Asset Management Plan 2015 – 2025

Eastland Network

1 April 2015

Summary of ENL's AMP

Purpose of the AMP

This Asset Management Plan ("AMP") has been prepared to meet regulatory compliance requirements, demonstrate responsible asset stewardship, integrate stakeholder views, and communicate and justify network management practice and expenditure to Eastland Network Limited ("ENL") stakeholders. Presentation of the AMP in this format also meets the requirements of the Electricity Distribution Information Disclosure Determination 2012.

Primary stakeholders include ENL's shareholder and customers, including retailers, generators and end-use electricity consumers. Other parties with an interest in ENL's asset management include contractors who physically work on the system and regulatory agencies.

Many factors impact on the effective long term management of a complex network of electricity assets, the life of which exceeds the tenure of the Managers responsible for them and whose operating environment introduces significant investment risks. For this reason, the overall scope of the AMP is wide, covering the regulatory environment, future service demands and technology development.

While making long term forecasts to provide sustainability and establish the framework for ENL's future, the AMP primarily drives work programs in the short to medium term. It is in all respects a living document. The practices and processes described are subject to continuous improvement, and detailed work programs are progressively refined throughout the year. The Eastland Group asset management team is the "owner" of this AMP.

Completion date & planning period

Preparation of the AMP was undertaken between January 2015 and March 2015.

The ten year planning period considered is from 01 April 2015 to 31 March 2025.

The plan documents how ENL ensures long lived network assets are being managed in a sustainable way over their lifecycle within defined boundaries of Shareholder returns, Regulatory requirements for performance and revenues, Customer expectations and Regulatory requirements for Safety and Quality.

The ENL Board of Directors approved the AMP for disclosure on 31 March 2015.
The next revision of the AMP, (covering the period 2016 to 2026) will be prepared for disclosure on 1 April 2016.

Transfer of the Eastland Transmission Spur Assets

In previous plans information relating to the possible acquisition of Transpower Eastland transmission spur assets by ENL was included in order to form part of the basis for discussions between ENL and the Commerce Commission regarding the proposal, (ie. impact on future ENL regulatory price resets and quality performance targets).
Post the satisfactory outcome of discussions with the Commerce Commission and negotiations with Transpower on 31 March 2015 ENL acquired the following Transmission Assets;

- Gisborne 110/50kV Substation
- Wairoa 110/11kV Substation
- Tuai 110/11kV T15 Transformer
- Tokomaru Bay 110kV Substation
- Tuai – Gisborne 110kV Transmission lines
- Tuai – Wairoa 110kV Transmisson lines
- Gisborne – Tokomaru Bay 110kV Transmission line

Acquisition of these assets previously owned and operated by Transpower was undertaken to provide the following benefits;

- Enhanced operation of the 110kV supply to the Gisborne and Wairoa regions;
- Material reduction in the cost of managing and operating the Eastland transmission spur assets;
- Optimisation of capital expenditure across, transmission, distribution and embedded generation;
- Reduced regional coincident peak demand.

As a consequence of the above, it is expected that the transfer of Eastland transmission spur assets to ENL will over the long term provide a sustainable economic benefit to the Gisborne and Wairoa regions, (and communities), through providing total transmission and distribution pricing stability and reduction. (Refer Section 4.7.1.1, Transmission Development for further detail).

There is significant opex and capex expenditure associated with the Eastland transmission spur assets, this expenditure has been included in forecasts. At this time these forecasts in the main reflect a carry over of Transpower's existing plans and expenditure budgets. As the assets are re-assessed updated expenditure forecasts will be included in future versions of this plan.

AM systems & information

A quality management system is used to provide policy and procedures covering, Health and Safety, Public Health and Safety, Risk Management, Design Standards, Project Management and Emergency Management.

Asset information covering physical attributes, condition and performance is stored in Databases associated with the GIS system. Standalone systems provide Work management and financial management capabilities.

This plan includes expenditure associated with replacing ENL's GIS and work management system, and upgrading ENL's drawing management system and a number of other ancillary systems. The replacement and upgrading of these systems requires an additional $1.5 million of non-network capex during the planning period. The expenditure is almost solely renewal/replacement related hence efficiency improvements will be relatively small. With that said, as the project business cases are developed it is expected that some efficiency benefits will be recognised and incorporated into future reviews of this plan.

A SCADA system (Supervisory Control and Data Acquisition) provides real time data, trending information and enables remote control of key components of the network. This data and network modelling software are used to analyse the network and assess the impact of changes in utilisation and operation.

Strategic Plans, Business Plans, Budget Processes and the asset management process set the programs for maintenance and asset development to ensure optimum customer service and operational efficiency within financial boundaries. This includes the recognition of the needs of customers that are willing to pay to have additional security and/or reliability of supply. Implicit in the asset planning process is an understanding and evaluation of the risks to operation and the consequences of failure.

The processes activities that form the core of asset management practice and decision making at ENL are regulatory requirement evaluation, condition assessment, reliability performance analysis, asset utilisation/capacity evaluation, risk management, economic optimisation, stakeholder feedback and benchmarking.

Management services are provided by the Eastland Group to ENL. The management services include executive support, financial management, general IT services, planning, design and network operating activities. Since all physical work on the network is contracted out, the network operating function includes significant responsibility for contractor management. In addition to applying commercial disciplines to project identification and justification, ENL negotiates competitive contracts for maintenance and capital projects. The need to train and continuously upgrade the skills of internal staff is recognised through improvement programs and specific training. In the case of contractors and suppliers, forward-looking commercial agreements encourage a partnering approach to skills development and productivity improvement.

ENL is continually striving to find more efficient ways to carry out its activities, reducing costs and improving productivity, and maintaining safety levels. The replacement of a number of ENL's core systems will provide a platform to initiate further developments with the specific purpose of improving efficiency.

Asset description

The distribution network assets included within the scope of the AMP are indicated below together with quantities and the depreciated replacement cost determined by the most recent audited information.

Asset description	Approx Quantity	Unit	Average age	Condition summary	RAB 2014 ($000)	Book Value 1/4/14 ($000)
01. Subtransmission Line	335	km	41	Ageing	$2,671	$3,014
02. Subtransmission Poles	2388	each	36	Average	$8,035	$9,127
03. Subtransmission Cable	1	km	11	Good	$1,438	$396
04. Other Subtransmission Assets		total	13	Good	$87	$71
05. Zone substation assets		total	19	New/good condition	$6,479	$7,083
06. Major Transformers		total	33	Average	$3,386	$4,665
07. Distribution Line	2400	Km	48	Ageing	$8,915	$9,431
08. Distribution Poles	25010	each	35	Average	$31,820	$29,013
09. Distribution Cable	134	km	27	Above Average	$11,956	$10,722
10. Distribution Substations	3629	each	33	Average	$4,314	$5,220
11. Distribution transformers	3629	each	31	Average	$10,644	$12,454

12. Switchgear	1820	each	34	Average	$11,159	$11,2724
13. Load Control Equipment		total	9	Average	$2,461	$2,239
14. Other Distribution Assets		total	13	Average	$458	$454
15. LV Lines incl Streetlighting	538	Km	46	Ageing	$3,649	$4,599
16. LV Poles	6575	each	40	Average	$4,518	$4,938
17. LV Cable incl Streetlighting	258	km	29	Average	$8,918	$9,344
18. Connection assets		total	37	Customer Drives upgrades	$2,689	$3,324
19. Communications		total	17	Technology determines Condition	$923	$831
20. SCADA & System Control		total	11	Technology determines Condition	$358	$500
21. Non System		total	8		$711	$600
Total			27		$125,598	$129,307

In addition, at 31 March 2015, Transmission Assets having an RAB value of $13.497m were acquired from Transpower. This value is excluded from the above figures

The System Fixed Assets Replacement Cost Roll-Forward Report, (AV3) completed as part of Information Disclosure, which is based on asset additions and removals since the ODV valuation in 2004 of $86.299m, determined the disclosed 2014 valuation as $125.598 million. This is an overall average increase from 2004 of 4% p.a.

Like most electricity network infrastructure, ENLs distribution assets are dispersed over a large area and are highly interdependent. Although the service area includes Gisborne City and Wairoa Township, the existing network is predominantly rural. It is also the cumulative result of around 80 years of investment and development.

The average age of the distribution network at the beginning of the planning period is estimated to be 27 years. This is expected to increase over the planning period with the estimated average age in 2024/25 being 32 years.

Service levels

The overall objective of asset management is to ensure the most efficient and optimum investment in assets to provide desired service delivery. Performance targets are established by considering a wide range of business and asset management drivers, some directly influenced by stakeholders, others a result of the historical pattern of development of ENLs network. ENL has surveyed customers and their representative groups in various market segments and considers their views and willingness to pay when making base investment decisions.

ENL's customers have clearly signalled that continuity and restoration are the two operational performance attributes that they value the most and at a minimum ENL needs to maintain current levels of performance without increasing its line charges. These service level targets have also been identified by the Regulator as key.

The AMP forecasts steady state service levels for the planning period as investment to improve service beyond regulated levels is seen as over investment and as such cannot be justified.
As the time frame covering historical trend data begins to match that of the asset lives the certainty of predictions will improve.
Issues regarding levels of achievable network investment and the effect on operational performance are being continually reviewed, as the data trends increase in accuracy, and will be updated as appropriate in future versions of the AMP.
ENL describes levels of service delivery and efficiency using well the recognised and disclosed industry performance measures. The method for calculation of the measures is in accordance with prescribed rules.

To measure operational performance with respect to continuity and restoration, ENL in accordance with industry standard practice and the Information Disclosure and Electricity Distribution Threshold regimes, sets targets for the next five years against the following key indices;

SAIDI – system average interruption duration index. The measure of how many system minutes of supply are interrupted per year.
SAIFI – system average interruption frequency index. The measure of how many system interruptions occur per year.

In 2014 the Regulator completed a review of historical performance for the primary customer service levels and determined new targets for the next regulatory period 2015-2020.
The new targets have been linked to financial and future target incentives for distribution lines businesses that do not have exemptions.
Accordingly ENL has set future network performance targets/forecasts in consideration of the regulated requirement.

It should be noted that external influences such as severe weather events and foreign interference, (ie. trees) dramatically impact upon reliability statistics and year-to-year variances can be large.

The performance targets for the next 10 years are:

Performance measure	Actual 2013-14	Forecast 2014-15	Target 2015-16	Target 2016-17	Target 2017-18	Target 2018-19	Target 2019-25
SAIDI: B ENL Planned	71.3	46.0	40.0	40.0	40.0	40.0	40.0
SAIDI: C ENL Unplanned	213.5	256.0	232.0	232.0	232.0	232.0	232.0
SAIDI: Total (B + C)	284.8	302.0	272.0	272.0	272.0	272.0	272.0
SAIDI ½B + C (ComCom target)	NA	NA	252.0	252.0	252.0	252.0	252.0
SAIFI B	0.4	0.4	0.54	0.54	0.54	0.54	0.54
SAIFI C	2.3	3.8	3.00	3.00	3.00	3.00	3.00
SAIFI: (B + C)	2.7	4.2	3.54	3.54	3.54	3.54	3.54
SAIFI ½B + C (ComCom Target)	NA	NA	3.27	3.27	3.27	3.27	3.27

A potential conflict between the stakeholders linked to the primary service levels has emerged.

On one side of the conflict, regulated service level targets have been set to reward improvement of security standards for network designs, maintenance, response and restoration of supply.

On the other hand regulated incomes are in place that limit the rate at which improvement can be made to the current security standards. In addition results of surveys from consumers strongly indicate a preference to maintain current security levels rather than increase costs to acheve improved security sevels.

Financial Efficiency Measure	Actual 2013-14	Forecast 2014-15	Target 2015-16	Target 2016-17	Target 2017-18	Target 2018-19	Target 2019-25
Operational expense ($/km)	$2,139	$2,065	$2,607	$2,487	$2,643	$2,659	$2,647
Operational expense ($/icp)	$307	$324	$408	$389	$412	$414	$411

Maintenance expenditure is the dominant component of the Operational expenses. ENL has previously achieved a lower than average industry level of expenditure however the forecast shows an increase reflecting the increase in maintenance following the acquisition of the Eastland transmission spur assets, and regulatory compliance costs as capital development stabilises.

The indirect cost expenditure forecast has increased to reflect changes to the management structure of Eastland Group.

Energy Delivery Efficiency Measure	Actual 2013-14	Forecast 2014-15	Target 2015-16	Target 2016-17	Target 2017-18	Target 2018-19	Target 2019-25
Load factor ENL	57%	59%	59%	57%	55%	53%	53%
Loss ratio ENL	7.0%	7.0%	9.5%	9.5%	9.5%	9.5%	9.5%
Capacity utilisation ENL	22.8%	22.8%	23.0%	23.0%	23.0%	23.0%	23.0%

When compared with averages for NZ companies the average load factor indicates that the load characteristic of the region is consistent with other areas. The above average loss ratio reflects the low density long line length characteristic of the region. The increase to 9.5% forcast from 2015 is due to inclusion of 110kV transmission losses following relocation of the Metering to Tuai GXP. For companies with no Transmission and Subtransmission assets the loss ratio is expected to be lower. The below average capacity utilisation reflects the low density connections using minimum size transformers that are larger than necessary. In general the results are in line with expected levels.

Lifecycle & development plans

Growth trends indicate a reasonably low average peak demand increase over time with significant variation. Growth is uncertain and is driven by the region's economic outlook, and in the longer term, by changes in technology and other factors. New technology and the use of distributed generation represent opportunities for ENL to reduce the need for future transmission and sub-transmission network upgrades. Also the acquisition/transfer of the Eastland transmission spur assets will enable the effective coordination of distribution, sub-transmission and distributed generation investments.

Facing the challenges associated with serving a consumer base that is very different to what was historically planned for ENL has used a variety of load forecasting techniques to help predict the impact of accumulated load growth on its capacity requirements and security standards. The coincident system peak demand has been forecast to grow from 65 MW in 2011/12 to a worst case of 80 MW in 2024. This gives an overall growth rate of approximately 1.5% p.a.

Alternatively the conservative scenario indicates minimal if any growth to 65 MW in 2024 which equates to a rate of 0% p.a.

Predictions consider both an optimistic/worst case and conservative projection from the most recent actual to ensure timely planning. This forecast includes foreseeable industrial developments. When making development decisions related to capacity requirements for long life assets, ENL uses the high load forecast to ensure investment covers the worst case scenario. To avoid over investment the investment in capacity is deferred as long as possible. For other decisions the low or medium forecasts are used as appropriate.

Specific triggers have been identified for major upgrades to ensure efficient investment to meet security standards and avoid capacity constraints.

Life cycle management plans outline exactly what is planned to manage and operate the assets at the target levels of service while optimising lifecycle costs. An assets life cycle starts with planning its necessity, continuing through design, investment, operation and maintenance, and concludes with replacement and/or disposal. Life cycle asset management encompasses the policies and practices applied during all phases of an assets life to ensure the sustainable delivery of a power supply in the most efficient manner.

ENL uses load flow analysis to assist in identifying solutions to network issues such as capacity constraints, security, power quality and uneconomic supplies. Alternative scenarios and options are modelled to optimise development plans, while the timing of work is largely determined as secure load limits are exceeded or requests for additional load are received.

Life cycle management plans are prepared by asset and expenditure category. Capital plans present background data and plans for renewal, replacement, augmentation and non-asset solutions in response to asset aging, growth, reliability, performance, compliance and quality. Maintenance plans detail the regular on-going work that is necessary to keep assets operating, including the basis for condition monitoring, equipment standards, planned maintenance and provisions for unplanned actions in response to faults or incidents. ENL drives maintenance work based on condition and reliability assessments, as opposed to planned maintenance based on time usage of an asset.

Since ENLs assets are in the age replacement phase of their life cycle, the management tactic focuses on replacement over heavy maintenance. The average age is forecast to increase as existing population profiles for conductor and poles in particular show the predominant installation period is nearing end of expected life while renewal rates have been minimized to balance renewal costs with allowable regulated revenues and return on asset value requirements.

Risk assessment

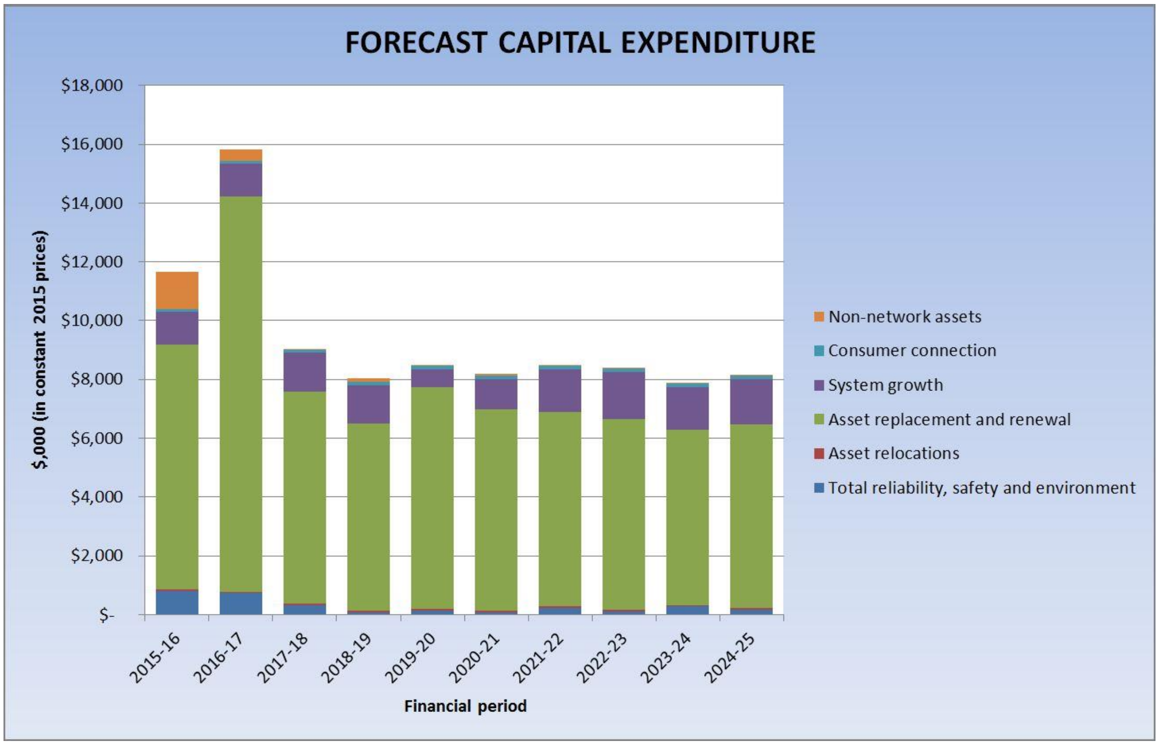
Effective risk management is required to protect the long-term viability of ENL and to protect its stakeholders. ENL uses a systematic outcome-based method for assessing asset related risks. This focuses on identifying and prioritising mitigating actions, which are subsequently captured in work programs and network development plans. The acquisition of the Eastland transmission spur assets will impact the risk profile of the ENL's network in respect of low probability, high consequence events. That is, the assets to be acquired have very high reliability, and given the nature of the assets, failures are rare but expensive to repair or replace (and can take significantly more time to repair). The risk assessment will be updated as part of the next review of this plan.

Financial Summary

Capital Expenditure

Capital expenditure for the planning period is $94.163m, ($71.130m current distribution assets + $21.002m transmission assets + $2.030m non network assets).

These forecasts include an average design/project management capitalisation allowance of 9.09%, ($8.376m for total period), applied to actual distribution and transmission asset construction costs. This capitalisation allowance is an increase on the average 4.7% allowance previously applied. In accordance with Electricity Distribution Information Disclosure Determination 2012 requirements the design/project management allowance is netted off System Operations and Network Support operating costs.



Comments on the categories of capital expenditure are made below.

Consumer Connection

For the planning period total Customer Connection expenditure is $1.117m, ($111.7k per year). This unplanned expenditure allowance is based on historical actual spend associated with the provision of new or upgraded assets which for the most part cannot be reasonable expected to be met by the customer. The exception is a customer capital contribution for the provision of Load Control Receivers which is forecast at $11k per year.

System Growth

For the planning period total System Growth expenditure is $12.452m.

All of System Growth expenditure is associated solely with current distribution assets. Any expected/forecast System Growth expenditure associated with transmission assets is beyond the planning horizon of the AMP.

This category of expenditure includes provision for the steady state customer driven network extension and capacity upgrades that cannot be avoided once trigger points have been exceeded. This includes 2015/16 and 2016/17 Mahia Sub-transmission upgrade@ $503k per year, fully funded by developer contributions which were recognised as revenue in 2014/15.

Asset Replacement and Renewal

Asset Replacement and Renewal total capital expenditure for the planning period is $75.067m. (Distribution assets $54.065m, ex-transmission assets $21,002m).

With respect to the renewal of current distribution assets, the average age is forecast to increase from 27 years at the beginning of the planning period to 32 years in 2024/25. In general renewal expenditure has been set to match the 10 year replacement rate of each asset type and budgeted network depreciation. Expenditure on overhead assets, (poles and conductor) predominates.

Asset replacement expenditure on the ex-transmission assets has been included in the AMP as forecast information received from Transpower. Of the total $21m forecast for the 10 year period, $8.2m is allocated to 110/11kV transformer replacements at Tuai and Wairoa in 2016/17. It is expected that having gained operational experience of these transformer assets that it will be possible to reduce/defer and/or smooth lumpy expenditure of this type.

Asset Relocation

Asset Relocation driven capital expenditure for the planning period is an annual unplanned allowance of $55.8k pa based on historical actual spend on distribution assets. Territorial authorities operating in ENL's network coverage area are regularly canvassed for information on immediate future and longer term requirements they might have regarding the relocation of ENL assets. Responses received at this time do not identify any specific requirements to relocate ENL assets.

No allowance has been made for the relocation of transmission assets.

Reliability, Safety and Environment

Reliability, Safety and Environment total capital expenditure for the planning period is $2.937m and is solely related to distribution assets, (at this time no requirement for transmission asset related expenditure has been identified).

This relatively low level of expenditure in this category is a result of large levels of expenditure that was undertaken between 2000 and 2004 for the purposes of addressing a backlog of safety and environmental issues and improvement of security of supply standards through the development of the distribution sub-transmission network.

Overhead to Underground Conversions

For the planning period total of $2.457m is forecast for overhead to underground conversions. This expenditure is included under Asset Replacement and Renewal or Reliability, Safety and Environment, Other.

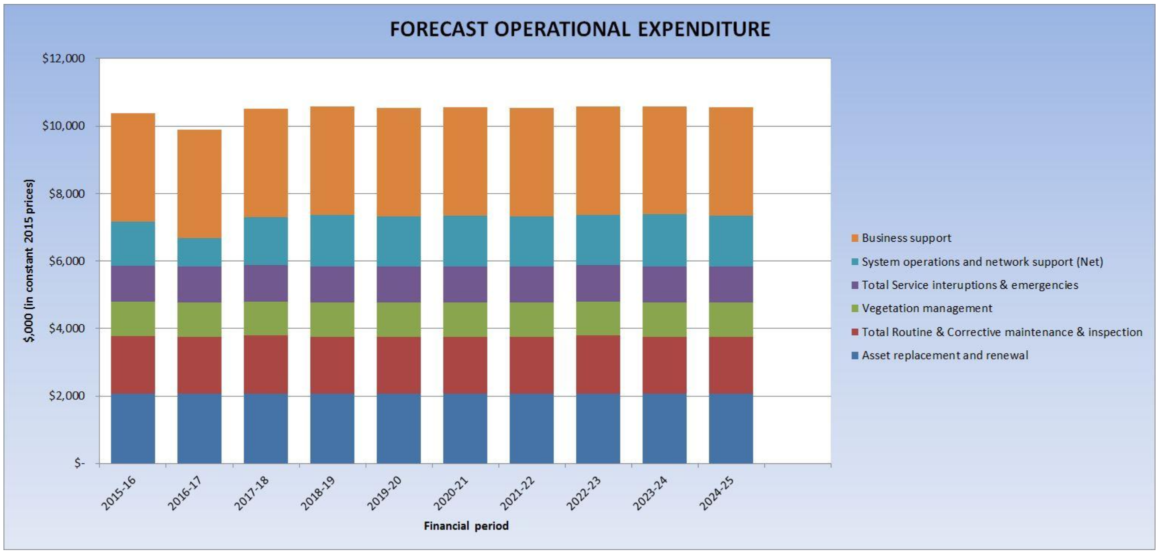
Non – Network Asset Capital

Non – Network Asset total capital expenditure for the planning period is $2.031m. The largest single items in this forecast are a $1.248m contribution to a new Asset Management IT System proposed for 2015/16 and $300k budgeted in 2016/17 for replacement GIS.

No allowance for other non – network assets such as PCs, office furniture and motor vehicles has been made as these items are supplied under the Shared Services/ Management Fee arrangement between ENL and Eastland Group Limited. EGL owns the assets and leases them to ENL at market rates.

Total Operational Expenditure Forecast

The Electricity Distribution Information Disclosure Determination 2012 requires that information on total operational expenditure; (maintenance + non-network operational expenditure) is presented. The following graph summarises total operational expenditure as presented in the AMP. The expenditure profile is flat which indicates that steady state assumptions apply.



Maintenance Expenditure

Total maintenance expenditure for the 10 year AMP period is forecast at $58.508m, ($47.280m current distribution assets and $11.228m ex-transmission assets).

For current distribution assets maintenance plans have been prepared by asset type and expenditure category. These plans detail the regular on-going work that is necessary to keep assets operating, including the basis for condition monitoring, equipment standards, planned maintenance and provisions for unplanned actions in response to faults or incidents. It has been identified that ENL's current distribution assets are in the age replacement phase of their life cycle. The management tactic is to therefore replace rather than to continue with a heavy maintenance strategy. The expected improvement in average asset condition will lift performance and allows low maintenance expenditure to be sustained.

Average annual distribution asset maintenance expenditure for the planning period has increased by $1.606m. This is a result of Audit advising that ACOD payments made from ENL to EGeL, (Waihi & Gensets) need to be included in the Asset replacement and renewal maintenance category as opposed to inclusion in non-network operational expenditure categories.

For transmission assets, Transpower maintenance forecasts totaling $11.228m have been applied from 2015/16. These forecasts are based on information supplied by Transpower and have been supplemented with additional information commissioned from 3rd party advisors during the due diligence process.

Maintenance expenditure forecasts in the AMP are provided by asset type and expenditure type as per EDIDD 2012 categories. The expenditure categories are;

Routine and Corrective Maintenance and Inspection

This expenditure that is driven by pre-planned and programmed work schedules and includes routine inspection/condition monitoring, testing and servicing activities.

For the planning period the total $17.107m, ($8.558m distribution assets and $8.549m transmission assets).

Service Interruptions and Emergency Maintenance

For the planning period the total Service Interruptions and Emergency Maintenance is $10.781m, ($10.527m current distribution assets and $253k ex-transmission assets).

Included in this expenditure category is a standing allowance of $303k pa for provision of a faults call centre and a fault management service.

