge protectors to customers. Surge protectors are provided to customers as part of the rollout of smart meters.

5.9.2.11 Network Non-technical Losses

TLC has evidence of a significant variation between actual losses and losses derived by retailers from the difference between metering data at GXPs and that used for billing at the customer ICPs. The technical losses have been calculated by modelling and make up about 55% of the losses. To get accurate data on the remaining 45% (approx.), is very difficult, with the non-technical losses being caused by metering, meter reading and retailer billing errors.

Losses are funded by customers when retailers add these costs back into energy rates. Improving the accuracy of billing does involve working with retailers to minimise non-technical losses. TLC has worked with its test house and found that about 20% of meter exchanges lead to errors in meter data/readings. For example there have been instances where meter readers have substituted reactive power for active power readings. Blown or disconnected VTs and reverse connected CTs also frequently lead to metering errors – usually underestimation of consumed kWh.

TLC believes the best solution for these kinds of errors is to improve metering technology. Remote meter reading will not be simple in the King Country due to geographic communication difficulties. However, deployment of improved metering (for example handheld units that read and record data automatically) as part of the 2015 compliance and TLC's demand metering needs will likely significantly reduce meter reading error.

5.9.2.12 Demand Side Management Summary

TLC uses as many approaches as possible to ensure customers' capacity and cost expectations are met. These tools include the construction of capacity, generation and demand side management initiatives.

Due to the remote nature of the TLC network and that it is sparsely populated, the cost of capacity construction can be high and often customers' ability to pay is limited. As a consequence of this, TLC is leading the way nationally in its charges that are designed to promote demand side management. It is acknowledged however, that demand control was used extensively in the 1950's and early 1960's. At that time though the technology such as electronic half hourly meters was not available to make this concept accessible to all customers. This technology is now possible.

TLC is in the process of rolling out advanced demand meters to all customers to improve the ability of customers to monitor their demand.

TLC's forward asset management plans are relying heavily on demand side management to control demand and alleviate the need for investment in development while larger renewal programmes are in place. The use of capacitors and generators are to postpone the need to upgrade the network and TLC has installed (and is planning more) voltage regulators on its feeders to push the ageing and small volume feeders to their limits, however, the forward expenditure for TLC does include conductor and system upgrades to manage the system growth in the long term.

5.10 Non-System Fixed Assets Capital Expenditure Forecast

Table 5.31 outlines the Capital expenditure for non-system fixed assets.

NON-SYSTEM FIXED ASSETS CAPITAL EXPENDITURE										
	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Building Re-structure	3,200,000	870,000	-	-	-	-	-	-	-	-
Data Systems	26,250	26,250	131,250	183,750	183,750	131,250	26,250	26,250	26,250	26,250
Misc Equip	10,871	10,871	10,871	10,871	10,871	10,871	10,871	10,871	10,871	10,871
Office Area	21,741	21,741	21,741	21,741	21,741	21,741	21,741	21,741	21,741	21,741
Vehicle Replacements	69,274	69,274	69,274	69,274	69,274	69,274	69,274	69,274	69,274	69,274
Total	3,328,136	998,135	233,136	285,636	285,636	233,136	128,136	128,136	128,136	128,136

Table 5.31 Capital Expenditure for Non-System Fixed Assets

Note: The vehicles listed in Table 5.31 are asset management vehicles and do not include TLC Contracting or other organisational vehicles.

5.11 Summary Description of Non-network Assets

5.11.1 Information and Technology Systems

TLC has a number of information and technology system that are used for network analysis, line design and mapping. Table 5.32 below outlines TLC's Information and Technology Systems.

DESCRIPTION OF TLC'S INFORMATION AND TECHNOLOGY SYSTEMS.	
Information and Technology System	Description
Electrical Transient Analyser Program	<p>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.</p> <p>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.</p>
CATAN	<p>CATAN is an integrated design package that provides accurate solution to overhead power line design. The software removes the tedium and inaccuracy of manual data entry and manual calculation.</p> <p>TLC is currently in the process of inputting pole data, pole location, circuit lengths, and conductor types etc. into the software to make line design more accurate and efficient.</p>
MicroStation	<p>Micro Station is a CAD software program used for designing and drafting. Micro Station provides interaction with 3D models and 2D designs to produce precise drawings, its robust data and analysis capabilities enable performance simulation of designs.</p> <p>TLC currently use Micro Station for detailed engineering design, mimic updates and line design.</p>
ESRI GIS system	<p>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.</p>

Table 5.32 description of TLC's information and technology systems

5.11.2 Asset Management Systems

The asset management system is based on BASIX software over an SQL server database. The BASIX system contains asset data for the whole TLC network and is used to calculate reliability statistics and valuations. It also produces reports that align with the network performance criteria in Section 4 of this Plan. The system is being extended further to include asset related customer service data.

The BASIX system is also used for many other asset related activities as detailed in subsequent sections. There has been a considerable amount of progress on the development of the system over the last 24 months and there is an extensive amount of development planned going forward. This will likely include things such as improved outage notification systems and the changed NZCC22 disclosure requirements.

5.11.3 Office Buildings, Depots and Workshops

TLC's main office is located on King Street East of Te Kuiti town. The office is a two story building which was commissioned in 1958. TLC recently had a seismic assessment completed through an external consultant. The conclusion to the assessment was that the building is not earthquake safe and needs strengthening and reinforcement. Building renewal projects are planned for 2016/17 and 2017/18.

5.11.4 Other Non-Network Fixed Assets

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

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

The TLC owned relays are 80% of the modern programmable electronic type. The remainder are old and electro-mechanical relays. The channel segmentations of these relays is typically that of the legacy lines company load control systems, i.e. about 10 channels randomly deployed for water heater controls, 2 channels for street lighting, other channels for times controls and a few other channels mostly allocated for encouraging electrical energy usage programmes from the Electro Corp marketing strategies of the 1980's. Looking forward, these channel layouts will be modified for the future to include more focus on demand billing, the fast load reduction frequency market and other activities involved with an advanced network.

5.11.5 Other Organisation Non-system Fixed Assets

TLC uses Navision which is well established Microsoft ERP system which well supported in the market. Navision is used extensively to maintain the accounting general ledger and sub ledger modules. Navision is interfaced with other core operating systems, including Gentrack (billing). The Navision system underwent a significant upgrade in 2015.

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. A project has begun to evaluate and recommend an upgraded Customer Information System with functionality to better support our direct customer interaction processes.

Section 6

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6. Lifecycle Asset Management Planning (Maintenance and Renewal)

6.1 Maintenance Planning Criteria and Assumptions

Detailed in the following sections are the key drivers for maintenance for the various asset categories. Maintenance is planned to allow the network performance to meet the targets listed in Section 4. The following maintenance planning criteria are used to ensure these performance standards are met:

Hazard Elimination and Minimisation - Ensure equipment is installed, labelled, maintained, fit for purpose and secured to eliminate or minimise hazards to staff, the public and the environment.

Reliability - Ensure equipment will reliably operate to produce the outcomes it was purchased and installed for.

Operation - Ensure equipment is maintained, used, and operated in the way that it was designed for.

Life Span - Ensure equipment is installed, operated, and maintained in a way that it reaches or exceeds its expected life span.

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. The renewal decisions should consider the criteria listed above against commercial, pragmatic, and customer considerations.

The commercial considerations include:

- Cost of maintenance versus renewal.
- Income the equipment assists in generating.

The pragmatic considerations include:

- Will it work and meet customers' expectations?
- Will it be accepted by the people who have to operate it?
- Is it reliable?
- Is there any environmental implications?
- Are any hazards associated with the equipment in line with current stakeholder expectations? (public or staff)
- How long will it last?
- If things change, can it be used elsewhere in the network?
- Is there good supplier support?

The customer considerations include:

- Will it work and provide a solution that allows customers to get on with their business?
- Are they prepared to fund the solution either directly or indirectly?

6.2 Routine and Preventative Maintenance Policies & Programmes

6.2.1 Summary of Maintenance Schedule

The key maintenance schedules are summarised in Table 6.1

MAINTENANCE SCHEDULE SUMMARY	
Item	Maintenance Framework
All Categories	<ul style="list-style-type: none"> » Follow up after faults, defects and hazard reports (including “Red Tagged poles”). The resulting work will include minor maintenance through to renewal.
Overhead Lines and Cables (Excludes Ski Field Areas), Distribution Poles	<p>Patrols:</p> <ul style="list-style-type: none"> » 18 monthly drive or foot patrol through urban areas and schools looking for potential problems including vegetation. (11kV and LV.) » 3 yearly helicopter patrols of rural areas looking for potential problems including vegetation. (11kV and LV.) » 12 monthly helicopter patrols of 33kV lines looking for potential problems including vegetation. » Fault patrols of all lines after a series of auto-recloses, tripping’s or other reports. When these fault patrols involve a 33kV line, a corona camera survey may be included. Most of these rural patrols are done from a helicopter. <p>Inspections:</p> <ul style="list-style-type: none"> » 15 yearly detailed inspection and renewal cycle. <p>Emergent:</p> <ul style="list-style-type: none"> » Renewals and maintenance as required to maintain supply and eliminate/minimise hazards. Emergent work often occurs as a result of following up after an event and includes a SMS hazard report.
Cables (Ski Field Areas)	<p>Patrols:</p> <ul style="list-style-type: none"> » 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. <p>Inspections:</p> <ul style="list-style-type: none"> » 15 yearly detailed inspections of cables and till boxes.
Vegetation	<ul style="list-style-type: none"> » 3 yearly patrol cycle for rural areas and 18 months for townships and schools (compliance driven). Emergent cutting to eliminate hazards or restore supply.
Zone Substations	<ul style="list-style-type: none"> » 2 monthly routine maintenance checks. » 12 monthly detailed checks. Actions include earth tests. » 2 yearly oil tests for major transformers. » 3 yearly maintenance of active oil filled circuit breakers. » 5 yearly tap changer oil and maintenance on major transformers. » 15 yearly major maintenance cycles, which include SCADA recalibration, busbar cleaning, circuit breaker timing checks, detailed inspections, earth testing, painting, protection checking and extensive cleaning of the site. » Hazard elimination/minimisation projects as detailed in Section 5 of this AMP. <p>Emergent:</p> <ul style="list-style-type: none"> » Renewals/maintenance necessary due to failures or damage. Other equipment renewals/refurbishment as detailed in Section 5 of this AMP. » Oil refurbishment based on the results of 2 yearly oil tests.
Pole Mounted Transformers	<ul style="list-style-type: none"> » 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.

MAINTENANCE SCHEDULE SUMMARY	
Item	Maintenance Framework
Ground Mounted Transformers and Ground Mounted Switchgear	<ul style="list-style-type: none"> » 12 monthly security check and minor urgent maintenance. » 5 year major maintenance and inspection cycle. » Hazard elimination/minimisation projects as detailed in Section 5 of this AMP. » Emergent renewals/maintenance necessary due to failures or damage. » Renewals/upgrades triggered by changed customer demands.
Service Boxes	<ul style="list-style-type: none"> » 5 yearly inspection and renewal cycle. » Planned hazard elimination/minimisation projects as detailed in Section 5 of this AMP. » Emergent renewals/maintenance necessary due to failures or damage (typically vehicle impacts). » Renewals/upgrades triggered by changed customer demands.
SCADA and Communication	<ul style="list-style-type: none"> » Maintenance repairs when the system, or parts thereof, do not operate. » Renewals of software and hardware with modern equivalents on failure. » Planned renewals to keep software and hardware up to date.
Load Control	<ul style="list-style-type: none"> » 3 monthly inspection of rotating plants and equipment room cleaning. » 2 yearly vibration analysis of rotating plants. » 12 monthly inspections of static plants and cleaning. » Planned renewals of plant as recommended by the supplier. » Hazard elimination/minimisation projects as detailed in Section 5 of this AMP. » Emergent renewals/maintenance necessary due to failures or damage. » Changes to control software triggered by changes to customer charging policies (driven by demand side management initiatives).
Three Phase Reclosers, Automated Switches and Voltage Regulators	<ul style="list-style-type: none"> » 12 monthly inspections. » Emergent renewals/maintenance necessary due to failures or damage. » Relocations and refurbishment of equipment to fit in with the long term development plan as detailed in Section 5 of this AMP.
SWER Systems	<ul style="list-style-type: none"> » 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.

Table 6.1: Summary of Maintenance / Renewal Strategies

Note: All patrols, inspections and works are recorded against the assets in the Basix asset management system.

6.2.2 Overhead Lines

Overhead lines form the highest value asset category owned and operated by TLC.

6.2.2.1 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 6.1. 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 33kV lines when carrying out helicopter patrols. Most of these faults are caused by insulator flashover from fertiliser build-up. In the extreme they escalate to cross arm failure. The corona camera has not proved successful for finding problems on 11kV lines.

Helicopter patrols are cost-effective and provide a quick way to cover long lengths of lines in rugged country. The average cost is \$50 to \$60 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 33kV line is to be used as an alternative supply while Transpower has a grid exit point out of service for maintenance, the line will be patrolled beforehand. Key lines are often patrolled preceding special events such as long holiday weekends.

Patrols may take place after a series of auto recloses to try and identify the cause of the tripping's. Patrols are also completed after customers express concern or report some type of problem with equipment.

Inspections are used to take a more detailed look at assets and drive the longer-term preventative maintenance and renewal programmes.

The inspection assessment includes:

- Travelling to each pole and assessing the condition of all hardware, cross-arms, conductors etc.
- Testing the pole - if practical and access is possible - with a mechanical strength tester.
- Photographing the pole and associated hardware.
- Plotting the position by GPS.
- Measuring span lengths.
- Checking vegetation and recording any other issues associated with line security.
- Visually checking the integrity of the transformer and equipment earthing.
- Visually checking all earthing at transformer and equipment sites. Testing is also completed.
- Visually checking all HV fuses and air break switches. This includes visually checking and testing the earthing system.
- Checking all switch and fuse labelling and re-labelling if they are not readable.
- Checking pole labelling and re-labelling with new asset numbers as required.
- Checking all transformers and other equipment labelling.
- Completing data sheets.
- Establishing walking access to pole sites. This may involve cutting a track through bush, scrub etc.

- Initial renewal specifications, and design when renewal is being proposed by the inspector. The inspectors' assessment and specified renewal requirements are desk top checked and calculations are completed.
- Site access details are recorded for renewal recommendations.
- Recording and specifying any minor maintenance needs

6.2.2.2 Processes for Ensuring Overhead Line Defects Identified by the Inspection and Condition Monitoring Programmes are Rectified

The following processes are used for rectifying defects and ensuring data are correct after detailed inspections:

- Appropriately qualified and experienced staff conduct the inspections.
- Inspections are reconciled against the asset data records.
- Gathered data and photographs are loaded into databases.
- Strength calculations on selected assets are carried out using a line design package.
- Field inspector's designs are reviewed and modified as necessary.
- Co-ordinate renewals and maintenance with other works.
- Investigate the outages needed to do the work and the implications of the outages.
- Put together work packages and specifications including specifying requirements to eliminate or minimise hazards.
- Notify landowners and discuss proposals.
- Prepare, obtain and check cost estimates. This includes reconciling industry current cost survey data.
- Issue work to contractors.
- Receive and process applications from contractors to work on network. Police contractors to ensure they eliminate/minimise hazards, are approved to work on network and have hazard control programmes in place.
- Receive notification from contractors that works are complete and audit work for compliance with the specifications.
- Review private line connections and ensure customers understand their liabilities under the Electricity Act and its regulations. In extreme cases for private lines that pose a significant hazard, details are forwarded to Energy Safety for follow up. (The Electricity (Safety) Regulations 2010 impose significant liability for private lines on the line owners. At this time the various government bodies do not appear to have co-ordinated their activities in this area, nor understood the implications of the liabilities the Regulations place on the rural communities.)
- Re-audit and where required issue further network instructions.
- Accept invoices and reconcile to original estimates.
- Carry out line owner follow-ups.
- Settle any outstanding landowner or line owner issues.
- Ensure all as built data and databases are updated.

6.2.2.3 Overhead Line Systemic Problems and Solutions

Table 6.2 summarises the systemic problems associated with lines and the steps taken to address these. Some of these issues were discussed in Section 3.

OVERHEAD LINE SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problems	Steps to Address
Insulator failures advanced by fertiliser build up and magpies.	» Taller insulators with longer creepage distances.
Air Break Switch failures due to poor manufacturing and connections.	» Greater quality focus on connections and use of proven switch types.
Tree and other environmental issues such as flooding and slips.	» Tree programme in place. » Equipment located away from flood prone land. » Slips continually watched during helicopter patrols and inspections. » Poles moved to less hazardous locations.
Wire clashing.	» Greater focus on line design, fault current control designs and wire spacing/tension.
Insulator wire ties breaking due to vibration and loading.	» Greater focus on quality of hardware. » Larger size binder wire used. » Galvanised steel pre-form wire ties that tend to corrode are not used.
Connection failure due to dissimilar metal reactions.	» Greater focus on the quality of connectors and types used. They must be straight forward and simple to apply, yet robust and able to handle dissimilar metals.
Conductor and jumper breaks due to corona or mechanical failure	» Focus during inspection on conductor » During renewal outages check all joints and conductor for strand break age that may lead to failure » Test parts of the network for embrittlement using tension testing » Trial ultra-sonic testing to detect the early onset of corona and target key defects
Drop out fuse failures.	» Careful component selection. » Attention to corrosion, connections and clearances for hazard elimination/minimisation.
Pole cross-arms and other hardware problems.	» Focus on component workmanship quality and design, in particular making sure correct pole and component strengths are used. » Planned renewal programme and making sure reported problems are followed up. This is critical for improving reliability, SMS, security and hazard control.
Private responsibility overhead lines interfering and causing problems with TLC assets.	» Increased fusing of private lines. » Increase publicity to owners to improve their awareness and understanding of the complex issues for compliance with Electricity Regulations. » Better data systems including more detail on ownership and responsibility for lines.

Table 6.2: Systemic Problems Associated With Lines

6.2.3 Cable (Ski Field Areas): Inspection, Testing and Condition Monitoring Practices

6.2.3.1 Foot Patrols

Foot patrols are used to find and overcome obvious immediate asset problems. Identified problems are photographed, the asset identifying numbers recorded and the location physically recorded with GPS co-ordinates. A report is completed after each patrol and data verifying that a patrol has taken place is recorded against each asset.

Annual Foot patrols are conducted in low valley areas, stream beds, rock movement areas, in/around tracks and high hazard areas. A foot patrol of the whole cable length is done over 3 years (the cable length is split into 3 sections and each section is done once in the 3 years). Patrols may take place after a series of auto recloses to try and identify the cause of the tripping's.

6.2.3.2 Inspections

Inspections are used to take a more detailed look at assets and drive the longer-term preventative maintenance. Cables are maintained on a time based programme.

Time based inspection and maintenance programmes include:

- Three yearly cable and till box integrity inspection
- 15 yearly detailed cable termination and till box termination inspections as well as earth testing and insulation resistance testing.

6.2.4 Vegetation

6.2.4.1 Reliability and Compliance of Vegetation Control Programmes

Analysis of tree data, collected since 2003, shows that complying with the Electricity (Hazards from Trees) Regulations 2003 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.

6.2.4.2 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.

Emergent notifications of tree problems are received from customers, staff and other sources. Records are taken of these notifications and the issues are investigated by TLC's line inspectors. Customer liaison, work specifications and instructions are undertaken for each site.

6.2.4.3 Processes for Ensuring Vegetation 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.

Health and safety changes together with traffic management requirements have increased costs per tree cut or felled as shown in the Figure 6.1 below. This shows the number of trees cut/felled has dropped 50% since 2008/09.

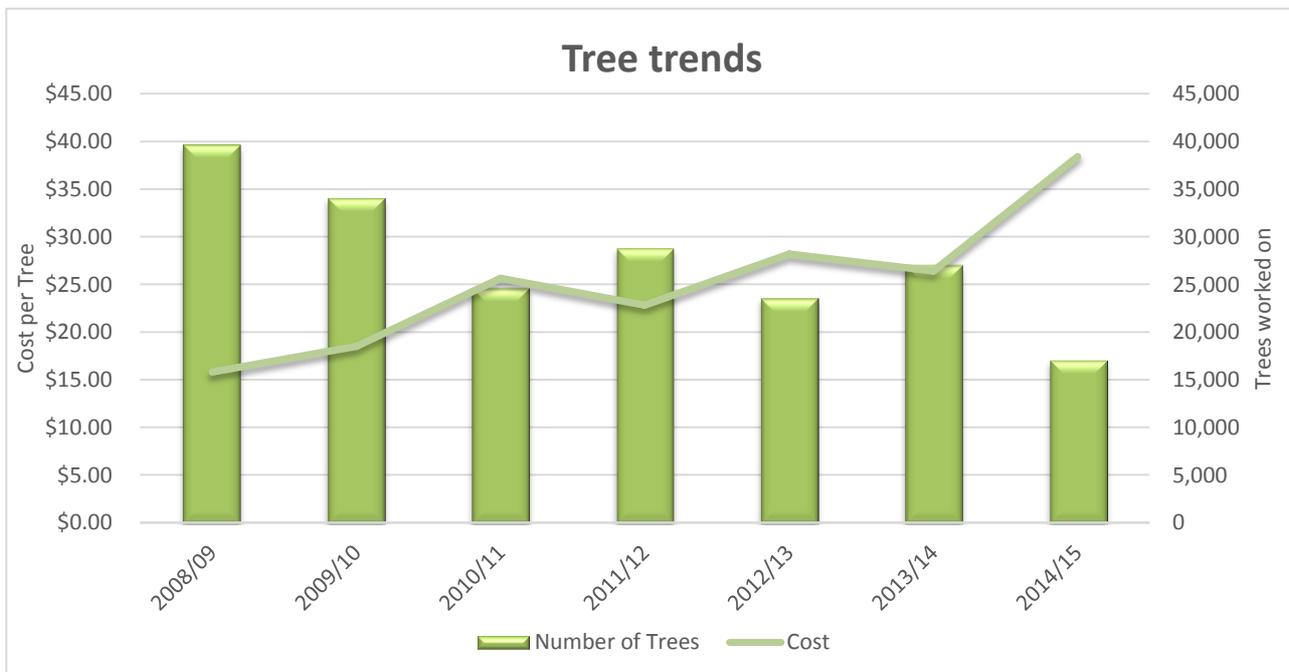


Figure 6.1 Escalating Tree Costs and Reducing Cut/Fell Numbers

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.

A reduced number of trees being cut has resulted in an increasing backlog of trees to trim. Together with increasing tree faults and benchmarking that shows TLC is spending less than it's cohort on tree management, the case for increased tree spend is compelling. It should be noted that on more remote parts of the network, tree trimming is based on trimming for reliability and not code.

6.2.4.4 Vegetation Systemic Problems and Solutions

Table 6.3 summarises the systemic problems and solutions associated with vegetation and the steps taken to address these.

VEGETATION SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problems	Steps to Address
Landowners planting under lines.	» 3 yearly patrols following up on new plantings.
Trees that breach the fall distance.	» Charging landowners for problems caused by trees that breach the fall distance if the tree does fall through lines.
Landowners not complying with Tree Regulations.	» Strict follow up on notices. » Account follow up on any invoiced charges.
Legacy issues.	» Issues are addressed one at a time when problems occur. They are mostly associated with plantation owners and their desire to maximise forest production.
Forest fires started by trees falling through lines.	» The Rural Fire Act has been poorly written, contains no rule for fall distance and leaves network companies liable for damage caused by trees, no matter how good their tree programmes are. Insurance is the only solution to potential liabilities.

Table 6.3: Systemic Problem and Solutions Associated with Vegetation

Note: TLC's vegetation's programmes are reviewed annually in conjunction with this plan.

6.2.5 Zone Substations

6.2.5.1 Inspection, Testing and Condition Monitoring Practices

Zone substations and voltage control equipment are maintained on both a time and a condition based programme.

Time-based inspection and maintenance programmes include:

- Inspections every two months to ensure site security and identify potential hazards. General operation is checked and minor maintenance issues addressed such as batteries, servicing and weed spraying.
- Annual substation earth tests.
- Two yearly oil and other testing as appropriate for the site: i.e. corona, partial discharge and thermo vision. Major equipment oil tests are conducted to ensure equipment, particularly transformers, are within operating specifications.

A fifteen year major maintenance cycle where equipment is extensively maintained and tested. The fifteen year major maintenance cycle was selected based on:

- The typical period a good paint job lasts, and an appropriate period for a repaint.
- The typical maximum period that technical equipment can be expected to operate reliably before extensive maintenance/renewal and testing. The scope of this work varies from site to site but typically includes protection testing, circuit breaker timing tests, SCADA calibration checks, busbar cleaning etc.
- Three yearly oil changes in active Oil Circuit Breakers.
- Five yearly tap changer oil changes.