Asset Replacement and Renewal Maintenance

For the planning period the total Asset Replacement and Renewal Maintenance is $20.580m, ($19.057m distribution assets and $1.523m ex-transmission assets).

As explained above incorporated in the distribution asset expenditure is $1.606m of annual ACOD expenditure.

This relatively low level of asset replacement and renewal maintenance for both distribution and transmission assets is a result of the comprehensive capital asset replacement and renewal program.

Vegetation Management

For the planning period the total Vegetation Management Maintenance is $10.041m, ($9.13mm distribution assets and $903k transmission assets).

This level of expenditure reflects the ongoing tree management programs required to maintain network performance.

Non Network Operational Expenditure

An Electricity Distribution Information Disclosure Determination 2012 requirement for AMPs is to provide information and forecasts on non-network operational expenditure.

The two classifications of non- network operational are as follows;

Business Support

This includes the usual "corporate" support costs associated with HR, IT, finance, legal, property services, Director costs, marketing, consultants (other than engineering) and corporate communications - most of which are included in the current Shared Services/Management Fee structure.

Additional items of expenditure included in this costs associated with category are Regulation, Pricing, Billing, Customer liaison (including Transpower) and revenue collection.

For the planning period total Business Support is forecast at $32.099m.

System Operations and Network Support

This includes the usual "direct" support costs such as asset management and planning, network engineering and design costs, network policies and standards, network record keeping and associated systems, engineering and technical consultants, IT and comms for network management and customer management.

For the planning period total System Operations and Network Support is forecast at $22.448m. This total is reduced by capitalised design/project management costs totalling $8.376m, giving a net System Operations and Network Support cost for the period of $14.112m.

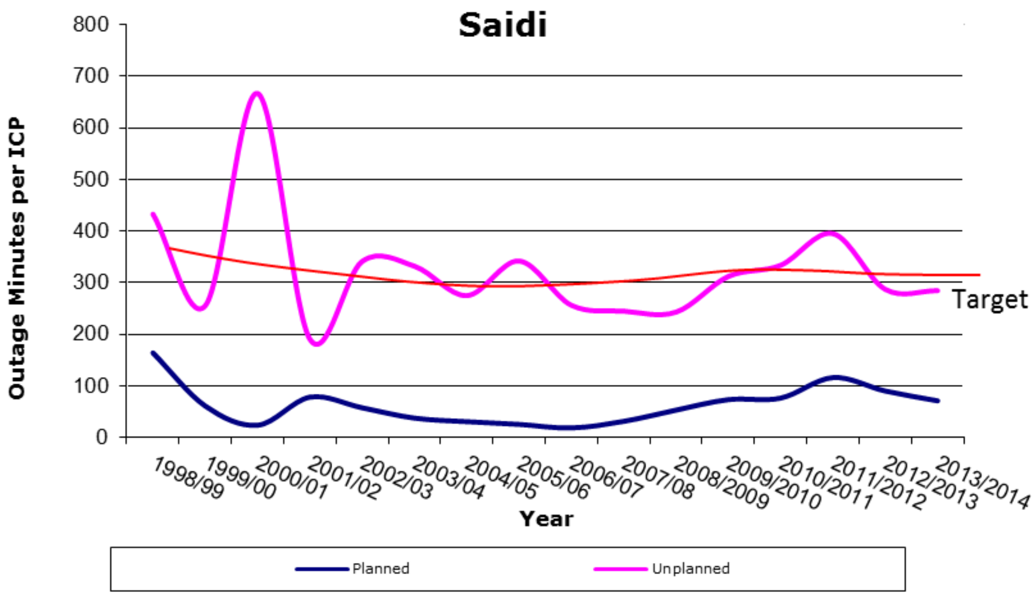
Performance & improvement plans

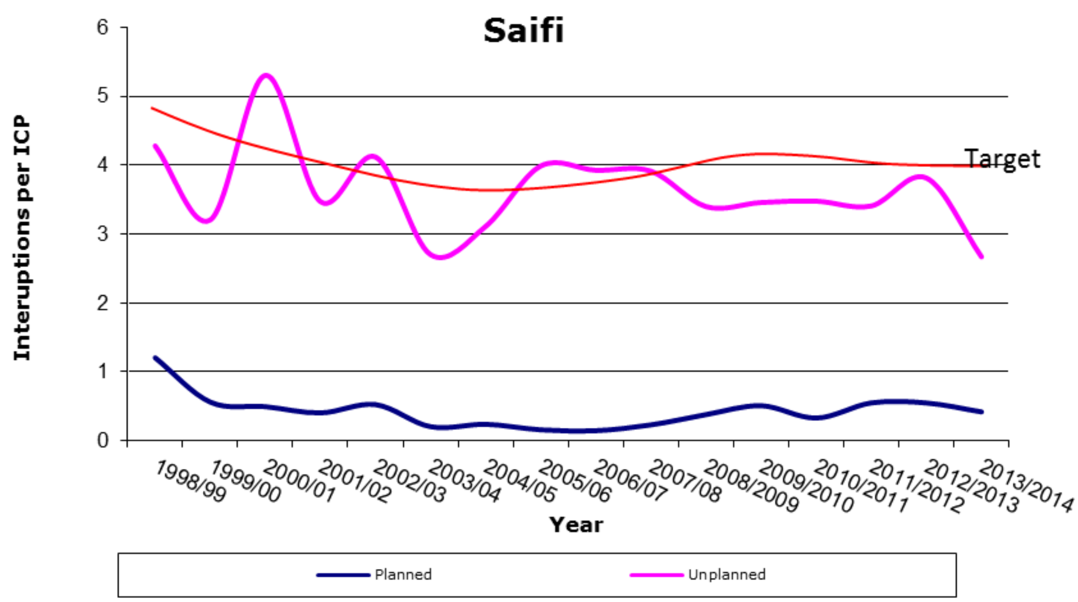
Improvement of the assets is achieved by strategic and business plans which contain agreed guidance and criteria. The primary responsibility of the asset management team is to identify options for improvement and asset management plans for input into the strategy and business planning process. The resulting improvement is continuous as the AMP is updated during the normal business planning cycle. Internal and external audits/reviews are undertaken at regular intervals to confirm the validity of technical content, assess asset management performance against best practice, and identify areas where implementation of asset management practice can be improved.

ENL reviews benchmarking results for similar companies in order to more effectively target improvements in line with national trends. Performance measures have been developed to ensure that meaningful comparisons with comparable lines companies can be undertaken and compliance with regulatory targets is maintained.

On-going asset management improvement initiatives target increased capture of detailed asset attribute and performance information, to aid predictions, which facilitates the development of improved capital and maintenance strategies to correct condition and asset deficiencies and meet growth requirements.

The primary indicators for reliability and performance are the SAIDI index and SAIFI index





Installation of remote diesel generators between 2002 and 2003 has reduced the impact of planned outages. On average over the past 7 years use of generators has avoided 300 SAIDI minutes p.a., or 90% of the current level, p.a. over the period. The extent of this reduction cannot be seen in the statistics as pole replacement on spur 50kV lines, previously deferred, was undertaken between 2003 and 2008 without any impact on outage statistics.

Use of Live line technologies has avoided an average of 10 SAIDI minutes p.a. between 2001 and 2008. As a result of skill shortages in 2007 and 2008 and an increase in line renewal work over rugged terrain, the use of Live Line technologies is currently suspended.
While the targeted SAIDI is below the regulated limit a shift to renewal projects on lines not suited to generator support will increase planned SAIDI figures. It is likely that the regulatory limits will be exceeded in future due to this increase in necessary maintenance and renewals work on the rural or spur lines.

Significant weather events and environmental factors such as slips after long periods of rainfall, generally considered as normal, have the most significant impact on ENL's ability to achieve its targets. The impact of these events on the Eastland transmission spur assets, while likely to be rare, will have a significant impact.

The low proportion of planned to unplanned makes it difficult to control to targets by manipulation of planned work. Where viable multiple contractors are pooled into a collective group for shutdown work to minimise the need for multiple outages on a specific project. An example of this is a pole replacement project where 7 separate companies were collectively engaged to minimise the number and length of outages for the project.

The steady decline in available field service contracting resources in New Zealand has resulted in critically low resource levels in the local region. ENL is actively contributing to training and development of new resource at the entry level to ensure improvement of its asset management activities in the long term.
ENL has a technology focus and is active in identification and development of equipment and systems designed to offset the effects of renewal investment and resourcing short falls.

Contents

1. Background & objectives

1.1 Purpose of this AMP

The purpose of this AMP is to provide a management framework that ensures that ENL…

Sets service levels for the electricity network that will meet owner, consumer, community and regulatory requirements.

Understands what network capacity, reliability and security will be required both now and in the future, and what issues drive these requirements.

Has a robust and transparent process in place for managing all stages of the network asset life cycle from conception to removal.

Has adequately considered the classes of risk the network business faces, and has systematic processes in place to mitigate identified risks.

Has made provision for funding phases of the network asset lifecycle while balancing levels of investment against allowable regulated revenue and return on asset value requirements.

Makes decisions within systematic and structured frameworks at each level within the business, and that it especially doesn't make ad-hoc decisions.

Has an ever-increasing knowledge of discrete asset components including locations, ages, conditions, performance and likely future behaviour as components deteriorate, age and are required to perform at different levels.

Presentation of the AMP in this format also meets the requirement 24 of the Electricity Distribution Information Disclosure Determination 1 October 2012.

1.2 Interaction with other goals & drivers

All of ENL's assets exist within a strategic context that is shaped by a wide range of issues including ENL's Statement of Purpose and Vision, the prevailing regulatory environment, government policy objectives, commercial and competitive pressures and technology trends. ENL's assets are also influenced by technical regulations, asset deterioration, the laws of physics and risk exposures independently of the strategic context, and indeed these issues may constrain the strategic plan.

1.2.1 Corporate purpose & vision

ENL's statements of purpose and vision therefore communicate a strong focus on the development of the local economy.

STATEMENT OF PURPOSE

Eastland Network will utilise existing assets to achieve an appropriate return for the shareholder while providing opportunities for business growth and improving the value delivered to customers.

VISION

Eastland Network will provide returns on assets, growth on investments and operating performance which places it in an average position relative to other New Zealand electricity companies with similar geographic, demographic and loading and fixed asset investment characteristics.

Safe, reliable and optimally-priced delivery of electricity influences the competitiveness of local wealth creating businesses. If they don't create long-term sustainable wealth ENL loses out as well.

1.2.2 Vision for asset management

ENL's vision for asset management is…

VISION FOR ASSET MANAGEMENT

Eastland Network's asset management function will strive to optimise its' investment in electricity distribution assets to provide levels of service that are acceptable to its customers and other stakeholders at a price that maximises economic efficiencies.

The key aspect of implementing this vision is through having well defined and robust processes for optimizing spend levels at all stages of asset lifecycles. These processes are discussed in Section 1.6 of this AMP.

1.2.3 Overview of asset management strategy and delivery

ENL's core planning document is the Strategic Plan which considers all the strategic drivers depicted in figure 1.2.3(a). The Strategic Plan regularly examines these issues at intervals appropriate to how fast each issue moves, and identifies the few important things ENL must focus on to fulfill its Statement of Purpose and its Vision. A key influencer of ENL's Strategic Plan is the increasing level of regulation that the lines sector faces – not only are ENL's prices and supply quality regulated, but many of ENL's activities such as the preparation of this AMP and disclosure of performance indices are heavily prescribed.

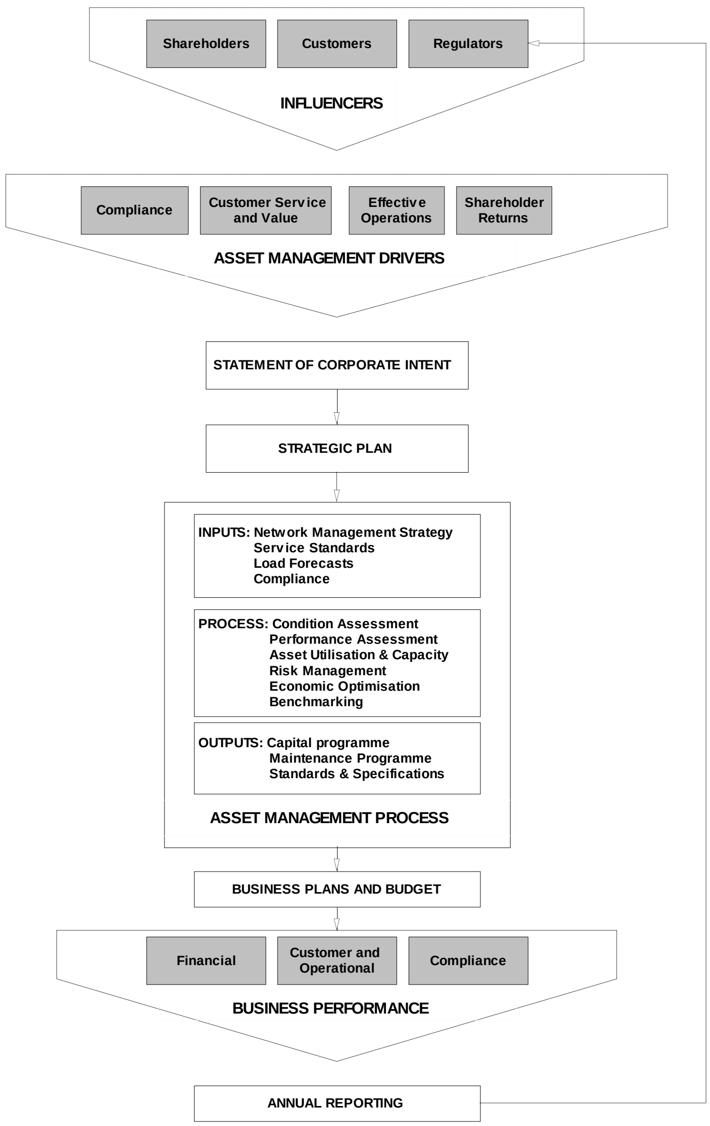
The relationship of the AMP to the Strategic Plan needs to consider the following issues;

The physical degradation of ENL's assets due to age and operating characteristics is largely independent of ENL's chosen business strategy (notwithstanding decisions to spend on the assets) and of the regulatory framework.

The nature and configuration of ENL's assets reflects past business strategies and policy environments more strongly than present strategies, e.g. past rural electrification has resulted in segments of network considered uneconomic in the current environment.

The preparation of the AMP proceeds in parallel with the preparation of the Strategic Plan and is shaped by it rather than being absolutely dependent on it.

Figure 3.1 - The ENL Asset Management Framework



1.2.4 Interaction of key planning documents

Interactions of the key planning documents are as follows…

Statement of Corporate Intent. This document defines the Director's intentions and objectives for ENL for the next three financial years and is agreed with the owners. This encompasses planned business activities and objectives, values, performance targets and communication methods.

Strategic Plan/Business Plan. Annual plans and key initiatives are established in these documents to support the achievement of performance targets. Because the AMP is a tactical plan and a repository for detailed asset information, these documents are closely coordinated during the business planning cycle.

Ten Year Financial Plan. The Ten Year Financial Plan identifies funding requirements necessary to achieve the capital and maintenance budgets as produced by the AMP, and any other business funding requirements. The Financial Plan identifies funding constraints that may affect the ability to achieve AMP objectives thereby influencing changes to the AMP and/or demonstrates that business performance and service objectives can be met.

Customer Relationship Management Plans. These plans record consultations with major electricity users regarding their current and future electricity supply requirements and their preferences for price and quality trade-offs. ENL also seeks to determine the needs of all electricity users from the Energy Retailers that represent them. The Energy Retailers have contractual arrangements with ENL that incorporate the desired requirements for energy delivery services to their customers. ENL focuses on the wealth-creating sector of the local economy and also consults with a number of other representative community groups such as Federated Farmers and Grey-Power as proxies for the mass-market.

The outputs from the asset management process are the operational, maintenance and capital work programs. These programs are contained within the AMP and include…

Operational Activities. The operational triggers and activities are described in Section 5.2.

Maintenance Plans. The trigger points and activities for maintaining the assets are presented Section 5.3.

Capital Replacement Plans. Analysis of asset performance age and condition result in optimal asset renewal programs presented in Section 5.4.

Development Plans. Analysis is undertaken to test growth and performance against service standards. A Network Development plan is then created in line with investment and risk policies. This is summarised in section 4.7.

Equipment and Design Standards. Detailed equipment and design specifications, based on the required functionality of the assets, are included in the Network Quality System. General standards and issues concerning quality and compliance are covered in the lifecycle management sections of this AMP.

1.3 Period covered by this AMP

This edition of ENL's AMP covers the 10 year period 1 April 2015 to 31 March 2025.
This AMP was prepared over the period November 2014 to March 2015 by Eastland Group's General Manager Energy and the Asset and Planning Manager.
The AMP was approved by the ENL Board of Directors on 31 March 2015 and publicly disclosed in accordance with Requirement 2.6 of the Electricity Distribution Electricity Information Disclosure Determination 2012.

1.4 Stakeholder interests

1.4.1 Stakeholder identification.

ENL defines its stakeholders as any person or class of persons that does or may do one or more of the following…

Has a financial interest in ENL (be it equity or debt).
Be physically connected to ENL's network.
Use ENL's network for conveying electricity.
Supply ENL with goods or services.
Be affected by the existence, nature or condition of ENL's network.
Have a statutory obligation to perform an activity in relation to the existence of ENL's network (such as request disclosure data or regulate prices).

1.4.2 Stakeholder interests

The interests of ENL's stakeholders generally fall into 1 of the 4 categories defined in Table 1.4.2(a) below…

Table 1.4.2(a) – Key stakeholder interests

	Interests			
	Viability	Supply quality	Safety	Compliance
Shareholder	✓		✓	✓
Bankers	✓			
Connected customers	✓	✓	✓	
Energy retailers	✓	✓		
Mass-market representative groups	✓	✓		
Industry representative groups	✓	✓		
Staff & contractors	✓		✓	✓
Public			✓	
Councils (excluding as a consumer)			✓	
Land Transport			✓	✓
Ministry of economic development			✓	✓
Commerce Commission		✓		✓
Electricity Authority				✓
Land Owners			✓	

1.4.3 Determining stakeholder interests

Stakeholder interests are determined via the following mechanisms…

Shareholders – Regular business performance reviews are conducted by the shareholders. Correspondence and meetings are held between the shareholders and ENL's directors /Management team to review performance and consult on strategic plans.

Bankers – Communication via direct discussion and written correspondence at regular intervals ensures that the formal agreements and interests of the bankers are adhered to.

Customers and representative groups – The interests of these stakeholders are determined through direct discussion with large customers, meetings with consumer and industry representatives, and customer surveys (refer section 3.1). ENL representatives are involved with the civil defence, Gisborne chamber of commerce, Regional development groups and regional working groups. At an operational level customers communicate their interests directly with either Engineering staff or ENL's call centre.

Staff and Contractors – Weekly meetings are held with contractors and staff which provide an open forum to determine and discuss individual interests and interests fed back from customers and the public via the individuals. All information is recorded and incorporated into revised plans where relevant.

Public – Public interests are generally relayed via local media, other authorities and representative groups. ENL provides open access for the public to engineering and management staff at its main offices in Gisborne and via its call centre.

Councils and Authorities – Monthly Utility meetings are held with representatives from Telecommunications, Gas, Council, Road Authorities and General contractors to determine both short and long term interests for incorporation into operational and long term asset management plans. In addition councils are consulted at all levels to establish the potential impacts of ENL strategies and activities.

Ministries and Commissions – The interests of these groups are identified through legislation and regulation. ENL has engaged Price Waterhouse Coopers and Chapman Tripp to monitor and represent ENL in this area. In addition ENL has significantly increased staffing and funding from 2008 to provide information, review and revise systems in order to accommodate the steadily changing requirements.

Landowners – ENL engineering staff maintain a close relationship with Landowners and developers to determine their interests on an open and informal basis. At an operational level formal access and tree notification processes provide for feedback that is incorporated into ENL's asset management systems.

1.4.4 Accommodating stakeholder interests

Table 1.4.2(a) provides a broad indication of how ENL accommodates stakeholder interests…

Interest	Description	Accommodating that interest
Viability	Viability is necessary to ensure that ENL's shareholder and providers of finance have sufficient confidence to retain ownership of ENL or provide	ENL accommodates its stakeholders' needs for long-term viability by delivering earnings that are sustainable and reflect an appropriate risk-adjusted return on employed capital While net prices are controlled to maintain

	finance to ENL. For users of line function services the prices must be affordable. For other stake holders the activities conducted by ENL should minimise negative impacts on viability of their activities.	compliance, changes to prices are analysed to determine individual impacts and step changes are managed to maintain them within affordable limits. Design standards and selection of assets for each application given careful consideration to ensure they are suited to the stakeholders needs.
Supply quality	Emphasis on continuity, restoration is essential to minimizing interruptions to ENL's customers businesses.	ENL accommodates stakeholders' needs for supply quality by focusing resources on continuity, provision of security and restoration which is what ENL's customers have said is important to them.
Safety	ENL's staff, contractors and the public at large must be able to live in close proximity to network assets and/or work on the network in total safety. Lines and equipment on private land must be operated and maintained to minimise interference to other activities carried out on the land and avoid serious harm or damage to property.	ENL ensures that the public at large are kept safe by managing the network assets so that they are installed, operated and maintained to relevant regulations, codes of practice and standards relating to their structural strength, electrical safety and design functionality. ENL ensures the safety of its staff and contractors through implementation of its Health & Safety Management System which prescribes the process and procedures for hazard identification/management, contractor management/auditing, staff/contractor training & competency assessment, the provision of safety equipment and safe work procedures. The safety management system documents processes to ensure safe operation of the network assets.
Compliance	ENL has a duty to comply with many statutory requirements ranging from safety to disclosing information and targeted threshold regimes for price, quality and customer consultation.	ENL ensures that all safety issues are adequately documented and available for inspection by authorised agencies. ENL discloses performance information in a timely and compliant fashion. ENL will restrain its net prices to within the limits prescribed by the price path threshold.

1.4.5 Managing conflicting interests

ENL's priorities for managing conflicting stakeholder interests are…

Safety. ENL will give top priority to safety. Even if ENL has to exceed budget, the safety of staff, contractors or the public, (and their property) are a primary consideration.

Viability. ENL will give second priority to sustainable financial viability because without it the business will cease to exist which makes supply quality and compliance pointless.

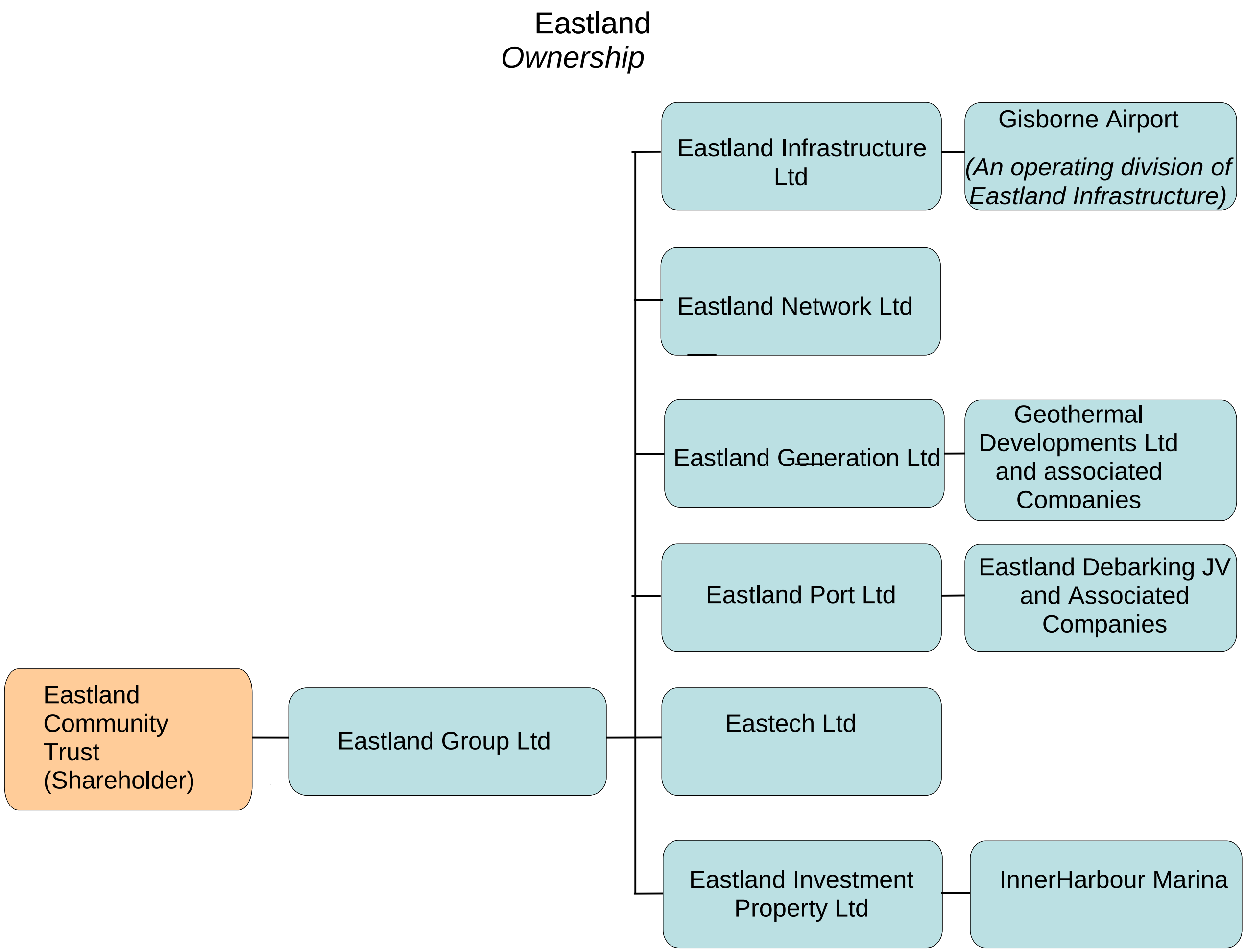
Supply quality. ENL will give third priority to supply continuity and quality as this is what makes energy users, and therefore ENL, successful.

Compliance. ENL has a duty to comply with all the regulatory requirements applicable to lines businesses and endeavours to meet those requirements. However ENL also understands that achieving compliance may on occasion be in tension with other interests such as financial viability. Under these circumstances ENL will decide a course of action that is sustainable and reflects a balanced view of all stakeholder wishes and expectations.

To achieve consistency regarding the management of conflicting stakeholder interests, the priority structure above is considered and applied during ENL's annual Strategic and Business planning cycles. The outcome is that the annual Business Plan provides at an operational level direction and detail on how prioritized objectives set out in the Strategic Plan will be realised and associated performance measured.

1.5 Accountabilities for asset management

The electricity assets of Eastland Network Ltd are 100% owned by the Eastland Community Trust (ECT). The ECT, originally the Eastland Energy Community Trust, was created in 1993 and took ownership of all the Poverty Bay Electrical Power Board's assets following the implementation of the Electricity Companies Act and subsequent Acts. The trustees of the ECT are appointed by the Gisborne District Council, (GDC). The GDC is the ultimate capital beneficiary of the Trust.
The ECT also owns other companies forming the Eastland Group, as shown below:

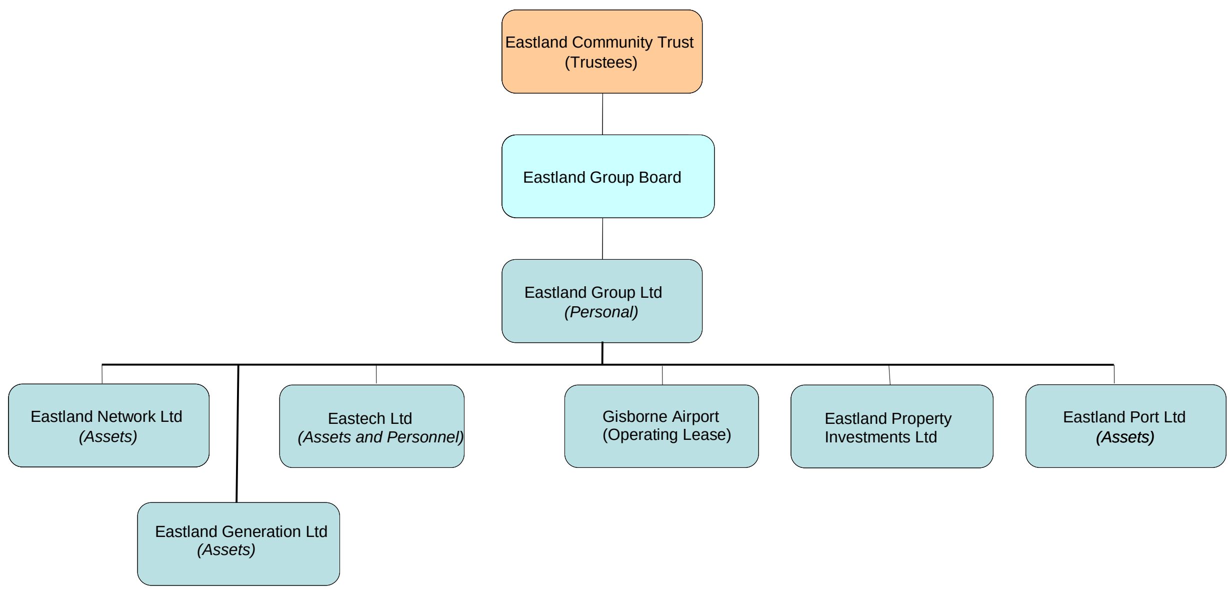


Eastland Group Ltd manages Eastland Network Limited, Eastland Generation Ltd, Eastland Port Ltd and Eastland Investment Property Ltd. Eastland Infrastructure Ltd also manages and operates Gisborne Airport on a long term lease from the Gisborne District Council. Eastech Ltd is owned by Eastland Group Ltd. Together these companies make up the Eastland Group.

Primarily, Eastland Group Ltd is a shared service provider to each of the companies within the Eastland Group. It employees management and operational staff required to operate the companies within the Group. Governance of the Eastland Group is provided by a common Board of Directors appointed by the ECT. This management/governance structure is illustrated below:

Eastland Group

Management Structure



With respect to the management of ENL distribution network assets, EGP provides the services and resources required to carry out all financial management, planning, design and network operating activities. Since all physical installation and maintenance work carried out on network assets is contracted out, the network operating function includes significant responsibility for the management of accredited independent contractors.

Contractors tender for packages of maintenance activity and/or capital works projects. Contracts are awarded on the evaluated performance criteria of price, quality/safety and timeliness. Contract tendering and management is carried out in accordance with NZS 3910:1998 "Conditions of Contract for Building & Civil Engineering Construction".

ENL believes that competitive tendering is beneficial for the business as it stimulates contractor innovation and results in field services being provided at the true market rate. As such ENL does not operate a system of preferred contractors. Any contractor is able to tender for ENL work provided that they are able to meet and maintain predetermined standards relating to demonstrating competency, the provision of quality, health & safety and financial management systems.

1.5.1 Accountability at governance level

Governance of Eastland Group is provided by a Board of Directors appointed by the Eastland Consumer Trust.
The inclusion of SAIDI, SAIFI and CAIDI targets and Direct and Indirect cost targets in the Statement of Corporate Intent makes ENL's Board intimately accountable to the shareholder for these important asset management outcomes. The inclusion of revenue and financial performance targets in the statement makes the Board additionally accountable for overseeing the price-quality trade-off inherent in projecting revenue and network performance.

The requirement for the Strategic Plan, the Business Plan, (including capital and maintenance expenditure budgets), and the AMP to be approved by the Board of Directors on an annual basis adds a further accountability function. On a monthly basis the Board receives updates on progress against service level and financial performance targets. All large projects $150K or higher are identified to the Board for approval and all purchase contracts in excess of $250k are approved by the Board. Performance against Statement of Corporate Intent targets is reported regularly to the Shareholder.

1.5.2 Accountability at executive level

Overall accountability to the Board of Directors for the performance of the electricity network, the port and the airport rests with Eastland Group's Chief Executive whose employment contract specifies *inter alia* the asset management outcomes to be created such as safety, reliability, revenue, profitability and compliance.

1.5.3 Accountability at Operational level

The General Manager Energy is accountable to the Chief Executive for the safe, reliable, profitable and compliant operation of the electricity network principally through his employment contract. Accountabilities of the General Manager Energy include overall responsibility for achieving compliance with all Eastland Group corporate policies and procedures, (including planning/reporting, human resource management, health & safety management, environmental management, contract tendering, contract management, regulatory disclosure management and financial/budgetary management).

The General Manager Energy activities, accountabilities, resources and responsibilities for achieving Eastland Group corporate policies and procedures are assigned as follows…

The long term planning function which undertakes asset planning and design work and includes the company's professional engineering resources and the drawing/information record keeping. Production of this AMP is a key accountability of the Asset and Planning Manager who reports to the Sector General Manager Energy.

The real-time and short term system operations function implements work programs, operates the network, and manages contractors. Delivery of reliability, budget cost, and safety performance are the key accountabilities of this group who on an individual basis are assigned responsibility for the implementation of specific capital and/or maintenance activities and budgets as determined in the AMP. Contract and operation reviews provide additional feedback from contractors.

Close interaction between Planning and Operations is achieved through the stewardship of the General Manager Energy. Real-time, short term and long term planning roles are assigned to individuals based on skills and experience held. Typically all individuals are assigned responsibilities involving both the short term operational and long term planning functions. Group responsibility for real time operation of the control room and the achievement of network reliability, budgetary, safety and environmental performance targets is also shared between the Planning and the Operations people based on capability and experience.

A diagram showing the structure of Eastland Group for the Gisborne based operations is shown below. On the left hand side of the diagram roles primarily associated with the Asset management and operation of ENL are highlighted with the Light Green. This group is also responsible for Asset Management and operation of Eastland Generation Limited. Business support functions are provided by the Finance (Pink) and Shared Services (Green) groups.

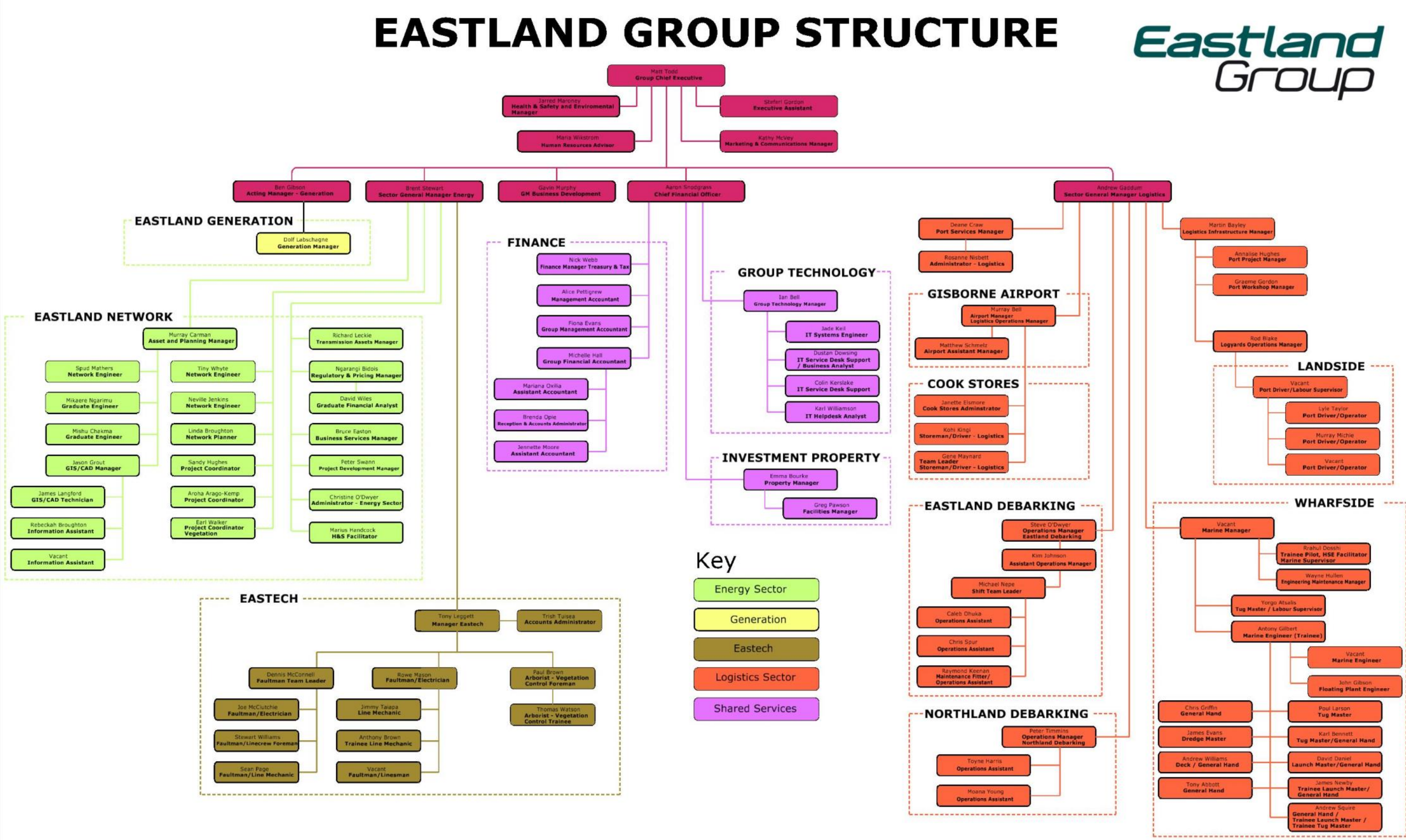
1.5.3.1 Planning and Operational Resource Development

A periodic review of staffing levels including skill and competency requirements to best serve the operational needs of ENL has confirmed the following additional resource requirements:

- The design planning and asset management function of ENL and EGL has expanded to a level where the current role needs to be split over additional resource. (Also identified during review of risk as a key role)
- An additional role to carry out activities relating to electricity pricing, management of the regulatory reporting and compliance, and distributed generation reporting.
- Development of a role to cover Electricity Billing and the Electricity Market requirements (succession planning)

Key drivers identified in the review included;
- Changes in requirements for on-going reviews, reporting and auditing associated with the Public Safety Management System.
- The need for separate reporting and forecasting for the Gisborne and Wairoa networks to align with the Information Disclosure Requirements.
- A steady increase in activity linked to Regulation of Electricity Distribution Businesses along with a shift to different skill requirements.
- Acquisition of additional Transmission assets in March 2015.
- Increased levels of investigation into non asset solutions identified in this AMP and the business plan.

While proposals for additional resource are subject to business planning approval, expenditure relating to the changes is included in System Operations and Network Support forecasts.


EASTLAND GROUP STRUCTURE
Matt Todd
Group Chief Executive
Jarred Maroney
Health & Safety and Enviromental Manager
Steferi Gordon
Executive Assistant
Maria Wikstrom
Human Resources Advisor
Kathy McVey
Marketing & Communications Manager
Ben Gibson
Acting Manager - Generation
Brent Stewart
Sector General Manager Energy
Gavin Murphy
GM Business Development
Aaron Snodgrass
Chief Financial Officer
Andrew Gaddum
Sector General Manager Logistics
EASTLAND GENERATION
Dolf Labschagne
Generation Manager
EASTLAND NETWORK
Murray Carman
Asset and Planning Manager
Spud Mathers
Network Engineer
Mikaere Ngarimu
Graduate Engineer
Mishu Chakma
Graduate Engineer
Jason Grout
GIS/CAD Manager
James Langford
GIS/CAD Technician
Rebeckah Broughton
Information Assistant
Vacant
Information Assistant
Tiny Whyte
Network Engineer
Neville Jenkins
Network Engineer
Linda Broughton
Network Planner
Sandy Hughes
Project Coordinator
Aroha Arago-Kemp
Project Coordinator
Earl Walker
Project Coordinator Vegetation
Richard Leckie
Transmission Assets Manager
Ngarangi Bidois
Regulatory & Pricing Manager
David Wiles
Graduate Financial Analyst
Bruce Easton
Business Services Manager
Peter Swann
Project Development Manager
Christine O'Dwyer
Administrator - Energy Sector
Marius Handcock
H&S Facilitator
FINANCE
Nick Webb
Finance Manager Treasury & Tax
Alice Pettigrew
Management Accountant
Fiona Evans
Group Management Accountant
Michelle Hall
Group Financial Accountant
Mariana Oxilia
Assistant Accountant
Brenda Opie
Reception & Accounts Administrator
Jennette Moore
Assistant Accountant
GROUP TECHNOLOGY
Ian Bell
Group Technology Manager
Jade Keil
IT Systems Engineer
Dustan Dowsing
IT Service Desk Support / Business Analyst
Colin Kerslake
IT Service Desk Support
Karl Williamson
IT Helpdesk Analyst
INVESTMENT PROPERTY
Emma Bourke
Property Manager
Greg Pawson
Facilities Manager
EASTECH
Tony Leggett
Manager Eastech
Trish Tuisea
Accounts Administrator
Dennis McConnell
Faultman Team Leader
Joe McClutchie
Faultman/Electrician
Stewart Williams
Faultman/Linecrew Foreman
Sean Page
Faultman/Line Mechanic
Rowe Mason
Faultman/Electrician
Jimmy Taiapa
Line Mechanic
Anthony Brown
Trainee Line Mechanic
Vacant
Faultman/Linesman
Paul Brown
Arborist - Vegetation Control Foreman
Thomas Watson
Arborist - Vegetation Control Trainee
Key
Energy Sector
Generation
Eastech
Logistics Sector
Shared Services
Deane Craw
Port Services Manager
Rosanne Nisbett
Administrator - Logistics
GISBORNE AIRPORT
Murray Bell
Airport Manager
Logistics Operations Manager
Matthew Schmelz
Airport Assistant Manager
COOK STORES
Janette Elsmore
Cook Stores Adminstrator
Kohi Kingi
Storeman/Driver - Logistics
Gene Maynard
Team Leader
Storeman/Driver - Logistics
EASTLAND DEBARKING
Steve O'Dwyer
Operations Manager
Eastland Debarking
Kim Johnson
Assistant Operations Manager
Michael Nepe
Shift Team Leader
Caleb Ohuka
Operations Assistant
Chris Spur
Operations Assistant
Raymond Keenan
Maintenance Fitter/
Operations Assistant
NORTHLAND DEBARKING
Peter Timmins
Operations Manager
Northland Debarking
Toyne Harris
Operations Assistant
Moana Young
Operations Assistant
Martin Bayley
Logistics Infrastructure Manager
Annalise Hughes
Port Project Manager
Graeme Gordon
Port Workshop Manager
Rod Blake
Logyards Operations Manager
LANDSIDE
Vacant
Port Driver/Labour Supervisor
Lyle Taylor
Port Driver/Operator
Murray Michie
Port Driver/Operator
Vacant
Port Driver/Operator
WHARFSIDE
Vacant
Marine Manager
Rrahul Dosshi
Trainee Pilot, HSE Facilitator
Marine Supervisor
Wayne Hullen
Engineering Maintenance Manager
Yorgo Atsalis
Tug Master / Labour Supervisor
Antony Gilbert
Marine Engineer (Trainee)
Vacant
Marine Engineer
John Gibson
Floating Plant Engineer
Chris Griffin
General Hand
James Evans
Dredge Master
Andrew Williams
Deck / General Hand
Tony Abbott
General Hand
Poul Larson
Tug Master
Karl Bennett
Tug Master/General Hand
David Daniel
Launch Master/General Hand
James Newby
Trainee Launch Master/
General Hand
Andrew Squire
General Hand /
Trainee Launch Master /
Trainee Tug Master

1.5.4 Responsibility for Business Support

Responsibilities associated with provision of business support services and financial services are assigned to Eastland Group's Chief financial Officer, by the Chief Executive Officer of Eastland Group.

1.5.5 Responsibility for Field Services

Responsibilities associated with field activities are monitored and managed by the Eastland Group personnel primarily associated with the Energy Business Asset management. Tasks carried out by these personnel include…
Contractor resource planning
Consents and approvals
Public and Worksite Safety Management
Shutdown planning and coordination
Contract preparation, tendering, management and monitoring
Work site auditing
Contractor approvals
Switching activities
Fault response and repair coordination
To ensure competencies ENL matches the tasks undertaken with qualifications, personality and experience attributes of asset management personnel. Peer and managerial review processes are in place to develop and improve capabilities of all personnel.

In general all physical installation and maintenance work in the field is contracted out to service providers. Eastland Group personnel assist with the activities to provide the necessary knowledge and experience. This compensates for any skill or resource shortages. The following service providers are used by Eastland Group for physical installation and maintenance work.

Service Provider	Key Services	Extent of Business Involvement
Eastech Limited (EGL owned)	Primary Fault response, Lines maint & install ,Vegetation Management	32%
Electrinet	Cables, Lines, Electrical, Technical maint & install	27%
In Line Construction	Lines maint & install	8%
Swanson	Supply of goods/materials	6%
Arborcare	Vegetation management	4%
Roberts Tree Surgeons	Vegetation management	3.8%

Eastland Tree Care	Vegetation management	3%
Gisborne Helicopters	Fault Response, Lines install	2%
Ideal	Supply of goods/materials	2%
Colvins	Communications	2%
Powerline Technologies	Fault Response, Asset Inspection, Lines maint & install	1.7%
Ray Grace Ltd	Civil Maintenance	1%
Power Connections Ltd	Fault Response, Cables/ Lines maint & install,	1%
Apex Power Systems Ltd	Fault Response, Lines/Cables maint & install	1%
CR Taylor	Civil Construction	0.3%
99Corporation	Fault response coordination/Call Centre	0.1%
Other		5%

In addition to physical work a number of these service providers are responsible for Design and planning activities associated with subdivisions, new connections, routine maintenance and asset renewal.

1.5.6 Competency and Skill analysis

ENL monitors the Skills, Competencies, and Experience of all persons involved in direct asset management activities at an individual level. A database is maintained of individual competencies and a supervision experience level is agreed between the individual and ENL. The level of attainment for any competency varies between individuals. In general 1 or 2 individuals can achieve a task unaided due to experience, while others need to refer to members of a team, and/or procedures/guides in order to complete the task. The competencies and supervision levels continually change and are reviewed as individuals gain new skills and experience or as the nature of an individual's regular activities or roles change. Audits and review processes are in place to ensure the desired accuracy of the competency database. The following charts summarise the key competencies in terms of the number of identified individuals that have attained the competency to identify any gaps in terms of risk management.

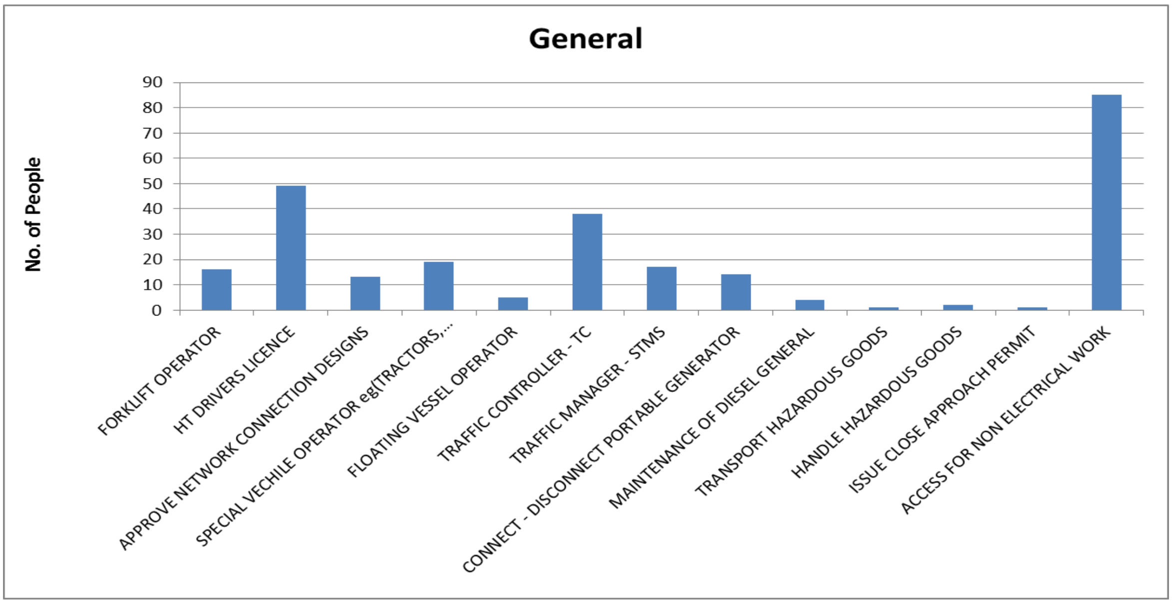
In all ENL has identified 114 key competency areas and approximately 98 individuals registered with at least 1 competency. A total of 2203 competencies are covered by the 98 individuals. The average of 22 competencies per individual indicates the high degree of multi skilling. This is further evident in the estimated 33 full time

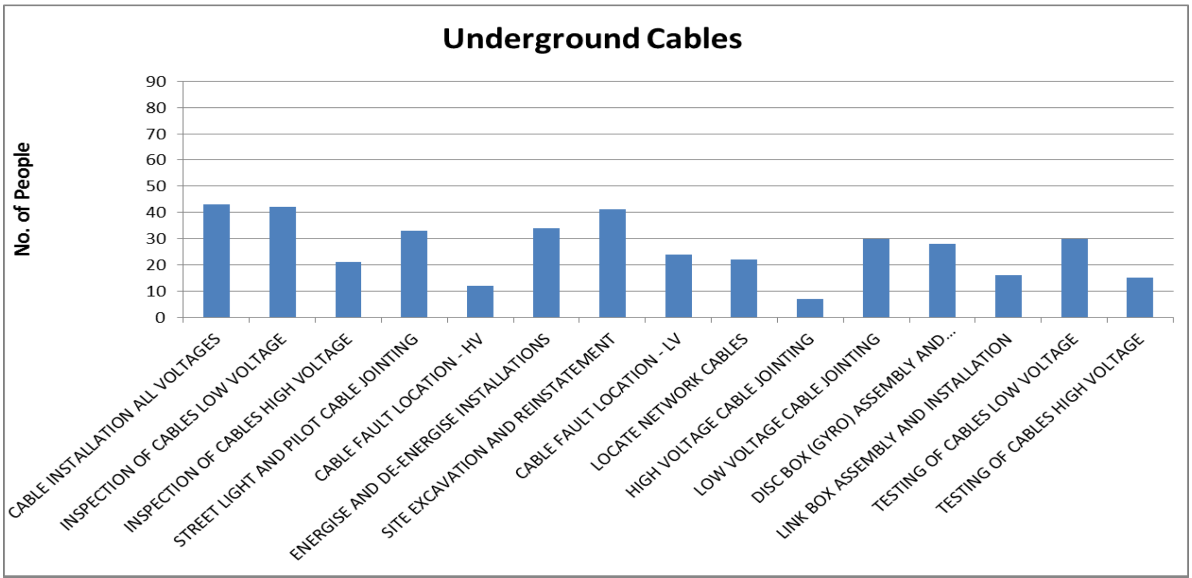
equivalent person-years p.a. paid to staff and contractors engaged in asset management activities.
The disadvantage of the highly multi-skilled workforce of which the majority is only involved with ENL activities for part of the time, is the limit on being able to do multiple tasks at the same time. ie while all the necessary skills exist in a few people there are insufficient people to get the work done at times.
Competency areas that are a constraint in exceptional events or afterhours include;

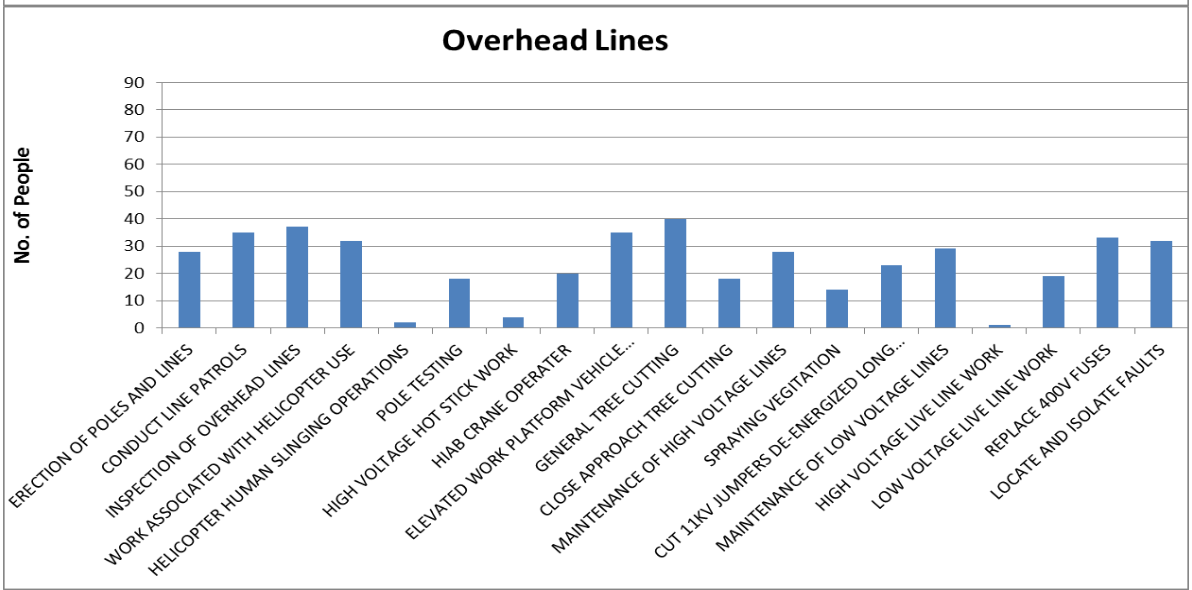
- Truck drivers (Generally limited by restrictions on work/driving hours)
- Cable jointers
- Crane operators
- Fault-electricians (Remote areas)
- Technicians.
- Line Mechanics

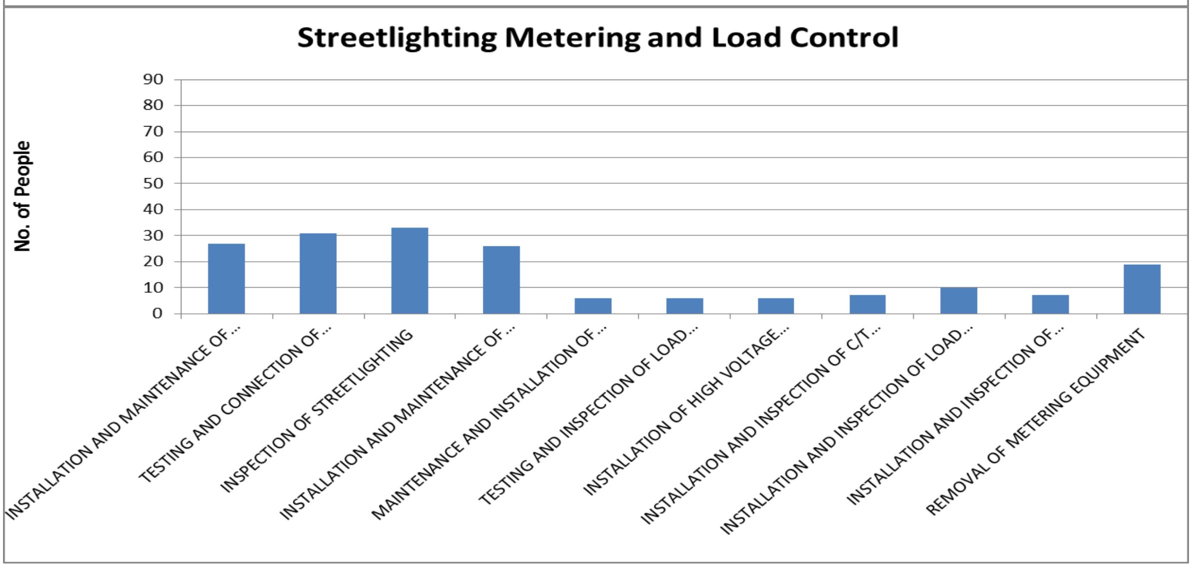
ENL currently manages these shortfalls by re-allocating experienced engineering staff from normal duties to field work.
Apprentice training programs are an option to secure future resourcing requirements but plans have not been approved by Eastland Group.
Given the steady state projections of asset renewal the current personnel levels are insufficient to carry out all of the work.
As the conductor renewal work increases further additional lines personnel will be required as the activity requires additional staffing over standard pole replacement activities.