The condition-based programmes include:

- Maintenance of equipment after faults.
- Maintenance of transformers after oil analysis.
- Renewal of faulty equipment.
- Maintenance or renewal after testing.

Table 6.4 summaries the inspection regime for substations.

SUBSTATION EQUIPMENT & MAINTENANCE SCHEDULES			
Asset Inspection	Routine Inspection Frequency Period	Scheduled Maintenance Frequency Period	Operations
1 Substation buildings and grounds	2 Monthly	-	
2 Power transformers and voltage regulating transformers:- - Oil sample and Dissolved Gas Analysis - Oil levels - Silica gel breather - Earth connections - Tank - Radiators - Tap changer mechanism - Tap changer oil & diverter switches - ABB & Cooper VR 32's - Buchholz - Insulation resistance	- 2 Monthly 2 Monthly - 2 Monthly 2 Monthly 2 Monthly 2 Monthly 2 Monthly 2 Monthly 2 Monthly - -	2 Yearly - Annually Annually 15 Yearly 15 Yearly 5 Yearly 5 Yearly 15 Yearly 5 Yearly 5 Yearly	50,000
3 Outdoor Busbars, Airbreak switches & structure supports	2 Monthly	15 Yearly	
4 Outdoors VTs and CTs	2 Monthly	15 Yearly	

SUBSTATION EQUIPMENT & MAINTENANCE SCHEDULES			
Asset Inspection	Routine Inspection Frequency Period	Scheduled Maintenance Frequency Period	Operations
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	6 Yearly	
13 Load Control Equipment	2 Monthly	Annually	
14 Battery Banks and Charges	2 Monthly	3 Yearly	
15 Substation phones and radios	2 Monthly	15 Yearly	
16 R.T.U's and Dehumidifiers	2 Monthly	15 Yearly	

Table 6.4: Zone Substation Equipment and Maintenance Regime

In addition to these practices, various components and architecture associated with zone substations are included in the long-term renewal and development programmes outlined in Section 5. This renewal and development work is implemented in addition to the above programmes.

Many of TLC's zone substation components are old and, when they fail, repairing existing equipment is not an option due to parts availability. In these situations components are renewed with modern equivalents.

6.2.5.2 Processes for Ensuring Zone Substation 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 and Faults: Works are specified 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: Every two years full Dissolved Gas Analysis testing of oil in main tanks of 33/11kV transformers occurs. The results are reviewed by a consultant and updated information used for the oil maintenance programme and long term asset condition. 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 work completed. 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 Tables 6.1 and 6.4

6.2.5.3 Zone Substation Systemic problems and solutions

Table 6.5 summarises the systemic problems associated with zone substations and the steps taken to address these.

ZONE SUBSTATION SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problem	Solutions
Voltage control and protection systems	» Repair or, if obsolete and parts not available, renew equipment.
Transformer failure after passage of fault current	» Limit fault current by design. » Dry and tighten transformer cores when oil test indicates high moisture content in insulation.
Lightning damage	» Design for lightning protection.
Switchgear failure	» Repair or, if obsolete and parts not available, renew.
Insecure fences	» Repair or renew.
Transformers ageing	» Regular oil tests. » Oil or transformer refurbishment. » Contingencies in case of failure.
Discharging switchgear and cables	» Clean, re-terminate or replace faulty components.

Table 6.5: Systemic Problems Associated with Zone Substations

6.2.6 Distribution Pole Mounted Transformers

6.2.6.1 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.

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.

Maintenance of pole hanging transformers typically involves painting, oil filtering and bushing replacement if damaged. Pole hanging transformers with internal winding faults are usually written off.

6.2.6.2 Systemic Problems and Solutions

Lightning damage, age and tank rust are the typical systemic problems with distribution transformers. The solution is either to refurbish or renew. Lightning arrestors and over-current protection fuses are fitted to all transformers. In recent times problems have been experienced with earthing systems being stolen for copper value. There are no solutions at present to eliminate this problem.

6.2.7 Ground Mounted Transformers

6.2.7.1 Inspection, Testing and Condition Monitoring Practices

Ground mounted transformers are inspected 5 yearly.

These checks include:

- Labelling and danger signs.
- Inspection of the physical integrity of the site including equipment, equipment numbering, hazard control labelling and earthing.
- Recording and resetting Maximum Demand Indicators.
- Locks, labels and any switchgear locks, fuses, operating equipment etc.
- Minor maintenance including painting over any superficial graffiti.
- Visual check of any switchgear attached to the site.
- General spot heat check of equipment.
- Data reconciled for site including photographs.

This annual inspection data feeds into a fifteen-year major maintenance programme. The major maintenance programme is also linked to other programmes such as line and switchgear renewals. Sites have been assessed and prioritised based on the annual data collected.

Major maintenance includes:

- Painting and site security (additional locks).
- Insulating exposed terminals.
- Internal cleaning and part replacement.
- Renewal is generally triggered by condition and the need to control hazards.

6.2.7.2 Systemic Problems and Solutions

All ground mount transformer sites have been inspected and assessed for hazards. Whilst some will be replaced in the renewal work programme, others will have maintenance completed to allow the renewal programme to be cycled. Systemic problems and solutions are summarised in Table 6.6.

GROUND MOUNTED TRANSFORMER SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problem	Solution
Graffiti	» Repaint
Rust and decay	» Treat and repaint » Renew if severe
Labels missing or faded	» Relabelled
Locks broken or seized up	» Replace or repair
Exposed bushings	» Tape or, if not practical, renew
Oil leaks	» Minor - on site repairs » Major – exchange/renew
Overheated connections	» Renew connections and associated equipment (circuit breakers, fuses etc.)
Damaged earthing	» Replace or repair earthing
Exposed LV	» Cover or renew

Table 6.6: Ground Mounted Transformers: Systemic Problems and Solutions

6.2.8 Service Boxes

6.2.8.1 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 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.

All service boxes are numbered and have details recorded in the asset database. The location details are added to the mapping database.

6.2.8.2 Systemic Problems and Solutions

Systemic problems and solutions are summarised in Table 6.7.

SERVICE BOX SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problem	Solution
Vehicle damage	» Straighten and re-secure or replace
Decay due to age (especially fibreglass units)	» Renew
Unearthed metal covers	» Replace covers with plastic or renew whole unit
Cover screws stripped or missing	» Replace screws, install new inserts or renew box as necessary to secure the unit.

Table 6.7: Service Boxes: Systemic Problems and Solutions

6.2.9 SCADA

6.2.9.1 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.

Checks of field equipment are completed as part of zone substation, recloser and regulator inspections. Batteries and the like are checked and, if outside specifications, are renewed at these times.

6.2.9.2 Systemic Problems and Solutions

Over the last few years, the most common systemic problems with SCADA have been lightning and fault current generated surges affecting electronic equipment. The solutions to these problems include a combination of bonding and earthing.

From time to time there are other minor problems associated with complex electronic equipment. The renewal programme discussed in other sections focuses on keeping equipment up to date and in good condition.

6.2.10 Radio Repeater Sites

6.2.10.1 Inspection, Testing and Condition Monitoring Practices

Radio voice and data communication equipment is critical to the safe operation of the network. Time-based work includes annual visits to repeater sites and checking of equipment at these sites. These checks include:

- Aerial and feeder cable inspections.
- Connector inspections.
- Building checks and minor maintenance.
- Battery and charger checks and servicing.
- Alignment and level checks including bandwidth and carrier frequencies.
- Other general minor works and adjustments.
- “Gain” and other radio tests.

Condition-based work includes repairs after failure or renewal of aged, obsolete equipment.

6.2.10.2 Systemic Problems and Solutions

Systemic problems and solutions are summarised in Table 6.8.

RADIO REPEATER SITE SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problem	Solution
Lightning damage	» Replace damaged equipment. » Ensure adequate protection devices installed.
Flat batteries	» Ensure annual servicing and battery replacements are completed.
Radio equipment out of specification	» Retune equipment. » Retain a strategy of renewing equipment to keep up to date.

Table 6.8: Radio Repeater Sites: Systemic Problems and Solutions

6.2.11 Load Control

6.2.11.1 Inspection, Testing and Condition Monitoring Practices

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.

An annual inspection and operational check is made of static plants. During this visit inductor and capacitor enclosures are also weed sprayed and cleaned as necessary. The plants are retuned, and inductance and capacitance values checked when injection power levels are out of specification.

6.2.11.2 Systemic Problems and Solutions

Systemic problems and solutions are summarised in Table 6.9.

LOAD CONTROL SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problem	Solution
No signal getting to plant	» Repair communication or SCADA system.
Plant power electronics or controller failure	» Repair using specialist technicians.
Electro Mechanical Plant generators not operating	» Vibration and regular checking of brushes etc.
Electro Mechanical Plant contactors failing	» Inspection and repairs of contacts.

Table 6.9: Load Control: Systemic Problems and Solutions

6.2.12 Three Phase Reclosers, Automated Switches and Voltage Regulators

6.2.12.1 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. (Remote control and SCADA)
- Checking/testing earthing.
- For electronic units, downloading all memory buffers and settings.
- Reconciling settings to records including load flow and fault study models.
- For manual reclosers, recording operations counters.
- Where recloser bypass switches are fitted, operate these to allow the switch remote and local operating functions to be tested.

6.2.12.2 Systemic Problems and Solutions

The systemic problems with this equipment and the solutions are summarised in Table 6.10.

THREE PHASE RECLOSERS AND AUTOMATED SWITCHES SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problems	Steps to Address
Faulty or flat batteries	» Replace after 3 years or manufacturers recommendation.
Software and programming errors affecting settings	» Download and reconcile annually » Re-adjust and monitor.
Hardware, connections and earthing	» Visually check annually. » Carry out repairs as necessary.
Operating outside settings	» Service, retest and tune as necessary. » Run network analysis to find a solution when necessary.

Table 6.10: Systemic Problems and Solutions for Three Phase Reclosers and Automated Switches

6.2.13 Single Wire Earth Return Isolating Transformer Structures

6.2.13.1 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. These results are analysed and specifications are prepared for improvements to sites with earth mats that have resistance values that are above the TLC's standard or/and outside regulatory values. Network analysis design software is used to assist with improving the earth mat design. Improvement work packages are issued to contractors. Repairs and invoices are reconciled to work orders and specifications. All works are recorded and reconciled against sites and annual plans.

6.2.13.2 Systemic Problems and Solutions

The systemic problems with this equipment, and the solutions, are summarised in Table 6.11.

SINGLE WIRE EARTH RETURN SYSTEM ISOLATING STRUCTURES SYSTEMIC PROBLEMS AND SOLUTIONS	
Systemic Problems	Steps to Address
Earth potential rises around earth mat	» Test and maintain
Structures have hazards that need elimination/minimising (working clearances, ground clearances etc.)	» Include in a Renewal Programme

Table 6.11: Systemic Problems and Solutions for Isolating Transformer Structures on SWER Systems

6.2.14 SWER (Single Wire Earth Return) Distribution Transformers Structures

6.2.14.1 Inspection, Testing and Condition Monitoring Practices

For SWER distribution systems to work effectively, low resistance earth systems must be installed and maintained. The earthing systems on distribution SWER systems were all reference tested during the 2006/07 and 2007/08 years. A number of improvements were completed. A 15 year cyclic testing programme has been introduced.

The objective of the programme is to ensure the hazards associated with SWER systems are minimised and, specifically, that the earth potential rises around earth mats are within acceptable limits. The maintenance earth inspections also focus on identifying sites where there is bonding between HV and LV earthing systems.

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.

6.2.14.2 Systemic Problems and Solutions

The systemic problems with this equipment and the solutions are summarised in Table 6.12.

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.	<ul style="list-style-type: none"> » Locate installations by inspection and testing. » Install separate earthing systems.
High impedance earth connections.	<ul style="list-style-type: none"> » 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 11kV current path).	<ul style="list-style-type: none"> » Install separate earthing systems.

Table 6.12: Systemic Problems and Solutions for Distribution Transformers on SWER Systems

6.3 Forward Maintenance Expenditure Predictions

6.3.1 Summary Maintenance Activities

Table 6.13 lists forward budgets for summary of maintenance activities by asset category.

SUMMARY MAINTENANCE ACTIVITIES COST ESTIMATES										
Classification	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Cable Maintenance	91,350	91,350	91,350	91,350	91,350	91,350	91,350	91,350	91,350	91,350
Distribution Transformer Maintenance	107,348	107,348	107,348	107,348	107,348	107,348	107,348	107,348	107,348	107,348
Faults and Standby	1,251,655	1,251,655	1,251,655	1,251,655	1,251,655	1,251,655	1,251,655	1,251,655	1,251,655	1,251,655
Line Maintenance	290,000	290,000	290,000	290,000	290,000	240,000	240,000	240,000	240,000	240,000
Network Equipment Maintenance	175,657	175,657	175,657	175,657	175,657	175,657	175,657	175,657	175,657	175,657
Vegetation Control	900,000	900,000	900,000	900,000	900,000	900,000	900,000	900,000	900,000	900,000
Zone Substation Maintenance	347,453	347,453	347,453	347,453	347,453	347,453	347,453	347,453	347,453	347,453
Total	3,163,462	3,163,462	3,163,462	3,163,462	3,163,462	3,113,462	3,113,462	3,113,462	3,113,462	3,113,462

Table 6.13: Forward Budget Summary for Maintenance Activities

Vegetation control, along with the costs incurred by trees falling through lines, will remain one of TLC's greatest maintenance costs.

Long-term maintenance expenditure is expected to increase at about the rate of inflation. It is generally accepted that capital expenditure will reduce maintenance costs in the long term. Due to the amount of renewal needed, this will be beyond the planning period included in this Plan. Analysis work completed to date of TLC cost structures would suggest this is true, but the amount of costs that capital expenditure will affect is relatively small. For example, most of the time-based work will still be required. There will be a drop off in faults and emergent work costs. Numbers included to date would suggest this saving would be only in the order of 5 to 10% of direct maintenance and associated overhead costs.

Emergent work is generally reducing, but perturbations occur when repairs are necessary after storms and other abnormal events.

The following sections give budget predictions for maintenance activities broken down by asset category for the planning period. Unless stated otherwise, the figures are in current dollars.

6.3.2 Cable Maintenance

Table 6.14 lists the cable maintenance predictions by asset category for the planning period.

CABLE MAINTENANCE PREDICTIONS										
Classification	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Cable 33/11kV	20,300	20,300	20,300	20,300	20,300	20,300	20,300	20,300	20,300	20,300
Cable LV	10,150	10,150	10,150	10,150	10,150	10,150	10,150	10,150	10,150	10,150
Pillar Box Maintenance	20,300	20,300	20,300	20,300	20,300	20,300	20,300	20,300	20,300	20,300
Cable Ski Fields	40,600	40,600	40,600	40,600	40,600	40,600	40,600	40,600	40,600	40,600
Total	91,350									

Table 6.14: Cable Maintenance Predictions for the Planning Period

6.3.3 Distribution Transformer and Site Maintenance

Table 6.15 lists the Distribution transformer and site maintenance predictions broken down by activity for the planning period.

DISTRIBUTION TRANSFORMER AND SITE MAINTENANCE PREDICTIONS										
Classification	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Transformer Audits	7,105	7,105	7,105	7,105	7,105	7,105	7,105	7,105	7,105	7,105
Transformer Grounds/Painting	14,718	14,718	14,718	14,718	14,718	14,718	14,718	14,718	14,718	14,718
Inspections	35,525	35,525	35,525	35,525	35,525	35,525	35,525	35,525	35,525	35,525
Transformer Workshop Refurbishment	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Total	107,348									

Table 6.15: Distribution Transformer and Site Maintenance Predictions for the Planning Period

6.3.4 Faults

Table 6.16 lists the Faults cost estimates for the planning period.

FAULTS PREDICTIONS										
Classification	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
LV Lines	260,000	260,000	260,000	260,000	260,000	260,000	260,000	260,000	260,000	260,000
11kV Lines	532,875	532,875	532,875	532,875	532,875	532,875	532,875	532,875	532,875	532,875
33kV Line	50,750	50,750	50,750	50,750	50,750	50,750	50,750	50,750	50,750	50,750
LV Cable and Pillar Boxes	35,525	35,525	35,525	35,525	35,525	35,525	35,525	35,525	35,525	35,525
33/11kV Cables	30,450	30,450	30,450	30,450	30,450	30,450	30,450	30,450	30,450	30,450
Disconnections for Safety	30,450	30,450	30,450	30,450	30,450	30,450	30,450	30,450	30,450	30,450
Regulators, Motorised Switches and Load Plant	30,450	30,450	30,450	30,450	30,450	30,450	30,450	30,450	30,450	30,450
SCADA and Radio	17,255	17,255	17,255	17,255	17,255	17,255	17,255	17,255	17,255	17,255
Substations	35,525	35,525	35,525	35,525	35,525	35,525	35,525	35,525	35,525	35,525
Transformers	20,300	20,300	20,300	20,300	20,300	20,300	20,300	20,300	20,300	20,300
Voltage Faults	5,075	5,075	5,075	5,075	5,075	5,075	5,075	5,075	5,075	5,075
Standby Costs	203,000	203,000	203,000	203,000	203,000	203,000	203,000	203,000	203,000	203,000
Total	1,251,655									

Table 6.16: Faults and Standby Predictions for the Planning Period

6.3.5 Lines Maintenance

Table 6.17 lists the lines maintenance predictions by asset category for the planning period.

LINE MAINTENANCE PREDICTIONS										
Classification	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
LV Lines	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000
11kV Lines	160,000	160,000	160,000	160,000	160,000	110,000	110,000	110,000	110,000	110,000
33kV Lines	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000	70,000
Permanent Disconnections	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000
Total	290,000	290,000	290,000	290,000	290,000	240,000	240,000	240,000	240,000	240,000

Table 6.17: Lines Maintenance Predictions for the Planning Period

6.3.6 Network Equipment Maintenance

Table 6.18 lists other network equipment maintenance predictions broken down by asset activity for the planning period.

NETWORK EQUIPMENT MAINTENANCE PREDICTIONS										
Classification	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Line Motorised Switches Inspections	20,300	20,300	20,300	20,300	20,300	20,300	20,300	20,300	20,300	20,300
Line Motorised Switches Renewal	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
Line Regulator Inspections	45,675	45,675	45,675	45,675	45,675	45,675	45,675	45,675	45,675	45,675
Load Plant Testing	23,195	23,195	23,195	23,195	23,195	23,195	23,195	23,195	23,195	23,195
Other Network Equipment/Spares Testing	10,150	10,150	10,150	10,150	10,150	10,150	10,150	10,150	10,150	10,150
Radio/Repeater Site Grounds and Access	5,075	5,075	5,075	5,075	5,075	5,075	5,075	5,075	5,075	5,075
Radio/Repeater Site Rentals and Licences	24,157	24,157	24,157	24,157	24,157	24,157	24,157	24,157	24,157	24,157
SCADA & Radio Testing & Investigation	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
SCADA & Radio Upgrades Renewal	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
Voltage Investigations	7,105	7,105	7,105	7,105	7,105	7,105	7,105	7,105	7,105	7,105
Total	175,657									

Table 6.18: Other Network Equipment Maintenance Predictions for the Planning

6.3.7 Vegetation Control Maintenance

Table 6.19 lists the vegetation control maintenance predictions for the planning period.

VEGETATION CONTROL MAINTENANCE PREDICTIONS										
Classification	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Initial Work	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000
Maintenance Existing	640,000	640,000	640,000	640,000	640,000	640,000	640,000	640,000	640,000	640,000
Patrols/Surveys	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Total	900,000									

Table 6.19: Vegetation Control Maintenance Predictions for the Planning Period

6.3.8 Zone Substation Maintenance

Table 6.20 lists the Zone substation maintenance predictions broken down by activity for the planning period.

ZONE SUBSTATION MAINTENANCE PREDICTIONS										
Classification	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Battery Charger Replacement	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000
Protection and Control	8,120	8,120	8,120	8,120	8,120	8,120	8,120	8,120	8,120	8,120
Transformers	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Building and Site Works	48,213	48,213	48,213	48,213	48,213	48,213	48,213	48,213	48,213	48,213
Inspections	131,950	131,950	131,950	131,950	131,950	131,950	131,950	131,950	131,950	131,950
Rates and General Maintenance	79,170	79,170	79,170	79,170	79,170	79,170	79,170	79,170	79,170	79,170
Total	347,453									

Table 6.20: Zone Substation Maintenance Predictions for Planning Period

6.4 Description of Asset Renewal and Refurbishment

TLC's refurbishment policy is based on renewing equipment that cannot be maintained and/or is no longer fit for purpose. The original construction was completed at the lowest possible cost. 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 elements in the network 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). However, with the increasing value of dairy farming and other activities, a more refined Reliability Centred Approach (RCM) is now followed that considers the customer value of lost load.

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.

TLC has done analytic work this year assembling the survival ages of replaced components. This allows a more accurate forecast of future capital replacement requirements. For the purposes of forecast modelling, pole lives were adjusted from 56 to 60 years and transformers from 55 to 58 years because the survival analysis completed shows that our assets are meeting these extended life-spans.

6.4.1 TLC Forecast and Modelled Replacement Capital

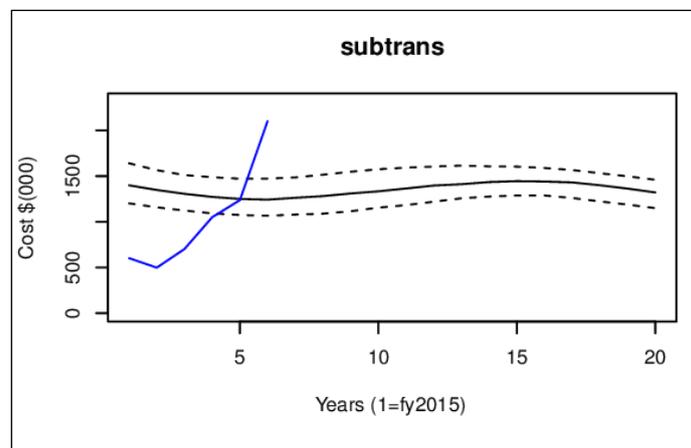
TLC has modelled future replacement capital (repex) using industry age profiles disclosed as part of regulatory requirements and calculated industry hazard functions. These hazard functions, when applied to TLC age profiles and using TLC costs, estimates the future replacement spend. The model allows a comparison of TLC disclosed forecast spend in asset categories. The differences allow a focus on key areas and their resolution supports a more robust repex forecast.

The following graphs compare TLC's forecast asset replacement expenditure with data from the repex model. The repex model for 20 years is shown in black on the charts below. The dotted black lines represent 1 standard deviation of modelling accuracy. This includes the age hazard modelling, cost variability and the smoothing of the 10-year age profile bands. The total modelled spend matches TLC forecast well. There are however differences at an asset level that are discussed below.

The forecast data comes from the 2015 AMP and is shown in blue in the following charts.

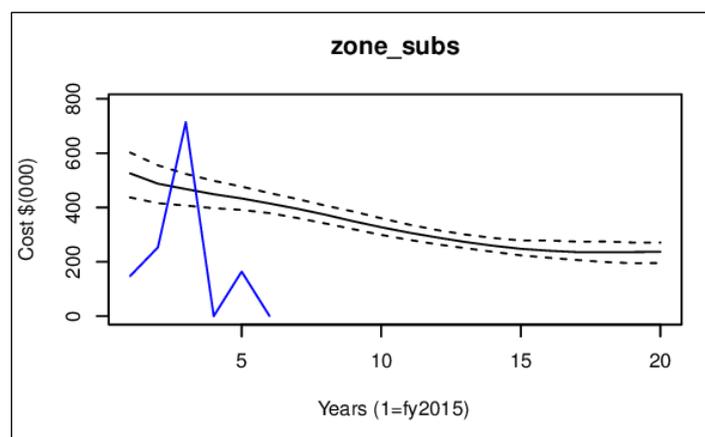
6.4.1.1 Subtransmission

The model and forecast expenditure are, on average, similar. The differences in timing is likely due to the TLC condition based inspection and therefore not of note. There is a difference in mix of expenditure between conductor and poles/cross arms with the model showing higher levels of conductor replacement similar to distribution lines.