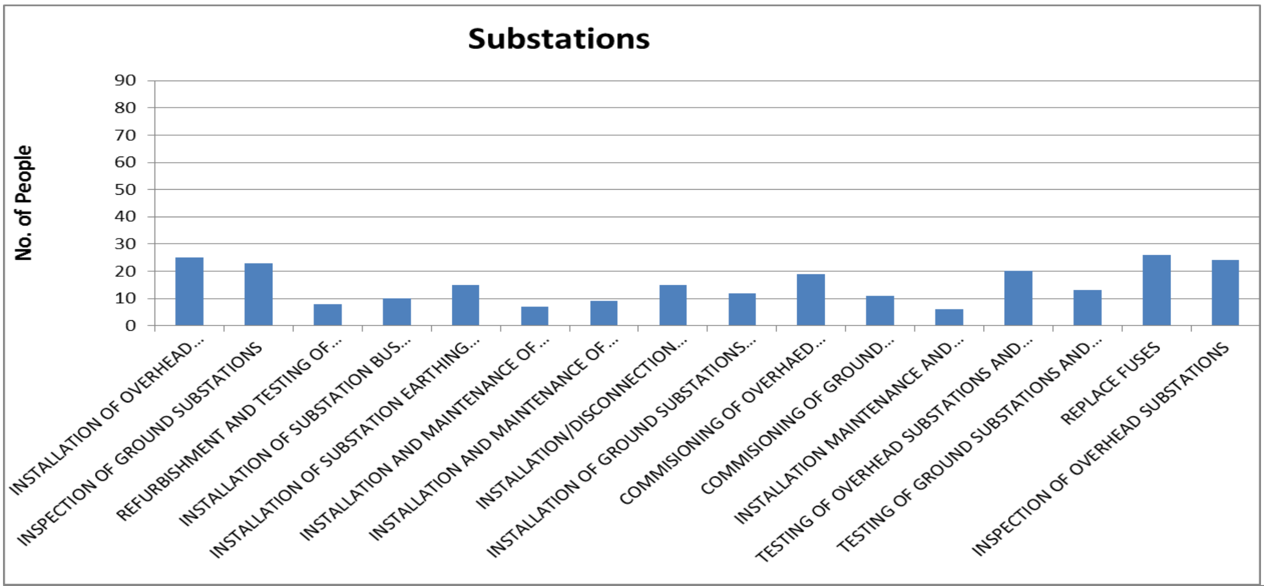
The following charts summarise the competencies and number of individuals that have attained the competency to a varying degree.



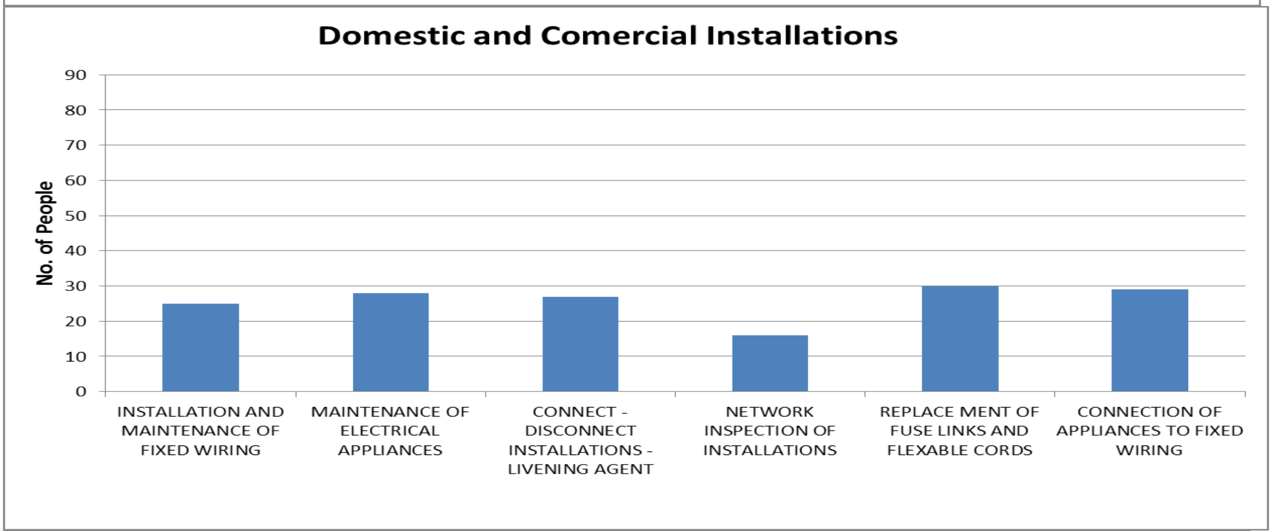

Underground Cables
No. of People
90
80
70
60
50
40
30
20
10
0
CABLE INSTALLATION ALL VOLTAGES
INSPECTION OF CABLES LOW VOLTAGE
INSPECTION OF CABLES HIGH VOLTAGE
STREET LIGHT AND PILOT CABLE JOINTING
CABLE FAULT LOCATION - HV
ENERGISE AND DE-ENERGISE INSTALLATIONS
SITE EXCAVATION AND REINSTATEMENT
CABLE FAULT LOCATION - LV
LOCATE NETWORK CABLES
HIGH VOLTAGE CABLE JOINTING
LOW VOLTAGE CABLE JOINTING
DISC BOX (GYRO) ASSEMBLY AND...
LINK BOX ASSEMBLY AND INSTALLATION
TESTING OF CABLES LOW VOLTAGE
TESTING OF CABLES HIGH VOLTAGE


Overhead Lines
No. of People
90
80
70
60
50
40
30
20
10
0
ERECTION OF POLES AND LINES
CONDUCT LINE PATROLS
INSPECTION OF OVERHEAD LINES
WORK ASSOCIATED WITH HELICOPTER USE
HELICOPTER HUMAN SLINGING OPERATIONS
POLE TESTING
HIGH VOLTAGE HOT STICK WORK
HIAB CRANE OPERATER
ELEVATED WORK PLATFORM VEHICLE...
GENERAL TREE CUTTING
CLOSE APPROACH TREE CUTTING
MAINTENANCE OF HIGH VOLTAGE LINES
SPRAYING VEGITATION
CUT 11KV JUMPERS DE-ENERGIZED LONG...
MAINTENANCE OF LOW VOLTAGE LINES
HIGH VOLTAGE LIVE LINE WORK
LOW VOLTAGE LIVE LINE WORK
REPLACE 400V FUSES
LOCATE AND ISOLATE FAULTS

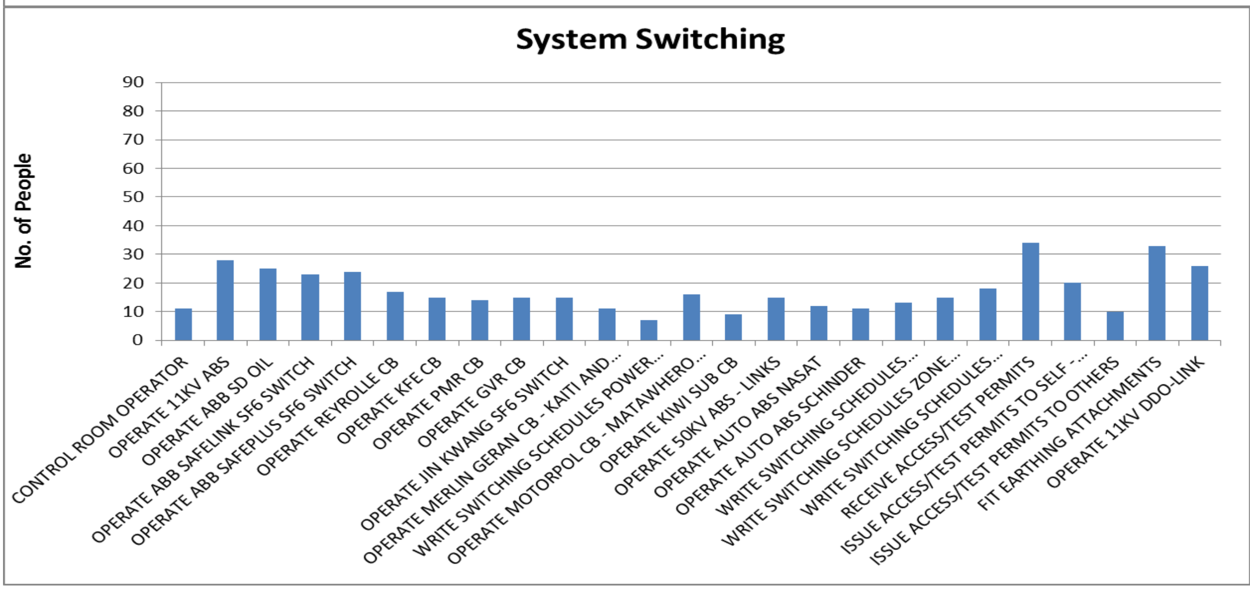

Streetlighting Metering and Load Control
No. of People
90
80
70
60
50
40
30
20
10
0
INSTALLATION AND MAINTENANCE OF ...
TESTING AND CONNECTION OF ...
INSPECTION OF STREETLIGHTING
INSTALLATION AND MAINTENANCE OF ...
MAINTENANCE AND INSTALLATION OF ...
TESTING AND INSPECTION OF LOAD...
INSTALLATION OF HIGH VOLTAGE...
INSTALLATION AND INSPECTION OF C/T...
INSTALLATION AND INSPECTION OF LOAD...
INSTALLATION AND INSPECTION OF...
REMOVAL OF METERING EQUIPMENT



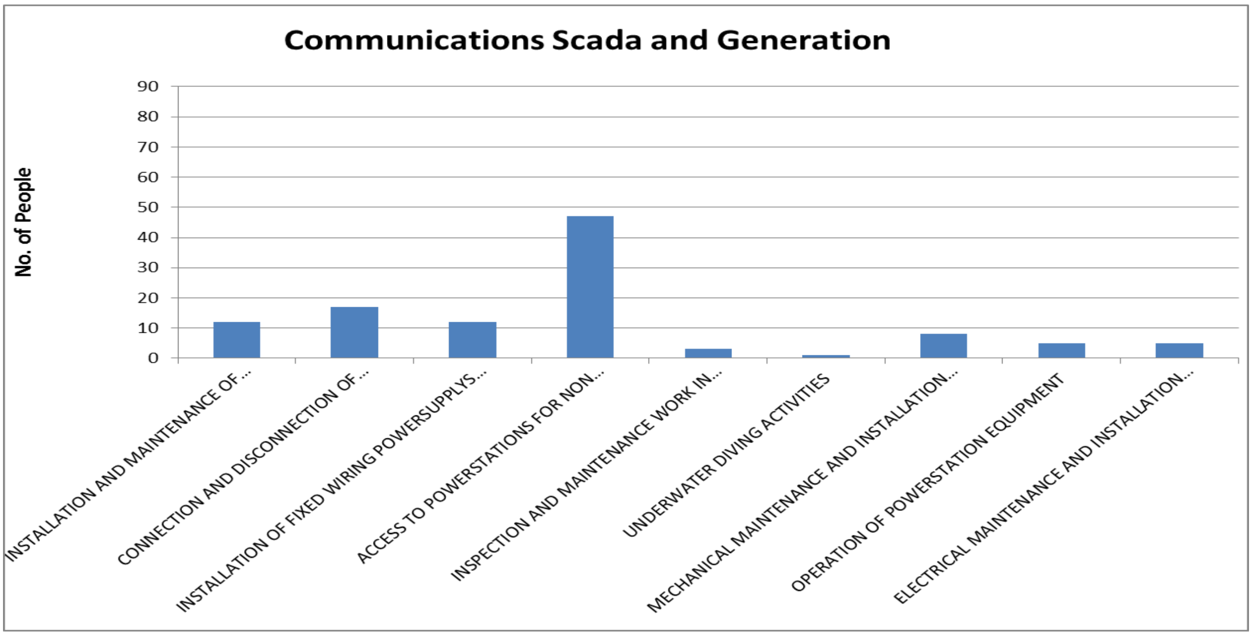
Substations
No. of People
90
80
70
60
50
40
30
20
10
0
INSTALLATION OF OVERHEAD...
INSPECTION OF GROUND SUBSTATIONS
REFURBISHMENT AND TESTING OF...
INSTALLATION OF SUBSTATION BUS...
INSTALLATION OF SUBSTATION EARTHING...
INSTALLATION AND MAINTENANCE OF...
INSTALLATION AND MAINTENANCE OF...
INSTALLATION/DISCONNECTION...
INSTALLATION OF GROUND SUBSTATIONS...
COMMISIONING OF OVERHAED...
COMMISIONING OF GROUND...
INSTALLATION MAINTENANCE AND...
TESTING OF OVERHEAD SUBSTATIONS AND...
TESTING OF GROUND SUBSTATIONS AND...
REPLACE FUSES
INSPECTION OF OVERHEAD SUBSTATIONS



Domestic and Comercial Installations
No. of People
90
80
70
60
50
40
30
20
10
0
INSTALLATION AND MAINTENANCE OF FIXED WIRING
MAINTENANCE OF ELECTRICAL APPLIANCES
CONNECT - DISCONNECT INSTALLATIONS - LIVENING AGENT
NETWORK INSPECTION OF INSTALLATIONS
REPLACE MENT OF FUSE LINKS AND FLEXABLE CORDS
CONNECTION OF APPLIANCES TO FIXED WIRING



System Switching
No. of People
90
80
70
60
50
40
30
20
10
0
CONTROL ROOM OPERATOR
OPERATE 11KV ABS
OPERATE ABB SD OIL
OPERATE ABB SAFELINK SF6 SWITCH
OPERATE ABB SAFEPLUS SF6 SWITCH
OPERATE REYROLLE CB
OPERATE KFE CB
OPERATE PMR CB
OPERATE GVR CB
OPERATE JIN KWANG SF6 SWITCH
OPERATE MERLIN GERAN CB - KAITI AND...
WRITE SWITCHING SCHEDULES POWER...
OPERATE MOTORPOL CB - MATAWHERO...
OPERATE KIWI SUB CB
OPERATE 50KV ABS - LINKS
OPERATE AUTO ABS NASAT
OPERATE AUTO ABS SCHINDER
WRITE SWITCHING SCHEDULES...
WRITE SWITCHING SCHEDULES ZONE...
WRITE SWITCHING SCHEDULES...
RECEIVE ACCESS/TEST PERMITS
ISSUE ACCESS/TEST PERMITS TO SELF - ...
ISSUE ACCESS/TEST PERMITS TO OTHERS
FIT EARTHING ATTACHMENTS
OPERATE 11KV DDO-LINK



1.6 Significant Assumptions

A number of significant assumptions have been made in order to determine likely outcomes of ENL's AMP. These key assumptions are summarised as follows…

Ownership- ENL's ownership is assumed to remain unchanged throughout the planning period.
Corporate Vision, Objectives and Targets – ENL's corporate vision, objectives and targets in section 1.2 are assumed to remain the same throughout the planning period.
Climate - ENL assumes normal climatic variation over the planning period including temperature, wind, snow and rain patterns consistent with its experiences since 2000.
Major disasters – The assumption has been made that major disasters will not exceed the capabilities of existing contingency measures over the planning period.
Stakeholder service levels – ENL has assumed the current stakeholder expectations regarding security and service levels in section 1.4 and section 3, will not alter significantly throughout the planning period.
Demand projections and Load Characteristics – Network loading and growth are assumed to occur in line with the demand forecasts in Section 4.3.
Individual large loads and embedded generation – ENL has not included large individual loads or significant embedded generation other than that identified in section 4.3. It is assumed that

developments that have not already been identified will not occur over the planning period.
External regulations, legislation and technical industry standards and codes of practice – ENL has assumed the current environment will be unchanged over the planning period.
Transpower's obligations and commitments - ENL has assumed the current arrangements will be unchanged over the planning period.
Relative input costs and exchange rates and the cost of borrowing- ENL has assumed the current financial environment will be unchanged over the planning period. All financial projections are provided at current values.
Resource availability- ENL has assumed the availability of resources will be at adequate levels over the planning period.
Technological change- ENL has assumed that no significant technological change will occur over the planning period.

1.6.1 Proposed Changes to the Existing Business

No changes are proposed to the existing business ownership and structure of ENL, and thus all prospective information has been prepared consistent with the existing ENL business ownership and structure.

1.6.2 Basis for Assumptions

All the significant assumptions identified above are based on the premise that ENL's is operating in a steady state with current conditions unlikely to vary significantly in future. The principal source of information from which future assumptions have been derived is historical data contained in the various systems described in section 1.7 of this AMP. These systems include the…

Works Management System
Network Control Systems
Financials
Network Modeling
Asset Information Systems
Gentrack Billing System
Safety Management Systems

1.6.3 Sources of Uncertainty

The assumptions made in relation to sources of uncertainty are listed in above. The potential effect of each on the prospective information contained in this AMP is:

Source of Uncertainty	**Potential Effect of Uncertainty**	**Potential Impact of the Uncertainty**
Ownership change	A change of ownership can potentially introduce new focus influencing primary inputs to the asset management plan.	Projected Expenditure may increase or decrease. Performance levels may decline or improve
Corporate Vision, Objectives and Targets	Changes will influence the primary inputs to the asset management plan.	Projected Expenditure may increase or decrease. Performance levels may decline or improve
New Acquisitions	New Acquisitions will affect service level asset value and financial forecasts	Projections will change in line with the change in scale and nature of the assets acquired.
Climate	A shift in weather patterns will influence the life cycle patterns of the assets and or design parameters of the network.	Projected Expenditure may increase or decrease. Performance levels may decline or improve. Load patterns may change.
Major disasters	Significant disasters may leave the network asset unviable requiring a new network to support a rebuild of the region.	Projected Expenditure likely to increase. Load patterns likely to be significantly altered.
Stakeholder service levels	Stakeholders could change their demands for service and willingness to pay.	Either higher or lower service targets will be established with an associated impact on expenditure.
Demand projections and Load Characteristics	Demand growth beyond expected levels will erode security levels. Negative growth will reduce income and leave an under-utilised asset.	Projected Expenditure may increase or decrease. Performance levels may decline or improve. Regional Development may be limited or new opportunities may emerge.
Individual large loads and embedded	Additional asset not covered by current development plans will be required. Development	Projected Expenditure may increase or decrease.

generation	timing for Transmission and subtransmission assets will alter.	
External regulations, legislation and technical industry standards and codes of practice	Current and forecast capital and maintenance programs will alter to accommodate changed requirements. Asset management systems replaced/altered to accommodate changing information requirements.	Projected Expenditure may increase or decrease. Performance levels may decline or improve. Financial viability of the network business may improve or decline.
Transpower's obligations and commitments	Can alter forecast capital and maintenance programs, performance levels and revenue requirements.	Projected Expenditure may increase or decrease. Performance levels may decline or improve. Financial viability of the network business may improve or decline. Regional Development may be limited or new opportunities may emerge.
Relative input costs and exchange rates and the cost of borrowing	Alters capital and maintenance expenditure forecasts.	Projected Expenditure may increase or decrease.
Resource availability	Impacts on the ability to match resources to work programs.	Projected Expenditure may increase or Performance levels may decline. Viability of the network business may decline.
Technological Change	Typically improves accuracy of information and analysis systems. Or improves characteristics of asset behavior.	Performance levels would typically improve but may incur a corresponding increase in expenditure.
Changes to Standard Lives	Impacts on assumptions where age is used to indicate general condition across similar asset populations.	Changes Asset Renewal and maintenance programs in consideration of the timing over the revised asset lifecycle.

1.6.4 Price Inflator Assumptions

In preparing the financial information disclosure in nominal New Zealand dollars, as required in the Report on Forecast Capital Expenditure (Schedule 11a.) and the Report on Forecast Operational Expenditure (Schedule 11b.), ENL has applied a price inflators.

The following price inflator assumptions are aligned with the CPI data used by the Commerce Comission forcasts ofcapital and operating expenditure for the 2015-2020 price reset.

Period	**CPI**
2015/2016	1.53%
2016/2017	1.507%
2017/2018	1.77%
2018/2019	2.1%
2019/2020	2.15%
2020/2021 – 2024/2025	2.0%

ENL will continue to monitor inflationary advice and will update related information in future AMPs as required.

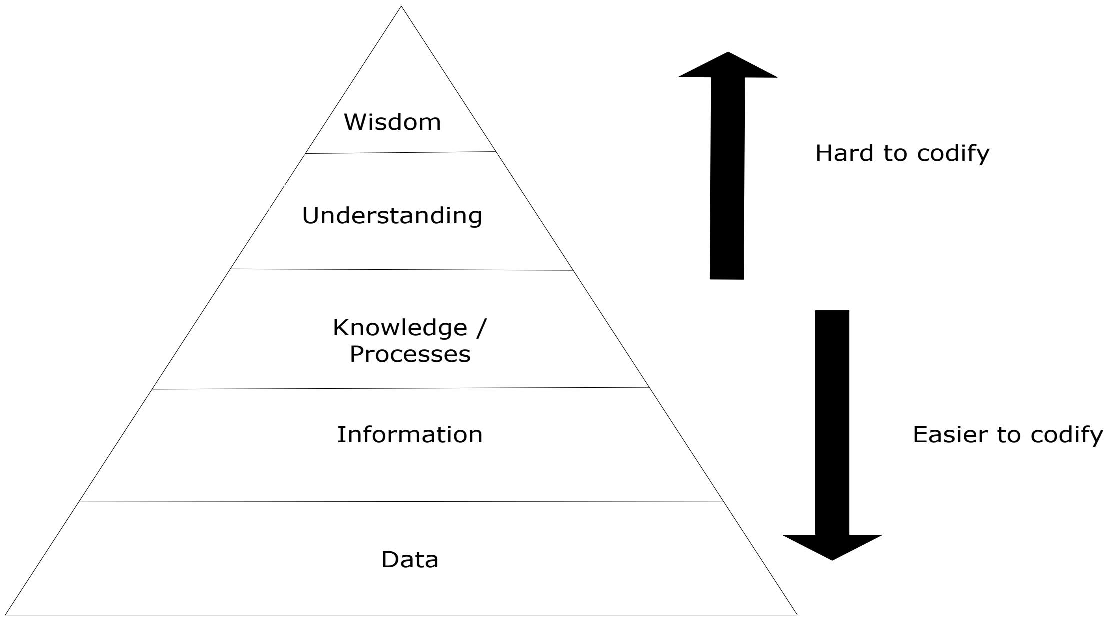
1.6.5 Factors that may lead to a Material Difference

Factors which may lead to a material difference between the AMP and future actual outcomes include any significant departure from the steady state trends or current conditions relating to the assumptions identified above.

1.7 ENL's processes & systems

The core of ENL's asset management activities lie with the detailed processes and systems that reflect ENL's thinking, manifest in its policies, strategies and processes and ultimately shapes the nature and configuration of its fixed assets. The hierarchy of data model shown in Figure 8(a) describes the typical sorts of information residing within the business which includes that held by employees by virtue of their skills and experience.

Figure 8(a) – Hierarchy of data



The bottom two layers of the hierarchy tend to relate strongly to the asset and operational data which reside in the GIS and SCADA respectively, and the summaries of this data that form one part of the decision making.

1.7.1 Asset Management Wisdom and Understanding

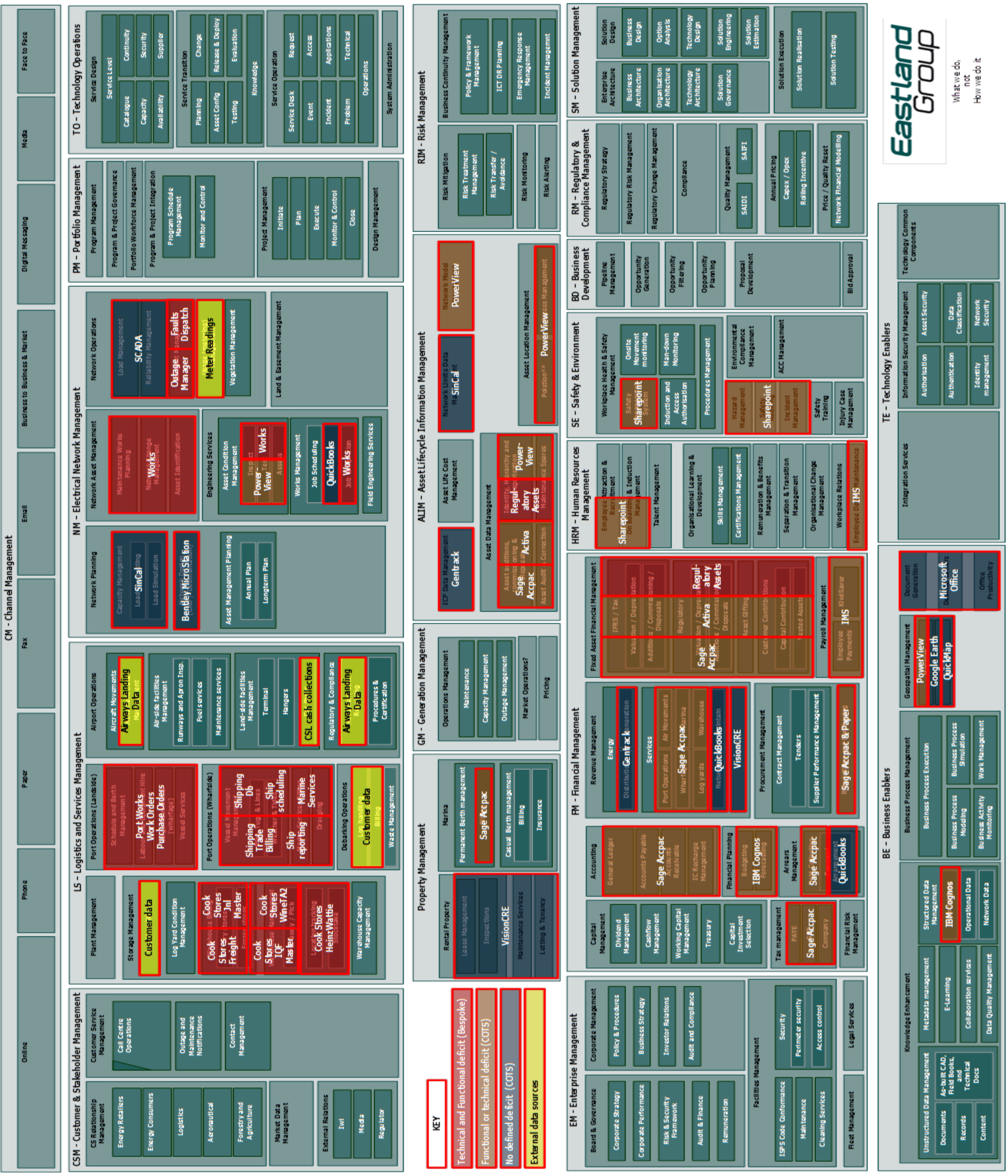
The top two layers of the data hierarchy tend to be very broad and are often difficult to define. It is at this level that key organisational strategies and processes reside at. As indicated in Figure 8(a) it is generally hard to codify these things, hence correct application is heavily dependent on skilled people. Eastland Group continually improves on these aspects of wisdom and understanding through its staff training and development programs. These layers provide ENL with the ability to establish key initiatives and produce optimum solutions forming the Network development plans in section 4 of this plan. In addition these layers are key to forming the strategies for managing the assets lifecycle in section 5 of this plan

1.7.2 Asset management Knowledge and Processes

The third layer of the data hierarchy – knowledge and processes– tends to be more broad and general in nature. This layer encompasses accumulated knowledge in the form of processes. Development and review of ENL's processes is on-going and changes are triggered as needs arise.

The asset management processes collect data and information, identify actions, develop solutions and prioritises the programs for maintenance and asset development to ensure optimum customer service and operational efficiency. Implicit in the asset planning processes is an understanding and evaluation of the risks to operation and the consequences of failure. Also critical is the collection of information from which performance can be monitored and improvement targets set.

The block diagram below summarises the software systems used by Eastland Group to support the processes used


CM - Channel Management
CSM - Customer & Stakeholder Management
LS - Logistics and Services Management
NM - Electrical Network Management
PM - Portfolio Management
TO - Technology Operations
RM - Risk Management
ALIM - Asset Lifecycle Information Management
GM - Generation Management
Property Management
SM - Solution Management
RM - Regulatory & Compliance Management
BD - Business Development
SE - Safety & Environment
HRM - Human Resources Management
FM - Financial Management
EM - Enterprise Management
TE - Technology Enablers
BE - Business Enablers
KEY
Technical and Functional deficit (Bespoke)
Functional or technical deficit (COTS)
No defined deficit (COTS)
External data sources
Eastland Group
What we do, not How we do it

The systematic processes that make up the core of asset management practices are those that collect and analyse data. The main processes are:
Safety Management
Every asset and activity is assessed in terms of the design, hazards, control measures and residual risk. Processes to manage risks relating to Occupational Health and safety, Public safety, and Damage to property requirements are incorporated into all aspects of asset management.

Condition Assessment
Every asset has a condition assessment action included in its maintenance program. This is used to confirm the necessity of further maintenance, target maintenance expenditure and provide ageing data. (refer Section 5.3)

Performance
Analysis of reliability statistics provides information on the performance of assets, the effectiveness of work practices, and helps target work programs which result in improved performance.
(refer section 3)

Asset Utilisation and Capacity
Load growth and changing profiles are obvious inputs into planning. However security risk and quality issues also require adjustment when load use patterns change. (refer section 4)

Risk Management
Network related risks are identified and ranked by risk reduction outcomes to help prioritise work programs. (refer section 6)

Economic Optimisation
The value of a network results from the asset management practices applied. Economic analysis can indicate whether valuation changes and lifecycle costs are in line with long-term sustainable objectives and therefore which tactics are appropriate for different network segments. Economic analysis is also applied to optimise the balance between capital and maintenance decisions across the life cycle of the network assets

Design
The design process ensures that all assets are installed to enable safe and reliable operation for an established range of operating conditions. New assets utilise design standards that take into account the past performance of previous standards and designs.

Modification to designs and standards is managed to continually improve the effectiveness, performance and cost of the assets accommodating new technologies and innovations where appropriate. (refer section 5.5)

Benchmarking
Analysis of disclosure information and industry benchmarks identifies the practices that are most effective and the performance levels that can be achieved given inherent network characteristics.

1.7.3 Information Management Data Systems

Processes for managing routine asset inspections and network maintenance are managed by the Works Management System which relates the budgeted activities described in section 5.3 of this plan to the physical activities undertaken.

As work is completed information is updated in the appropriate data stores and feedback as necessary into the design process or works management system for corrective actions.
Urgent actions are dealt with immediately while other data captured is fed into the decision process ultimately shaping future maintenance and/or capital strategies.

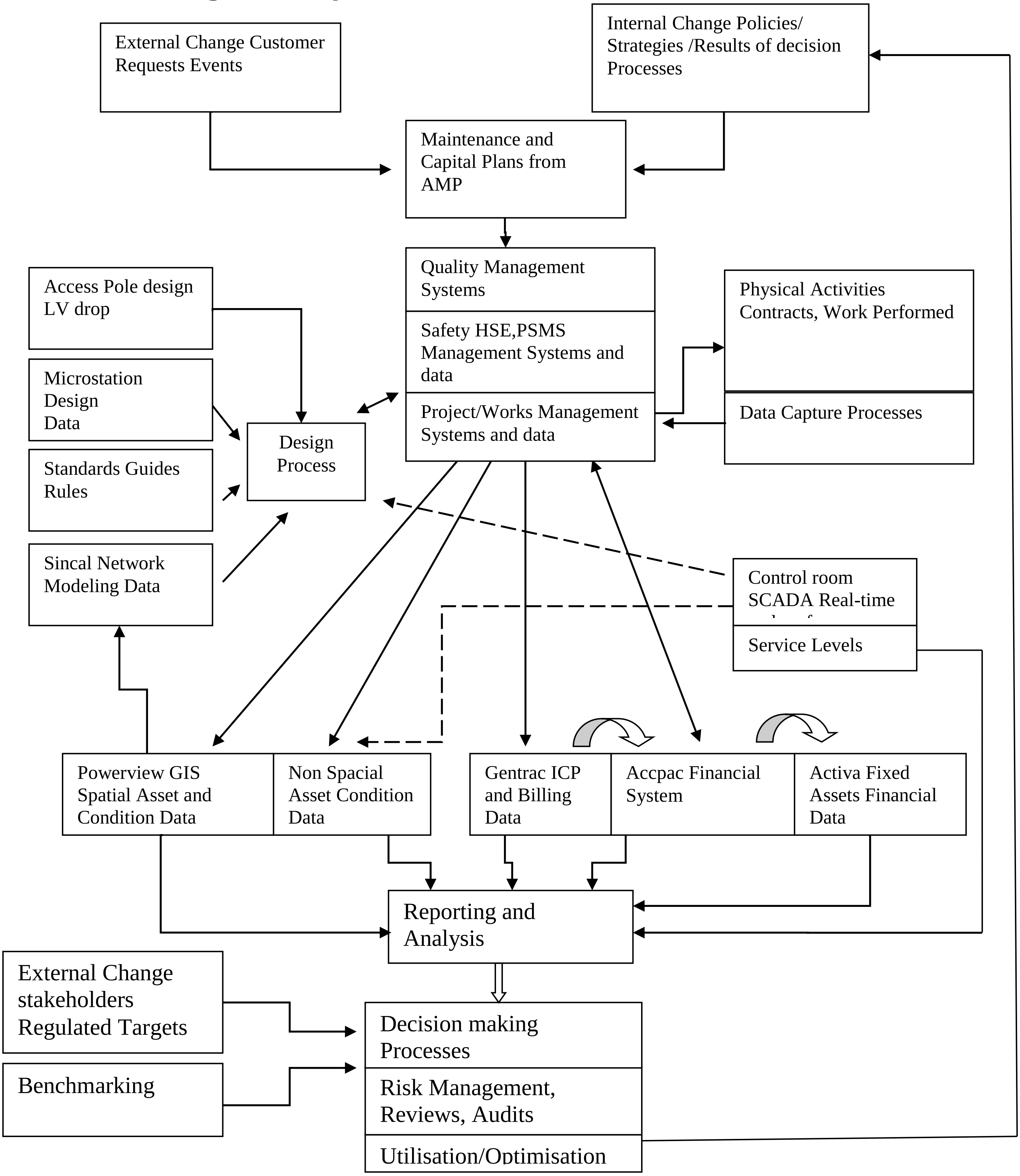
The processes used to analyse the data and identify changing data requirements are documented in the Asset Management System. Refer 1.7.7 below.

Real time data and data for determination of service levels a task associated with the Control room operations function. As the data is accumulated it is fed into the reporting systems and decision making process.

Data requirements associated with the safety management system required by the Electricity Act 1992, Act amendments 2006 and Electricity (Safety) Regulations 2009 is closely linked to the works management system.

The linkage and co-ordination between ENL's asset management processes and systems involves storage of a wide range of data and a complex flow of information as shown below;

Asset Management System Information Flows



1.7.4 Asset Management Data

The following information systems are used to, store information on ENL's assets including relevant condition and performance information.

Works Management System
This system is used to:

-Manage routine asset inspections and network maintenance.

-Monitor the status of planning and network development projects

-Manage defect notification and safety management system corrective actions relating to assets.

The Works Database provides job cost functionality and is used to manage faults, defects, maintenance and the work management activities over the assets lifecycle described in section 5 of this plan. This is essentially a job and contract management tool with linkages to the GIS and Financial systems to provide cost reporting. It provides information on progress, commitments, forecasts and cash flow at job and project level.

Financials
The financial systems are key in providing information relating to network performance in terms of financial efficiency.

The company uses ACCPAC as its main financial management IT-platform. This is supplemented with Activa to maintain the financial asset register, which is separate to the engineering asset database.

The Works Database is reconciled with ACCPAC during monthly reporting.

Cognos software is used to provide Group Budgets and account consolidation to Group level.

Network Control and Monitoring
These Data Systems systems store information used to measure network physical performance. Systems include Outage Notification Management, Control Log, Outage Statistics and

The SCADA system provides real time operational data and enables remote control of key components of the network. Reporting functions for service levels and performance are also contained within these systems

The Substation Management System provides remote access to the Major substations for download of log information and reconfiguration of equipment including Tapchanger controllers, protection relays, and Battery System Controllers.

Network Modelling Data
ENL uses PSS Sincal (Power System Simulation/Utilisation) network modelling software to analyse the network and the impact of changes in utilisation and operation. The software is sufficiently sophisticated to permit advanced network optimisation and analysis and assist investment decision-making.

Internal Line design software solutions are used for structural engineering/line design.

LV Drop software is primarily used for Low voltage design.

Fixed Asset Data
The Powerview Geographical Information system operating on Microsoft Access Databases is used for management of asset data, maintenance and summary inspection records. A number of associated Microsoft Access Databases / applications are used in conjunction with the Powerview databases to manage non-spatial assets. The Powerview system is coupled to Google Earth and Quickmap mapping products to provide flexible alternatives to users of the information depending on their specific needs.

Microstation Draughting Software is primarily used to maintain information in Schematic form. Complex structural and circuitry design information is also stored in the Microstation format. Hard copy records include Maps, field record books, and Maintenance/ Commissioning Records. Tools have been developed that allow reconciliation of GIS information with the Schematic information to ensure consistency across data stores.

Gentrac is the product used to manage ICP records in an SQL Database format and linked to the GIS data. A software update/upgrade was completed in 2010.

Activa Software is used to manage the Financial Fixed asset register. The fixed assets spacially identified within the GIS system are reconciled with the Activa fixed asset register using tools developed inhouse.

Microsoft Access is used to Manage the Regulatory Fixed asset register which incorporates tools for reconsilation between GIS and the Financial asset registers

Filing Systems

A manual paper based filing system with cross indexing features is used for long term storage of historical asset management condition and maintenance information. New information can either be stored in this system or a computer based replica of the system.

Data Accuracy

The following table indicates an assessment of the asset management data and information and accuracy. The percentage completeness indicates the confidence that the asset can be identified as existing as is recorded as existing, while the assessment of accuracy indicates an average confidence in attribute information for the asset. The attribute information for assets varies in significance depending on the nature of the information and how it is used. The assessment of accuracy typically covers key information used to make critical asset management decisions, e.g. Asset attributes, Install and Inspection dates. In general condition information that guides trends or "nice to know information" is maintained on field capture paper records with only summary, e.g. inspection date, information entered into databases.

Data/Information	Completeness	Accuracy
Real time data		
Analog loading substations	98% of all Feeders monitored	+/- 10%
Discrete I/O Status	100% all automatic switches monitored	97% reliable indication
Asset Components		
HV Conductor/Cable	97%	70% certainty in attribute information
Poles	97%	70% certainty in attribute information
HV Switchgear	100%	90% certainty in attribute information
Transformers	100%	90% certainty in attribute information
LV Conductor Cable	90%	80% certainty in attribute information
LV Switchgear	85%	75% certainty in attribute information
Service connections	100%	60% certainty in attribute information
Comms equipment	90%	80% certainty in

		attribute information
LV Pillars	85%	85% certainty in attribute information
Load control	60%	60% certainty in attribute information
Scada equipment	99%	99% certainty in attribute information
Zone Sub Equipment	99%	80% certainty in attribute information

1.7.5 Data Controls and Improvement Initiatives

The primary requirement in determining useful asset and condition data is the requirement to ensure the asset or assets are electrically safe in accordance with the definition in the Electricity safety regulations. Reviews and checks on the data are undertaken at all stages of the processes. Verification of field information is achieved by overlapping inspection and documentation procedures that bring inconsistencies to the attention of asset management personnel. Data entry is monitored by automatic data validation and exception reports incorporated into database systems. The degree of control on data accuracy and consistency varies depending on the value contained within the data. eg data relating to the existence of a high voltage switch that directly relates to safety has a higher significance than data relating to an asset make that can be easily verified by a second inspection if necessary.

All critical asset management decisions involving the assets a qualified by a field captured condition assessment prior to an action (refer section 5.3) hence there is no need to invest heavily in high data accuracy other than to meet regulatory reporting requirements.

The table below outlines the asset management system and data improvement initiatives for ENL. In defining these initiatives ENL has recognized a certain degree of incompleteness and inaccuracy of the asset data. However, the ENL asset data still represents a valuable reference source.

There is a trade-off in establishing a 100% accurate dataset and the required resource and ENL considers system and data improvements at each review of this plan.

System/Data	Improvement Initiative	Timeframe	Budget
Transformer and HV switch assets	Transformer and HV switch assets are key in terms of safety for real time switching operations. The system mimic is verified against the GIS data on a regular basis to identify inconsistencies. In 2010 in- house development of software to automate verification of data between the key systems was developed	On-going	In system operations and network support forecast
All asset data	During field operations inconsistencies are easily identified and corrected as they are found. Historical date attribute information where it is recorded on the equipment is updated on an ongoing basis as it is collected during inspections. Where it is not recorded on equipment the dates typically align with historical records and have proven adequate for asset management decision making to date.	On-going	In system operations and network support forecast
LV switchgear LV Pillars and Load control relays	LV switchgear LV Pillars and Load control relays are currently incomplete record sets. Inspection and renewal programs (refer section 5.3.13) for these assets are enabling the accumulation of data for these assets.	On-going	In system operations and network support forecast
Regulatory Asset Register	Continue development of Regulatory asset register intergration with Financial Asset register and GIS Asset information.	2015-2016	In system operations and network support forecast. Refer 4.7.3
Works Management Systems Software	Corporate review of systems may identify alternative systems to the systems currently in use to improve consistency across all Eastland group businesses in the area of works/asset management systems being used.	2015-2016	In system operations and network support forecast. Refer 4.7.3
Asset management system	Review asset management systems (GIS, works management system and drawing management system with consideration of the requirements for condition information stored in the databases and Closer intergration with Works Management systems and asset registers.	2015-2016	In system operations and network support forecast. Refer 4.7.3
GIS System Software	As identified in Refer 2.3.14.2 the ability to support the software on new hardware/ platforms is declining. No software support options exist and development is in house. Options for replacement or integration into other systems are under consideration	2016-2017	In system operations and network support forecast.

1.7.6 Asset Management System Integration

A high degree of interaction between the asset management processes and systems occurs at multiple levels depending upon the nature and urgency of the information.

With the exception of the real time SCADA system all data is initially captured using paper based systems. The asset databases focus on capture of asset attributes and install/inspection date information. To avoid excessive data entry condition records are summarised into work programs and maintained as paper records. i.e. not entered into databases.

1.7.7 Asset management System

ENL has a formal asset management system comprised of

Quality Management System

The Quality Management System documents policies, procedures, processes, design standards, contingency plans, risk analysis and links to relevant external documents and resources, relating to all aspects of ENL's operation including:

-Hazard Identification and control
-Contractor Management
-Legislative compliance
-Public Safety Management
-Project Management
-Workplace Hazard Management
-Incident Management
-Worksite activities Hazard management
-Customer Relationship Management
-Hazardous Substances
-Emergency Procedures
-Defect Notification
-System operational Procedures
-Works Management Procedures (Contracts, Verification, Quality Control)
-Product control and purchasing
-Risk Management
-Field Procedures
-Inspection Procedures
-Communication Procedures
-Inspection and Maintenance Procedures
-Information Reporting and Data Capture Procedures
-Purchasing Specifications
-Design Standards
-Equipment Standards
-Connection Standards
-Audit, Review and document control

Safety Management System

The safety management system documents the information and processes relating to hazards as defined by section 169A of the Act using the format defined by NZS7901.

The Safety Management system is essentially a subset of the Quality Management system containing documents procedures, processes and asset performance information relating to prevention of serious harm to the public and significant damage to property.

Technical Library.

A library of technical information is maintained to ensure information is readily available design, maintain and repair the network asset. The need for Eastland Networks's own standards created in the past has steadily reduced as industry standards, codes and technical information has emerged. Development and review of standards is on-going and changes are triggered as needs arise.

1.7.8 Asset Management System Reviews

Review processes and procedures are incorporated into ENL's quality management system. The system documents the controls to ensure quality and accuracy of information. Internal reviews of the quality management system are undertaken on an on-going basis at appropriate frequencies.
The key external and internal reviews are discussed in section 8.4 to 8.6 of this plan.

1.7.9 Asset Management Communication and Participation

ENL has a number of processes in place to communicate asset management strategies, objectives, policies and plans to stakeholders that are involved in the delivery of the asset management requirements.

At and individual level an Employee Performance incentive program incorporates the asset management performance targets and efficiency measures into the individual employment contracts.

All external contracts to contractors and consultants have terms and conditions of contract that link to the asset management objectives relevant to the contracted service.

The Quality system and Public safety management system contain documented procedures covering distribution and control of standards, designs, inspection procedures. The distribution and communication of changes to external parties is also controlled in line with documented procedures. Meetings and reviews with employees and contractors forming the key asset management teams ensure timely communication when necessary.

The Employee participation program in place provides an alternative tool allowing any individual to contribute to performance and efficiency improvements either directly or indirectly related to ENL asset management strategies plans procedures and processes.

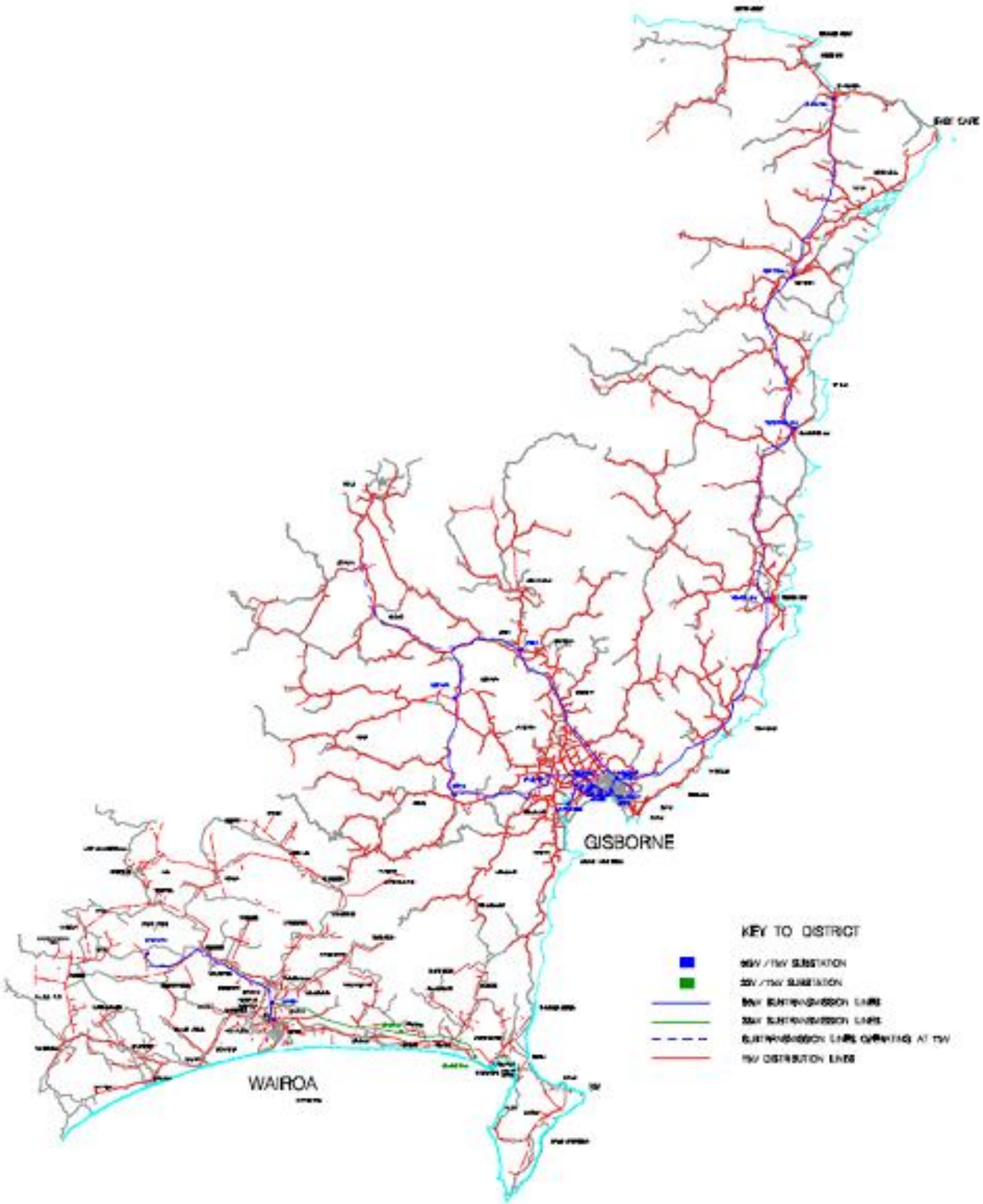
The above tools and methods to ensure communication options are available are internally reviewed and externally audited to ensure the processes are robust and meet the needs of the business.

2. Details of ENL's assets

2.1 ENL's distribution area

2.1.1 Geographical coverage

ENL's distribution area broadly covers the East Cape and Northern Hawkes Bay areas as shown below within the red ring. This area corresponds to the jurisdictions of the Gisborne District Council and the Wairoa District Council.



Topography ranges from fertile plains around Gisborne and Wairoa to rugged mountainous areas further inland. The 11kV(red) network is generally consists of ties between substations supplied by the 50kV (blue) and 33kV (green) Sub-transmission, with radial feeds inland via river valleys and ridges.