6.4.1.2 Zone Substations

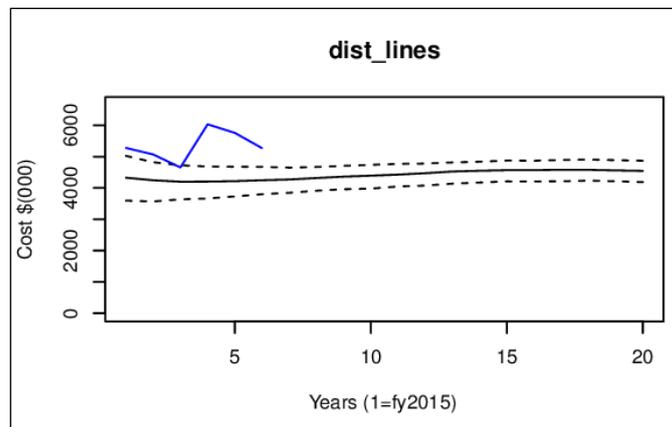
Modelling shows an amount of 33kV pole mounted switches over the industry mean age for replacement. TLC has been replacing some and refurbishing others. Given the model assumes replacement rather than refurbishment, the model and forecast would appear to be within reasonable agreement. Some ground mounted 11kV switchgear replacement is also indicated by the model. TLC are monitoring busbar condition and replacing carriages at a lower cost than complete replacement where this is justified by condition and safety features.



6.4.1.3 Distribution Lines

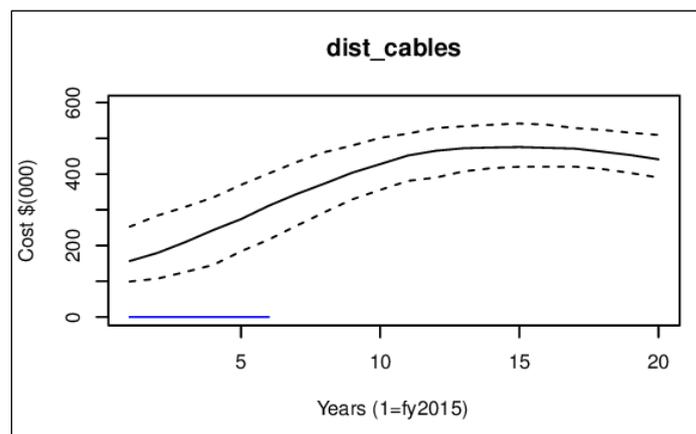
There are differences between the forecast and the model expenditure in the chart below. Under designed poles and low quality assets are not considered in the model. The model assumes that cross arms will last until the pole needs replacing. This is not always the case. Poles and cross arms need replacement due to damage from large trees or other non-age related causes. There are a group of poles assigned an installation date of 1 July 1980. These are likely to be poles of unknown age. Age profile uncertainty will affect model accuracy. For these reasons the forecast expenditure above the model is likely to be sensible.

There is however a difference in allocation between the model and forecast spend. The model includes circa 80% of the spend on conductor and 20% on poles, while TLC budgets have the majority of spend on poles. Distribution overhead conductor and SWER conductor age profiles are showing assets over the mean industry life. This causes elevated replacement levels in the model. While the model is indicating lower pole replacement, care should be exercised for the reasons above. However, given the improving reliability due to replacement programmes on poles and cross arms there would appear to be a justification for reviewing expenditure particularly on the SWER. TLC staff agree that increased conductor replacement is required and reliability data confirms this. Some funding is in this plan however there needs to be further condition-based evidence to enable targeting. There is also no specific data on TLC conductor lives and they may vary from the industry average.



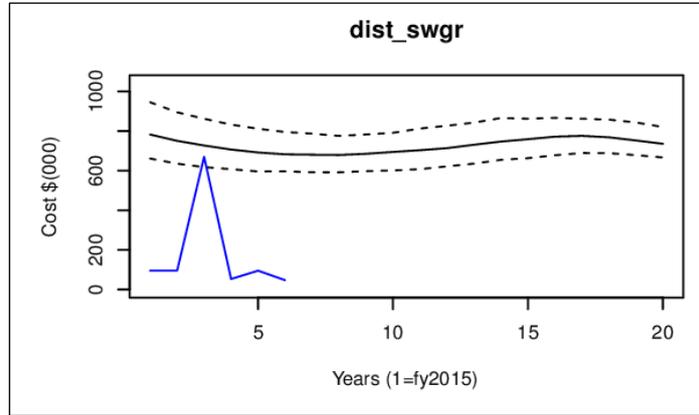
6.4.1.4 Distribution and LV Cables

The Distribution and LV Cable model indicates increasing cable replacement over time. The TLC forecast was done for the 2015 AMP before cable failures at Turangi and Ohakune. Planned replacement forecasts appear in the 2016 AMP and will continue to be refined. There is some evidence of past poor installation practice requiring rectification and this may cause expenditure to exceed the model for a period of time. There is an increasing spend required over time due to aging assets.



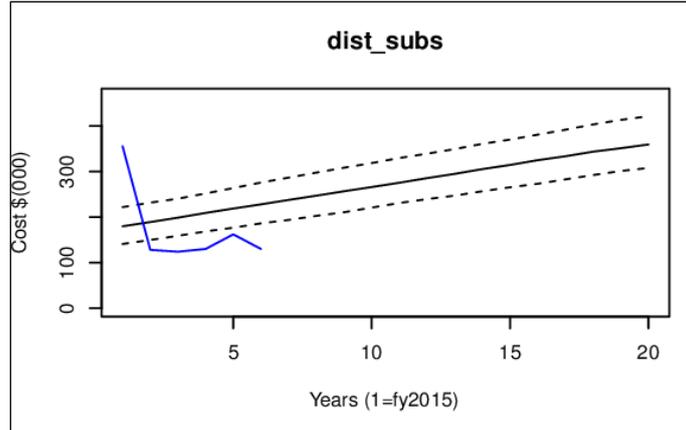
6.4.1.5 Distribution Switchgear

The difference between the model and TLC forecast below is in part due to aging reclosers and Air Break Switches (ABS). Some switchgear replacement is disclosed in safety. Where possible, TLC is refurbishing older oil reclosers and sectionalisers rather than replacing them. The aging reclosers are reported to be performing well. Active monitoring of condition and maintenance cost for these reclosers is warranted. The Distribution Switchgear age profile demonstrates that active replacement is occurring. For these reasons the forecast appears reasonable.



6.4.1.6 Distribution Substations

Distribution substation modelled results using TLC survival ages, show a reasonable match between the model and forecast replacement spend. Some distribution transformers (two pole subs) are disclosed as safety, and if added to the forecast would make the match closer. The model is indicating increasing spend over future regulatory periods.



6.4.2 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 33kV lines, 10% is LV lines and the remaining 80% is 11kV lines in various configurations.

The pole population is mixed with about one third wood, one third iron rail and one third concrete. The lines are generally old and many components are from the original construction. Few of the lines are on the roadside with most in remote rugged hill country. The iron rails typically spent the first 50 years of their life carrying trains. In the 1950s these were removed from the railway lines and the sections of track have carried power lines for the last 60 or so years. In addition to these recycled steel members much of the hardware was also recycled from earlier use in transmission lines (typically suspension insulators).

Customers are deemed to own lines from the point of connection at all voltages. The point of connection is normally where the line to their particular property taps off the main line.

As described in earlier sections, line assets have been broken into asset groups. These asset groups form the basis for renewal planning and performance measurement. The asset groups aggregate up to the service level standards described in earlier sections. The renewal programme consists of a matrix of these asset groups prioritised and arranged into a consistent 15 year cyclic programme. The cost estimates from this matrix produce the annual and long term estimates.

6.4.2.1 Planned Overhead Renewals Policies and Procedures

Once the data are gathered by lines inspectors as described in earlier sections, a detailed review of the asset group takes place. The long term asset programme consists of these asset groups laid out and estimates have been allowed that drive into the long term plan, assuming about a 10% to 15% pole replacement level.

Overall considerations include:

- Hazard elimination/minimisation.
- Faults data.
- Equipment and transformer earth test and earthing systems inspection data.
- Service level performance.
- Importance of the line to the network, including long term significance and income generation. (Models have been put together based on accepted disclosure criteria to calculate sections of feeders that are uneconomic. These models will continue to be developed and more data on assets revenue generation ability will become available during the planning period.)
- Other customer and landowner driven issues.
- Estimate of project costs in the long term plan.

The engineering analysis includes:

- Consideration of any hazards.
- Checking of line strengths required on renewal.
- Evaluation of alternative designs.
- Selection of renewal design options.
- Specification and preparation of plans including earthing improvements and labelling.
- The potential for non-asset solutions including alternative supplies.

The administration functions include:

- Entering and reconciling inspection data with previous records.
- Filing and linking photographs.
- Preparing packages for engineering consideration.
- Taking engineering results and putting together work packages.
- Issuing work packages and updating asset records.
- Detailing material requirements.
- Monitoring spends against estimate.
- Issuing audit packages.

- Receiving audit packages back from auditors.
- Issuing non-compliance notes.
- Follow-ups.
- Related records updated.

The renewal trigger criteria for components of overhead lines does vary depending on importance, geographical location and other practical “real world” issues.

In summary the trigger criteria are:

Poles

- Failure of pole test.
- Bad splitting etc. that will probably deteriorate excessively in the next 15 years.
- Iron rails that have extensive corrosion.
- Concrete poles that are cracked or have large amounts of reinforcing showing.
- Poles that, when a line review is done, are well under strength for the situation they are in, to the point that they will fail at wind strengths in the 100 to 120km/hr. range.
- Conductor height above ground.
- Other rot or corrosion that means a structure cannot perform to expectations.

It should be noted that the programme does not replace iron rail poles as a matter of course. Iron rail poles are only replaced if they are corroded or obviously under strength. The cost of wholesale replacement of iron rail poles would add significant additional funding difficulties to the renewal programme.

Cross arms

- Decay that will not allow them to last another 15 years.
- Too short for the span lengths.

Note: Care is taken not to change cross arms too early. Most are rotten, to the extent that daylight can be seen through them, before they are recommended for changing.

Insulators

1950s 830 type insulators, and 3320 type insulators that are susceptible to fertiliser build up and discharges, are replaced when poles or cross arms are changed.

Conductor

Conductor is renewed when it shows signs of corrosion that will lead to failure in next 15 years. (Conductor is not usually renewed unless broken strands are obvious, if there are large numbers of joints, or there has been a recent history of failures, sometimes due to corrosion, in the section of line being renewed.)

Environmental

Slips, forest, reserves, rivers, access, and other environmental factors.

Landowner and Land Use

Various landowner and land use issues may influence the trigger criteria. Once field data have been measured against these criteria, engineering analysis is completed and asset performance data are considered, asset group work packages are put together. They are issued to the service provider.

Once the service provider has the job pack, a pre job briefing takes place between the sites works controller and the asset management group. The objective of the briefing, which may include an on-site visit, is to:

- Identify and develop on site control measures for any hazards associated with the project.
- Outline the renewal decisions made and the reasons for these.
- Discuss landowner and site access.
- Develop outage plans.
- Discuss other local and individual project issues.

At the completion of works, an audit against specifications takes place. Poles, and a selection of cross arms that have been removed, are inspected and analysed from at least one renewal project annually to ensure the renewal decision was correct. The results of this analysis are discussed at a post job briefing. (All poles removed are also photographed and filed in the asset database and these form a basis for much of the analysis and discussions around the renewal decisions made and the justification for these. This process leads to continuous improvement and review practices.

6.4.2.2 Unplanned Overhead Line Renewal Policies and Procedures

The unplanned renewals and high risk repairs focus on maintaining supply and minimising/eliminating the hazards in the immediate area. High risk repairs that are more complex and need attention before the next planned renewal cycle in that area are inspected and specifications are produced for contractors. The focus of these is to repair the problem to present day design criteria outlined in the previous section, but confine this to the immediate problem area. Examples of this type of work include under height conductors and red tagged poles that have to be changed within three months for compliance.

These emergent repairs, however, should be to a standard that do not require total rework when the next 15 year cycle is completed. Emergency repairs after faults are often temporary and will maintain supply until inspected by lines inspectors or a line designer. The workflows as described in earlier are then followed to ensure the best option is taken for the permanent, emergent repairs., the planned line inspection and renewal process is based on a 15 year cycle in addition to patrols, which take care of short term hazards and reliability issues.

6.4.2.3 15 Year Overhead Line Asset Inspection Period

The principal reasons for this 15 year 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

Some TLC's customers have limited ability to pay. This means that, unless funds come from some other source, TLC is limited in some parts of the network to 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 11kV and shorter cycle patrols of urban areas and 33kV lines (as described in earlier sections) coupled with fault patrols take place and are designed to identify any "short term" or urgent issues.

Project Management: Project reviews

TLC places a significant amount of importance on continuous improvement and the need for staff and stakeholders at all levels to be able to understand renewal programmes and contribute to the continuous improvement process. Pre and post project briefings reviews take time. Shorter cycles would reduce our ability to complete this process comprehensively and, as a consequence, the learning process would not develop as quickly. The continuous improvement process is leading to cost savings and focuses heavily on hazard control. In saying this, the 15 year programme is also reviewed and reconsidered to ensure that it is still an appropriate strategy.

Overall Analysis and Data

The 15 year cycle produces data and information that allows detailed analysis and long term solutions to be found, including the consideration of non-asset solutions. This often involves complex landowner discussions. Considerably more resource and cost would be needed to handle data analysis, resolution of landowner issues and other planning and design issues if a shorter cycle were adopted.

The repairs, after high risk defects are found during patrols, focus on ensuring that the structure or structures are serviceable until the planned works programme completes renewal of the asset group within which the assets are located. The 15 year cycle is wider than just the lines. Other renewals in an area are completed at the same time while resources are in the region.

For example, as mentioned earlier, the condition of distribution transformers is assessed and units in poor condition are changed. Landowners are also notified of private lines in poor condition and fuses are installed at the tap-off points. Transformer earthing is tested and checked. The programme is focused on asset groups (typically 10km lengths of line) and the areas receiving attention, in any year, are spread throughout the network. A long term plan is being followed, cycling through asset groups.

It should also be noted that local knowledge and a detailed knowledge of each line asset including such things as how exposed lines are on hill tops, landowners, and a multitude of other issues are also in the back of one's mind when line renewal work is being planned. There are also a number of short term issues like slips, storms, landowners' needs, etc. that create a level of unplanned work needs.

6.4.3 Other Equipment Renewal Policies and Procedures

6.4.3.1 Zone Substation, Voltage Control, Distribution Substations, Cables, Switchgear and Other Distribution Asset Renewal (excluding Line Renewal)

This section covers the capital expenditure primarily associated with replacement and refurbishment of existing assets. This work is to maintain the network and equipment to meet target levels of service.

The policy is to renew when the existing equipment will cost more to refurbish than renew or it is not possible to refurbish up to a level that will meet present day hazard control, operational or customer service targets. This means for example that if a relatively major component fails in an item of switchgear, and it is not possible to get suitable parts that will ensure the switch will operate reliably, then it would be replaced with a present day equivalent.

The general principle of economic evaluation is to use regulatory cost for the particular piece of equipment that has failed. If the cost of refurbishment is greater than the regulatory cost, then it would generally be renewed. The ages used in depreciation calculations are those in the Commerce Commission regulatory documents.

The factors that may modify this approach are:

- Parts availability.
- Availability of equivalent replacements.
- Importance in network, i.e. how long and what are the risks of equipment being out of service for either refurbishment or renewal periods.
- Any other justified technology gains or other advances by renewal.
- On-going guaranteed reliability of renewal vs. refurbishment.
- TLC's pricing models for the area or local area that show the regulatory valuation and level of return being generated.

The renewal or refurbishment is triggered by:

- An emergent failure where equipment either has to be renewed or refurbished to keep the network operational.
- A 15 year detailed inspection and review of the assets.
- Test results that indicate the need for renewal or refurbishment. An example of this is oil test results and other transformer tests that signal the need for refurbishment.
- Hazard elimination/minimisation issues.
- Customer requests for capacity changes.
- Environmental issues.
- Equipment identified to be at the end of its life.

If equipment is old but in good operational condition and meets service expectations, then it would not be considered for refurbishment or renewal.

Generally, when good quality parts are available and repairs can be done to a standard that will ensure reliability and the cost is below regulatory cost and the equipment will last to periods expected, then refurbishment takes place as opposed to renewal. The expected lives used in assessments are those listed in the information disclosure handbook for valuations of lines companies. Examples of equipment that would be renewed because they would not meet the refurbishment criteria in each of the asset sub categories are:

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.

Zone Substations

- Electro mechanical relays that stops operating or are not meeting test criteria.
- Batteries that are outside manufacturer's age criteria or are not testing correctly.
- Hardware that is corroded.
- Insulators that are cracking or have failed.
- Other equipment that has failed and if repaired cannot be trusted to give reliable service.
- Low, inadequate fencing.
- Underrated switchgear.
- Conductor with low clearance into structures.
- Equipment that is exposed to fault current greater than ratings.

Voltage Control

- Old regulators are replaced when they have failed and parts are no longer available.
- Electro mechanical voltage relays are replaced on failure or when it becomes difficult to adjust them to the operating requirements of the network.

Distribution Substation

- Ground mounted substations are replaced when they are found to be in poor condition and maintaining them on site is not an option.
- On failure of integral LV or HV switchgear.
- When there is a lack of, or underrated, HV and LV switchgear and this equipment is part of the structure.
- When the operation of HV or LV equipment places the operator at risk of contact with live conductors or an arc flash.
- When a site has a high risk of vehicle impact.
- When structures or enclosures can be accessed easily by the public.
- When inspections or tests show that earthing systems are inadequate.
- When ground mounted enclosures with dropper wires coming down are found to be hazardous.

Cables

- Cables are replaced when test results indicate that joining pieces together will no longer give reliable operation.
- When live terminals on termination structures have less ground clearance than specified in the codes of practice.

Switchgear

- When it fails and parts are no longer available.
- Underrated or has a possibility of putting the operator or public at risk.

Distribution Transformers

- On failure or when they are in poor condition and the cost of repair is greater than the regulatory value. (If repair costs are greater than this then the unit would be written off.)
- If bushing arrangements, tapping ranges and other fixtures do not allow unit to be used in structure layouts and the cost of altering a unit is greater than the regulatory value.

6.4.3.2 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.

SCADA

SCADA equipment is renewed on failure and on an on-going basis typically after 15 years' service or when it is no longer supported. TLC works closely with an independent specialist SCADA Engineer/Technician to review the equipment annually and select equipment that is not performing or obsolete and in need of renewal. Priority is placed on key equipment that has a significant impact on the overall system operation.

This strategy has resulted in relatively few failures of equipment and, when they do occur, repairs can be quickly completed because parts and support are available.

Communication Equipment

TLC works closely with an independent specialist communications Engineer/Technician to review the equipment annually and select equipment that is not performing or is obsolete and in need of renewal. Priority is placed on key equipment that has a significant effect on the overall system operation.

Examples of equipment that would be renewed as not meeting the refurbishment criteria for communication equipment are:

- Batteries that are old or are not testing correctly.
- Aged radio sets that have failed and that are no longer supported by the manufacturer.
- Radio aerials and hardware that have failed or when a frequency adjustment is needed as required by the spectrum allocations regulator.

(Note: TLC is slowly converting the legacy analogue system to a digital system. The main driver for this is the band width requirements of the spectrum regulator. It should be noted that the system being implemented does not have a high data rate transfer; cost makes high data transfer rate difficult to justify).

6.5 Asset Replacement and Renewal Programmes 2016/17 to 2020/21

6.5.1 Summary Replacement and Renewal Expenditure Forecast

The following Table 6.21 summaries the Replacement and Renewal programmes in place for the next 5 years.

REPLACEMENT & RENEWAL EXPENDITURE FORECAST SUMMARY					
Project	2016/17	2017/18	2018/19	2019/20	2020/21
Overhead Line Renewals	6,379,884	6,460,959	6,288,684	6,265,234	6,220,664
Conductor Renewal Program	420,000	420,000	420,000	420,000	420,000
Cable Renewal Program	-	236,250	236,250	498,750	236,250
11kV Feeder Switch Renewal	115,500	-	126,000	-	-
Equipment Renewals	900,561	689,511	554,723	677,284	554,723
Relay Changes	68,828	37,328	16,328	-	-
Sub & 33 Dev - Substations	73,500	-	166,577	-	239,794
Tx & Service Boxes - GMT	-	-	-	-	87,392
Grand Total	7,958,273	7,844,048	7,808,561	7,861,268	7,758,822

Table 6.21: Summary Replacement and Renewal Expenditure Forecast

6.5.2 Overhead Line Renewal

6.5.2.1 Description

The line renewal capital expenditure is primarily associated with replacement and refurbishment of existing pole and crossarms. Fusing for private line tap-offs at the point they meet the Network is routinely included, along with dilapidated transformer replacements. The work is done to maintain the network and equipment to meet target levels of service. Each network feeder is divided into Asset Group for more detailed asset identification. Each Asset Group is included in the full 15 year inspection cycle. Where practicable, Low Voltage renewals are aligned with the 11kV renewal. The list of projects for the next 5 years is divided into 33kV, 11kV and Low Voltage (LV) sections. Table 6.22, 6.23 and 6.24 list the projects and forecast renewal expenditure. Each voltage category includes a contingency for Emergent Renewal work which may eventuate from faults or other unforeseen issues.