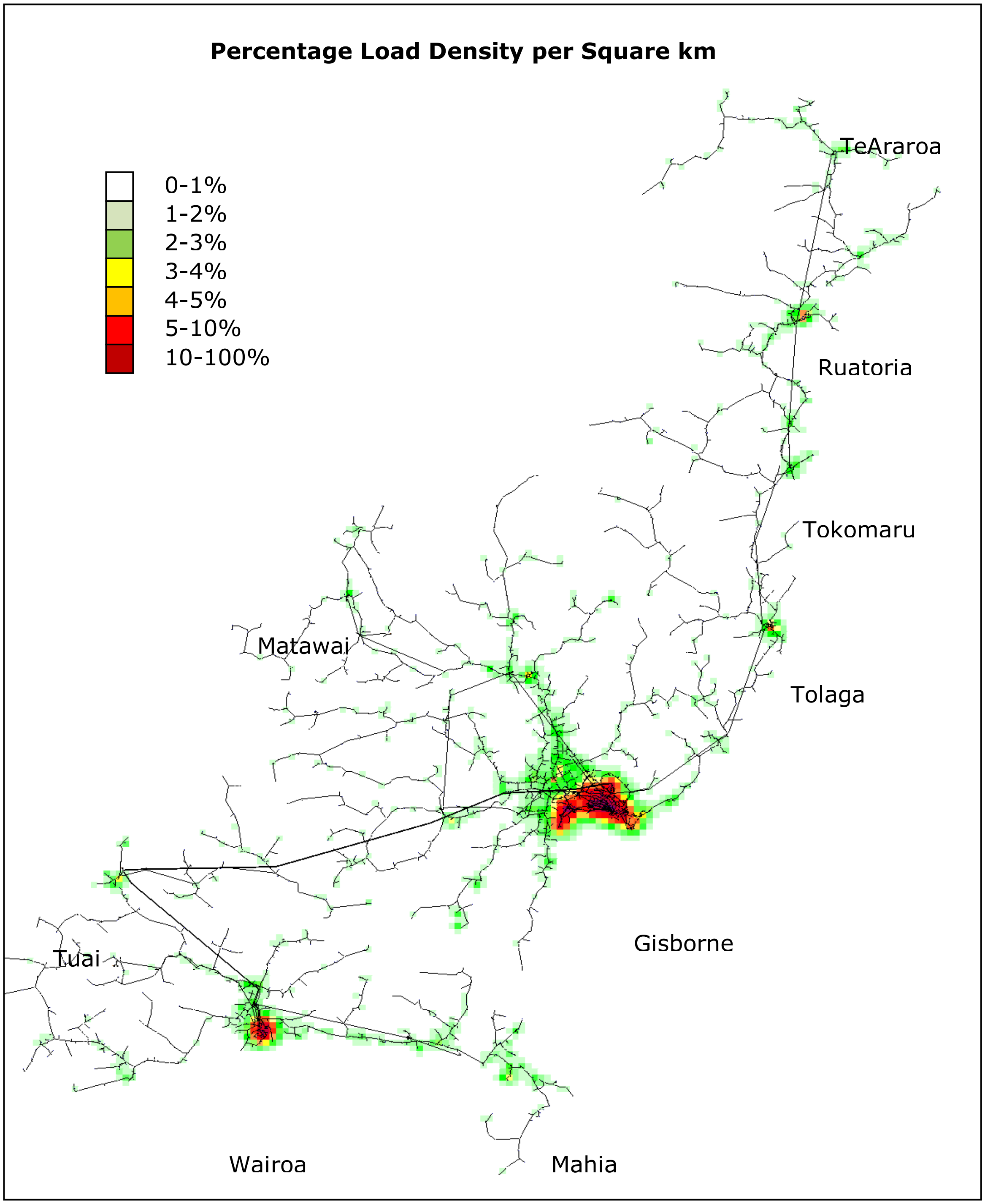
2.1.2 Demographics and Characteristics

The population of ENL's distribution area is approximately 53,000 of whom about 41,000 live in the urban Gisborne area and a further 5,000 live in the urban Wairoa area. The remaining 7,000 live in small settlements (such as Te Karaka, Tolaga Bay, Tokomaru Bay, Ruatoria, Matawai and Mahia) and in rural areas. The last three censi indicate slightly declining populations in both the Gisborne and Wairoa Districts.

It is a feature of the ENL network that 75% of ICPs are Domestic. Accordingly any expected contraction of max demand or network investment requirements due to the slight decline in population is likely to be more than off-set by decreasing occupancy rates (i.e. more dwellings but with fewer inhabitants), increased load (i.e. cheap electric heaters, cheap air-con units) and new connections over-taking a previous trend of rural ICP consolidation. ICP numbers for the past 8 years are;

Year ending	ICPs	Change	Domestic	Non-Domestic
31/03/04	24,849	(-327)	19115	5734
31/03/05	24,854	(+5)	19149	5705
31/03/06	24,871	(+17)	19228	5643
31/03/07	24,975	(+104)	19324	5651
31/03/08	25,196	(+221)	19513	5683
31/03/09	25,300	(+104)	19554	5746
31/03/10	25,432	(+132)	19691	5741
31/03/11	25,514	(+82)	19748	5766
31/03/12	25,567	(+53)	19850	5717
31/03/13	25,550	(-17)	19940	5610
31/03/14	25,353	(-197)	19298	6055

Specific load characteristics for different parts of the region are described in 2.2.3. The following map showing the percentage load density per square km provides an overview of the regions characteristic. The majority of the line assets are associated with load densities below 1% of the regions total demand per sq. km, while Gisborne and Wairoa Urban centres have the regions highest load density.



2.1.3 Key industries

Key industries relate strongly to the primary produce value chain – cultivation, harvesting, processing, storage and transportation of timber, root and leaf vegetables, pip and stone fruits, grapes, meat

and fin fish. There are a number of significant processing and storage installations on the western outskirts of Gisborne, clustered in the Gisborne industrial estate, the Gisborne Port area and in Wairoa.
The companies located in these areas which have a significant impact on the regions demand are listed in the table below.

Industry		Demand
Juken NZ Limited	Timber Processing - Gisborne	3.5MW
Affco	Meat Processing -Wairoa	3.5MW
Bernard Mathews	Meat Processing- Gisborne	2MW
Tairawhiti Healthcare	Heath care provider- Gisborne	2MW
Cedenco	Food processing- Gisborne	2MW
Eastland Group	Cool Store Operations- Gisborne	1.5MW

The nature and size of the operations carried out by these industries does not significantly impact on the network at an individual level. However the combined consumption of these companies on average is 15% of the total energy conveyed and 25% of the total demand for the region. Direct contact is maintained with these companies to assess their needs and adequacy of current service levels.
There are no issues associated with the operations of these companies, e.g. changes in demand are not expected to have a significant impact on the network over the planning period.

A key issue arising from the nature of these consumers is because of the nature of their industrial processes they have gradually increasing requirement for continuity of supply, improved restoration times and less flicker and sag.

Eastland Group regularly engages with customers on all manners of business and common interest. Also Eastland Group uses an external advisor to formally consult with the 25 largest, (by energy consumption) customers specifically on the issue of price and supply quality. The last such consultation was carried out in 2010. (Refer Section 3.1)

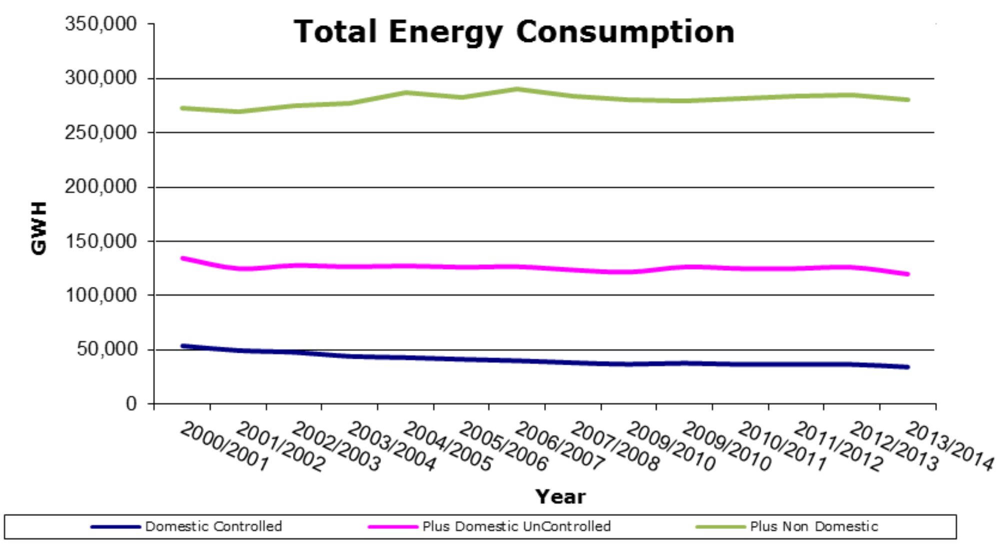
2.1.4 Energy & demand characteristics

Key energy & demand figures for the 2013/14 year are as follows…

Parameter	Value	Trend

Energy Distributed	299,970GWH	Annual variations due to weather patterns. Average increase of <1% p.a.
Maximum System demand	59.86 MW	Average increase of <1% p.a.
Load factor	0.57	Conveyed Units/ Maximum Demand x Hours p.a.. Stable trend with variation <1%

The historical consumption p.a. shows <1% growth or variation due to weather patterns. The system demand trend was influenced by a change in Load control strategy over the period 2001 to 2004. Since 2004 the demand trend has displayed an annual variation of <1%. Low figures for 2003/2004 were a result of a national energy crisis during which advertising to control energy usage and energy retailer requests for hot-water load control beyond that usually required for peak demand control had an impact on demand. During 2010 - 2011 Global financial instability has indirectly influenced usage and growth behaviours. This may account for the decline in this period however it is difficult to determine the impact of this on the trends. Annual variation due to climate is higher than the growth hence it is not possible to make definitive conclusions on the asset utilisation trends. The steady decline in domestic energy usage is noticeable in the trend and has had an impact on energy price over the years.



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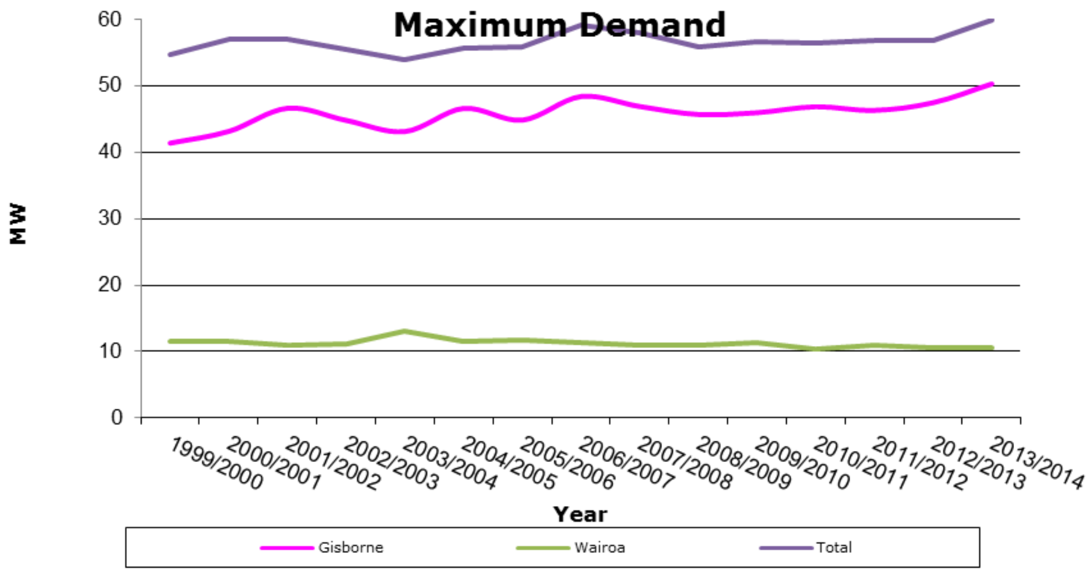


2.2 ENL's network configuration

To supply ENL's consumers ENL owns and operates an electricity network which includes Transmission assets (110kV), Subtransmission assets (50kV & 33kV), Dustribution assets (11kV) and Reticulation assets (400V.230V).

Prior to 1999 the electricity network consisted of lines and cables in the Gisborne and Eastcoast regions as Poverty Bay Electric Power Board, Eastland Energy Limited and Eastland Network Limited. ENL acquired the electricity network and generation business of Wairoa Power Ltd in 1999 which covered the Wairoa and Tuai regions. Prior to this Wairoa Power had sold its retail business to Trust Power and Eastland Energy had sold its retail business to Contact Energy Ltd. In April 2015 ENL acquired the Transmission assets from Transpower, linking the Gisborne, Eastcoast, Tuai and Wairoa regions.

2.2.1 Bulk Supply and Embedded Generation

2.2.1.1 Tuai GXP

The Tuai Grid Exit Point is located near near Lake Waikaremoana and provides the connection of ENL's electricity network to the North Island Transmission Gird owned and operated by Transpower. The Tuai GXP also provides for conection of Genisis Generation Assets in the area. ENL is supplied from this GXP via 5 110kV circuits. One Circuit supplies ENLs Tuai Substation, Two circuits supply ENL's 110kV lines to Wairoa and two circuits supply ENL's 110kV Lines to Gisborne.

2.2.1.2 Embedded generation

Generation connected to ENL's electricity network provides additional sources of energy to the Region. In accordance with the Electricity Industry Participation Code 2010 Part 6 (Connection of Distributed Generation), ENL has entered into contractual agreements with Generators where ENL recognises the benefits provided by the distributed generation. Agreements have been entered into with both Matawai Hydro Limited and Eastland Generation Limited.
Matawai Hydro Limited and Eastland Generation Limited also have contractual agreements directly with energy retailers regarding the sale of units from the generation;

Benefits to ENL derived from operating the generators include…

- Provision of alternative transmission to meet the requirements of grid emergency procedures
- Providing localised continuity of supply during outages due to sub-transmission and Distribution faults or as required facilitating network maintenance.
- Reduction of ENL's max demand at GXP's and contribution to the RCCP by anything up to 10MW.
- Easing of constraints on transmission connections to and within ENL's network, thereby avoiding and/or deferring transmission and distribution asset upgrading investment.

Hydro Generation

Embedded in the Wairoa network ENL utilises the 5.0MW Waihi Hydro scheme which is owned by Eastland Generation Limited.
Waihi Hydro's has two 2.5MVA 6.6kV Generators connected to ENL's Waihi Subststion via a 6.3MVA 6.6/50kV transformer. The Waihi Hydro scheme has enabled ENL to defer investment in 11kV/33KV assets in the Wairoa and Kiwi Substation area.
Contractural agreements covering the benefits provided to the Wairoa network through Eastland Generation Limited's 5MW Waihi Hydro scheme are in place.

Embedded in the Gisborne Network a 2x1MW induction Hydro generation facility was installed in 2009. This facility owned and operated by Clearwater Hydro Ltd depends on adequate river flows over a weir and is located in the Matawai area. This facility has increased the load on the Puha substation and increased the load on the Matawai feeder to 90 % of its rating during periods of the schemes maximum output.
ENL in accordance with the Electricity Industry Participation Code 2010 Part 6 (Connection of Distributed Generation) on an annual basis makes payments to Clearwater Hydro for Matawai Hydro's contribution to the avoided cost of transmission, (max demand peak reduction) on ENL's Network.
Currently no benefits to the network in the local area from the Matawai Hydro have been identified.

Diesel Generation

ENL utilises six 1MW and one 0.5MW diesel generators throughout the Gisborne and Wairoa Regions, which are owned by Eastland Generation Limited. The units are housed in shipping containers and weigh about 23 tons each. These can be deployed anywhere in the network that is accessible to a large mobile crane and where up to 1MW can be injected at 11kV.

The 1MW generators are located and connected to the network at Mahia,Matawhero Substation, JNL Substation, Puha Substation, Ruatoria Substation, Te Araroa Substation and Tolaga Bay Substation on a semi-permanent basis.
The 0.5MW unit is also used as required to maintain customer supply during planned and/or unplanned outages. Upgrading of the 0.5MW unit's 400V circuit breaker, starting system and 11kV connecting leads

was completed in 2006/07 full synchronizing capability was installed in 2008 and the AVR was upgraded in 2010. The 0.5MW unit is currently out of service with AVR issues.

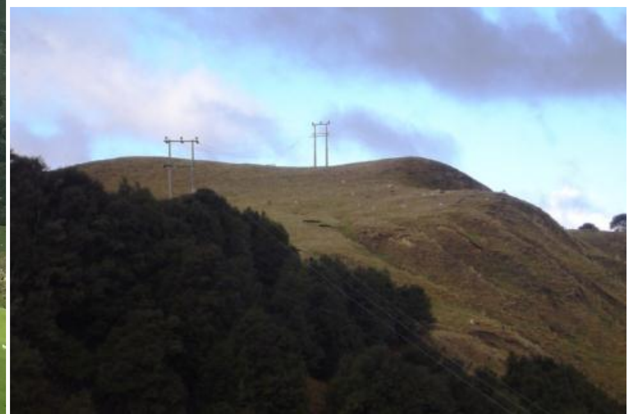
Backup Generation

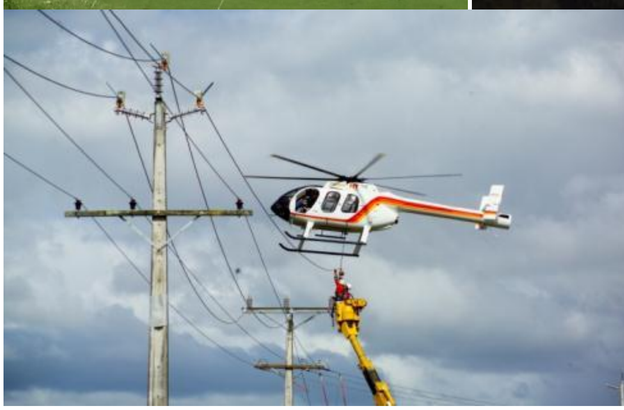
Generation is in common use throughout the region. Privately owned and operated units are used on a standby basis (ie during power outages). The units are not connected to the network.
While there is no mandate or systems in place to obtain information on generation of this type the known sites include…

Gisborne waterworks	-1MVA,200kVA
Gisborne Sewage outlet	-200kVA,30kVA
Sewage Treatment Gisborne	-1MVA
Emerald Hotel	-300kW
Gisborne Hospital	-500kVA est
Gisborne Airport	-5kVA
Gisborne Exchange	-200kVA est
Eastland Group	-14KVA
Wairoa Pump station	-200kVA

In addition an estimated 15% of rural connections have access to petrol generators, 1 to 3 kW, for use during power outages.

2.2.2 Transmission and Sub-transmission Assets



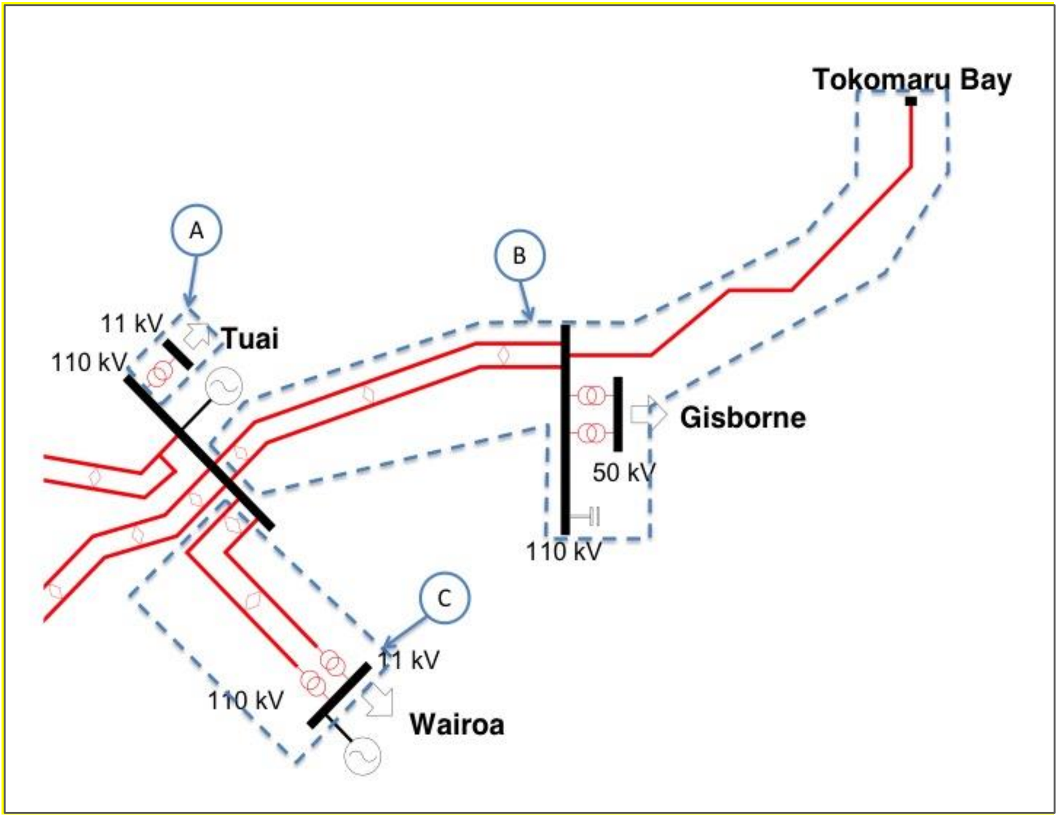


The diagram below illustrates the Eastland transmission Assets, which include:

a. <u>The Tuai Subtransmission substation supply</u>:

b. <u>The 110kV supply to Gisborne and Tokomaru Bay:</u>

c. <u>The 110kV supply to Wairoa:</u>



The assets were aquired (as at 31 March 2015) for approximately $13 million, The cost includes the cost of land/easement transfers. Approximately $770,000 of transfer work in progress project costs are also included. The transfer projects covered:

- Transfer of telemetry and control from Transpower SCADA system to ENL’s SCADA system and establishing new communication links between ENL’s control room to Tuai, Wairoa and Gisborne 110kV substations;
- The purchase of 110kV line and station spares; and,
- The purchase of temporary tower equipment (non-network assets).

While some of the costs were incurred prior to April2015 the outstanding items are incorporated into forcasts in this plan.

The following table summarises the lengths of the various classes of Transmission and Subtransmission lines

Class	Voltage	Total Length (m)	Length Gisborne (m)	Length Wairoa (m)

OH EHV 110kV	110 KV	328300	254900	73400
OH EHV 50kV & 33kV	50 kV	300466.3139	268106.11	32360.2
UG EHV 50kV & 33kV	50 kV	1344.625	1344.625	0
OH EHV 50kV & 33kV	33 kV	34322.6	0	34322.6
UG EHV 50kV & 33kV	33 kV	65.236	0	65.236

In addition to the lines, Pole and Towers, ENL manages a variety of assets associated with access to the Lines. These assets include land/easements/agreements, Gates, Bridges, Tracks, Retaining Walls and Shelterbelt structures.

2.2.2.1 Gisborne Region transmission

The Tuai Gisborne transmission Line consists of a double circuit 110kV tower line from Transpower's Tuai Substation near Lake Waikaremoana. The tower line splits into two double-pole under-hung circuits near Patutahi (about 7km west of Gisborne) and then re-converges into a double circuit tower configuration for about 12 spans immediately west of Gisborne Substation. The route length of the Tuai/Gisborne 110KV lines is approximately 91.4km. It consists of 308 Tower Structures, 16 Pole structures. The line was comissioned, in 1957.

The Gisborne to Tokomaru transmission Line consists of a single circuit 110kV tower line. The route length of the line is 71.5km. It consists of 206 Tower Structures and 2 Pole Structures.

The two 110kV circuits are supplied by a ring-bus at Tuai that is coupled by a 110kV breaker. Bus zone protection was installed in 2010 reducing the risk of a bus fault at Tuai tripping both 110kV lines to Gisborne Substation.
The double-circuit 110kV configuration in part installed on single structures while providing (n-1) electrical security does not give true (n-1) security. i.e Failure of a single tower will interrupt supply via both circuits.
The 110kV circuits into Gisborne Substation are currently summer/winter rated at 49MW/60MW.
To meet max demand exceeding 60MW, will ultimately require the installation of a third Tuai/Gisborne line.

It is noted that Transpower's efforts to obtain a line easement in 2000 for a third line were not completed and easement options have now lapsed.
Alternatives such as local generation and load control/demand side management will influence the timing of the third line requirement.

Options for development covering these issues are in section 4.7 of this plan.

2.2.2.2 Wairoa Region transmission

The Wairoa transmission Line consists of a double circuit 110kV tower line from Transpower's Tuai Substation near Lake Waikaremoana.

The Route Length = 36.7Km with 58 Tower Structures comissioned in 1976 and 16 Concrete Poles commissioned in 2001.

The two 110kV circuits are supplied by a ring-bus at Tuai that is coupled by a 110kV breaker. Bus zone protection was installed in 2010 reducing the risk of a bus fault at Tuai tripping both 110kV lines to Wairoa Substation.
The double-circuit 110kV configuration in part installed on single structures while providing (n-1) electrical security does not give true (n-1) security. i.e Failure of a single tower will interrupt supply via both circuits.

Options for development covering these issues are in section 4.7 of this plan.

2.2.2.3 Gisborne Region sub-transmission

The Gisborne Region sub-transmission network comprises the following asset configurations…

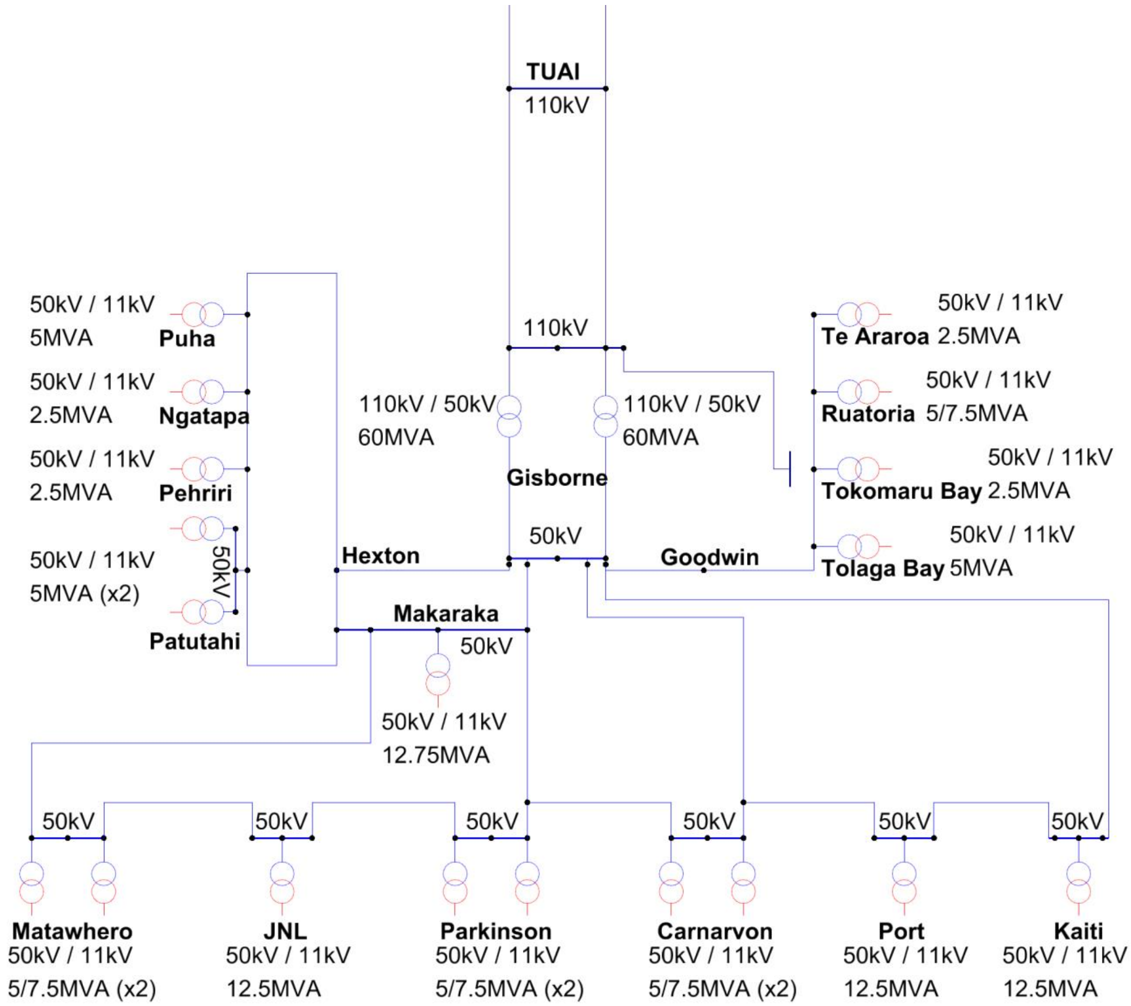
A 50kV spur from Massey Rd up the east coast that was originally constructed by the NZED as far as Tokomaru Bay (1955) then to Ruatoria (1964) and finally to Te Araroa (1971). Ownership of the Massey Rd – Tokomaru section of this line was transferred to the PBEPB in 1980 when the NZED completed its own 110kV tower line.
A switching station at Goodwin Rd was installed to prevent faults on the Massey Rd - Tokomaru 50kV line from causing tripping of the 50kV circuit to Kaiti and the Port. This consists of a SCADA-controlled circuit breaker with an associated isolator/earth switch and fence enclosure. It was constructed in 2002.