6.5.2.2 Annual Detail and Forecast Expenditure

6.5.2.2.1 33kV Overhead Line Renewal Programme

33kV OVERHEAD LINE RENEWAL 2016/17 TO 2020/21						
POS	Project	2016/17	2017/18	2018/19	2019/20	2020/21
All	EMERGENT	224,340	224,340	224,340	224,340	224,340
Hangatiki	Gadsby / Wairere 307-03	588,000	-	-	-	-
Hangatiki	Te Waireka Road 303-01	184,800	-	-	-	-
Tokaanu	Tokaanu / Kuratau 607-02	302,000	-	-	-	-
Hangatiki	Gadsby Road 305-03	-	60,000	-	-	-
Hangatiki	Gadsby / Wairere 307-01	-	123,500	-	-	-
Hangatiki	Gadsby / Wairere 307-02	-	94,000	-	-	-
Hangatiki	Waitete 306-01	-	237,500	-	-	-
Hangatiki	Te Kawa Street 304-01	-	200,550	-	-	-
Ongarue	Nihoniho 603-02	-	308,700	-	-	-
Whakamaru	Whakamaru-33 310-03	-	275,100	-	-	-
National	National Park/Kuratau 609-04	-	-	273,500	-	-
Ongarue	Nihoniho 603-01	-	-	278,250	-	-
Whakamaru	Whakamaru-33 310-01	-	-	120,500	-	-
Whakamaru	Whakamaru-33 310-04	-	-	383,250	-	-
National Park	National Park/Kuratau 609-02	-	-	-	559,000	-
National Park	National Park/Kuratau 609-03	-	-	-	587,500	-
Hangatiki	Taharoa B 302-01	-	-	-	-	567,000
Hangatiki	Taharoa B 302-02	-	-	-	-	488,250
Tokaanu	Kuratau Power Station Site	-	-	-	-	51,450
Tokaanu	Kuratau Top Yard 610-01	-	-	-	-	51,450
33kV OVERHEAD ANNUAL TOTAL		1,299,140	1,523,691	1,279,840	1,370,840	1,382,490

Table 6.22: 33kV Overhead Line Renewal Expenditure Forecast

6.5.2.2.2 11kV Overhead Line Renewal Programme

11kV OVERHEAD LINE RENEWAL 2016/17 TO 2020/21						
POS	Project	2016/17	2017/18	2018/19	2019/20	2020/21
All	EMERGENT	724,710	724,710	724,710	724,710	724,710
Hangatiki	Caves 101-12	271,425	-	-	-	-
Hangatiki	Caves 101-13	134,925	-	-	-	-
Hangatiki	Gravel Scoop 109-12	6,000	-	-	-	-
Hangatiki	Mahoenui 113-07	114,975	-	-	-	-
Hangatiki	Maihihi 111-10	315,000	-	-	-	-
Hangatiki	Maihihi 111-11	156,450	-	-	-	-
Hangatiki	Maihihi 111-14	84,000	-	-	-	-
Hangatiki	McDonalds 110-03	90,300	-	-	-	-
Hangatiki	McDonalds 110-04	41,475	-	-	-	-
Hangatiki	Mokau 128-05	194,250	-	-	-	-

11kV OVERHEAD LINE RENEWAL 2016/17 TO 2020/21						
POS	Project	2016/17	2017/18	2018/19	2019/20	2020/21
Hangatiki	Rangitoto 106-02	32,550	-	-	-	-
Hangatiki	Southern 409-04	64,575	-	-	-	-
Hangatiki	Te Mapara 117-06	236,775	-	-	-	-
Hangatiki	Western 403-03	150,675	-	-	-	-
Hangatiki	Wharepapa 122-01	155,400	-	-	-	-
National Park	National Park 411-01	158,025	-	-	-	-
Ongarue	Gravel Scoop 109-11	55,650	-	-	-	-
Ongarue	Mokau 128-02	210,000	-	-	-	-
Ongarue	Waiotaka 427-01	177,450	-	-	-	-
Tokaanu	Motuoapa 425-01	108,675	-	-	-	-
Tokaanu	Wharepapa 122-02	403,200	-	-	-	-
Whakamaru	Gravel Scoop 109-10	47,000	-	-	-	-
Whakamaru	Southern 409-01	361,200	361,200	-	-	-
Hangatiki	Aria 114-06	-	151,725	-	-	-
Hangatiki	Benneydale 103-09	-	399,000	-	399,000	-
Hangatiki	Caves 101-04	-	90,825	-	-	-
Hangatiki	Gravel Scoop 109-07	-	335,475	-	-	-
Hangatiki	Gravel Scoop 109-13	-	66,150	-	-	-
Hangatiki	Maihihi 111-01	-	47,250	-	-	-
Hangatiki	Maihihi 111-06	-	224,175	-	-	-
Hangatiki	Maihihi 111-12	-	108,150	-	-	-
Hangatiki	Otorohanga 112-01	-	345,450	-	-	-
National Park	National Park 411-02	-	105,000	-	-	-
Ongarue	Ohura 413-07	-	139,650	-	-	-
Ongarue	Ongarue 421-01	-	210,000	-	-	-
Ongarue	Southern 409-08	-	245,000	-	-	-
Ongarue	Western 403-04	-	102,900	-	-	-
Tokaanu	Kuratau 406-03	-	256,725	-	-	-
Whakamaru	Mangakino 118-01	-	390,600	-	-	-
Hangatiki	Aria 114-01	-	-	248,850	-	-
Hangatiki	Mahoenui 113-04	-	-	262,500	-	-
Hangatiki	Mahoenui 113-08	-	-	231,000	-	-
Hangatiki	Piopio 116-02	-	-	198,450	-	-
Hangatiki	Rangitoto 106-01	-	-	171,675	-	-
Hangatiki	Te Kuiti South 104-02	-	-	374,325	-	-
National Park	Chateau 419-01	-	-	21,000	-	-
National Park	Raurimu 410-02	-	-	367,500	-	-
Ongarue	Manunui 407-01 (was Affco)	-	-	134,925	-	-
Ongarue	Manunui 408-01	-	-	195,825	-	-
Ongarue	Tuhua 422-03	-	-	393,750	-	-

11kV OVERHEAD LINE RENEWAL 2016/17 TO 2020/21						
POS	Project	2016/17	2017/18	2018/19	2019/20	2020/21
Tokaanu	Tokaanu 420-01	-	-	30,975	-	-
Whakamaru	Whakamaru 120-01	-	-	361,200	-	-
Whakamaru	Whakamaru 120-02	-	-	113,400	-	-
Whakamaru	Wharepapa 122-03	-	-	175,350	-	-
Whakamaru	Wharepapa 122-04	-	-	265,650	-	-
Hangatiki	Coast 125-01	-	-	-	224,700	-
Hangatiki	Mahoenui 113-01	-	-	-	227,850	-
Hangatiki	Mahoenui 113-06	-	-	-	292,950	-
Hangatiki	Mokauiti 115-01	-	-	-	137,550	-
Hangatiki	Otorohanga 112-02	-	-	-	157,500	-
Hangatiki	Otorohanga 112-05	-	-	-	68,250	-
Hangatiki	Rangitoto 106-07	-	-	-	295,575	-
National Park	Raurimu 410-03	-	-	-	327,600	-
Ongarue	Manunui 408-02	-	-	-	409,500	409,500
Ongarue	Ongarue 421-04	-	-	-	398,475	-
Ongarue	Southern 409-02	-	-	-	101,325	-
Ongarue	Southern 409-09	-	-	-	192,150	-
Whakamaru	Huirimu 121-01	-	-	-	199,500	-
Whakamaru	Tihoi 124-00	-	-	-	10,500	-
Whakamaru	Tihoi 124-01	-	-	-	177,975	-
Hangatiki	Benneydale 103-10	-	-	-	-	286,125
Hangatiki	Benneydale 103-11	-	-	-	-	286,125
Hangatiki	Caves 101-03	-	-	-	-	44,625
Hangatiki	Mokau 128-10	-	-	-	-	279,405
Hangatiki	Piopio 116-04	-	-	-	-	488,775
National	Otukou 418-01	-	-	-	-	359,100
National	Raurimu 410-04	-	-	-	-	362,250
Ohakune	Turoa 415-04	-	-	-	-	199,500
Ongarue	Manunui 408-03	-	-	-	-	150,000
Ongarue	Southern 409-05	-	-	-	-	355,425
Whakamaru	Mokai 123-02	-	-	-	-	288,750
11kV OVERHEAD ANNUAL TOTAL		4,294,685	4,303,985	4,271,085	4,345,110	4,234,290

Table 6.23: 11kV Overhead Line Renewal Expenditure Forecast

6.5.2.2.3 Low Voltage Overhead Line Renewal Programme

LOW VOLTAGE OVERHEAD LINE RENEWAL 2016/17 TO 2020/21						
POS	Project	2016/17	2017/18	2018/19	2019/20	2020/21
All	EMERGENT	115,634	115,634	115,634	430,634	535,634
Hangatiki	Gravel Scoop 109-10	68,250	-	-	-	-
Hangatiki	Mokau 128-02	28,350	-	-	-	-
Hangatiki	Mokau 128-05	99,225	-	-	-	-
National Park	National Park 411-01	204,750	-	-	-	-
Ongarue	Southern 409-04	99,225	-	-	-	-
Tokaanu	Motuoapa 425-01	170,625	-	-	-	-
Hangatiki	Maihihi 111-01	-	34,125	-	-	-
Hangatiki	Otorohanga 112-01	-	227,325	-	-	-
Tokaanu	Kuratau 406-03	-	113,925	-	-	-
Whakamaru	Mangakino 118-01	-	142,275	-	-	-
Hangatiki	Aria 114-01	-	-	22,575	-	-
Hangatiki	Piopio 116-02	-	-	142,275	-	-
Hangatiki	Rangitoto 106-01	-	-	136,500	-	-
Ongarue	Manunui 407-01 (was Affco)	-	-	31,500	-	-
Ongarue	Manunui 408-01	-	-	119,175	-	-
Tokaanu	Tokaanu 420-01	-	-	56,700	-	-
Whakamaru	Whakamaru 120-02	-	-	113,400	-	-
Hangatiki	Coast 125-01	-	-	-	5,775	-
Hangatiki	Rangitoto 106-07	-	-	-	16,800	-
Ongarue	Manunui 408-02	-	-	-	28,350	-
Ongarue	Ongarue 421-04	-	-	-	11,025	-
Ongarue	Southern 409-02	-	-	-	56,700	-
National Park	Otukou 418-01	-	-	-	-	68,250
LOW VOLTAGE OVERHEAD ANNUAL TOTAL		786,059	633,284	737,759	549,284	603,884

Table 6.24: Low Voltage Overhead Line Renewal Expenditure Forecast

6.5.3 Conductor Renewal Programme

6.5.3.1 Description

The conductor renewal programme is an expenditure contingency for fatigued conductor identified in the 2016/17 Conductor Assessment Project. As specific projects are identified, funds will be designated in more detail. The need for conductor renewal has been identified as a Network priority. To date, limited renewal has been undertaken. The costs and outages required to replace conductor need to be carefully balanced against the fault risk if not replaced and reliability benefits. Table 6.25 documents the renewals.

6.5.3.2 Annual Detail and Forecast Expenditure

CONDUCTOR RENEWAL PROGRAMME 2016/17 TO 2020/21						
POS	Project	2016/17	2017/18	2018/19	2019/20	2020/21
All	Renewal Contingency	231,000	420,000	420,000	420,000	420,000
Hangatiki	Mokau 128-06 : 6km	189,000	-	-	-	-
CONDUCTOR RENEWAL PROGRAMME TOTAL		420,000	420,000	420,000	420,000	420,000

Table 6.25: Conductor Renewal Expenditure Forecast

6.5.4 Cable Renewal Programme

6.5.4.1 Description

Aging cable on the Network has been identified as an area for a continued investigation. At this stage, a renewal plan for the ski fields area has been developed, as illustrated in Table 6.26. The initial focus will be on high risk areas such as the where the cable passes through the chain fitting area at Turoa. Whakamaru Village stage 2 LV cable reticulation upgrade is also included in the 5 year forecast period.

6.5.4.2 Annual Detail and Forecast Expenditure

CABLE RENEWAL PROGRAMME 2016/17 TO 2020/21						
POS	Project	2016/17	2017/18	2018/19	2019/20	2020/21
National Park	Chateau 419-01	-	126,000	126,000	126,000	126,000
Ohakune	Turoa 415-03	-	110,250	110,250	110,250	110,250
Whakamaru	Whakamaru Village 120-03 (stage 2)	-	-	-	262,500	-
CABLE RENEWAL PROGRAMME TOTAL		-	236,250	236,250	498,750	236,250

Table 6.26: Cable Renewal Expenditure Forecast

6.5.5 11kV Feeder Switch Renewal

6.5.5.1 Description

The renewal programme looks to replace aged switches on the distribution network – often with Ring Main Units (RMU) to allow improved isolation of transformers. Table 6.27 documents the renewals.

6.5.5.2 Annual Detail and Forecast Expenditure

11kV FEEDER SWITCH RENEWAL 2016/17 TO 2020/21						
Local ID	Project	2016/17	2017/18	2018/19	2019/20	2020/21
10S34	Re-positioning of RMU's to provide better security of supply to Turangi township.	115,500	-	-	-	-
FED120	Whakamaru Village stage 1. RMU and transformer with provision for generator insertion point. Provides options for backup, backfeed and switching of 11kV circuits. Stage 2 sees LV cable reticulation upgrade.	-	-	126,000	-	-
11kV FEEDER SWITCH RENEWAL TOTAL		115,500	-	126,000	-	-

Table 6.27: 11kV Feeder Switch Renewal Expenditure Forecast

6.5.6 Ground Mount Transformer Renewal

6.5.6.1 Description

Transformers that are reaching end of life are planned to be changed out with modern ground mounted transformers. Table 6.28 lists the renewals planned in the next 5 years.

6.5.6.2 Annual Detail and Forecast Expenditure

GROUND MOUNT TRANSFORMER RENEWAL 2016/17 TO 2020/21						
Local ID	Project	2016/17	2017/18	2018/19	2019/20	2020/21
08J47	Replace existing transformer in Rimu St, Manunui with standard ground mount.	-	-	-	-	42,630
10S27	Replace existing transformer in Te Hei Place, Turangi with front access ground mount and LV generator connection point.	-	-	-	-	44,762
GMT RENEWAL TOTAL		-	-	-	-	87,392

Table 6.28: Ground Mount Transformer Renewal Expenditure Forecast

6.5.7 33kV Substation Assets Renewal

6.5.7.1 Description

33kV substation assets may be replaced due to age or failing reliability and condition. Where viable, major assets such as transformers will be refurbished increase life expectancy rather than replaced. Depending on the asset condition, refurbishment may be a more cost effective option. If quality spare parts are no longer available however then total replacement may be required to ensure performance requirements are met. Table 6.29 documents the renewals.

6.5.7.2 Annual Detail and Forecast Expenditure

SUBSTATION ASSET RENEWAL 2016/17 TO 2020/21						
Local ID	Project	2016/17	2017/18	2018/19	2019/20	2020/21
ZSub207	Replace relays CB 681 and 685 at Wairere.	21,000	-	-	-	-
ZSub508	Upgrade voltage control relays at Borough.	52,500	-	-	-	-
ZSub206	Replace Waitete 11kV bulk oil breakers.	-	-	70,659	-	-
ZSub207	Refurbish Wairere T1 transformer.	-	-	95,918	-	-
ZSub207	Refurbish Wairere T2 transformer.	-	-	-	-	95,918
ZSub203	Replace Te Waireka 11kV bulk oil breakers.	-	-	-	-	53,288
ZSub215	Replace Atiamuri bulk oil circuit breaker.	-	-	-	-	90,589
33kV SUBSTATION ASSET RENEWAL TOTAL		73,500	-	166,577	-	239,794

Table 6.29: Substation Asset Renewal Expenditure Forecast

6.5.8 Equipment Renewal

6.5.8.1 Description

Equipment renewals covers general non item-specific equipment renewal. The equipment categories identified incorporate some specific projects along with more generic contingencies to ensure continued network stability. Table 6.30 documents the expenditure forecast for each of the following categories.

Radio Contingency

TLC owns and operates 20 repeater sites for data and voice communications throughout the network. Each of these sites contains various numbers of radios, batteries, chargers, aerials and other electronic equipment that need to be replaced on an on-going basis as the equipment ages. The data radio system is the backbone of network automation and in recent times there have been a lot of additional remote circuit breakers, substations and other controlled equipment added. If the radio network fails, communication with remote equipment is lost. When this occurs, load control inputs and signals cannot be sent and automated equipment cannot be communicated with. Potential cost increases come from loss of load control during peaks. The contingency is for unforeseen radio equipment replacement.

Radio Specific

TLC is upgrading its radio communication sites. This equipment upgrade is being completed to comply with the regulations of changing from 25 kHz bandwidth to 12.5 kHz bandwidth. The equipment that is used to achieve the upgrade is capable of switched between analogue and digital. The upgrade programme has been prepared by a communications consultant. Due to the important nature of the load control signals, the introduction of a backup communications path via cell phone links (GSM) is to be installed.

SCADA Contingency

TLC now has automation in some form at approximately 30 zone substations, a distributed generation site, 11 load control plants and about 80 field devices. In addition to operation of field devices the equipment provides the central summation function of system load, generation and dispatch of load control signals. 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. The contingency is for unforeseen SCADA equipment replacement.

SCADA Specific

This work is 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.

Distribution Transformer Renewals

Transformers may fail, suffer damage, lightning strike or deteriorate in condition due to rust. The contingency amount per annum is for the renewal of distribution transformers that are uneconomic to repair - typically when the repair cost is greater than the regulatory value.

Distribution Equipment

This category includes other distribution equipment such as switchgear and regulators. From time to time these units fail and, due to the age of the assets, parts to repair are no longer available. When this occurs, the purpose of the equipment is reviewed and planned changes assessed to see if it should be replaced with a modern equivalent.

Protection & Voltage Relays

The TLC network has around 150 relays plus a similar number of other tripping and alarming relays in service. These assets operate to protect the network from interference. The contingency is mostly to renew but sometimes refurbish the relays in the event of failure.

Other

Expenditure set aside for specific projects not already covered. This may include items being purchased as stock in order to facilitate maintenance programme execution or asset refurbishment. This Plan includes two items. A regulator purchase in order to have a spare unit that can be put into service while the existing asset is refurbished or undergoing maintenance work. Also include is the progressive replacement of the Mk1 SFUK controllers for the 317Hz load control plants. These ripple control units are falling out of warranty and whilst a spare is being held, they need to be replaced to with the new version to ensure signal reliability.

6.5.8.2 Annual Detail and Forecast Expenditure

EQUIPMENT RENEWAL 2016/17 TO 2020/21					
Category	2016/17	2017/18	2018/19	2019/20	2020/21
Radio Specific	359,100	179,550	44,762	44,762	44,762
Radio Contingency	12,256	12,256	12,256	12,256	12,256
SCADA Specific	44,762	44,762	44,762	44,762	44,762
SCADA Contingency	18,651	18,651	18,651	18,651	18,651
Distribution Transformer Renewals	362,355	362,355	362,355	362,355	362,355
Distribution Equipment	59,682	59,682	59,682	59,682	59,682
Protection & Voltage Relays	12,256	12,256	12,256	12,256	12,256
Other: Regulator stock item	31,500	-	-	-	-
Other: Load Plant Mk1 SFUK Controller replacement	-	-	-	122,561	-
EQUIPMENT RENEWAL TOTAL	900,561	689,511	554,723	677,284	554,723

Table 6.30: Equipment Renewal Expenditure Forecast

6.5.9 Load Control Relays

6.5.9.1 Description

With the renewal of load control plants to support a lower frequency ripple system complete in the Northern area, the programme for load control relay replacement is now underway. This programme has been combined with TLC's advanced meter programme rollout required for recertification and renewal under the Electricity Authority's rules. Advanced meter firmware has now been developed to the point that it will read both retailer and TLC demand based charging data and includes the capabilities for future communications and in-home displays. The metering on the network is substantially owned by a TLC subsidiary company.

As Table 6.31 illustrates, it is envisioned that the rollout programme will continue for the next 3 years, after which a contingency for any ongoing replacements that are required will come into effect. The allowance included in this Plan is based on the amount it would cost to replace the relays only. It is based on a model of a typical relay replacement programme and forms a contribution to the meter rollout; the numbers and costs are not fully funding the meter rollout.

The decision to use lower frequency load control system was made by the Board in 2008, after analysis showed it to be the lowest cost and most effective option. TLC requires relays and meters that will operate with the new ripple plants 317Hz decabit signal, which will improve TLC's ability to use demand side management load control. There are about 5500 relays in the northern area that are affected by the load plant change out. The network must fund the renewal of relays and the associated administration systems to control these assets – not doing so would reduce the effectiveness of the load control plants.

6.5.9.2 Annual Detail and Forecast Expenditure

LOAD CONTROL RELAY RENEWAL 2016/17 TO 2020/21					
Project	2016/17	2017/18	2018/19	2019/20	2020/21
Load control programme relay replacement	68,828	37,328	16,328	-	-
LOAD CONTROL RELAY RENEWAL TOTAL	68,828	37,328	16,328	-	-

Table 6.31: Load Control Relay Renewal Expenditure Forecast

6.6 Asset Replacement and Renewal Projects 2021/22 to 2025/26

The final years of asset replacement and renewal planning continue to follow the renewal programmes adopted in the 2016/17 to 2020/21 period.

Renewal programmes based on the 15 year cycle for 33kV, 11kV and LV lines continue. The full details of the line renewal and replacement programme are discussed in the lifecycle asset management planning – Section 3 of this document.

Conductor and Cable renewal programmes will be refined and more specifically identified based on assessment projects.

Section 7

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7. Risk Management

7.1 Overview

TLC has reviewed the entire risk management process to align it with the international ISO 31000 standard. Going forward this will form the basis for risk management across the business.

TLC uses formal reviews to identify any risks. Risk management is a continual improvement process that encompasses many things including assets, health and safety, the community, operations, public hazard control, natural events and other infrastructure flaws.

Most of TLC's business processes and activities have an element of risk management. A key driver for this business approach is the company's corporate objective of delivering a strong sustainable network to the greater King Country. A high risk approach to business activities may not achieve this. The AMP, Annual Plan, Safety Management System (SMS) and Public Safety Management System (PSMS) are documents that manage risk. These plans and other inputs are used to manage the network in such a way that continually focuses on the identification of hazards and their control (elimination, isolation or minimisation).

Documenting and having strategies in place to manage and reduce risks is a key aspect of this Plan. The cost of not completing renewal and other activities to satisfactorily manage risk has a high potential liability cost.

The risk framework to meet ISO 31000 is recent and High Focus Risks (HFR) and controls are currently evolving.

7.2 Risk Policies

7.2.1 Risk Framework

TLC has a structure of policies and standards that are used to manage corporate risk. A subset of the distribution-related policies and standards 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 approval and review process is illustrated in Figure 7.1.

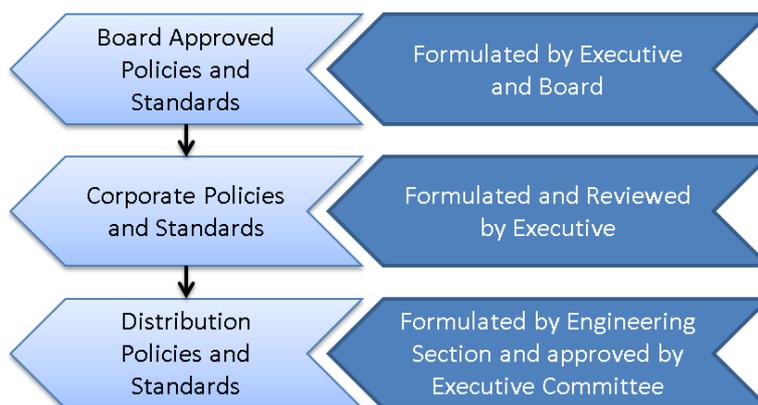


Figure 7.1: Approval and Review Process for Policies and Standards

The methods used to assess risk issues include:

- Previous events
- Legislation and Regulation
- Financial security
- Strategic requirements
- Network performance analysis
- The cost and implications of not controlling risks
- Public hazards are mitigated via the SMS and the PSMS

The details that the risk policies cover include hazard control, compliance, financial, strategic, human resources, and events.

Risk analysis and its considerations are fundamental to business and corporate strategy to provide customers with a network that produces a reliable, adequate quality and hazard controlled service at an affordable price.

7.2.2 Distribution Asset Risk Policies

The asset risk policies are mostly placed within the Distribution Policies and Standards as illustrated in figure 7.1. 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 (AMP)
- The Safety Management System (SMS)
- The Public Safety Management System (PSMS)
- Individual project specifications and standards
- Insurance for equipment other than overhead lines related hardware.

These policies consider the probability of an event and its consequences. These include:

- Physical failure risks
- Operational risks
- Natural environmental events
- Factors outside of the organisation's control
- Stakeholder risks
- Risk associated with the different life cycle phases of assets
- Public related hazard control.

TLC policies recognise that risk is defined as the product of probability and consequences. For example, as described in Section 5, planning criteria and assumptions are based on this recognition.

The policies include various techniques for identifying, quantifying and managing asset related risks with varying levels of complexity. TLC is constantly reviewing its individual requirements in terms of risk identification, including the availability of information and implementation practicalities of reduction strategies.

TLC uses the understanding 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, the implementation of this plan and annual plan subsets.

A key strategic tool for the implementation of the asset management process is the Basix information system. This allows performance to be measured, and forms the foundation for on-going risk assessment and prioritising projects for risk.

7.3 Network Risk and Methods to Mitigate Risk Events

7.3.1 High Focus Risks

The table below includes those risk that are reported to the executive under the organisation risk policies and have actions to mitigate them in place where possible. They are current as at the end of 2015 and will have changed by the time of publication of this document.

HIGH FOCUS RISKS					
Strategy	Risk	Controls	Residual Risk Impact	Residual Value of Risk	Comments
Overhead Line - Failure and Operational Risks	Vegetation	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.	Moderate / Likely	\$ 525,000	The backlog of trees to be trimmed is increasing. Tree faults are increasing. The opex is constrained by the Commerce Commission determination and a judgement between exceeding allowed opex and reliability incentive payments may be required.
Overhead Line - Failure and Operational Risks	Aged Equipment Faults	Renewal programmes, patrols, follow ups after faults and auto recloses, customer and staff reports, inspections, observations, outage data, and performance monitoring are all methods used to mitigate risk with aged overhead lines.	Moderate / Likely	\$ 525,000	Conductor and jumper aging is causing increased risk level and increasing numbers of faults and the need for increased spend.
Overhead Line - Failure and Operational Risks	Single 33kV supply to zone substation with inadequate 11kV ties	Inspection, maintenance and renewal programmes are in place. Generator insertion points.	Major / Possible	\$ 375,000	33kV circuits are maintained to a higher standard than 11kV and single circuit 33kV receive more regular inspection and action than areas with redundant circuits. A review of tie capacity has occurred.
Overhead Line - Environmental and Stakeholder Risks	Fire started by overhead lines	Renewal and maintenance programmes included in the AMP. Protection systems set up in accordance with industry practice.	Moderate / Likely	\$ 525,000	Caused by aged equipment failing (Cracked insulators causing tracking along cross arms). While there is an element of attention to insulators during inspection that can occur funding constraints means this risk is difficult to reduce.
Zone Substation and Voltage Regulation	Zone Substation Aged Equipment Faults	Inspection, maintenance and renewal programmes are in place.	Moderate / Likely	\$ 525,000	Recent failures have highlighted that, despite regular monitoring of oil and transformer condition, not all defects can be detected. A review of aging plant will be done to ensure all replacement and contingency plans match recent experience.
Zone Substation and Voltage Regulation	Zone Substation Testing Procedures	Testing procedures Test records Qualified technicians	Moderate / Likely	\$ 525,000	The frequency and records associated with primary injection testing of zone substation protection functions will be reviewed.

HIGH FOCUS RISKS					
Strategy	Risk	Controls	Residual Risk Impact	Residual Value of Risk	Comments
Zone Substation and Voltage Regulation - Physical Failure and Operational Risk	Protection Systems Operating Incorrectly	Protection setting data base. Protection trained staff. Standardised protection.	Moderate / Likely	\$ 525,000	Multiple events indicates a need for a systematic protection review.
Zone Substation and Voltage Regulation	Power Transformer Failure at single transformer zone subs with inadequate backup 11kV ties	Inspection and maintenance programmes are in place. Generator insertion points.	Moderate / Likely	\$ 525,000	There are a number of zone substations where tie capacity is not sufficient for moderate load period transfers. The economics of addressing this and availability of funds will be investigated.
Zone Substation	Zone Substation - Seismic	Zone substation transformers and the effects of seismic activity have been assessed. Buildings have not at this time.	Catastrophic / Unlikely	\$ 300,000	Multiple container subs and other hold down arrangements are not to standard. Rigid buses not to current standards. A review and fixes need action.
Distribution Substations, Switchgear and Underground Systems	Legacy underground systems that have been constructed using low cost methods	Renewal programmes are in place to identify and implement hazard controls.	Minor / Very Likely	\$ 468,750	Some work done around Turangi. More to do, some issues at Whakamaru and Ohakune. Asset getting to end of life.
Distribution Substations, Switchgear and Underground Systems	Protection systems operating incorrectly	The set up and performance of protection systems associated with distribution switchgear is closely monitored.	Major / Possible	\$ 375,000	Multiple events indicates a need for a systematic protection review maintenance of reclosers and attention to defects.
Asset Other Equipment	Asset Management Processes	HR processes. Remuneration policies.	Moderate / Likely	\$ 525,000	Process documentation, engineering design review, business case formats and auditing of major work is not occurring at desirable levels due to staff shortages.
Asset Other Equipment	Asset/Contracting prioritisation	Prioritisation meetings.	Moderate / Likely	\$ 525,000	Asset Management system Basix work priorities do not transfer to the contracting management system and prioritisation of high priority work is not being managed with multiple customers across organisational boundaries.
Asset Other Equipment	Contracting capacity	HR policies Remuneration policy	Moderate / Likely	\$ 525,000	There is a shortage of test technicians across the industry and there is equipment out of service or defects that have not been addressed due to contracting specific skill shortages.

HIGH FOCUS RISKS					
Strategy	Risk	Controls	Residual Risk Impact	Residual Value of Risk	Comments
Asset Other Equipment - Distributed Generation, Physical Failure and Operational Risks	Major customer unable or unwilling to maintain joint usage facilities	Operating Procedures Contractual requirements	Moderate / Likely	\$ 525,000	The substation at Taharoa Iron sands is beside the sea and badly corroded. Due to the price of iron ore and a major expansion under consideration, the client has been reluctant to commit to rebuild the substation. This has reached an unacceptable situation, with operating restrictions, and work must be done.

Table 7.1 Special Focus Risks

7.3.2 Overhead Lines

Table 7.2 and Table 7.3 summarise the overhead line risk assessment and mitigation:

ASSET OVERHEAD LINE - FAILURE AND OPERATIONAL RISKS				
Risk	Controls	Residual Risk	Details	Conclusions
Vegetation Faults	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.	Moderate / Likely	The programme consists of planned patrols and follow ups and emergent activities as detailed in this Plan.	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 Faults	Renewal programmes, patrols, inspections, observations, outage data, and performance monitoring are used to mitigate risk.	Moderate / Likely	The various policies, strategies, processes and plans detailed in this Plan.	Mitigating old overhead lines risk forms a large part of this Plan.
Line Clashing	Fault investigation to identify possible causes. Line design review when problem areas are identified.	Minor / Likely	When line clashing is suspected, upstream fault current recording devices are downloaded and reconciled to analysis programs. A site patrol is carried out to pin point the exact location and designs are completed to remove the problem.	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	Line inspections include recording of overhead line heights above ground ensure they comply with Regulations. Signs are also put in place.	Moderate / Unlikely	Boat masts coming into contact with overhead lines is a problem around the shores of Lake Taupo when boat operators forget to lower their masts. Warning signage is in place and is being monitored as part of line patrols and inspections.	Line clashing caused by boat is difficult to guard against. More signage is planned to help mitigate the risk.

ASSET OVERHEAD LINE - FAILURE AND OPERATIONAL RISKS				
Risk	Controls	Residual Risk	Details	Conclusions
Theft of copper	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.	Minor / Likely	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.	Earthing systems are critical for hazard control. The theft of components of these systems leads to risks.
Capacity	Asset and engineering staff monitor field equipment loadings and annually work through the entire network reconciling data to network models. Some equipment also has alarms set at certain load points. Protection systems are in place.	Minor / Possible	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.	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	The renewal programmes, patrols, follow-ups after faults, auto recloses, inspections, priority setting, observations, outage data, and performance monitoring. Protection systems are set up in compliance with legislation and industry practice. SMS and accreditation of this to a standard.	Moderate / Unlikely	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.	Mitigating the hazards associated with old overhead lines risk forms a large part of this Plan.
Fault Currents	The effects of fault currents on overhead lines are considered by modelling fault current levels and checking these throughout the network.	Minor / Possible	Levels are looked at regularly and reconciled to line strength and spacing. (Experience has shown that fault levels above 100MVA on standard 11kV light construction will cause problems.) Control of fault current levels is one of the reasons why the modular substation concept was developed,	Mitigating the hazards caused by fault currents has been included in this plan.
Private Lines Connected to TLC Lines	Inform line owners of hazards observed on their lines when patrols and inspections are taking place.	Minor / Possible	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.	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.

ASSET OVERHEAD LINE - FAILURE AND OPERATIONAL RISKS				
Risk	Controls	Residual Risk	Details	Conclusions
Maintenance procedures	Maintenance standards and in house work practice.	Minor / Likely	Ongoing development and collection of appropriate information.	Technical library holds information on most items of plant.
Multiple 11kV circuits on the same structure	Alternative supplies are available to areas feed from structures with multiple 11kV circuits.	Moderate / Unlikely	As a part of the line renewal program structures with multiple circuits are replaced with multiple structures where possible or are constructed to a higher strength.	Mitigating old overhead lines risk forms a large part of this Plan.
Single 33kV overhead supply to zone substation with inadequate 11kV ties	Inspection, maintenance and renewal programmes are in place. Generator insertion points.	Major / Possible	Generation insertion points are installed near zone substations were only limited backfeed supply is available.	There are risks of extended outages in a number of areas that would be unacceptable to customers.
Poor workmanship in line work	As a part of the line renewal program all work is audited and where issues are identified rework is conducted.	Moderate / Unlikely	Inspection and renewal program that is described in this plan.	Robust auditing of line work is conducted to mitigate the impact of poor workmanship.

Table 7.2 Overhead Lines – Physical Failure and Operational Risks

ASSET OVERHEAD LINE - ENVIRONMENTAL AND STAKEHOLDER RISKS				
Risk	Controls	Residual Risk	Details	Conclusions
Slips	Potential slips are identified during patrols, 15 yearly inspections or other reports.	Minor / Possible	Plans completed and lines/poles moved as required.	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	15 year renewal programme, patrols and other reports.	Minor / Likely	Line design programme used to ensure line strengths are adequate when renewal and patrol data analysed.	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	Poles and other equipment likely to be washed out or affected by floods identified as part of 15 year programme.	Minor / Unlikely	Major issues resolved as part of 15 year programme.	Pole washouts and difficulties accessing key equipment are the greatest flood risks.
Seismic	Construction standards used to ensure the impact of seismic events on pole loadings are considered.	Moderate / Possible	Line design calculations include seismic considerations.	Many of the older sections of the network have inadequate seismic strength.
Lahar	Lahar paths are identified by 15 year inspections, patrols and other special events.	Minor / Rare	Lines are kept out of Lahar paths or, where this is not practical, protection is put in place.	TLC had protected poles prior to the 2007 Mt. Ruapehu event. Lahars are a consideration when lines are being designed.
Geothermal	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.	Minor / Unlikely	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.	TLC has to be aware of geothermal activity.
Volcanic	TLC has several active volcanoes in the network area. The potential of ash contamination has to be considered when selecting insulators and positioning equipment.	Major / Unlikely	The size of insulators used in the network generally has been increased to improve performance when subject to ash and fertiliser.	A number of lines have the potential to be affected by ash and volcanic activity.

ASSET OVERHEAD LINE - ENVIRONMENTAL AND STAKEHOLDER RISKS				
Risk	Controls	Residual Risk	Details	Conclusions
Snow, ice and other storm hazards	Renewal programmes that take into account likely snow and ice loadings when line designs are reviewed.	Major / Unlikely	Existing and proposed designs are checked with a line design computer programme before work is issued.	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	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.	Major / Unlikely	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.	Care is taken to minimise the risk of natural events. It is not possible to eliminate all possible events as costs would be prohibitive.
Extensive destruction of overhead lines	Renewal programmes included in this AMP need to be completed to manage risk. Overhead lines are not insured.	Major / Unlikely	Patrol and inspection programmes as detailed in the AMP.	The steps for controlling hazards detailed in this plan are designed to manage shareholder risk.
Fire started by overhead lines	Renewal and maintenance programmes included in the AMP. Protection systems set up in accordance with industry practice.	Moderate / Likely	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.	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	Age of assets recognised in the plan and strategies put in place to control these.	Moderate / Possible	Patrol and renewal inspections and the corrective actions that come out of these plans is the base for renewals.	Have a long term plan to change out overhead assets before they reach the end of their lifecycle and fail.

ASSET OVERHEAD LINE - ENVIRONMENTAL AND STAKEHOLDER RISKS				
Risk	Controls	Residual Risk	Details	Conclusions
Supply quality components into the network as part of the renewal programme	Have clear quality standards for components and checking of items to ensure they meet these standards.	Moderate / Unlikely	Constantly reviewing, updating, standards, monitoring and auditing performance of components to ensure they will meet lifecycle expectations.	Component quality is vital to minimise the risks associated with different lifecycle phases of assets. Early failure will cause costs and customer disruption.
Fire damage to overhead lines	Protection systems set up in accordance with industry practice.	Moderate / Unlikely	Vegetation control programme helps reduce the risk of fire. TLC works with forest owners where practical to advise them of this risk.	Charge forest owner for damage should it occur.

Table 7.3 Overhead Lines – Environmental and Stakeholder Risks

7.3.3 Zone Substations and Voltage Regulation Equipment

Table 7.4 and Table 7.5 summarise the zone substation and voltage regulation risk assessment and mitigation.

ASSET ZONE SUBSTATION AND VOLTAGE REGULATION - PHYSICAL FAILURE AND OPERATIONAL RISK				
Risk	Controls	Residual Risk	Details	Conclusions
Aged Equipment	Inspection, maintenance and renewal programmes are in place.	Moderate / Likely	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.	The risk of aged equipment failing in zone substations is being mitigated by this Plan.
Electronic Equipment and Software	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.	Minor / Unlikely	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.	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	Security is enhanced by improving fences, gates and increasing the number of locking devices. Security is also an important design consideration.	Moderate / Unlikely	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.	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	Hazards to the public and their property, i.e. livestock is reduced with a programme of substations inspections, other switchgear/equipment inspections, line patrols, line inspections and observations.	Minor / Unlikely	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.	Earthing systems are critical for hazard control. The theft of parts of these systems may lead to risks for staff and the public.
Capacity	The existing network is modelled, as is any future load predictions, when alternative supplies are configured. An annual detailed review of load and capacity takes place.	Moderate / Unlikely	Loading data are used to check capacity constraints. The models are set up to assist with identifying equipment that is operating beyond capacity limits.	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.

ASSET ZONE SUBSTATION AND VOLTAGE REGULATION - PHYSICAL FAILURE AND OPERATIONAL RISK				
Risk	Controls	Residual Risk	Details	Conclusions
Substations with limited alternative supply options	Various methods are included in this plan to put in place some form of alternative light load supply.	Moderate / Unlikely	Alternatives are being developed with the deployment of modular substations and adding additional modular switchgear.	There are risks of extended outages in a number of areas that would be unacceptable to customers.
Testing Procedures	Industry standards and codes applied.	Moderate / Likely	Network testing procedures align to industry standards and codes.	Appropriate test procedures and what would be considered acceptable tests used.
Operating Procedures	Industry standards and in house developed procedures.	Moderate / Possible	Some in house and some industry standard procedures have been developed. Migration to standard operating procedures where possible.	TLC operating procedures are in line with codes and guides used in industry.
Protection Systems Operating Incorrectly	Back up protection in place. Primary and secondary testing as required.	Moderate / Likely	When protection is suspected to have operated incorrectly a download of the actual settings installed is compared with records to identify any discrepancies.	Generally a reason for non-operation can be found or concluded. This does require high level knowledge of protection systems.
Transformer failure at single transformer zone substations with inadequate backup 11kV ties	Bi-monthly zone substation inspections to monitor the condition of zone substation assets. Generator insertion points near zone substations to allow for generator support in emergencies.	Moderate / Likely	Generator connection points developed. Depending on site if 5MVA spare suits or other 33/11kV transformer available at time of failure. Some smaller sites can be backed up by operating the 33kV line at 11kV (Kiko Road, Te Anga)	There are risks of extended outages in a number of areas that would be unacceptable to customers.
11kV bus or incomer failure to zones subs with inadequate 11kV ties	Bi-monthly zone substation inspections to monitor the condition of zone substation assets.	Moderate / Unlikely	Generator connection points development. Switchgear bypassed to run on backup protection.	There are risks of extended outages in a number of areas that would be unacceptable to customers.
Inadequate emergency zone substation spares	Identify strategic spares and catalogue where spares can be obtained or purchased.	Moderate / Possible	Spare bushings and tap changer parts are held for some aging transformers. Where possible spares are obtained.	As spares become available the get stored at appropriate sites to where they will most likely get used.
High load damage	Monitoring of system loading to ensure equipment is not run beyond its capabilities.	Major / Unlikely	In the event of overloading detailed oil tests are taken to determine the impact on the Transformers lifecycle.	Careful monitoring of the system when running in non-standard configurations greatly reduces the risk of overloading.

Table 7.4 Zone Substation and Voltage Regulation - Physical Failure and Operational Risks

ASSET ZONE SUBSTATION AND VOLTAGE REGULATION - ENVIRONMENTAL AND STAKEHOLDER RISKS				
Risk	Controls	Residual Risk	Details	Conclusions
Wind, Snow, Ice and other storm hazards	Zone substations and regulator sites are designed and positioned to withstand expected winds, snow, ice, etc. Vegetation around zone substations is controlled.	Moderate / Possible	Zone substations and regulator sites have been assessed for their ability to withstand storms etc.	Where shortfalls have been identified these have been included in this Plan, e.g. protection and switchgear improvements.
Flooding	Zone substations and regulator sites in flood prone areas have been identified.	Moderate / Unlikely	The Plan includes proposals for alternative supplies for substations that are in flood prone areas.	Flooding is a low probability, high impact risk that has been considered and mitigated against in this Plan, e.g. Taumarunui north.
Lahar, Geothermal	Locations of zone substations have been evaluated for potential Lahar and geothermal risk.	Moderate / Unlikely	Zone substations are not located in Lahar paths or geothermal areas.	Zone substations are not located in Lahar paths or geothermal areas.
Volcanic	Locations of Zone substations have been evaluated for risk due to volcanic activity.	Major / Unlikely	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 33kV supply to this third site by alternative lines. The Plan includes improvements to several sites that will increase resistance to volcanic eruptions.	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	Zone substation transformers and the effects of seismic activity have been assessed. Buildings have not at this time.	Catastrophic / Unlikely	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.	Earthquake effects on zone substations are a relatively certain, but infrequent event, and have been mitigated. Note: Consideration has been given to the effects of the Canterbury earthquakes. Based on the information that has come available, we believe TLC's Plan will address the needs adequately.
Network events that are more severe than Standards and Codes	When it is obvious that a risk exists that exceeds the design requirements listed in codes, additional engineering is applied.	Moderate / Unlikely	Designers are aware of local issues and these are included in the design process.	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.

ASSET ZONE SUBSTATION AND VOLTAGE REGULATION - ENVIRONMENTAL AND STAKEHOLDER RISKS				
Risk	Controls	Residual Risk	Details	Conclusions
TLC's demand billing system failing to influence demand side management	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.	Moderate / Unlikely	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.	TLC is committed to developing its demand based billing and integrating it into its overall asset management strategy.
Major failure of zone substation resulting in an extended outage.	TLC is increasing diversification as detailed in this Plan to minimise this risk.	Moderate / Unlikely	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.	Risk is being reduced through diversification at the lowest possible cost.
Equipment failing	Renewal programmes are in place and there are contingencies for equipment that is run beyond its lifecycle.	Moderate / Unlikely	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.	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.
Hazard Control	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.	Minor / Possible	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.	Hazard control and minimising/eliminating risks of incident/accident and harm, is one of the main focuses of this Plan.
Environmental risks associated with operational issues	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.	Minor / Likely	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.	TLC is addressing legacy environmental issues and is finding innovative ways to address future environmental issues at the lowest possible cost.

Table 7.5 Zone Substation and Voltage Regulation - Environmental and Stakeholder Risks

Note: Equipment insurance policies with excesses in the \$20k to \$30k range are in place for substation equipment.

7.3.4 Distribution Substations, Switchgear and Underground Systems

Table 7.6 and Table 7.7 summarise distribution substations, switchgear and underground systems risk assessment and mitigation.

ASSET DISTRIBUTION SUBSTATIONS, SWITCHGEAR AND UNDERGROUND SYSTEMS - PHYSICAL FAILURE AND OPERATIONAL RISK				
Risk	Controls	Residual Risk	Details	Conclusions
Earthing Systems, particularly SWER systems causing earth potential rise	Design and test earthing systems including considering the effects of fault currents.	Moderate / Unlikely	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.	The risk associated with earthing systems is recognised and being mitigated as part of this Plan.
Loss of Circuit Breaker Electronic Setting Data	The importance of equipment data settings and firmware is recognised.	Moderate / Unlikely	An annual dump of data occurs as part of maintenance programmes. These are reconciled to originals and copies are kept off site.	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.	Initially, and on an on-going basis, check and upgrade security. SMS reporting.	Minor / Unlikely	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.	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 to low standards	Renewal programmes are in place to identify and implement hazard controls.	Minor / Very Likely	A renewal design review process is used to develop prioritised solutions	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	Renewal programmes in place that considers known equipment failure modes. Contingencies in place in case of failures.	Moderate / Unlikely	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.).	Contingencies for equipment failures is part of TLC's planning processes.

ASSET DISTRIBUTION SUBSTATIONS, SWITCHGEAR AND UNDERGROUND SYSTEMS - PHYSICAL FAILURE AND OPERATIONAL RISK				
Risk	Controls	Residual Risk	Details	Conclusions
Capacity	Equipment loadings monitored. Network analysis package used.	Moderate / Possible	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.	The risk of equipment being required to operate beyond its ratings is closely monitored.
Protection systems operating incorrectly	The set up and performance of protection systems associated with distribution switchgear is closely monitored.	Major / Possible	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.	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	Detailed as built drawings and auditing processes in place to ensure records are correct. Competitive cable location service.	Minor / Likely	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.	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	On-going training of staff, either in-house or external courses.	Moderate / Unlikely	Systems in place to identify needs and schedule training. The importance of ensuring staff with the intellectual knowledge are retained is recognised.	Protection systems built into distribution equipment switchgear have become more complex in recent years. Systems have to be in place to manage this complexity.
Destruction of whole switching structure	Annual switchgear inspections.	Major / Unlikely	There are a small number of switching structures (Kuratau and Kaahu Tee) that would have a large impact if they were destroyed.	Basic repair materials are generally ex stock or can be sourced.
Inadequate emergency switchgear spares	Emergency spares are held to cover all aerial switchgear.	Minor / Possible	There is a wide variety of aerial switchgear in service.	Contingency is to either bypass or to replace with a modern equivalent.
Asset or equipment obsolescence	Spares held.	Moderate / Possible	Replacement of equipment is scheduled after initial availability of spares is checked.	Obsolete equipment target of replacement.
400V Cable failure	Renewal programmes are in place to identify and implement hazard controls.	Minor / Possible	A renewal design review process is used to develop prioritised solutions	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.

Table 7.6 Distribution Substations, Switchgear and Underground Systems - Physical Failure and Operational Risks

ASSET DISTRIBUTION SUBSTATIONS, SWITCHGEAR AND UNDERGROUND SYSTEMS - ENVIRONMENTAL AND STAKEHOLDER RISKS				
Risk	Controls	Residual Risk	Details	Conclusions
Seismic	Designs to include seismic requirements.	Major / Unlikely	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.	TLC considers seismic risk as part of its renewal and new construction design practices. It mitigates this risk.
Flooding	Underground equipment is, where possible, located away from flooding areas.	Minor / Possible	Where equipment is located in areas that may flood waterproof and sealed equipment is used as far as practical.	Flooding risk is considered and mitigated as far as practical.
Wind, Snow, Ice and other System Hazards	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.	Moderate / Unlikely	Local knowledge and TLC's design package, which contributes to codes, are used to mitigate this risk.	Local knowledge and TLC's design package, which contributes to codes, are used to mitigate this risk.
Lahar, Geothermal and Volcanic	Lahar, geothermal and volcanic areas have been identified.	Minor / Unlikely	Distribution substations, switchgear and underground systems are not located in Lahar paths or geothermal areas.	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.
Natural events that are more severe than expected	Have emergency procedures in place to help minimise the effects. Use available intellectual knowledge to include designs to minimise the effects.	Major / Unlikely	TLC has emergency event handling procedures in place. Local knowledge is used to vary designs to minimise the effects of severe events.	Unexpected events will happen. It is not possible, practical and economic to eliminate this risk.
Traffic accidents and other damage	Have emergency procedures in place to help minimise the effects. Have emergency stocks of materials. Designs that reduce the risks.	Minor / Likely	TLC has emergency event handling procedures and holds minimum stock levels.	Unexpected events happen. The severity has to be controlled by emergency procedures.
Public access to Pillar boxes in areas where power is underground	Have a planned inspection programme to inspect and record pillar box conditions.	Major / Unlikely	TLC replaces approximately 50 service boxes per year. The new boxes are labelled and securely fastened with padlocks and security screws.	Unauthorised access is minimised by the use of security locking and pillar box design.

ASSET DISTRIBUTION SUBSTATIONS, SWITCHGEAR AND UNDERGROUND SYSTEMS - ENVIRONMENTAL AND STAKEHOLDER RISKS				
Risk	Controls	Residual Risk	Details	Conclusions
Theft of earthing systems copper	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.	Minor / Likely	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.	Earthing systems are critical for hazard control. The theft of parts of these systems leads to risks.
Damage caused by third parties who do not wish to pay	Resources are assigned to making sure that third party damage repair costs are recorded.	Minor / Likely	Incidents are followed-up and accounts are sent. Bad debts are chased until the issues are resolved.	Stakeholders understand that debts will be followed up
Early life and end of life failures	Recognises that early and end of life failures occur and have contingencies in place to control these.	Moderate / Possible	Contingencies include back feeds set up or things such as emergency spares.	The reality is that the probability of early, and end, of life failure rates are higher with most components.
Distribution equipment failure to critical infrastructure with no alternative supply	Mobile generator to provide back up in the event of a fault.	Moderate / Unlikely	Critical sites are evaluated and work to improve security of supply are added to the plan once these sites are identified.	There are still many sites with only a single supply point. Provisions are made for generation connections when these sites are upgraded.

Table 7.7 Distribution Substations, Switchgear and Underground Systems - Environmental and Stakeholder Risks

7.3.5 Other equipment including SCADA, Radios and Load Control Plant

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.