Two 50kV lines from Massey Rd to Makaraka.

A single open 50kV ring to the west of Gisborne supplied from half way along one of the Makaraka lines at the Hexton switching station to supply 50/11kV substations at Puha, Ngatapa, Pehiri, Patutahi and back to Makaraka. Between Puha and Ngatapa there is a 50kV spur supplying Matawai which operates at 11kV. The Hexton switching station was installed as part of the project to construct the second 50kV line into Makaraka from the Massey Rd – Puha circuit in 2001 to prevent faults in the Puha–Ngatapa-Pehiri-Patutahi segment of the 50kV ring from affecting supply to Makaraka, Matawhero and Parkinson St.

Two 50kV urban rings, one supplying 50/11kV substations at Kaiti, Carnarvon St and the Port from Massey Rd, and the other supplying Matawhero, JNL and Parkinson from Makaraka. These rings can be connected between Carnarvon and Parkinson which occurs regularly to enable maintenance of Transpower assets on the 50kV structures at Massey Rd without loss of supply.

The figure below the Gisborne sub-transmission network ….



When Gisborne substation assets were transferred to ENL in April 2015. Transpower owned land and houses adjacent to the substation site, were excluded and are intended to be sold by Transpower.The first few spans of 50 KV line across the houses on the land to be sold are being reviewed as a consequence of the sale and the possibily exists that these spans will require relocation if ENL is unable to aquire the land.

2.2.2.4 Wairoa Region sub-transmission

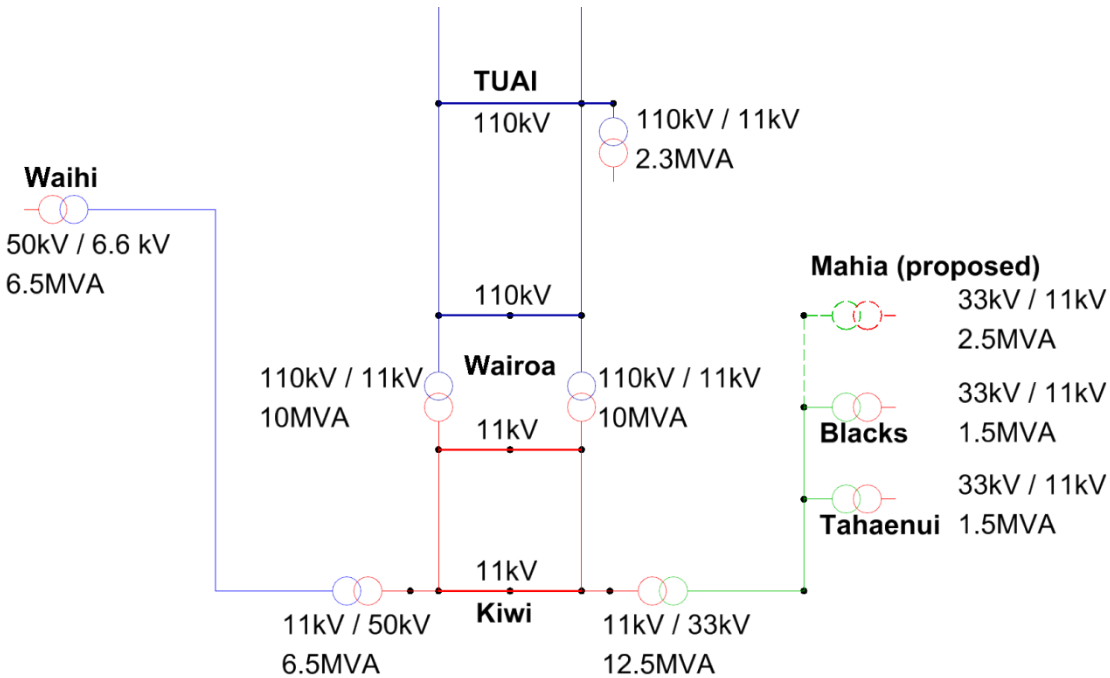
The Wairoa sub-transmission network comprises two main components…

A 33kV line stretching 35km from an 11/33kV step-up substation at Wairoa Substation to Blacks' Pad substation at the north end of the

Mahia peninsula. Prior to 2000 this line was operated at 50kV despite parts of the line being only insulated to 33kV.

A 50kV line from Waihi hydro to ENL's Kiwi substation which includes some under-built 11kV in places. The 50kV line was origionally built from Tuai to Wairoa as the original supply for Wairoa Substation and still utilises the original insulators which have begun to fail.

The figure below depicts the Wairoa sub-transmission network…



2.2.3 Major substations

2.2.3.1 Gisborne Region Substations

ENL's Gisborne region substations are summarised in the following table and described more fully by the following narratives.

Sub.	Area supplied	Description
Gisborne Substation	Transmission Substation Supplying 50kV Subtransmission Lines to the Region	Substantial two Transformer Transmission Substation

Carnarvon St Substation	CBD and central Gisborne.	Substantial two transformer urban sub.
JNL Substation	Primarily supplies a single large consumer, likely to supply additional similar customers in the medium-term.	Single transformer industrial sub with provision for a second transformer.
Kaiti Substation	Residential Kaiti area, some load being shifted to Port.	Substantial single transformer urban sub with provision for second transformer.
Makaraka Substation	Semi-rural Makaraka area immediately west of Gisborne.	Substantial rural single transformer sub, also provides significant switching point for the 50kV ring and also for ripple injection.
Matawhero Substation	A number of large produce processing consumers about 8km west of Gisborne.	Substantial two transformer industrial sub.
Ngatapa Substation	Rural Ngatapa area and surrounding district about 30km west of Gisborne.	Minimalist single transformer rural sub.
Parkinson Substation	Industrial estate in south-west Gisborne.	Substantial two transformer urban sub.
Port Substation	Port area of Gisborne including taking residential load from Kaiti and CBD load from Carnarvon.	Substantial single transformer urban sub.
Patutahi Substation	Semi-rural area around Patutahi about 18km west of Gisborne.	Minimalist rural sub with two banks of three 1-phase transformers.
Pehiri Substation	Rural area around Pehiri about 30km west of Gisborne.	Single transformer rural sub.
Puha Substation	Mountainous rural area around Te Karaka, Whatatutu and Matawai about 40km north-west of Gisborne.	Three 1-phase transformer substantial rural sub supported by 1MW of diesel generation.
Ruatoria Substation	Small settlement of Ruatoria and surrounding district about 90km north of Gisborne.	Substantial single transformer rural sub supported by 1MW of diesel generation.
Te Araroa Substation	Small settlement of Te Araroa and surrounding district about 115km north of Gisborne.	Substantial single transformer rural sub supported by 1MWe of diesel generation.
Tokomaru Substation	Small settlement of Tokomaru By and surrounding district about 60km north of Gisborne.	Substantial single transformer rural sub.
Tolaga Substation	Small settlement of Tolaga Bay and surrounding district about 35km north of Gisborne.	Substantial three 1-phase transformer rural sub supported by 1MW of diesel generation.

Gisborne Substation

The Gisborne substation is supplied by two 110kV Circuits from Transpowers Tuai GXP. The Substation is located in Massey Rd on the northern outskirts of Gisborne.
The substation previously owned and maintained by Transpower was acquired by ENL in April 2015

Gisborne Substation has two 60MVA 110/50kV transformers (designated T1 and T2) which supply a 50kV bus via two 50kV incomers. The 60MVA units, installed in March 2007, replaced two 30 MVA transformers, overcoming a net maximum demand constraint. The substation supplies four 50kV Subtransmission feeders, two on each side of the bus. Installation of Neutral Earthing resistors and on-load tap-changers and a 50kV bus upgrade were also components of the transformer upgrade. These items corrected issues identified in The transformers are fitted with neutral earthing resistors to reduce fault levels on the subtransmission network for compliance with step-touch/Earth potential rise regulations.

A spare 100/50kV 30MVA Transformer Bank is also located in the substation which could be utilised if necessary as a contingency.

Issues associated with the Gisborne Substation are;
-The 50kV Bus currently supplying 4 feeders needs to be expanded to increase the number of feeders giving potential to reduce impact on saidi by reducing the number of affected customers in subtransmission fault events.

Carnarvon St Substation

Supply to Carnarvon is as follows…

One 50kV line from Gisborne Substation in Massey Rd.

A second teed 50kV line from the Port Substation that can also connect to Parkinson Street Substation.

The 50kV bus at Carnarvon includes a 50kV circuit breaker allowing operation as a closed ring. There are two 3-phase 50/11kV 12.5MVA transformers, each 50% loaded and an 11kV board comprising 2 incomers, a bus tie and 9 feeders.

There are no outstanding issues at the site

<u>JNL Substation</u>

The JNL substation was constructed in 2005. The 11kV switchboard was livened mid 2005 and supplied load to JNL via a 50kV line from Matawhero operating at 11kV. The completion of this substation allows surplus capacity at Matawhero to be used to supply significant industrial load increases, (i.e. wood processing plants) forecast to be required within the next 3 years.

The substation comprises…

A 50kV Line from Matawhero Substation

A 50kV line from Parkinson St substation, completed in 2006/07

A 50kV bus CB to allow closed 50kV ring operation

1 3-phase 12.5MVA transformer bank with room for a second transformer
A Portacom switch room housing an 11kV Reyrolle switchboard with 1 incomer, 2 feeders, a fuse switch for local service and a bus coupler for future extension or generator connection.

There are no outstanding issues at the site

<u>Kaiti Substation</u>


The Kaiti area was originally supplied at 11kV directly from Massey Rd, but by the mid-1980's this load could no longer be adequately supplied at 11kV so in 1987 the PBEPB built a new substation. Kaiti now comprises…

An incoming 50kV line from Massey Rd.

An outgoing 50kV line to the Port.

A minimum oil 50kV circuit breaker providing incoming protection for the transformer and a 50kV bus breaker for closed ring operation.

A single 12.5MVA 50/11kV transformer (with provision for a second transformer).

An 11kV Reyrolle board with 2 incomers, a bus tie, a fuse switch and 7 feeders.

Issues at this site:
-The 11kV Switchboard has issues with the reliability of trip and close solenoid operation. In spite of frequent maintenance , infrequent operation of the equipment results in failure of the solenoids to operate. A design modification is being considered or alternatively replacement of the switch-board may be required. The Switch gear is no longer supported and the model has been superceeded by the manufacturer.

-The close proximity to houses means that transformer noise and vibration is an issue which is exacerbated by the high impedance of the transformer. Some form of noise reduction fencing and or vibration dampening may be required in the future.

Vandalism issues resulting in insulator damage and an accumulation of debris at the site may drive the need to enclose the transformer.

The #1 incomer cables have failed in service and the transformer currently supplies load via incomer #2. The incomer CB has been used to replace a failed CB hence replacement of the #1 incomer cables and an additional CB will be required if a second transformer is ever installed at the site.

Makaraka Substation


Makaraka was originally constructed in 1974 as a switching point for the Gisborne - Patutahi 50kV line which also teed off to Carnarvon. A second incoming 50kV line from Gisborne Substation, which has been tapped off the Gisborne - Puha line, was built in 2001. At time Makaraka was upgraded from a switching station to a single transformer zone substation by the installation of a new 12.75MVA transformer.

Makaraka now comprises…

Two incoming 50kV lines from Gisborne Substation (one via Hexton).

A 12.5MVA 50/11kV transformer capable of running off either side of a split 50kV bus.

A Portacom switch room with an 11kV Reyrolle switch-board comprising an incomer, 4 feeders and a fuse switch.

A 50kV load control injection coupling cell (outdoor).

A hut containing a load control static converter.

Three outgoing 50kV circuits to Patutahi, Matawhero and Parkinson.

There are no outstanding issues at the site

Matawhero Substation


ENL built Matawhero in 2000 as a single transformer substation primarily to supply JNL because the existing 11kV cables from Parkinson had become inadequate (although they have been left in situ to provided additional security of supply). In 2003 ENL augmented Matawhero with a second transformer, a second 50kV breaker and two additional 11kV feeders to supply the rapidly growing cold storage load in this area. Matawhero now comprises…

An incoming 50kV line from Makaraka.

An outgoing 50kV line to the new JNL substation.

A 50kV bus circuit breaker to allow 50kV operation as a closed ring.

Two 5/7.5MVA 50/11kV transformers.

A Portacom switch room with an 11kV board comprising two incomers, a bus coupler, five feeders and a fuse switch. The bus rating at 11kV is 800A

The key issue at Matawhero is the proximity of a major river.
This substation is located in an area that is likely to have large industrial load growth which may require capacity upgrades of the 7.5MVA transformers to 12MVA with a corresponding upgrade of the 11kV switchboard to 1250A

Ngatapa Substation

The PBEPB built Ngatapa in 1964 as part of closing the 50kV ring between Puha and Patutahi. In 2008 the two 500kVA transformers and outdoor 11kV bus were replaced eliminating previous issues associated with the site. Ngatapa currently consists of…

An incoming and an outgoing 50kV line forming the 50kV ring from Makaraka to Hexton (which also supplies the Patutahi, Pehiri and Puha Substations).

One 2500kVA 50/11kV transformer. An 11kV regulator is used to regulate voltage for the backup supply via Patutahi.

A Portacom switch room with an 11kV Reyrolle switch-board comprising one incomer, three feeders and a fuse switch.

Ngatapa substation has also been identified as an alternative supply to Matawai and some support to Puha. To achieve this an 11kV line would need to be upgraded along Hihiroroa Rd then extended under the 50kV line to the top of Otoko Hill with dog conductor.

There are no outstanding issues at the site.

Parkinson Substation

The industrial load in and around Parkinson St was originally supplied at 11kV from Gisborne Substation (similar to the domestic load in Kaiti) which was no longer adequate by the mid-1980’s. In 1987 the PBEPB built a Zone substation in Parkinson St in an identical configuration to Kaiti. In 2004 a second transformer was added at Parkinson St.

Parkinson currently takes supply from a tee off the Makaraka – Carnarvon 50kV line and is also connected to the new JNL dedicated substation via a 50kV line. Parkinson currently comprises…

Two 12.5MVA 50/11kV transformers. The first was installed in 1987 and the second is the former Carnarvon T1 that was refurbished and installed in 2004.

A 50kV bus breaker to allow operation as a closed ring.

An 11kV MerlinGerin switch-board with 2 incomers, a bus tie, a fuse switch and 7 feeders. The Origional protection Relays were replaced with SEL351 relays in 2013.

An SF6 RMU connected to one of the feeders to provide for the local service supply transformer.

Issues at this site:
-The 11kV Switchboard has issues with the reliability of trip and close solenoid operation. In spite of frequent maintenance , infrequent operation of the equipment results in failure of the solenoids to operate. A design modification is being considered or alternatively replacement of the switch-board may be required. The Switch gear is no longer supported and the model has been superceeded by the manufacturer.

<u>Port Substation</u>

Port substation was completed in December 2003 to enable continued load growth at Kaiti and for Carnarvon to be off-loaded. This provided security provision for the Kaiti area. Port currently comprises,

An incoming 50kV line from Kaiti.

A second 50kV line from Carnarvon.

A 50kV bus breaker to allow operation as a closed ring.

A 12.5MVA 50/11kV transformer.

An 11kV Reyrolle board with an incomer, a fuse switch and 4 feeders.

There are no outstanding issues at the site.

Patutahi Substation

Patutahi was built in 1929 by the State Hydro Electric Department as the main bulk supply point to the Gisborne area. The following upgrades have taken place over the years….

The original transformers were replaced with other ex-NZED transformers dating from the 1940's.

The original brick building was considered an earthquake risk and was replaced in 1991.

The original 11kV board was replaced in 2000 with second-hand Reyrolle LMT panels and new VCB's.

The 50kV air operated breakers were replaced in 2006.

Patutahi now comprises…

An incoming 50kV line from Gisborne Substation via Makaraka.

An incoming 50kV line from Gisborne Substation via Makaraka, Hexton, Puha, Ngatapa and Pehiri.

A 50kV line breaker for isolating faults from Pehiri.

Two banks of 50/11kV 1.67MVA 1-phase transformers. There are also two spares, one of which has failed in service and is considered uneconomic to repair.

A single 11kV incomer, four feeders and one fuse switch.

An outdoor structure consisting of mostly steel lattice and concrete poles with copper wire bus bar.

The key issues at Patutahi are mainly that the original design standards for earthing, construction, drainage and oil containment have been overtaken by modern standards. These will be addressed as part of a planned conversion of Patutahi to a single transformer substation that will be secured by off-loading capacity to Matawhero and Makaraka.

Pehiri Substation


The PBEPB built Pehiri in 1964 along with Ngatapa as part of the 50kV ring extension from Puha to Patutahi. ENL upgraded Pehiri in 1998 to include a 2.5MVA transformer with an on-load tap changer. If this transformer needs to be removed from service ENL can supply most of Pehiri's load via the 11kV from Patutahi and using an old 11kV regulator at Pehiri to boost the voltage.

Previous issues were corrected in 2011 by installation of a new 50KV CB to protect the Transformer and removal of the old 50kv line CB

Pehiri now comprises…

An incoming and an outgoing 50kV line which forms part of the 50kV ring from Makaraka to Hexton.

A 2.5MVA 50/11kV transformer.

An 11kV voltage regulator.

An 11kV incomer and four 11kV feeders on an outdoor bus.

There are no outstanding issues at the site.

<u>Puha Substation</u>


The PBEPB built Puha in 1960 to supply the Te Karaka, Whatatutu and Matawai areas to the north-west of Gisborne. Originally Puha was supplied by a single 50kV line from Gisborne Substation, but in 1963 Puha was given a second supply when the 50kV ring was closed. Since the original construction ENL has done the following upgrades…

Earthing and transformer bunding upgrades.

Replacement of the outdoor 11kV bus and breakers with an ABB Safeplus SF_6 indoor board.

Installation of a new 50kV Merlin Gerin SF6 breaker on T1.

Puha currently comprises…

An incoming and an outgoing 50kV line forming the 50kV ring from Makaraka to Hexton.

Three 1.67MVA 50/11kV 1-phase transformers.

An 11kV board comprising a single incomer, a fuse switch and four feeders.

One of ENL's 1MW diesel generators to augment the limited transformer capacity for which an RMU is being installed.

Key issues with Puha are…

Max demand cannot be fully off-loaded to other substations via the 11kV. In addition to operating one of ENL's 1MW diesels at Puha, this is also being addressed by providing for Matawai to be supported via an upgrade at Ngatapa, extending the Ngatapa feeder to Otoko Hill and possibly reinforcing the Lavenham feeder from Patutahi. Increased loading from an embedded Induction generator at Matawai.

There is no oil separator facility for the bunded area, and any work on this has been deferred to coincide with replacement of the transformer bank.

Ruatoria Substation

The PBEPB built Ruatoria in 1965 to supply the wider Ruatoria area including Wahareponga, Kopuaroa and Whakawhitira. Over the last decade ENL has upgraded Ruatoria as follows…

In 1998 ENL installed two refurbished MetroVick 50kV bulk oil breakers, a new 50kV bus and four new SF_6 pole-mounted 11kV breakers. In 2011and 2012 The MetroVick 50kV bulk oil breakers were replaced with SF6 ABB Circuit Breakers

In 1999 ENL installed a new 5/7.5MVA 50/11kV transformer and upgraded the bunding, and also did some earthing upgrades.

In 2001 ENL replaced the four pole-mounted 11kV breakers with an indoor Safeplus SF6 board in a Portacom. This enabled removal of the outdoor 11kV structure and reduction of the yard size as well as improving the earthing and yard surface.

Ruatoria currently comprises…

An incoming 50kV line from Tokomaru Bay.

A 5MVA 50/11kV transformer.

An 11kV board comprising a single incomer, a fuse switch, three feeders and a generator connection point.

A 1MW diesel generator.

There are no outstanding issues at the site.

<u>Te Araroa Substation</u>

The PBEPB built Te Araroa in 1971 to supply the wider Te Araroa area including Hicks Bay, Horoera and Awatere Valley. Recent upgrades include…

In 1998 ENL replaced the original 11kV switchgear with second hand Reyrolle LMT panels and new VCB's and also installed a 2.5MVA transformer with an on-load tap changer with bunding and oil containment facilities.

In 2001 ENL installed a MetroVick 50kV bulk oil breaker on the transformer and removed the earth throw switch originally used for transformer protection. The voltage regulator that was used for security was also removed after it failed in service.

In 2011 ENL Replaced the MetroVick 50kV bulk oil breaker.

Te Araroa currently comprises…

A single incoming 50kV line from Ruatoria.

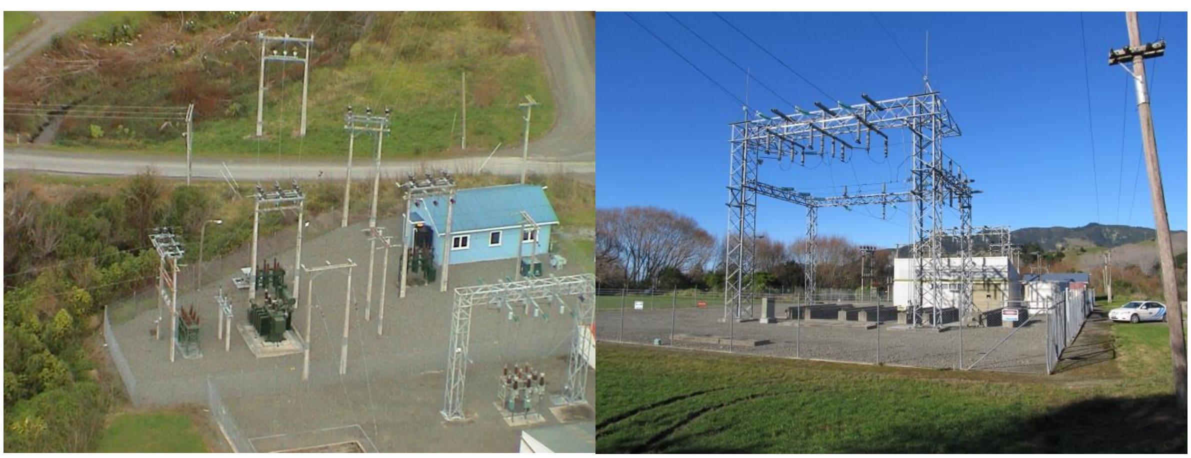
A single 2.5MVA 50/11kV transformer.

An 11kV board comprising a single incomer, a fuse switch, three feeders and a generator connection point.

A 1MW diesel generator.

There are no outstanding issues at the site.

<u>Tokomaru Bay Substation</u>



The PBEPB built Tokomaru in 1958 adjacent to the Transpower GXP to supply the surrounding area including Te Puia Springs and Mawhai

Point. The Transpower GXP at Tokomaru Bay was supplied by a 110kV single-circuit tower line from Gisborne Substation.
ENL relinquished supply from this GXP in 2000 and instead supplied this area from its own 50kV sub-transmission network. Supply security is provided by diesel generators as required.
In March 2015 the Transpower Tokomaru Bay substation was acquired from Transpower. The site is imeadiately adjacent to ENL's Tokomaru Bay Subtransmission/Zone Substation

The 110kV line between Gisborne and Tokomaru Bay is currently left energised to provide capacitive voltage support for Gisborne Substation.
It is disconnected at Tokomaru Bay by an open 110kV incoming isolator. The 110kV/ 50kV transformers from the site were removed in 2004 while the site was owned by Transpower.
Due to the proximity between the 110kV and 50kV Circuits at both Gisborne Substation and Tokomaru Bay Substation, It is feasible to disconnect the 110kV line and jumper the line to the 50kV network at each end as a contingency strategy. Alternativly the 30MVA single phase transformer bank, currently not in service at Gisborne, could be used at Tokomaru bay.

Since the original construction ENL has upgraded Tokomaru as follows…

In 1998 ENL installed a new 2.5MVA transformer with an on-load tap changer and bunding. ENL also upgraded the earthing at the same time.

In 1999 ENL replaced the 11kV switchgear with a second hand Reyrolle LMT board with new VCB's.

In 2001 an oil separator was added.

In 2011 and 2012 ENL Replaced the MetroVick 50kV bulk oil breakers with ABB SF6 Circuit Breakers.

Tokomaru currently comprises…

A single incoming 50kV line from Tolaga Bay.

A single outgoing 50kV line to Ruatoria.

A single 2.5MVA 50/11kV transformer.

An 11kV board comprising a single incomer, a fuse switch and three feeders.

Issues at the site are:
Two stay wires from the 50kV bus in the substation extend across a river through trees to a Depot yard. The stays are considered an unnecessary vaunrability.
The VT on the 11kV switchboard is noisy.

Tolaga Bay Substation

The PBEPB built Tolaga Bay in 1963 to supply the surrounding area including Hauiti and Wharekaka. Since the original construction ENL has upgraded Tolaga as follows…

In 2000 ENL installed a MetroVick 50kV bulk oil breaker to provide transformer protection. The earthing for the remaining substation yard was upgraded as part of the project. This CB was replaced with An SF6 CB in 2013.

In 2001 ENL undertook a significant rationalisation that included erecting a switch-room and installing an indoor Safeplus SF_6 board, removing and scrapping the spare 50/11kV transformer, removing the out-dated 11kV outdoor bus and halving the size of the yard.

Tolaga now comprises…

A single incoming 50kV line from Goodwin Rd switching station.

A single outgoing 50kV line to Tokomaru.

A 5MVA 50/11kV bank comprising three 1.67MVA transformers and a spare.

An 11kV board comprising a single incomer, a fuse switch and four feeders.

A 1MW diesel generator.

Key issues at Tolaga are:

There is currently no oil separation. Installation has been deferred to coincide with replacement of the transformers.

All but 300kVA of load can be back-fed from adjacent substations on the 11kV. The remaining 300kVA can be adequately supported by the diesel generator.

2.2.3.2 Wairoa Region Substations

ENL's Wairoa substations are summarised in the following table and described more fully by the following narratives…

Sub.	Area supplied	Description
Blacks Pad	Opoutama, Kaiwaitau and the Mahia peninsula.	Minimalist single transformer rural sub supported by 1MWe of diesel generation over Christmas and Easter.
Kiwi	Urban Wairoa including AFFCO plant.	Substantial switching station supplied at 11kV from Transpower and houses the 50/11kV step-down transformer for the Waihi line.
Tahaenui	Semi-rural area around Nuhaka and Morere, also back-feeds to Blacks Pad.	Minimalist single transformer rural sub.
Waihi	Step-up substation at 5MW hydro station.	Minimalist single transformer sub.
Wairoa	Substantial Supply substation for the Region Plus Step-up substation for supply to Mahia	Two Transformer Substation plus single step up transformer. With ripple injection Plant
Tuai	Rural Area covering Waikaremoana and Ruakituri	Single Transpomer with out door 11kV CB's

Blacks Pad Substation

Blacks Pad is located at the north end of the Mahia peninsula. Initially the substation included three 50/11kV single-phase transformers totaling 5MVA supplied by a 50kV line from Wairoa. In 2000 the 50kV line was formally converted to 33kV to improve reliability and the transformer replaced with a single 1.5MVA 3-phase transformer. Other equipment includes 33kV drop-out fuses and an 11kV pole-mounted circuit breaker. Bunding, fencing and earthing upgrade work was all completed in 2000 in conjunction with the transformer change. The transformer does not have on-load tapchanger capability.