ASSET OTHER EQUIPMENT - DISTRIBUTED GENERATION, PHYSICAL FAILURE AND OPERATIONAL RISKS				
Risk	Controls	Residual Risk	Details	Conclusions
Distributed Generation Applications	Demand billing to reduce the risk of volume changes. Researched lists of engineering issues that need considering when completing distributed generation analysis.	Minor / Possible	TLC has a list of about 25 conditions for intermediate and large distributed generation plant to be connected. TLC insists on these as it is aware of the damage unstable distributed generation can cause. Distributed generators can then complain to the Electricity Authority and add considerable legal costs to TLC.	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).
Electronic Software	Current copies taken and kept off site.	Moderate / Unlikely	Backup copies of SCADA and other software are kept on and off site.	A software problem with key equipment is a low probability high impact risk.
Repeater failure	Maintain the existing systems to a reliable standard. Establish a level of redundancy on key links during the planning period.	Moderate / Possible	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.	TLC's automation is very important for the network operation. Repeater links are the backbone of the system.
SCADA Failure	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.	Minor / Unlikely	: 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.	A failure of the SCADA system especially during periods of network stress will lead to a low probability high impact risk.
Load control plant failure	Load control plants are 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 replaced. A level of backup between the new plants will be possible through the 33kV network.	Minor / Possible	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 three 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 risk to load control going forward is the effects of distributed generation on signal levels. Units are being well sized to cover this risk.	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	Maintenance and renewal programmes. Critical supplies have generation backup.	Moderate / Unlikely	Batteries and chargers are subject to testing as part of the maintenance programmes and time based renewal. Critical supplies have generator backup.	Batteries are critical for the operation of many items of modern equipment.

ASSET OTHER EQUIPMENT - DISTRIBUTED GENERATION, PHYSICAL FAILURE AND OPERATIONAL RISKS				
Risk	Controls	Residual Risk	Details	Conclusions
Technical equipment failure through incorrect or inappropriate use	Design of equipment, training and on-going monitoring of the activities it is used for.	Minor / Likely	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.	Care is taken to ensure equipment is used for intended purpose.
Theft of earthing systems copper	Hazards to the public and animals is reduced by substations inspections, other switchgear /equipment inspections, line patrols, line inspections and other observations. The SMS also reports on these activities.	Minor / Likely	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.	Earthing systems are critical for hazard control. The theft of parts of these systems leads to risks.
Full Transpower Outage	Faults number, phone answering service to inform major customer list, Account manager to contact key staff at affected sites.	Major / Unlikely	Discussions are undertaken with Transpower to time planned shut downs to minimise any disruption to customers.	The impact of a full Transpower outage is minimised due to the availability of full or light load backup of all supply points except Hangatiki. As Hangatiki has N-1 supply the likelihood of a full outage is greatly minimised.
Partial Transpower Outage	Faults number, phone answering service to inform major customer list, Account manager to contact key staff at affected sites.	Minor / Likely	Discussions are undertaken with Transpower to time planned shut downs to minimise any disruption to customers.	The impact of a partial Transpower outage is minimised due to the strong relationships with industrial customers allowing them to reduce load to meet the constraint of the partial outage.
Latent Material defect	Testing of failed equipment to identify issues as they arise.	Moderate / Unlikely	Equipment condition and remaining serviceable life assessments.	If cost effective to repair, this is carried out otherwise it is replaced.
Asset Management Processes	Adherence to good engineering and maintenance practice.	Moderate / Likely	Upskill in the functions and roles of Asset Management. Train/contract out as required.	Improved Asset Management process and knowledge to feed back into the Asset Management Plan.
Asset/Contracting prioritisation	Equipment status, records and Basix work order numbers.	Moderate / Likely	Some tasks not attended to in a timely manner.	Coordination between Asset and Contracting should improve this area.
Contracting capacity	In house staff contracts with suitable 3 rd party providers.	Moderate / Likely	Work flows tied to financial years. Construction times to seasonally favourable line construction periods (Spring to Autumn) which is interrupted by the change in financial year.	Scope of work and required resource to be part of design process.

Table 7.8 Other Equipment - Distributed Generation, Physical Failure and Operational Risks

ASSET OTHER EQUIPMENT - ENVIRONMENTAL AND STAKEHOLDER RISKS				
Risk	Controls	Residual Risk	Details	Conclusions
Seismic	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.	Minor / Likely	Load control equipment set up with protection. Equipment in radio repeater sites secured. Control room and associated support rooms have equipment secured.	The need for seismic constraints is a certain but infrequent requirement and it is often overlooked.
Flooding	Contingencies are in place for events such as loss of access to the control room.	Minor / Unlikely	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.	Loss of access to the control room is a low probability high impact event.
Earthquake damage to Control Centre	Contingencies are in place for loss of access to the control centre. There are currently plans to build a new control centre.	Moderate / Possible	Initial results indicate there is an earthquake risk with the control room. There are currently plans to build a new head office that will address these earthquake risks.	There is a risk associated with the present building that is currently being quantified.
Wind, snow, ice and other storm hazards	Renewal and development programmes consider these effects.	Minor / Possible	Radio repeater sites are constructed to withstand wind, snow, and ice. Load control plants are designed to be capable of withstanding storm conditions.	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.
Harmonics	TLC is monitoring network harmonic levels. Harmonics have the potential to cause complex customer equipment interference.	Minor / Unlikely	Harmonics data are being gathered by spot checks and from distribution equipment. These are reconciled with network analysis models. Controls are being put on new customer connections. SWER lines in particular are susceptible. Electronic appliances are potentially increasing levels and in addition to customer interference may be considered in the future to have adverse health effects. If necessary filtering is put in place to remove these effects. At this time no such filtering has been included in this Plan.	Harmonics are a credible low probability high impact risk. TLC recognises they need to be monitored and researched.
Voltage Flicker	TLC uses standard AS/NZS 61000.3.7-2001 with recommended limits.	Minor / Unlikely	The network analysis program is used to calculate voltage flicker levels. The standard is used to apply these to customer requests.	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.

ASSET OTHER EQUIPMENT - ENVIRONMENTAL AND STAKEHOLDER RISKS				
Risk	Controls	Residual Risk	Details	Conclusions
Voltage Surges	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 and cables.	Minor / Possible	TLC deploys arrestors at key points in the network that restrict surge values. Standards require arrestors at transformers and cables. TLC has purchased and is giving away to customers 15,000 plug-in protectors. It also promotes the importance of surge protection being included in the installation of switchboards via newsletters, customer clinics, focus groups and newspaper articles.	Surge suppression from a customer perspective is a low probability high consequence event.
Extensive equipment being destroyed by an abnormal event	In addition to the risk control strategies described in earlier sections, the majority of this type of equipment has backstop insurance	Moderate / Unlikely	Equipment has back stop insurance in place.	Large scale loss of equipment is an on-going risk for TLC.
Risk associated with different life cycle phases of assets	Recognise that risk of failure is a greater risk at the beginning and end of lifecycle.	Moderate / Possible	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.	Contingencies are put in place to minimise risk.
Distributed Generation	Connection agreements that outline required protection standards to be met by generators.	Minor / Possible	TLC has a list of conditions that need consideration before intermediate and large distributed generation plant can be connected. TLC insists on this as it is well aware of the damage unstable distributed generation can cause on the network.	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).
Unlawful or unsafe network connection	Inform line owners of hazards observed on their lines when patrols and inspections are taking place.	Moderate / Possible	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.	Privately owned lines are now better covered by the Electricity (Safety) Regulations.
Major customer unable or unwilling to maintain joint usage facilities	Continued contact with major customers generally in their interest to allow joint use.	Moderate / Likely	Clear contracts to outline the responsibility of each party.	Major customers are mature and rational, and this issue would be flagged with time to cater for it.
Loss of institutional knowledge	On-going training of staff, either in-house or external courses.	Moderate / Possible	Systems in place to identify needs and schedule training. The importance of ensuring staff with the intellectual knowledge are retained is recognised.	Continued development of information database, staff and working relationships with specialist 3 rd parties who have specific skills to work on equipment.

Table 7.9 Other Equipment - Environmental and Stakeholder Risks

7.3.6 Areas where Analysis Highlights the Need for Specific Development Projects or Maintenance Projects

The analysis in Table 7.1 highlighted the need for the various maintenance, renewal and development programmes outlined in Section 5 and Section 6 of this Plan.

Tables 7.2-7.9 did highlight two areas where the Plan has been modified to cover these off. Specifically, these are the levels of contingency for risks associated for different lifecycle phases of assets, and the effects of a load control plant failure, given TLC's demand based billing strategy and the importance of load control looking forward into the future.

7.3.6.1 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 11kV transformer and related control/protection equipment. TLC hires in additional generators as needed. Unfortunately, there are no local hire companies and this plant has to come by truck from Auckland, Hamilton, Waihi or New Plymouth. The establishment time is normally about 12 hours from the fault to supply from the generator. A delay of this length is unacceptable to most customers.

The above analysis has highlighted an associated risk. Further analysis has shown that often back-up supplies can be maintained by connecting a reactive power source to the network, as opposed to expensive generators. As a consequence, TLC has development of mobile reactive power sources to help mitigate this risk.

7.3.6.2 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 7.8 highlighted TLC's exposure to a plant failure and the need for some form of contingency. The development section of the plan includes an allowance for having a contingency plan in place.

7.4 Risks associated with Economic Downturn and the need for On-Going Hazard Elimination/Minimisation

As outlined in other sections, the TLC network assets are old and many were constructed using second hand materials. Many of these assets have hazard risks. This Plan is designed to address these in a prioritised way and by 2020 a significant improvement will be achieved. The revenue required to implement the Plan will require price rises and during times of economic downturn there will be pressure not to move prices. Failing to renew assets will result in unaddressed hazard issues and stakeholders need to be aware of this. (Tables 7.2-7.9 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.

Risk is being mitigated by the proportion of this comprehensive asset management plan and strategies to make stakeholders aware of the issues. Looking forward, the Plan is to further develop detailed asset data and system, to provide continually improved planning and asset knowledge.

There is a risk however that the political and governance pressure not to do this work nor to increase prices to fund it will stall the hazard renewal programme. It is expected that other pressures such as the Electricity (Safety) Regulations and on-going strengthening of HSE regulations/enforcement will go some way in mitigating this risk.

7.5 Details of Emergency Response and Contingency Plans

7.5.1 Civil Defence

TLC has in place an approved Civil Defence plan and has been involved with the Horizon and Waikato lifelines groups. Staff attends group meetings and contact lists are maintained. Communication channels are set up whenever an event occurs.

Contingency event procedures are invoked whenever supply is lost to 50 or more customers. As events become more serious, more and more layers of contingency action are applied. A staff member has been assigned the responsibility of maintaining, reviewing and updating the Civil Defence Plan.

7.5.2 Event Management

The event management process is initiated when it is likely that 1000 customers will be affected for 10 minutes or 50 customers for 4 hours. As the event worsens, the additional staff layers include Duty Engineer, Engineering Manager, Communication Managers, Staff Welfare Management and Civil Defence functions.

This response and layers of contingency depending on the event seriousness is used to manage events when they occur. TLC has in place a 24/7 service using local people. When an event occurs this is scaled up and additional resources are called in.

The event management procedure is a formal approved procedure and is reviewed/updated annually. Additional rooms around the control room are transformed into communication and co-ordination centres when an event occurs. These rooms have radio plugs, additional telephones, maps, computer connections, emergency lighting and the like, wired in ready for these events. Various staff have nominated responsibilities for staff communications, staff welfare, dispatch, stores etc. when an event occurs.

7.5.3 Seismic

It is anticipated that a seismic event will cause damage to poles and transformers. Depending on the size of the event, the procedure described in the above section will be implemented.

The contingency process would involve despatch of line repair and technical staff. If the control room were destroyed this function would have to be set up at any of the alternative three sites where system drawings are kept and access to internal and external communication systems are available.

Recent analysis of the control centre has indicated that strengthening is required. Options for this will be developed through the coming year.

7.5.4 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 11kV lines in the Tangiwai Lahar path, which could affect customers on the Tangiwai feeder if the Lahar level were to be substantially higher than the 2007 event.

A plan was produced in December 2001, dealing with the steps that should be taken and this is reviewed after each Lahar planning meeting. When the 2007 event occurred, no damage resulted because of the planning that had previously taken place.

7.5.5 Emergency Event in Control Room

If an abnormal serious event occurs in the control room or on the network, and the Controller becomes under stress, overworked or unsure of what is needed, he contacts the Duty Engineer who provides additional support.

7.5.6 Damage to Control Centre

In the event of damage to the control centre TLC will relocate to a recovery centre. Two full copies of all key control room drawings are kept at alternative sites. Contingencies are in place to get SCADA, telephone and radio systems going at these alternative sites.

7.5.7 Emergency Generators

TLC network owns a number of both small and large generators that are used in emergencies. There are several small, compact, electronic inverter units that are made available to customers who have emergency needs. A recent example of their deployment was to two families with essential medical equipment on the end of a remote SWER line. In this case an absentee landowner's trees kept destroying the line and it took a number of weeks before they co-operated and brought in heavy equipment to remove the trees.

7.6 Capability to Deliver

The network and financial performance are taken into consideration when preparing the AMP. Part of the review process of the AMP is that TLC continues to add more detail to its long-term renewal and maintenance plans.

7.6.1 Asset and Network Maintenance

The renewal and development expenditure plan lists expected renewals under lines (33kV, 11kV and LV), substations, distribution transformers, SCADA, communications, protection and switchgear renewal by individual jobs, items, and asset groups. Estimates are derived from the type of projects, previous expenditure on similar projects, cost of equipment in today's dollar and the cost of labour. Estimates are reported in equipment categories and Commerce Commission disclosure format.

The long-term renewal and maintenance plan is on a year-by-year and activity-by-activity basis extended out to year 2027/28. The activities for each coming year are then extracted and reviewed. These form the basis of the annual plan for the coming year. The plan is adjusted when justified due to previously unknown environmental, customer, equipment and other issues, which mostly feed into the 1 to 5 year forecast period.

Over the planning period, all predictions and control are transferred into the BASIX system. The long-term plan flows down and controls the various asset inspections, network maintenance (renewals), planning and network development projects.

7.6.2 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. Areas that are underperforming are analysed further, rectification for these areas are then included in the plan.

7.7 Asset Management Structure, Training, Standards and Authority

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.

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

Specialist work such as SCADA (Supervisory Control and Data Acquisition) and communications is controlled directly by the AMG group. Specialist SCADA and communication contractors complete the work. Vegetation work is controlled and issued by the AMG group to tree contractors who have the necessary quality and hazard control systems in place. These contractors include a local helicopter operator who provides a large proportion of the overhead line fault finding service.

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

In summary the stakeholders require a sustainable network and as such the AMP forms the key document to achieve this. If the requirements listed are not achieved then the network will likely not be sustainable. The document is used to drive the structure and strategic direction of the organisation.

Section 8

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8. Operational and Capital Expenditure Forecasts

8.1 Changes from the Previous Year

Changes in Opex from last year’s plan to this year are indicated in Figure 8.1. The small increase in the current figures reflects an increased tree trimming expense due to escalating costs of traffic management and safety over time and tree reliability worsening. Trimming for reliability on the remote parts of the network is unlikely to be consistent with changes to the Health and Safety at Work act. 2016/17 also includes funding for a network conductor assessment program. Total figures have been offset by refinement of maintenance replacement and renewal budgets to better align to historical actuals.

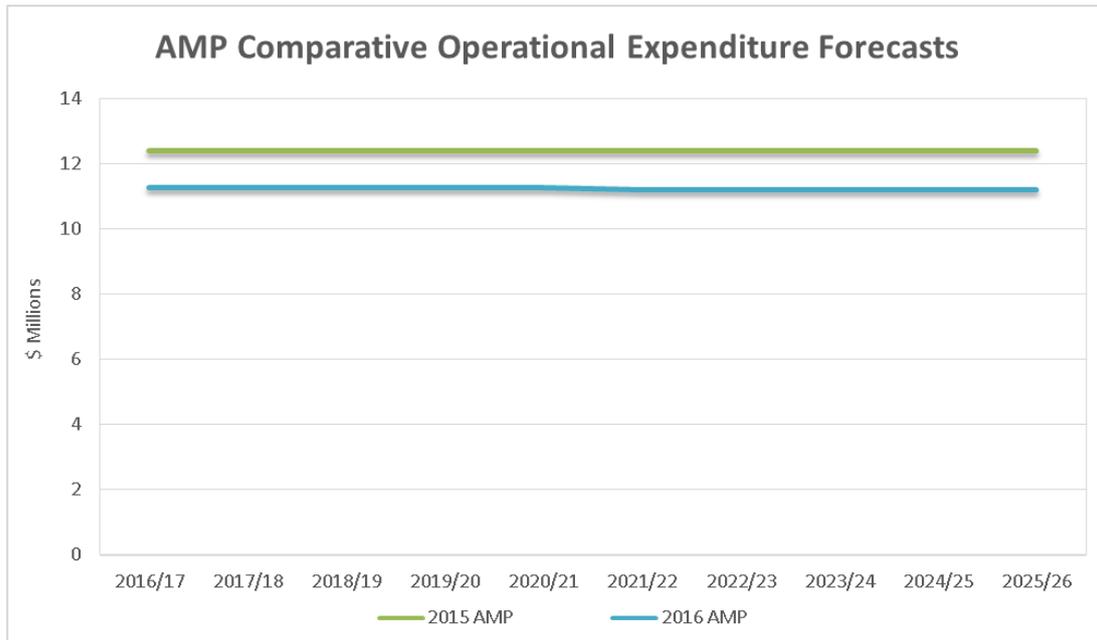


Figure 8.1: Changes in Opex from Last Years Plan

Changes in capital expenditure (Capex) from last years plan to this year are indicated Figure 8.2 below. There are changes between years but the overall level of expenditure is similar.

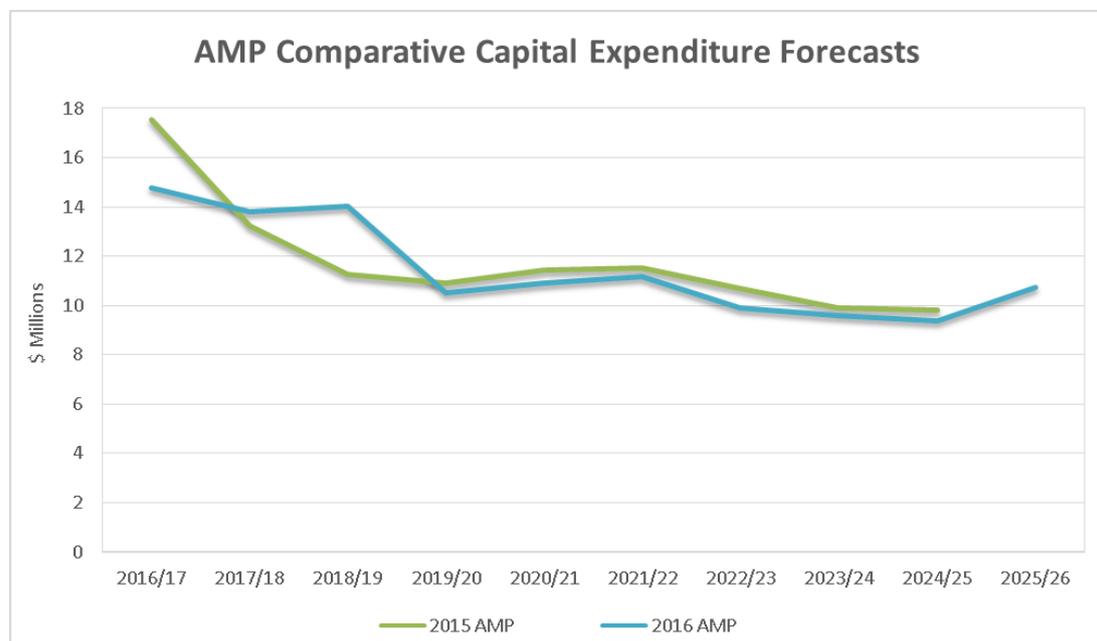


Figure 8.2: Changes in Capex from Last Years Plan

8.2 Operational Expenditure Forecast by Category

The predicted total expenditure including operating and business costs is included in Figure 8.3. As above, costs are stable over time but have increased due to increasing tree cutting costs.

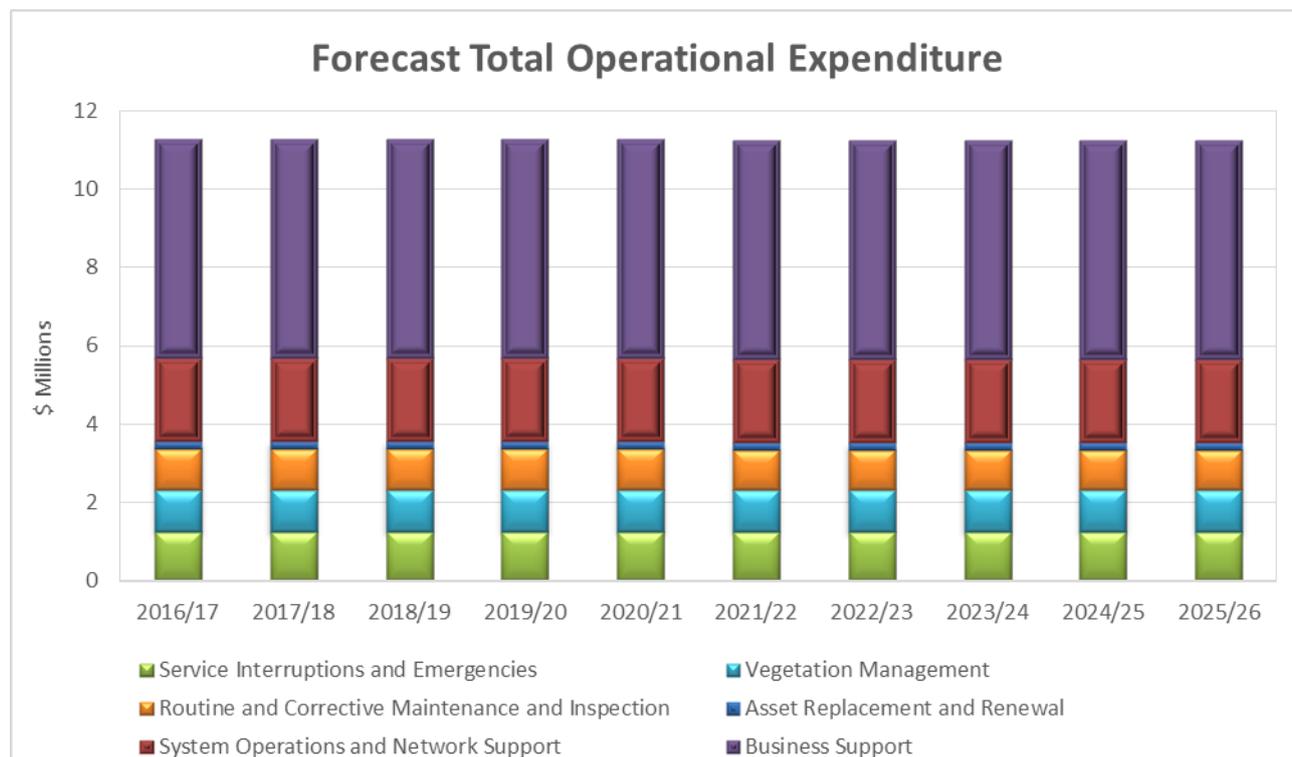


Figure 8.3: Forecast Total Operational Expenditure

TOTAL OPERATIONAL EXPENDITURE										
\$ 000's	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Service Interruptions	1,252	1,252	1,252	1,252	1,252	1,252	1,252	1,252	1,252	1,252
Vegetation Management	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061
Routine Maintenance	1,069	1,069	1,069	1,069	1,069	1,019	1,019	1,019	1,019	1,019
Asset Replacement and Renewal	190	190	190	190	190	190	190	190	190	190
System Operations and Network Support	2,124	2,124	2,124	2,124	2,124	2,124	2,124	2,124	2,124	2,124
Business Support	5,574	5,574	5,574	5,574	5,574	5,574	5,574	5,574	5,574	5,574
TOTAL	11,269	11,269	11,269	11,269	11,269	11,219	11,219	11,219	11,219	11,219

Table 8.1: Total Operational Expenditure (\$ 000's)

Business support costs are a large proportion of the overall operational expenditure. Section 1.4 shows these costs to be high in benchmarking with other companies.

8.3 Capital Expenditure Forecast by Category

Figure 8.4 illustrates forecast capital expenditure for the planning period in constant dollars.

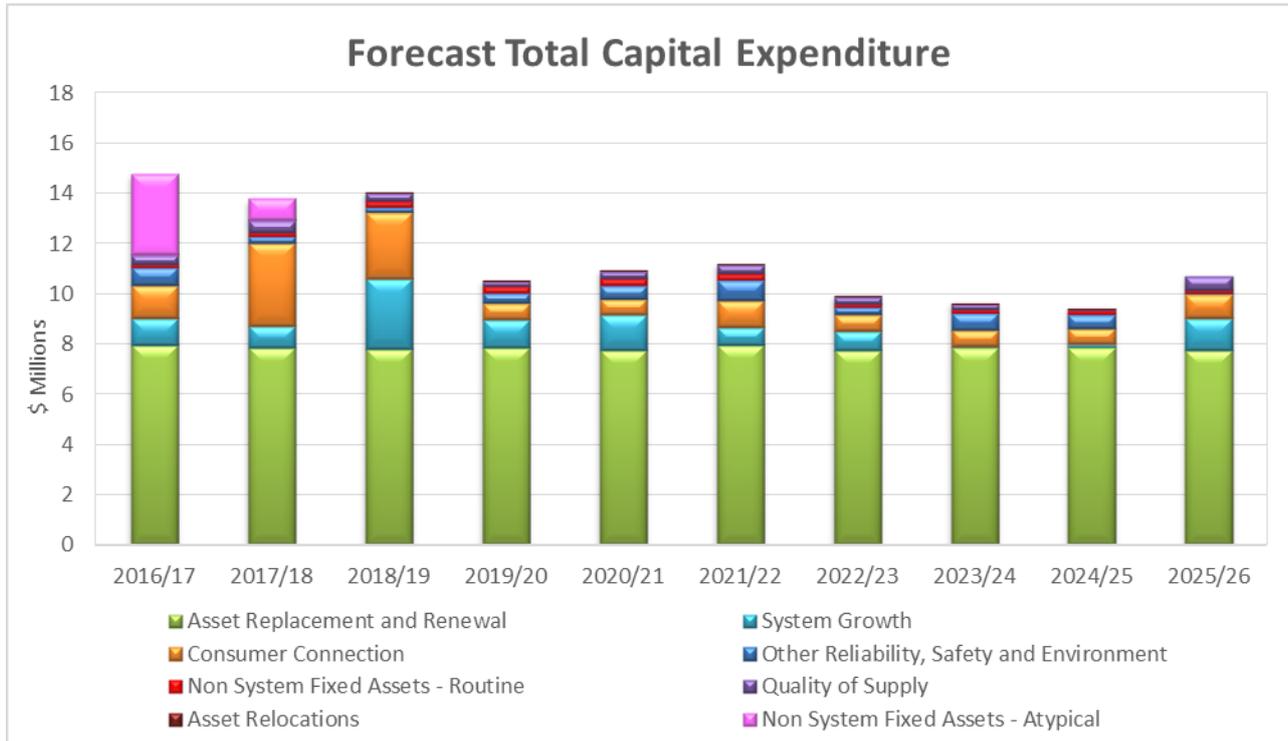


Figure 8.4: Forecast Capital Expenditure by Category

TOTAL CAPITAL EXPENDITURE										
\$ 000's	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Consumer Connection	1,277	3,272	2,642	647	647	1,074	647	647	647	940
System Growth	1,090	894	2,821	1,128	1,404	720	791	53	107	1,281
Asset Replacement and Renewal	7,958	7,844	7,809	7,861	7,759	7,971	7,747	7,846	7,882	7,757
Asset Relocations	11	11	11	11	11	11	11	11	11	11
Quality of Supply	379	486	339	190	272	349	269	218	59	567
Other Reliability, Safety and Environment	736	298	189	390	534	813	286	706	558	58
Non System Fixed Assets - Routine	128	128	233	286	286	233	128	128	128	128
Non System Fixed Assets - Atypical	3,200	870	0	0	0	0	0	0	0	0
TOTAL	14,780	13,802	14,044	10,514	10,912	11,171	9,880	9,609	9,392	10,742

Table 8.2: Forecast Capital Expenditure (\$ 000's)

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

- The expansion of the Taharoa site to meet a customer’s needs (Customer Connection category)
- The rebuild of the King Street office (Non-System Fixed Assets category)

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

An assessment of the performance and age profile of network assets has emphasised the need to renew assets as they reach the end of their service lives. The key drivers of replacement and renewal are:

- Expectation of continued line renewal work including increasing conductor replacement
- Half-life servicing of zone substation transformers
- Replacement of zone substation bulk oil breakers and protection
- Replacement of ground mounted transformers that have reached their end of life
- Renewal of deteriorating cables in urban areas.

Key hazard reduction and environmental improvement work includes:

- Oil containment facilities to avoid risks of contamination of waterways
- Replacement of 2 pole structures that have height related hazards
- Switchgear that does not meet current safety standards.

Key reliability Improvement work includes:

- Automated switch installation
- Upgraded feeder ties.

Section 9

9.	ASSET MANAGEMENT IMPROVEMENT	351
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9. Asset Management Improvement

9.1 Asset Management Objectives

The AMP currently outlines several objectives including:

- Network performance improvements from capital projects;
- Positive changes to risk management;
- Management of constrained funds to the most valuable projects.

9.2 Asset Management Maturity Assessment Tool

The Asset Management Maturity Assessment Tool (AMMAT) has been developed to assess the maturity of EDB asset management systems. The tool consists of a self-assessment questionnaire which is derived from ISO 55000. This has highlighted key areas in the asset management system that TLC will need to improve on. Engineering resources will need to be directed to developing the asset management system to show improvements.

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

Table 9.1 below shows the AMMAT Maturity Rating Scale. TLC achievement using these scores is illustrated in Figure 9.1 and has been revised following external reviews in the following areas:

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

The results of the review have highlighted a number of areas in which TLC requires improvements; this has formed the basis of the improvement plan.

ASSET MANAGEMENT MATURITY ASSESSMENT 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 (ISO 55000)

Table 9.1 AMMAT Maturity Rating Scale

Figure 9.1 shows TLC current self-assessed score for the 2015/16 AMMAT and forecast score for 2016/17.

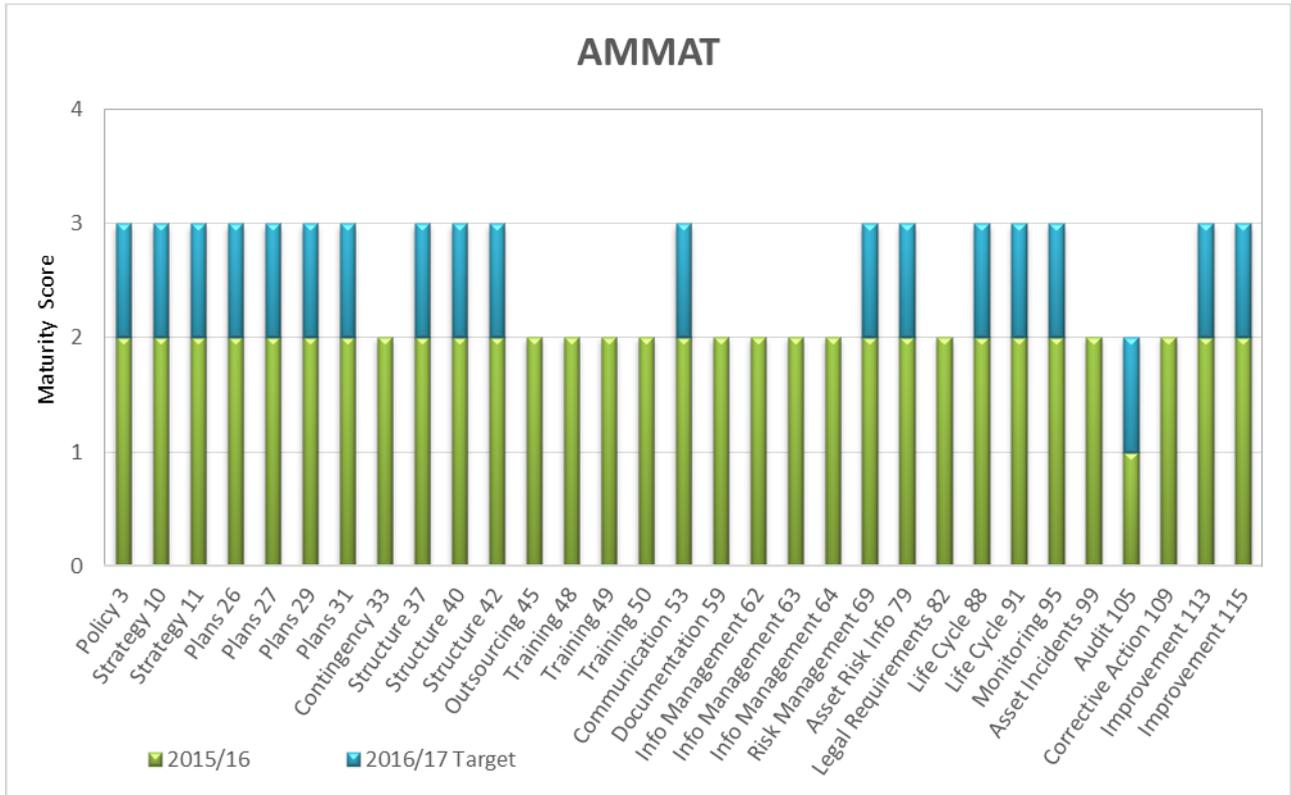


Figure 9.1: Current Self-Assessed Score for the 2015/16 AMMAT and Forecast Score for 2016/17.

9.3 Asset Management Gaps to Maturity Level 3

An assessment of each functional area of asset management shows the following gaps to competent (Maturity level 3):

AMMAT IMPROVEMENT OPPORTUNITIES	
ISO 55000 SECTION	INTERMEDIATE (Maturity Level 3 – Competent)
2.1 AM Policy Development	<ul style="list-style-type: none"> Wide engagement with Stakeholders and communication of Strategy and Policy. Expectations of each activity area defined with detailed action plans, resources, responsibilities and timeframes. Communication of the Asset Management Plan.
2.2 Levels of Service and Performance Management	<ul style="list-style-type: none"> Customer Group needs analysed. Customers are consulted on significant service levels and options.
2.3 Demand Forecasting	<ul style="list-style-type: none"> A range of demand scenarios is developed (e.g.: high/medium/ low).
2.4 Asset Register Data	<ul style="list-style-type: none"> Systematic and documented data collection process in place. High level of confidence in critical asset data.
2.5 Asset Condition	<ul style="list-style-type: none"> Condition assessment programme derived from benefit- cost analysis of options. Condition assessment of assets documented to allow review of key life cycle decisions and outcomes of Data validation process in place.
2.6 Risk Management	<ul style="list-style-type: none"> Risk Framework embedded in the organisation. Risk managed consistently across the organisation. High Focus Risk Actions Monitored.
3.1 Decision Making	<ul style="list-style-type: none"> Formal decision making and prioritisation techniques are applied to all operational and capital asset programmes within each main budget category. Critical assumptions and estimates are tested for sensitivity to results.
3.2 Operational Planning	<ul style="list-style-type: none"> Emergency response plans and business continuity plans are routinely developed and tested. Documented incident and Root Cause Analysis (RCA).
3.3 Maintenance Planning	<ul style="list-style-type: none"> Contingency plans for all key maintenance activities. Asset failure modes understood. Frequency of major preventative maintenance optimised using benefit-cost analysis. Life Cycle Planning of all assets Maintenance Backlog Transparent.
3.4 Capital Works Planning	<ul style="list-style-type: none"> Formal options analysis and business case development has been completed for major projects in the 3-5 year period. Processes for Design, modification and procurement documented including safety aspects.
3.5 Financial and Funding Strategies	<ul style="list-style-type: none"> Asset revaluations have data confidence. Ten year+ financial forecasts based on current comprehensive AMPS with detailed supporting assumptions / reliability factors. Asset Expenditure easily linked to finance databases.
4.1 AM Teams	<ul style="list-style-type: none"> All staff in the organisation understand their role in AM, it is defined in their job descriptions, performance plans, performance reviews and they receive supporting training aligned to that role.
4.2 AM Plans	<ul style="list-style-type: none"> Effective customer engagement in setting Levels of Service, ODM/risk techniques applied to major programmes.
4.3 Information Systems	<ul style="list-style-type: none"> Input of Data at Source to improve accuracy. More automated analysis reporting on a wider range of information. Asset information systems Plan.
4.4 Service Delivery Mechanisms	<ul style="list-style-type: none"> Internal service level agreements in place with internal service providers. Contracting approaches reviewed to identify best delivery mechanism. Tendering / contracting policy in place. Competitive tendering practices applied. Prioritisation and resourcing is planned to deliver AMP.
4.5 Quality Management	<ul style="list-style-type: none"> Process documentation implemented in accordance with the Quality Management System plan. All processes documented to appropriate level of detail. (Inspection. Design, Auditing, Asset Planning, Life cycle, AMP) Auditing of Asset Management processes.
4.6 Improvement Planning	<ul style="list-style-type: none"> Formal monitoring and reporting on the improvement programme to Executive Team. Project briefs developed for all key improvement actions.

9.4 Specific Asset Management Plan Improvements

Specific Asset Management Plan Improvements from the development of this Plan include:

Process

- Development of a formal Asset Management Policy and Strategies
- Prioritisation tools and process for development and replacement to value benefits and determine cost/benefit outcomes including reliability
- Ripple relay channel review and optimisation
- Document value created by AMG

Reliability

- Review the impact of lower routine and renewal spend than cohort on SAIFI, including capitalisation
- Review Tree Spend effectiveness and overall levels
- Provide guidance for coding weather and unknown faults to minimise them below a total of 20% of SAIDI
- Complete the reliability Improvement Plan
- Determine how to optimise SAIFI for lower groups for non pole/cross arm faults. Do groups need to be split with more reclosers.
- Develop a plan to reduce SAIFI to the cohort level including cost and priorities.
- Determine Value of Lost Load (VOLL) for different customer groups and apply to cost benefits
- Confirm impact of generators on SAIFI and any practical mitigations

Comparative Performance

- Engage with finance to determine if appropriate to update disclosure lives

Development

- Economics, solutions and cost benefit of stand alone power supplies for remote parts of the network due for replacement
- Include historical loads in forecasts for zone substations, subtransmission and Feeders
- Complete Point of Supply studies
- Introduce High, Medium and Low load forecasts and expenditure
- Engage with Commercial to resolve generator contracts for network support

Maintenance and Replacement

- Document switchgear lives, maintenance and replacement plans including cost, risk and asset value in relation to cohort. Confirm whether assets can age to cohort proportions.
- Document distribution transformer maintenance and replacement plans including cost, risk and asset value in relation to cohort. Confirm whether assets can age to cohort proportions.
- Confirm and document zone substation maintenance and replacement expenditure consistent with reliability needs and risk
- Determine the failure rates of 5-15 year defect poles and therefore the need for reinspection or replacement.
- Sample, analyse, tension test conductor to determine failure modes, determine maintenance and replacement processes. Forward forecast expenditure.
- Old ripple plant decommissioning plan and action.
- Measure and report tree and maintenance/replacement backlogs.

Appendix A

Disclosure 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 Network Demand
- 12d Report on Forecast Interruptions and Duration
- 13 Report on Asset Management Maturity

Company Name	The Lines Company Ltd
AMP Planning Period	1 April 2016 – 31 March 2026

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
 EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
 This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
		for year ended 31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
9	11a(i): Expenditure on Assets Forecast	\$000 (in nominal dollars)										
10	Consumer connection	3,255	1,277	3,330	2,746	687	702	1,190	734	750	766	1,138
11	System growth	368	1,090	909	2,931	1,197	1,523	799	896	61	126	1,550
12	Asset replacement and renewal	7,532	7,958	7,983	8,114	8,345	8,417	8,838	8,779	9,086	9,329	9,382
13	Asset relocations	11	11	11	11	12	12	12	12	13	13	13
14	Reliability, safety and environment:											
15	Quality of supply	326	379	494	352	202	295	387	305	253	69	685
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	918	736	303	197	414	579	902	324	817	661	70
18	Total reliability, safety and environment	1,243	1,116	797	549	616	874	1,289	630	1,070	730	755
19	Expenditure on network assets	12,408	11,452	13,031	14,352	10,857	11,528	12,128	11,050	10,980	10,965	12,838
20	Expenditure on non-network assets	4,497	3,328	1,016	242	303	310	258	145	148	152	155
21	Expenditure on assets	16,905	14,780	14,046	14,594	11,161	11,838	12,386	11,195	11,128	11,116	12,993
22												
23	plus Cost of financing	236	172	195	215	163	173	182	166	165	164	193
24	less Value of capital contributions	30	-	-	-	-	-	-	-	-	-	-
25	plus Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26												
27	Capital expenditure forecast	17,111	14,952	14,242	14,810	11,323	12,011	12,568	11,361	11,293	11,281	13,185
28												
29	Assets commissioned	12,408	11,452	13,031	14,352	10,857	11,528	12,128	11,050	10,980	10,965	12,838
30												
31												
32		\$000 (in constant prices)										
33	Consumer connection	3,255	1,277	3,272	2,642	647	647	1,074	647	647	647	940
34	System growth	368	1,090	894	2,821	1,128	1,404	720	791	53	107	1,281
35	Asset replacement and renewal	7,532	7,958	7,844	7,809	7,861	7,759	7,971	7,747	7,846	7,882	7,757
36	Asset relocations	11	11	11	11	11	11	11	11	11	11	11
37	Reliability, safety and environment:											
38	Quality of supply	326	379	486	339	190	272	349	269	218	59	567
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	918	736	298	189	390	534	813	286	706	558	58
41	Total reliability, safety and environment	1,243	1,116	783	529	581	806	1,162	556	924	617	624
42	Expenditure on network assets	12,408	11,452	12,804	13,811	10,228	10,626	10,938	9,752	9,481	9,264	10,614
43	Expenditure on non-network assets	4,497	3,328	998	233	286	286	233	128	128	128	128
44	Expenditure on assets	16,905	14,780	13,802	14,044	10,514	10,912	11,171	9,880	9,609	9,392	10,742
45												
46	Subcomponents of expenditure on assets (where known)											
47	Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
48	Overhead to underground conversion	-	-	-	-	-	-	-	-	-	-	-
49	Research and development	-	-	-	-	-	-	-	-	-	-	-
50												

Company Name **The Lines Company Ltd**
 AMP Planning Period **1 April 2016 – 31 March 2026**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
 EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
 This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
		for year ended 31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
	Difference between nominal and constant price forecasts	\$000										
54	Consumer connection	-	-	58	104	40	55	117	86	102	119	197
55	System growth	-	-	16	111	69	119	78	105	8	20	269
56	Asset replacement and renewal	-	-	139	306	484	658	867	1,031	1,240	1,447	1,626
57	Asset relocations	-	-	0	0	1	1	1	1	2	2	2
58	Reliability, safety and environment:											
59	Quality of supply	-	-	9	13	12	23	38	36	35	11	119
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	-	5	7	24	45	88	38	112	102	12
62	Total reliability, safety and environment	-	-	14	21	36	68	126	74	146	113	131
63	Expenditure on network assets	-	-	227	541	629	902	1,189	1,298	1,499	1,700	2,224
64	Expenditure on non-network assets	-	-	18	9	18	24	25	17	20	24	27
65	Expenditure on assets	-	-	244	550	647	926	1,215	1,315	1,519	1,724	2,251

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
		for year ended 31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
68	11a(ii): Consumer Connection	\$000 (in constant prices)					
69	<i>Consumer types defined by EDB*</i>						
70	Urban A	138	350	895	723	177	177
71	Rural B	57	140	358	289	71	71
72	Rural C	103	259	665	537	131	131
73	Rural D	2,919	431	1,105	892	219	219
74	Remote Rural E	20	51	130	105	26	26
74	Remote Rural F	19	47	119	96	24	24
75	<i>*include additional rows if needed</i>						
76	Consumer connection expenditure	3,255	1,277	3,272	2,642	647	647
77	less Capital contributions funding consumer connection	-	-	-	-	-	-
78	Consumer connection less capital contributions	3,255	1,277	3,272	2,642	647	647

79	11a(iii): System Growth						
80	Subtransmission	-	-	-	-	181	-
81	Zone substations	-	-	630	1,722	735	485
82	Distribution and LV lines	-	869	207	992	105	616
83	Distribution and LV cables	-	-	57	-	-	107
84	Distribution substations and transformers	263	-	-	-	-	90
85	Distribution switchgear	-	221	-	107	107	107
86	Other network assets	105	-	-	-	-	-
87	System growth expenditure	368	1,090	894	2,821	1,128	1,404
88	less Capital contributions funding system growth	-	-	-	-	-	-
89	System growth less capital contributions	368	1,090	894	2,821	1,128	1,404

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
 EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
 This information is not part of audited disclosure information.

sch ref

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
11a(iv): Asset Replacement and Renewal	\$000 (in constant prices)					
Subtransmission	498	1,299	1,524	1,280	1,371	1,382
Zone substations	253	142	37	183	123	240
Distribution and LV lines	5,069	5,501	5,357	5,429	5,314	5,258
Distribution and LV cables	-	-	236	236	499	236
Distribution substations and transformers	128	362	362	362	362	450
Distribution switchgear	95	219	72	198	72	72
Other network assets	1,489	435	255	120	120	120
Asset replacement and renewal expenditure	7,532	7,958	7,844	7,809	7,861	7,759
less Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
Asset replacement and renewal less capital contributions	7,532	7,958	7,844	7,809	7,861	7,759

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
11a(v): Asset Relocations	\$000 (in constant prices)					
<i>Project or programme*</i>						
Miscellaneous	11	11	11	11	11	11
	-					
	-					
	-					
	-					
<i>*include additional rows if needed</i>						
All other project or programmes - asset relocations	-					
Asset relocations expenditure	11	11	11	11	11	11
less Capital contributions funding asset relocations	-	-	-	-	-	-
Asset relocations less capital contributions	11	11	11	11	11	11

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
11a(vi): Quality of Supply	\$000 (in constant prices)					
<i>Project or programme*</i>						
11kV Fdr Dev - Feeder Development	-	-	-	63	-	-
11kV Fdr Dev - Switch Automation and Renewal	273	274	171	213	190	272
Sub & 33 Dev - Substations	53	105	-	63	-	-
Sub & 33 Dev - Supply Points	-	-	315	-	-	-
	-					
<i>*include additional rows if needed</i>						
All other projects or programmes - quality of supply	-					
Quality of supply expenditure	326	379	486	339	190	272
less Capital contributions funding quality of supply	-	-	-	-	-	-
Quality of supply less capital contributions	326	379	486	339	190	272

Company Name **The Lines Company Ltd**
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SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
11a(ix): Non-Network Assets						
Routine expenditure						
<i>Project or programme*</i>						
Eng & Asset Capital - Data Systems	96	26	26	131	184	184
Eng & Asset Capital - Misc Equip	11	11	11	11	11	11
Eng & Asset Capital - Office Area	21	22	22	22	22	22
Eng & Asset Capital - Vehicle Replacements	68	69	69	69	69	69
Eng & Asset Capital - Metering	2,800	-	-	-	-	-
<i>*include additional rows if needed</i>						
All other projects or programmes - routine expenditure	-	-	-	-	-	-
Routine expenditure	2,997	128	128	233	286	286
Atypical expenditure						
<i>Project or programme*</i>						
Eng & Asset Capital - Building Re-structure	1,500	3,200	870	-	-	-
	-	-	-	-	-	-
	-	-	-	-	-	-
	-	-	-	-	-	-
	-	-	-	-	-	-
<i>*include additional rows if needed</i>						
All other projects or programmes - atypical expenditure	-	-	-	-	-	-
Atypical expenditure	1,500	3,200	870	-	-	-
Expenditure on non-network assets	4,497	3,328	998	233	286	286

Company Name **The Lines Company Ltd**
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SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes). This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10	
	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	
9	Operational Expenditure Forecast	\$000 (in nominal dollars)											
10	Service interruptions and emergencies	1,262	1,252	1,274	1,301	1,329	1,358	1,388	1,418	1,449	1,481	1,514	
11	Vegetation management	851	1,061	1,080	1,103	1,127	1,151	1,177	1,203	1,229	1,256	1,284	
12	Routine and corrective maintenance and inspection	1,062	1,069	1,088	1,110	1,134	1,159	1,129	1,154	1,180	1,206	1,232	
13	Asset replacement and renewal	302	190	193	197	202	206	211	215	220	225	230	
14	Network Opex	3,477	3,572	3,635	3,711	3,791	3,875	3,904	3,990	4,078	4,168	4,260	
15	System operations and network support	3,114	2,124	2,161	2,207	2,255	2,304	2,355	2,407	2,460	2,514	2,569	
16	Business support	3,787	5,574	5,672	5,792	5,916	6,047	6,180	6,315	6,454	6,596	6,742	
17	Non-network opex	6,901	7,697	7,834	7,999	8,171	8,351	8,534	8,722	8,914	9,110	9,311	
18	Operational expenditure	10,378	11,269	11,468	11,710	11,962	12,225	12,439	12,712	12,992	13,278	13,570	
19		\$000 (in constant prices)											
20	Service interruptions and emergencies	1,262	1,252	1,252	1,252	1,252	1,252	1,252	1,252	1,252	1,252	1,252	
23	Vegetation management	851	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061	1,061	
24	Routine and corrective maintenance and inspection	1,062	1,069	1,069	1,069	1,069	1,069	1,019	1,019	1,019	1,019	1,019	
25	Asset replacement and renewal	302	190	190	190	190	190	190	190	190	190	190	
26	Network Opex	3,477	3,572	3,572	3,572	3,572	3,572	3,522	3,522	3,522	3,522	3,522	
27	System operations and network support	3,114	2,124	2,124	2,124	2,124	2,124	2,124	2,124	2,124	2,124	2,124	
28	Business support	3,787	5,574	5,574	5,574	5,574	5,574	5,574	5,574	5,574	5,574	5,574	
29	Non-network opex	6,901	7,697										
30	Operational expenditure	10,378	11,269	11,269	11,269	11,269	11,269	11,219	11,219	11,219	11,219	11,219	
31	Subcomponents of operational expenditure (where known)												
32	Energy efficiency and demand side management, reduction of energy losses	346	630	630	630	630	630	630	630	630	630	630	
33	Direct billing*	1,187	1,629	1,629	1,629	1,629	1,629	1,629	1,629	1,629	1,629	1,629	
34	Research and Development	-	-	-	-	-	-	-	-	-	-	-	
35	Insurance	212	156	156	156	156	156	156	156	156	156	156	
37	* Direct billing expenditure by suppliers that direct bill the majority of their consumers												
38													
39													
40		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10	
41		for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
41	Difference between nominal and real forecasts	\$000											
42	Service interruptions and emergencies	-	-	22	49	77	106	136	167	198	230	262	
43	Vegetation management	-	-	19	42	65	90	115	141	168	195	222	
44	Routine and corrective maintenance and inspection	-	-	19	42	66	91	111	136	161	187	213	
45	Asset replacement and renewal	-	-	3	7	12	16	21	25	30	35	40	
46	Network Opex	-	-	63	140	220	303	383	469	557	646	738	
47	System operations and network support	-	-	38	83	131	180	231	283	336	390	445	
48	Business support	-	-	99	218	343	473	606	742	881	1,023	1,168	
49	Non-network opex	-	-	136	302	474	653	837	1,025	1,217	1,413	1,613	
50	Operational expenditure	-	-	199	441	693	956	1,220	1,494	1,773	2,059	2,351	

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SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref	Asset condition at start of planning period (percentage of units by grade)										
	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1-4)	% of asset forecast to be replaced in next 5 years
7											
8											
9											
10	All	Overhead Line	Concrete poles / steel structure	No.	0.66%	0.95%	65.39%	12.09%	20.91%	3	6.35%
11	All	Overhead Line	Wood poles	No.	1.72%	1.83%	40.55%	6.42%	49.48%	2	6.35%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	N/A	-	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	12.66%	66.39%	0.15%	20.79%	2	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	N/A	-	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	41.18%	22.67%	36.15%	2	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	N/A	-	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	N/A	-	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	N/A	-	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	N/A	-	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	N/A	-	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	N/A	-	-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	N/A	-	-
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	N/A	-	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	88.89%	11.11%	-	3	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	N/A	-	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	N/A	-	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	1.82%	52.73%	45.45%	-	3	3.64%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	N/A	-	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	16.75%	69.63%	13.61%	-	3	-
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	N/A	-	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	N/A	-	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	N/A	-	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	2.78%	-	73.61%	23.61%	-	3	5.56%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	83.33%	16.67%	-	3	-
35											

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SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

		Asset condition at start of planning period (percentage of units by grade)									
Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1-4)	% of asset forecast to be replaced in next 5 years	
36											
37											
38											
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	-	89.47%	10.53%	-	3	5.26%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	15.28%	62.77%	0.67%	21.28%	2	1.68%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	N/A	-	-
42	HV	Distribution Line	SWER conductor	km	-	13.77%	47.01%	0.64%	38.58%	2	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.35%	1.26%	5.04%	7.53%	85.82%	2	4.07%
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	-	-	N/A	-	-
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	N/A	-	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	0.49%	2.43%	46.12%	26.21%	24.76%	2	4.85%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	100.00%	-	3	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	0.05%	8.62%	66.71%	19.26%	5.35%	2	0.04%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	27.78%	72.22%	-	3	5.56%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	62.50%	37.50%	-	3	-
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.02%	0.21%	64.51%	16.39%	18.87%	2	0.15%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.57%	-	71.95%	27.48%	-	3	2.29%
53	HV	Distribution Transformer	Voltage regulators	No.	-	3.03%	65.66%	31.31%	-	3	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	44.44%	55.56%	-	3	-
55	LV	LV Line	LV OH Conductor	km	-	9.83%	48.14%	0.65%	41.37%	2	-
56	LV	LV Cable	LV UG Cable	km	-	0.49%	2.39%	1.75%	95.37%	2	0.49%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	4.69%	41.92%	0.19%	53.20%	2	-
58	LV	Connections	OH/UG consumer service connections	No.	0.70%	0.13%	64.47%	26.35%	8.36%	2	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	8.89%	90.37%	0.74%	-	3	-
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	8.53%	6.20%	62.79%	22.48%	-	3	-
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	100.00%	-	4	-
62	All	Load Control	Centralised plant	Lot	-	33.33%	41.67%	25.00%	-	3	-
63	All	Load Control	Relays	No.	-	-	88.89%	11.11%	-	3	-
64	All	Civils	Cable Tunnels	km	-	-	-	-	N/A	-	-

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SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 12b(i): System Growth - Zone Substations

8		Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	<i>Existing Zone Substations</i>									
10	Arohena	3.0	-	N	1.7	-	-	-	No constraint within +5 years	
11	Atiamuri	10.0	-	N	-	-	-	-	Transformer	Due to backfeed when Whakamaru (T8) is out of service.
12	Awamate Road	1.2	-	N	1.3	-	-	-	No constraint within +5 years	
13	Borough	8.7	5.0	N-1	2.5	175%	5.0	175%	No constraint within +5 years	
14	Gadsby Rd	6.2	-	N	5.5	-	-	-	No constraint within +5 years	
15	Hangatiki	3.8	-	N	1.3	-	-	-	No constraint within +5 years	
16	Kaahu Tee	1.7	-	N	0.9	-	-	-	No constraint within +5 years	
17	Kiko Rd	1.3	-	N	0.4	-	-	-	No constraint within +5 years	
18	Kuratau	2.6	1.5	N-1	0.1	174%	3.0	90%	No constraint within +5 years	
19	Mahoenui	1.2	-	N	0.5	-	-	-	No constraint within +5 years	
20	Manunui	1.8	-	N	1.2	-	-	-	No constraint within +5 years	
21	Maraetai	5.0	-	N	0.5	-	5.0	119%	No constraint within +5 years	
22	Marotiri	2.7	-	N	1.3	-	-	-	No constraint within +5 years	
23	Mokai	3.2	-	N	1.1	-	-	-	No constraint within +5 years	
24	National Park	1.9	-	N	1.2	-	-	-	No constraint within +5 years	
25	Nihoniho	0.6	-	N	0.7	-	-	-	No constraint within +5 years	
26	Oparure	1.5	-	N	1.1	-	-	-	No constraint within +5 years	
27	Otukou	0.2	-	N	-	-	-	-	No constraint within +5 years	
28	Taharoa	14.2	10.0	N-1	-	-	15.0	162%	Transformer	Industrial customer driven load growth
29	Tawhai	4.5	-	N	0.7	-	-	-	No constraint within +5 years	
30	Te Anga	2.1	-	N	0.2	-	-	-	No constraint within +5 years	
31	Te Waireka Rd	10.8	10.0	N-1	2.1	-	10.0	116%	No constraint within +5 years	
32	Tokaanu	0.2	-	N	-	-	-	-	No constraint within +5 years	
33	Tuhua	1.3	-	N	0.8	-	-	-	No constraint within +5 years	
34	Turangi	5.8	5.0	N-1	2.0	-	5.0	107%	No constraint within +5 years	
35	Waiotaka	0.5	-	N	0.5	-	-	-	No constraint within +5 years	
36	Wairere	2.9	2.5	N-1	1.1	115%	2.5	118%	No constraint within +5 years	
37	Waitete	8.9	10.0	N-1	3.8	89%	10.0	71%	No constraint within +5 years	

¹ Extend forecast capacity table as necessary to disclose all capacity by each zone substation

Company Name **The Lines Company Ltd**
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SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

12c(i): Consumer Connections		Number of connections					
		Current Year CY 31 Mar 16	CY+1 31 Mar 17	CY+2 31 Mar 18	CY+3 31 Mar 19	CY+4 31 Mar 20	CY+5 31 Mar 21
Number of ICPs connected in year by consumer type							
Consumer types defined by EDB*							
Urban A		43	29	29	29	29	29
Rural B		2	4	4	4	4	4
Rural C		19	20	20	20	20	20
Rural D		56	44	44	44	44	44
Remote Rural E		5	5	5	5	5	5
Remote Rural F		2	4	4	4	4	4
Connections total		127	106	106	106	106	106
*include additional rows if needed							
Distributed generation							
Number of connections		8	8	8	8	8	8
Capacity of distributed generation installed in year (MVA)		0.02	0.02	0.02	0.03	0.03	0.03
12c(ii) System Demand							
Maximum coincident system demand (MW)							
GXP demand		56	57	57	58	59	60
plus Distributed generation output at HV and above		8	8	8	8	9	9
Maximum coincident system demand		64	65	66	67	68	69
less Net transfers to (from) other EDBs at HV and above		-	-	-	-	-	-
Demand on system for supply to consumers' connection points		64	65	66	67	68	69
Electricity volumes carried (GWh)							
Electricity supplied from GXPs		299	303	308	312	316	321
less Electricity exports to GXPs		4	4	4	4	4	4
plus Electricity supplied from distributed generation		67	68	69	70	71	72
less Net electricity supplied to (from) other EDBs		(11)	(12)	(12)	(12)	(12)	(12)
Electricity entering system for supply to ICPs		373	379	384	389	395	400
less Total energy delivered to ICPs		339	344	349	354	358	364
Losses		34	35	35	36	36	37
Loss factor		67%	67%	67%	67%	67%	67%
Loss ratio		9.2%	9.2%	9.2%	9.2%	9.2%	9.2%

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Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
8							
9							
10	SAIDI						
11	Class B (planned interruptions on the network)	39.5	39.5	39.5	39.5	39.5	39.5
12	Class C (unplanned interruptions on the network)	169.3	169.3	169.3	169.3	169.3	169.3
13	SAIFI						
14	Class B (planned interruptions on the network)	0.25	0.25	0.25	0.25	0.25	0.25
15	Class C (unplanned interruptions on the network)	2.82	2.82	2.82	2.82	2.82	2.82

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Company Name
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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB's self-assessment of the maturity of its asset management practices.

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2	The Lines Company's (TLC) Asset Management Policy is derived from, and is consistent with TLC's Statement of Corporate Intent. The Asset Management Policy is consistent with other organisational policies. The Asset Management Policy is reviewed and updated every 12-18 months by the TLC Board of Directors. The Asset Management Policy and Strategy flow into the Asset Management Plan (AMP) and one of the objectives of the AMP is to communicate the Asset Management Policy and Asset Management Strategy to stakeholder, regulatory bodies, customers, TLC employees and the general public. An electronic copy of the AMP is available on the TLC website and bound paper copies are available be by request.	TLC Statement of Corporate Intent, AMP, Asset Management Policy.	Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (e.g., as required in PAS 55 para 4.2 I). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	2	The Asset Management Strategies are identified from the Strategic review and the Statement of Corporate Intent; the agreement between TLC and its owners. TLC ensures that the Asset Management Strategy is consistent with other organisational policies and strategies and aligns with the needs of other stakeholders. The AMP is aligned to and is part of TLC's Asset Management Policy and forms a significant part of the asset management strategy. One of the objectives of AMP is to communicate the Asset Management Policy and Asset Management Strategy to stakeholder, regulatory bodies, customers, TLC employees and general public.	TLC Statement of Corporate Intent, AMP	In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (e.g., as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same policies, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	2	When establishing the a long term asset management strategy TLC has considered the asset related risk, the physical condition of the assets, age profile, flexibility and suitability of the assets and their intended use. Other items that have been considered are asset type, condition, and historical asset related information such as reliability, maintenance records and operational performance.	AMP	Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2	The Asset and Engineering Team prepare the AMP annually. Part of the process is reviewing the previous years AMP and discussing information that stakeholders wish to have included. When establishing the Asset Management Plan TLC has taken into consideration: <ul style="list-style-type: none"> • Asset Management Policy • Risk management Policy • TLC's existing asset management objectives and performance and condition targets • Financial and resource capabilities or constraints • Life cycle costs • Legal, regulatory, statutory and other asset management requirements • Historic and predicted asset condition, deterioration and failure mechanism and performance profiles. 	AMP	The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2	At the start of each financial year completed copies of the AMP are distributed to TLC's Trust shareholders, Board of Directors, Finance Team, Communications Team, Asset and Engineering Team, Contracting Team and various regulatory bodies. Electronic copies of the AMP are available for all employees on TLC's Network database. An electronic copy of the AMPs available on the TLC website for customers and members of the public, bound paper copies are available by request. TLC keeps an up to date record of all distributed AMPs.	AMP Distribution Register	Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	2	Designated responsibilities for delivery of the AMP are documented and set out in the asset and engineering team structure. The asset and engineering team is governed by the Chief Asset Officer. The Chief Asset Officer has overall responsibility of network management, including the preparation, drafting, and implementation of the AMP. These are also documented in employee position descriptions.	Copy of the structure can be found in section 2 of the AMP and in employee position descriptions.	The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	2	TLC endeavours to align the staff numbers, structure and skills to ensure an efficient and cost effective implementation of the asset management plan. TLC has resources in place for the implementation of the asset management plan; however these resources are not yet adequately sufficient. Due to the difficulty of attracting staff to the King Country and the increasing regulatory requirements it is not always possible to have the required staff numbers.	AMP	It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	2	TLC's Contingency budgets are set in section 5 (Reliability, Safety and environmental Development Program) of the AMP, the Risk Policies are outlined in Section 7 (Risk Management) of the AMP. Contingency budgets are set aside each year to cover any unforeseen capital works such as tap-off fuses for new connection, SCADA, distribution transformers, protection relays and radio systems including repeater sites. TLC recognise that risk is defined as the product of probability and consequences therefore the planning criteria and assumptions are based on this recognition. TLC has in place a Civil Defence Plan and an Event Management Plan.	AMP Section 5 (Reliability, Safety and environmental Development Program) of the AMP, the Risk Policies are outlined in Section 7 (Risk Management) Civil Defence Plan and an Event Management Plan	Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	2	The Asset and Engineering Team are responsible for carrying out the various activities that are specified in the AMP and individuals within the groups have various delegated authorities to implement the Asset Management Plan. Designated responsibilities for delivery of the Asset Management Plan are documented and set out in the Asset and Engineering Team structure.	Copy of the structure can be found in section 2 of the AMP and Employee position descriptions.	In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets e.g., para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	TLC understands the need for sufficient resources; a budget has been allocated for resources such as staff, material, equipment and services from third parties. TLC endeavours to align the staffing, the structure and skills with the AMP to ensure effective and efficient implementation.	Section 2 of AMP.	Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and charge hands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	2	Top management communicate the importance of meeting its asset management requirements during an annual road show.	Company Road Show.	Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (e.g., PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walkabouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	2	Most asset management tasks, including asset inspection, are undertaken in-house by the Asset and Engineering Team. The Engineers in the team inspect and prepare detailed designs and specifications, including legal and regulatory approvals for all capital and maintenance works, these are then issued to TLC's in-house service provider or external specialist contractors. The internal service provider is mainly staffed for fault response, however they carry out about 70% of the capital and maintenance works. The balance of the work is then subcontracted out to external contractors. Independent Contractor Agreements are put in place with external providers; the contract agreement provide detailed designs and specifications of the work to be done, the legal and regulatory requirement associated with the job and the rules and procedures that the contractor shall abide by when working on TLC's network. Specialist work such as SCADA, communications and vegetation is controlled directly by the Asset and Engineering Team but is completed by contractors.	Section 2 of AMP, Service Agreements with contractors	Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (e.g., PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2	TLC uses the understandings gained from the asset management policies and strategies to help identify the resources requirements and then plan, provide and record the training necessary to achieve the competencies. The current strategy has been to employ a number of industry experienced and qualified personnel, and then use them to impart their knowledge in training local people.	Section 2 of the AMP.	There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2	TLC uses the understandings gained from risk assessments and the performance of risk control strategies to identify the competency requirements and then plan, provide and record the training necessary to achieve the competency level. TLC supports personal development and training of all employees.		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (e.g., PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	2	Moving forward TLC's strategy to overcome the skills shortage will be to encourage personal development and training of current employees. TLC has also undertaken a programme to attract local graduates to the organisation.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	2	Two way communication exists between TLC and its shareholders, TLC provides its shareholders with regular newsletters, which include information on non-financial performance. Annual and Half yearly reports comprising of a report from the board of directors covering the operations for the reporting period and consolidation financial statements for the reporting period are delivered to the shareholders. TLC also supplies its shareholders with auditors' report on the financial statement and the performance targets (together with other measures by which the performance of the company has been judged in relation to the Company's objectives). Furthermore TLC provides its stakeholders with the annual capital expenditure budget adopted by the board, including identification of all programmed projects with a capital expenditure in excess of \$200,000.	Statement Of Corporate Intent	Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	TLC has used three systems; a Financial System (Navision), Billing System (Gentrack), and an Asset Data System (Basix). All have an SQL server databases and data is being exchanged between systems. The financial system is based on a Navision software package over an SQL server database. In addition to processing and providing financial information for the various companies associated with TLC, it includes detailed job costing packages. The financial system is stable, but further development is needed to give the low level detailed reports required. The billing software is based on a heavily modified Talgentra system over an SQL server database. The "off the shelf" volumetric traditional billing system had to be modified to an extent far greater than originally envisioned to cope with demand based billing. The asset management system is based on BASIX software over an SQL server database. The BASIX system contains asset data and is used to calculate reliability statistics and valuations. It also produces reports that align with the network performance criteria in the Asset Management Plan.	Section 2 of the AMP	Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (i.e., the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (e.g., s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	2	TLC has determined what its asset management information system should contain by reviewing historically recorded data, the increasing requirements from various regulatory bodies, the safety management system requirements, internal information required for pricing and billing, as well as the intellectual knowledge of staff. The asset management information system is regularly reviewed and improved when necessary.	Section 2 of the AMP	Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document Information
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	2	The data in Basix is stored in various SQL server tables that are viewed and written to by the various Basix user interface forms. Reports are run in SQL to pick up variances between actual data and the system held data. Control of the database is maintained by assigning individuals different levels of authority. Mandatory field are set up in the Basix database, this means that when new assets are entered into the database these fields must be populated before the program allows you to save the asset. All asset changes are tracked through an audit tracer that is built into the database.	Section 2 of the AMP	The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (e.g., s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	TLC's asset management information system is reviewed and aligned current asset management requirements, it also aligns with the increasing regulatory and safety management requirement. TLC has included in the annual plan a budget for information system upgrades and maintenance, the asset management information system is regularly reviewed and improved when necessary.	Section 2 of the AMP	Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2	TLC uses formal and informal studies based on industry experience and information to identify risks. The process and procedures for the identification and assessment of asset and asset management related risks throughout the asset lifecycle is documented in the Distribution Policies and Standard. The details of asset risk policies are included in the distribution standard codes, policies and other documents. The policies also include various techniques for identifying, quantifying and managing asset related risk with varying levels of complexity. TLC constantly review its individual requirements in terms of risk identification, including the availability of information and implementation practicalities of reduction strategy.	Section 7 of the AMP	Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (e.g., para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	TLC reviews and analyses the results of the risk assessment, once an understanding is gained the results are then used to help identify the resources, training and competency requirements to achieve the asset management strategy. TLC believes on-going training, assessment and monitoring is important to ensure staff are competent to complete assigned tasks.	Section 7 of the AMP	Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	2	The Asset Management Policy identifies TLC's legal, regulatory and statutory requirements. It also identifies the regulatory compliance documentation that must be prepared and published by the asset and engineering team. Electronic copies of TLC's regulatory documents are available on the TLC website and bound paper copies are available by request.	Stated in the AMP	In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (e.g., PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	2	TLC's overarching asset management strategy is to have policies, systems and procedures in intellectual understanding to create, operate and maintain a sustainable network. TLC has established an asset management procedure to assist with the implementation of the Asset Management Plan; the procedure outlines the responsibilities of the asset management group, this includes the responsibilities of maintenance and project works. The design, modification, construction and commissioning activities are set out in TLC's distribution standards and the operations of assets are covered by the operating procedures. The Basix database allows TLC to monitor the life cycle activities of all network assets. The Basix database is used to record the creation, acquisition, procurement and enhancement of network assets as well as recording asset information, condition and expenditure.	AMP, Distribution Standard, Operating Procedures, Basix Database	Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (e.g., PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	2	TLC's process and procedures are reviewed regularly; the asset management procedure, distribution standard and operating procedure are reviewed every 12-18 months. Due to the increasing regulatory requirement the Basix database is constantly reviewed and updated to ensure it is effective and efficient as well as ensuring it aligns with the asset management policy, strategy and objectives and the asset management plan.	AMP, Distribution Standard, Operating Procedures, Basix Database	Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (e.g., as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	Reliability monitoring is done via the Basix system. Fault information is entered from daily reporting sheets, which in turn are completed from a variety of sources including SCADA, sentries, the telephone database and control room data. Monthly performance reports are generated and reviewed at management level and reported at board level. Equipment failures in the various sections of the network and the SAIDI/SAIFI effects of these are monitored closely. Reports are set up in the Basix system to produce the regulatory and internal performance data, including Commerce Commission Decision reports. The BASIX system is used to report asset performance and effectiveness such as voltage complaints and system component failures. The ratio of billed kVA to the sum of the kVA of distribution transformers is determined from BASIX and the billing data boxes by running sequel server reports. Network technical losses are calculated using models that include the effects of generation. The BASIX system is also used to report on the customer service levels. These include time to restore supply and maximum number of shutdowns.	AMP, Basix Database	Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to-end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).

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Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document Information
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformance is clear, unambiguous, understood and communicated?	2	The responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non-conformances are documented and outlined in TLC's Accidents/Incident Management Procedure and the Network Access and Operating Competency Procedure. The Accidents/Incident Management Procedure is communicated to employees during the company induction. The Network Access and Operating Competency Procedure is communicated during the network induction Process.	Accidents/Incident Management Procedure. Network Access and Operating Competency	Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformance. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on internet etc.
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	1	TLC recognises and understands the need for systematic checks, especially of the effectiveness of its asset management process. Currently the asset management procedures and processes are reviewed every 12-18 months; changes to the procedures and processes are made to reflect the outcomes of the review.	Review Log for Processes and Procedure	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (e.g., the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	2	Investigation and mitigation of asset-related failures, incidents and emergency situations and non-conformances are documented in TLC's Accidents/Incident Management Procedure and the Network Access and Operating Competency Procedure. As part of the accident/incident investigation a Root Cause Analysis (RCA) is conducted is to identify the factors that resulted in the nature, the magnitude, the location, and the timing of the harmful outcomes (consequences) of one or more past events in order to identify what behaviours, actions, inactions, or conditions need to be changed to prevent recurrence of similar harmful outcomes and to identify the lessons to be learned to promote the achievement of better consequences.	Nonconformities and incidents are outline in operating procedure 12 - appendix D. Root Cause Analysis is carried out on asset related failure.	Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	2	TLC is continually assessing and improving the performance, condition, related risk, and cost of assets across their whole lifecycle. TLC has performance measures in place to meet regulatory requirement, to ensure each customer is receiving the promised standard of service and to measure the performance of the assets both physically and financially. Where gaps, poor performance and non-conformance exist TLC instigate appropriate corrective and/or preventative action to eliminate or prevent the causes. Where performance targets are achieved TLC finds new and innovative ways to maintain or improve asset performance both financially and physically.	Performance Target, Basix database improvements	Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather than reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.

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Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document Information
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	2	TLC acquires knowledge about new asset management related technology and practices by researching international papers and standard to identify benchmarks for asset management practices, as well as sending engineering staff on conferences and forums to gain knowledge of new and innovative asset management techniques and practices. TLC also actively engage in industry discussions with other networking companies, professional bodies and regulatory bodies about what are the best asset management system, technology and practices.	R&D documents.	One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (e.g., by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.