A key issue with Blacks Pad is that the Christmas and Easter load at Mahia often exceeds the 1.5MVA transformer rating which has been relieved by operating one of ENL's diesel generators at Mahia beach. Loading in general at Mahia is increasing in conjunction with beach front subdivisional activity and as more holiday homes become permanent residences.
Development actions include the Mahia 33kV extension project which will address future Mahia load increases issues. In 2008 due to potentially permanent delays in easement negotiations the extension project was deferred. As a result no new load can be connected to the existing lines in the area. In addition as load disconnects reconnection

is not permitted until the load can be supported by the network without the need for the generator.

Kiwi Substation

Kiwi was built as part of the Waihi hydro station in 1983 and takes supply as follows…

Via a 6.3MVA 50/11kV transformer from Waihi.

Via two 11kV feeders from the Wairoa Substation.

The 11kV board includes two incomers, a bus tie and seven out-going feeders.

Key issues with Kiwi include…

The risk of minor flooding which happens occasionally and places supply to almost the entire Wairoa network at risk. Stop logs are installed at the doorways to the switch-room to reduce this risk.

Oil capture and separation facilities would be required for the 50/11kV transformer but this transformer will be removed as part of a long term 33kV development plan.

Wairoa Substation

The Wairoa substation previously owned and operated by Transpower was acquired by ENL in March 2015.

Supply to the Wairoa Substation is by a double-circuit 110kV line from Transpower's Tuai GXP near Lake Waikaremoana.

The Substation comprises two banks of 3 x 110/11kV 10MVA single phase transformers and an 11kV board comprising two incomers, a bus tie and eight feeders.
Since ENL rationalised its supply configuration in 2002 only 2 of the 8 feeders are used.

A 12.5MVA 11/33kV step-up Transformer supplies the Mahia Peninsula at 33kV. The installation includes a 33kV CB and pole-mounted 11kV breaker.

A load control plant injecting at 11kV is also located at the site.

Issues at this site include…

Six switch panels on the 11kV board are currently out of service.

The initial 40m of each of the 2 outgoing 11kV feeders consists of cable that is limited to 8MW.

The Transformers are near end of life

There is potential for between 20MW and 40MW of gas-fired generation near Frasertown hence renewal of the transformers needs to consider this potential load.

The proximity of the 50kV line from ENL's Waihi power station to ENL's Kiwi substation lends itself to rationalising the whole supply to both Wairoa and Mahia.

Tuai Substation

ENL has approximately 600kVA of load in and around Lake Waikaremoana and the Rukaturi area
The ENL Assets comprising the Tuai Substation are contained within the Transpower Tuai GXP Site These assets were acquired by ENL in April 2015.

The ENL Tuai Substation Assets comprise

2 11kV KFE Outdoor Circuit Breakers

A 110kV/11kV 6MVA supply transformer comprising 4 x 2.25MVA single phase transformers.

Minimal Protection and Control Equipment

The reclosers were installed in 2000, and are fitted with basic SCADA controls.
One of the original recloser units failed in early 2014 and has been replaced with a similar unit.

Issues at this site:
-The KFE Circuit Breakers a overdue for replacement.
-The Transformer is due for replacement. It has a failed tapchanger and low insulation test on a Bushing.
-The 11kV cable from the transformer has no redundancy and runs via an inaccessible route through the Transpower substation.
-The Supply to the Transformer occupies a 110kV Bay that is needed by Transpower to reconfigure a tied 110kV Transmission Line to Hawkes Bay.
-Replacement of the Transformer needs to consider the potential to supply up to 4 MW of the Wairoa load by construction of 1kM of 11kV line and some 11kV reconfiguration.

Tahaenui Substation

Tahaenui was built in 2001 and is located between Wairoa and Blacks Pad and comprises incoming 33kV drop out fuses, a 1.5MVA 3-phase transformer with manual tap settings, a pole mounted 11kV circuit breaker and an 11kV RMU. Tahaenui is used primarily to supply Morere and also provide limited 11kV back-feeding capability to Blacks Pad.

There are no current issues with Tahaenui.

Waihi Substation

This site comprises a 6.6kV to 50kV stepup transformer installed to enable connection of the Waihi Power Station Generators.

Waihi Power Station is a 5MW hydro power station located off the highway between Frasertown and Tuai. Assets at the site that come within the scope of this AMP include the 6.3 MVA 6.6/50kV transformer and the 50kV line from Waihi to Kiwi. The transformer installation includes oil separation facilities. Manual rest trip relays were replaced with remote reset devices in 2010.

Waihi is potentially ideally located to provide an 11kV supply to the immediate area and also back feed into the far ends of the Raupunga and Frasertown 11kV feeders. Plans have been developed to rationalise the 50kV line and 6.6/50kV transformer at Waihi with distribution assets solving a number of development issues.

A key issue with Waihi is that any transformer tripping will activate a phase to phase 50kV throw switch to isolate the 50kV line between Waihi and Kiwi.

2.2.3.3 Substation Security

The levels of security that are applicable to each substation depend on the Purpose and size of the load supplied by the substation. The security levels applicable and impacts of future load for each substation are provided in section 4.2.2.4.

The methods to achieve the current Transmission and Subtransmission/Zone substation security levels are as follows…

Subtransmission/Zone Substation Support Capacity		
Location	**% Load Support**	**Security/Contingency Method**
Gisborne Substation	100%*	Dual Transformers and Dual Incomming Circuits. *Note Circuits on Same Towers.
Te Araroa Substation	100%	Generator 100% or Ruatoria 30% via 11kV
Ruatoria Substation	100%	Generator 100%or TeAraroa 30% and Tokomaru 35% via 11kV
Tokomaru Bay Substation	100%	Ruatoria 50% and Tolaga 50% via 11kV
Tolaga Bay Substation	100%	Generator 100% or Tokomaru Bay 40% and Kaiti 40%
Kaiti Substation	100%	Load supplied from Port Substn and Carnarvon St via 11kV
Carnarvon Substation	100%	Dual Transformers or Port 50% and Parkinson 50%
Parkinson Substation	100%	Dual Transformers or Carnarvon 50% ,Matawhero 20% and Makaraka 30%
Makaraka Substation	100%	Carnarvon 50% ,Matawhero 20% Patutahi 10% &Parkinson 20%
Patutahi Substation	100%	Matawhero 50%, Pehiri 20%,Makaraka 20% and Puha 10%
Pehiri Substation	100%	Patutahi 100% (Uses Voltage Regulator)
Ngatapa Substation	100%	Patutahi 100% (Uses Voltage Regulator)
Puha Substation	100%	Generator 80% and Makaraka/Patutahi 20%
Matawhero Substation	100%	Dual Transformers or JNL 100%
Port Substation	100%	Carnarvon 50% and Kaiti 50%
JNL Substation	100%	Matawhero 100%
Wairoa Substation	100%*	Dual Transformers and Dual Incomming Circuits. *Note Circuits on Same Towers.
Kiwi Substation	100%	Waihi 50% or Dual supplies at 11kV

Blacks Pad Substation	100%	Generator 100%
Tahaenui Substation	100%	Kiwi Sub 100%
Waihi Substation	0%	Connection point for Generation
Tuai Substation	0%	Relocatable generator required.

2.2.3.4 Substation Demand

The current and future demand predictions for each substation are provided in section 4.3.4.2.

2.2.4 Distribution network

2.2.4.1 Coverage

ENL's distribution network is clustered mainly along the east coast from Te Araroa in the north to Raupunga in the south-west. Isolated inland areas such as Matawai tend to be fed by spur lines that traverse rugged uninhabited areas. The distribution network is solely 11kV (no 6.6kV or 22kV) and comprises the following…

	Gisborne	Wairoa	Total
3 Phase Overhead	1648050 m	665878 m	2313928 m
1 Phase Overhead	69027 m	17580 m	86608 m
Underground	116067 m	17626 m	133693 m

Note the above lengths exclude 374364 m of privately owned overhead line and 4209 m of privately owned underground cable.

2.2.4.2 Configuration

In rural areas the configuration is predominantly radial with only some meshing between feeders and between adjacent zone substations. A high degree of meshing exists in the urban Gisborne and Wairoa areas via either ABS's or RMU's.

2.2.4.3 Construction

ENL's network construction differs between rural and urban as follows…

Rural areas are predominantly wooden pole, flat construction with wooden cross-arms and pin insulators.

Urban areas are predominantly concrete pole with wooden cross-arms.

Cable network is concentrated in the CBD and newer subdivisions.

ENL's past standard of 11kV line construction uses a range of conductors as shown in the following table. Copper conductors used historically are progressively substituted with Aluminium conductors for new construction. Galvanised steel conductors are still used for large spans.

Conductor Type	Length km	% Population
7/14 Cu OH	507.47	21.1%
7/16 Cu OH	434.27	18.1%
7/16 St OH	372.47	15.5%
3/12 St OH	240.71	10.0%
Gopher OH	154.17	6.4%
Ferret OH	139.11	5.8%
Dog OH	124.95	5.2%
Rango OH	54.02	2.3%
19/14 Cu OH	46.20	1.9%
Racoon OH	43.48	1.8%
19/16 Cu OH	37.16	1.5%
Weke OH	35.02	1.5%
No 8 Cu OH	28.99	1.2%
Magpie OH	27.19	1.1%
7/.118 Cu OH	24.98	1.0%
7/.093 Cu OH	19.57	0.8%
Flounder OH	17.33	0.7%
Shrike OH	14.19	0.6%
Robin OH	13.60	0.6%
No 8 St OH	11.93	0.5%
3/128 Cu OH	10.65	0.4%

19/17 Cu OH	8.80	0.4%
Mink OH	8.03	0.3%
Swan OH	5.32	0.2%
Rabbit OH	3.88	0.2%
Squirrel OH	3.42	0.1%
Swallow OH	3.25	0.1%
7/14 St OH	2.62	0.1%
19/18 Cu OH	2.56	0.1%
3/12 Cu OH	2.41	0.1%
7/12 Cu OH	0.74	0.0%
16mm Cu OH	0.39	0.0%
Kutu OH	0.29	0.0%
Cockroach OH	0.20	0.0%
25mm Cu OH	0.10	0.0%

Cable types used are medium sized conductors. Paper insulated cables are preferred for most circuits with XLPE conductor being only used on short runs such as tails from fuse-switches to transformers. For new work the larger 185 and 300 sq mm Aluminum conductors are generally used.

Conductor Type	Length km	% Population
HV 3c-95mm Al PILC UG	27.779821	20.76%
HV 3c-70mm Cu PILC UG	18.219997	13.61%
HV 3c-16mm Cu PILC UG	16.153169	12.07%
HV 3c-95mm Al PILC HDPE UG	14.051223	10.50%
HV 3c-300mm Al XLPE UG	8.221223	6.14%
HV 3c-300mm Al PILC HDPE UG	8.053523	6.02%
HV 3c-95mm Al XLPE UG	8.05117	6.02%
HV 3c-185mm Al PILC UG	6.879097	5.14%
HV 3c-16mm Cu PILC HDPE UG	5.46482	4.08%
HV 3c-16mm Cu XLPE UG	3.512079	2.62%
HV 3c-185mm Al XLPE UG	3.238066	2.42%
HV 3c-0.0225 Cu PILC UG	3.032512	2.27%
HV 3c-185mm Al PILC HDPE UG	2.811228	2.10%
HV 1c-25mm Al XLPE UG	2.398696	1.79%
HV 3c-185mm Cu PILC UG	2.189817	1.64%
HV 3c-25mm Al XLPE UG	1.206013	0.90%
HV 3c-16mm Al PILC HDPE UG	0.758613	0.57%
HV 3c-150mm Cu PILC UG	0.672284	0.50%
HV 3c-25mm Cu XLPE UG	0.205977	0.15%
HV 1c-300mm Cu XLPE UG	0.198758	0.15%

HV 3c-120mm Cu PILC UG	0.179524	0.13%
HV 1c-95mm Al XLPE UG	0.262358	0.20%
HV 3c-25mm Cu PILC UG	0.075549	0.06%
HV 3c-95mm Cu PILC HDPE UG	0.070821	0.05%
HV 3c-35mm Cu PILC UG	0.067511	0.05%
HV 1c-185mm Al XLPE UG	0.032064	0.02%
HV 1c-25mm Cu XLPE UG	0.016794	0.01%
HV 1c-16mm Cu XLPE UG	0.011358	0.01%
HV 1c-95mm Al PILC UG	0.00785	0.01%
LV 1c-300mm Al XLPE PVC UG	0.002472	0.00%

2.2.4.4 Per substation basis

On a per substation basis the split of distribution network is presented in the following sections. Customer density is obviously a strong driver of viability and significantly influences ENL's allocation of time, effort and funds.

Gisborne

Substation	11kV length (km)	Total ICP's	ICP density per km
Te Araroa	123.11	488	3.96
Ruatoria	168.54	792	4.70
Tokomaru Bay	165.84	590	3.56
Tolaga Bay	171.68	661	3.85
Kaiti	120.88	3041	25.16
Carnarvon	45.97	4622	100.53
Parkinson	30.84	1812	58.76
Makaraka	167.39	3086	18.44
Patutahi	206.59	1186	5.74
Pehiri	138.13	274	1.98
Ngatapa	104.64	251	2.40
Puha	336.49	1091	3.24
Matawhero	25.46	237	9.31
Port	26.41	2724	103.14
JNL	0.1	2	20

Wairoa

Substation	11kV length (km)	Total ICP's	ICP density per km
Tuai	116.11	368	3.17
Wairoa	8.89	1	0.11
Kiwi	443.38	3382	7.63
Tahaenui	82.28	871	10.59
Blacks Pad	50.29	276	5.49

2.2.4.5 Terrain

As the terrain in the region is generally characterised by hilly terrain with relatively narrow weaving river valleys many rural lines tend to be constructed on steep hillsides away from the road edge. Feeders typically begin in rural townships or urban centres and supply both urban and rural customers. The lines pass over the open flats on main transport routes from the townships and quickly transition into the rugged hilly terrain frequently passing over small pockets of rural land with good access. The split of 11kV and LV line length over the various areas is indicated in the following table…

Location	Total (m)	Gisborne (m)	Wairoa(m)
Urban Only	58859	50457	8402
Rural Only	1280152	1030177	249975
Remote Only	298714	235788	62927
Urban Rugged	1576	1576	0
Rural and rugged	541787	327163	214624
Remote and Rugged	220171	71917	148254

Remote lines are defined as being more than 75 km direct line from the main works depot and rugged lines are lines with a span length greater than 130 meters.

2.2.5 Distribution Substations

Just as Subtransmission substation transformers form the interface between the 50kV or 33kV and 11kV networks, distribution transformers form the interface between ENL's 11kV and LV networks. These distribution substations range from 1-phase 15kVA pole-mounted transformers with only to 3-phase 1,500kVA ground-mounted transformers dedicated to single customers.

Distribution substations fit into 1 of the following typical arrangements or classes…

Single pole mounted transformer installations up to 100kVA. A few older 'pole with half pole' sites still exist in the Wairoa district. These installations are protected with minimal fuse protection. There are no 2-pole substations over 100kVA on the network.

Green metal enclosed pad mount installations 30kVA+. These installations are typically located on private property for single customer installations, ENL land adjacent to road reserves and on grass berm's in road reserve. Installations of this type may have in some cases a secondary enclosure consisting of a mesh fence, concrete block wall or wooden fence. In overhead areas minimal overhead fusing is used while in underground areas 11kV fuse switches provide the protection.
5 to 30 KVA pole style transformers with secondary plastic or metal covers. Only a few installations of this type exist.
There are approximately 10 ENL owned Kiosk type building installations housing larger ground mount transformers. A small number of the customer only substations are also located within concrete block building arrangements similar to the kiosks. Note for the purposes of valuation substations are considered with two major components being the Transformer and the siteworks i.e. earth-mat and pad / building.

Rating	Number (includes 78 private transformers)			
	Gisborne		Wairoa	
	Ground(494)	Pole(2300)	Ground(105)	Pole(808)
1 kVA		44		11
5 kVA		63		6
10 kVA	1	520	2	167
15 kVA	1	884	1	225
20 kVA		2		89
25 kVA	3	146		55
30 kVA	40	429	4	149
50 kVA	17	159	6	65
75 kVA	2	1		2
100 kVA	45	50	17	28
150 kVA		1	1	3
200 kVA	105		36	6
250 kVA	60	1		
300 kVA	131		21	2
400 kVA	1			
500 kVA	46		7	

750 kVA	2		3	
1000 kVA	37		7	
1500 kVA	3			

For management purposes ENL also classifies its nine 11kV voltage regulators as distribution transformers. The regulators are ground mounted and have wire mesh fence enclosures.

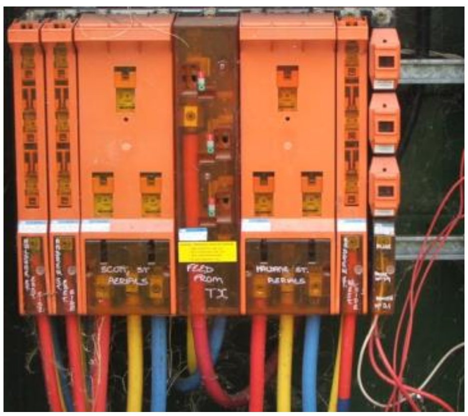
Location	Purpose
Pehiri	Security
Kopuaroa (between Ruatoria and Tokomaru)	Security
Tatapouri (between Kaiti and Tolaga)	Distance boost
Ngatapa	Security
Matawai	Distance boost
Waingake	Support water works
Muriwai	Distance boost.
Waihua (west of Wairoa)	Distance boost
Mahia	Distance boost

2.2.6 Distribution Switchgear

The distribution switchgear associated with the underground distribution network substations is predominantly ABB SD series Oil filled switchgear or ABB Safeplus SF6 gas filled switchgear. Switchgear installations are pad mounted and either located adjacent to or a short distance away from the substation installations.

For the overhead network pole mounted 3 phase Air Break Switches are widely used. In more remote locations single phase links or fuses are used to isolate spur lines.
There are a number of pole mounted Circuit Breakers and SF6 Switches also in use on the network
Hawker Sydley PMR
Hawker Sydley GVR
Cooper Systems KFE
Jin Kwang SF6 SW
Age profiles and further related information is provided in section 2.3.

2.2.7 LV network



2.2.7.1 Coverage

ENL’s LV networks are predominantly clustered around each distribution transformer. The coverage of each individual LV network tends to be limited by volt-drop to about a 200m radius from each transformer hence LV coverage is not as extensive as 11kV.

Class	Length Gisborne m	Length Wairoa m	Length Total m
OH LV 400V	390278	136418	526297
UG LV 400V	201930	47892	249822
OH SL 400V	12379	161	12541
UG SL 400V	7255	315	7570

2.2.7.2 Configuration

The LV networks are almost solely radial with minimal meshing even in urban areas.

2.2.7.3 Construction

Construction of LV network varies considerably and can include overhead LV only, LV under-built on 11kV, LV under-built on 50kV, PILC cables, XLPE cables or conjoint PILC – XLPE cables.
The conductor types used are shown in the tables below

Conductor Type O/Head	Length km	% Population
7/14 Cu OH	261.662	48.58%
7/16 Cu OH	88.110	16.36%
7/16 St OH	46.504	8.63%
Ferret OH	21.824	4.05%
19/14 Cu OH	18.569	3.45%
Rango OH	17.493	3.25%
Gopher OH	11.987	2.23%
LV 1c-4mm Cu N/S OH	11.023	2.05%
19/17 Cu OH	8.875	1.65%
Weke OH	7.346	1.36%
Dog OH	6.538	1.21%
3/12 St OH	5.743	1.07%
16mm Cu OH	5.238	0.97%
No 8 Cu OH	4.727	0.88%
LV 95mm Al PVC Covered OH OH	4.210	0.78%
19/16 Cu OH	3.820	0.71%
70mm Cu OH	2.637	0.49%
Wasp OH	1.632	0.30%
LV 2c-6mm Cu N/S OH	1.280	0.24%
LV 7c-2.5mm Cu SWA OH	1.258	0.23%
7/18 Cu OH	0.858	0.16%
25mm Cu OH	0.664	0.12%
19/18 Cu OH	0.662	0.12%
Swan OH	0.563	0.10%
Kutu OH	0.510	0.09%
25mm Al OH	0.482	0.09%
Mink OH	0.477	0.09%
LV 3c-16mm Cu N/S OH	0.415	0.08%
3/12 Cu OH	0.357	0.07%
LV 35mm Al ABC Covered OH	0.313	0.06%

No 8 St OH	0.307	0.06%
No 10 Cu OH	0.304	0.06%
7/14 St OH	0.301	0.06%
7/.118 Cu OH	0.298	0.06%
7/.093 Cu OH	0.295	0.05%
3/128 Cu OH	0.268	0.05%
LV 1c-16mm Cu N/S OH	0.260	0.05%
Poko OH	0.233	0.04%
Magpie OH	0.175	0.03%
Racoon OH	0.111	0.02%
7/12 Cu OH	0.084	0.02%
Squirrel OH	0.083	0.02%
LV 3c-25mm Cu N/S OH	0.039	0.01%
LV 2c-4mm Cu N/S OH	0.034	0.01%
Rabbit OH	0.019	0.00%
LV 2c-16mm Cu N/S OH	0.014	0.00%

Conductor Type Underground	Length km	% Population
LV 1c-106mm Al (Beetle) UG	154.8945	59.258%
LV 1c-150mm Al (Weta) UG	20.16751	7.715%
LV 1c-185mm Al (Huhu) UG	16.89864	6.465%
LV 4c-95mm Al XLPE PVC UG	14.24534	5.450%
LV 3c-16mm Cu N/S UG	6.396104	2.447%
LV 1c-16mm Cu N/S UG	5.532862	2.117%
LV 2c-4mm Cu N/S UG	5.325591	2.037%
LV 3c-35mm Cu N/S + P UG	5.215365	1.995%
LV 4c-150mm Al XLPE PVC UG	3.082402	1.179%
LV 1c-70mm CU XLPE PVC UG	3.034754	1.161%
LV 3c-95mm Al N/S UG	2.794585	1.069%
LV 4c-70mm Cu PILC UG	2.427373	0.929%
LV 1c-50mm Al (Kutu) UG	2.342381	0.896%
LV 1c-25mm Cu XLPE PVC UG	2.00711	0.768%
LV 1c-35mm Cu XLPE PVC UG	1.733074	0.663%
LV 3c-25mm Cu N/S UG	1.413677	0.541%
LV 1c-185mm Al XLPE PVC UG	1.260898	0.482%
LV 1c-4mm Cu N/S UG	1.254988	0.480%
LV 3c-35mm + P N/S UG	1.224826	0.469%
LV 1c-95mm Cu XLPE PVC UG	1.176572	0.450%
LV 4c-185mm Al XLPE PVC UG	0.872915	0.334%

LV 2c-16mm Cu + P N/S UG	0.827969	0.317%
LV 3c-70mm Cu + P N/S UG	0.706337	0.270%
LV 3c-70mm + P N/S UG	0.676519	0.259%
LV 1c-25mm+ P N/S UG	0.547507	0.209%
LV 2c-6mm Cu N/S UG	0.541544	0.207%
LV 2c-16mm Cu N/S UG	0.530252	0.203%
LV 3c-120mm Cu N/S UG	0.40047	0.153%
LV 3x1c-19/.052 + 1c-7/.036 UG	0.371102	0.142%
LV 3c-35mm Cu + P N/S UG	0.340987	0.130%
LV 4c-35mm PILC UG	0.339238	0.130%
LV 1c-25mm Al XLPE PVC UG	0.334061	0.128%
LV 1c-6mm Cu N/S UG	0.328036	0.125%
LV 3x19/105 Al PVC UG	0.299214	0.114%
LV 3c-35mm Cu N/S UG	0.294783	0.113%
LV 4c-70mm Cu + P PILC UG	0.28956	0.111%
LV 4c-300mm Al XLPE PVC UG	0.238582	0.091%
LV 1c-120mm Cu Cantol UG	0.210907	0.081%
HV 3c-95mm Al PILC UG	0.162093	0.062%
LV 1c-70mm Cu PVC UG	0.120229	0.046%
Unknown	0.11259	0.043%
LV 4c-95mm Al PVC UG	0.110914	0.042%
LV 1c-300mm Al XLPE PVC UG	0.048168	0.018%
HV 3c-95mm Al PILC HDPE UG	0.044248	0.017%
LV 1c-185mm Cu XLPE PVC UG	0.041678	0.016%
LV 4c-70mm Al XLPE PVC UG	0.03616	0.014%
LV 3c-35mm +P N/S UG	0.034371	0.013%
LV 4c-185mm Cu PILC UG	0.032506	0.012%
LV 3c-16mm Cu N/S OH	0.026921	0.010%
HV 3c-25mm Al XLPE UG	0.020719	0.008%
LV 2c-7/0.064 + 1c-7/0.036 N/S UG	0.010792	0.004%
LV 2c-10mm Cu N/S UG	0.00583	0.002%
LV 4c-25mm Cu PILC UG	0.004112	0.002%
LV 1c-16mm Cu N/S OH	0.001308	0.001%

Approximate populations of various construction types are presented below…

Description	Length (m)	
	Overhead	Underground
LV Only	77007	166635

LV Only Remote	14227	70
LV Only Roadside	139979	21815
LV Only Roadside Remote	13146	214
LV Only Rugged	5972	0
LV Only Rugged Remote	2887	0
LV Under built	101193	56054
LV Under built Remote	20713	0
LV Under built Roadside	122880	6485
LV Under built Roadside Remote	20099	0
LV Under built Rugged	3955	0
LV Under built Rugged Remote	2825	0

2.2.7.4 Per substation basis

On a per substation basis the split of LV network is laid out in the following sections. Similar to the distribution network, customer density is a strong driver of viability and influences ENL's allocation of time, effort and funds.

Gisborne

Sub.	LV Line length (km)	Customers (ICPs)	Customer density
Te Araroa	18.6	488	26.22
Ruatoria	37.7	792	21.02
Tokomaru Bay	24.1	590	24.53
Tolaga Bay	26.3	661	25.14
Kaiti	70.6	3041	43.09
Carnarvon	85.8	4622	53.85
Parkinson	32.6	1812	55.51
Makaraka	102.1	3086	30.22
Patutahi	60.7	1186	19.53
Pehiri	14.0	274	19.63
Ngatapa	11.4	251	22.02
Puha	46.7	1091	23.36
Matawhero	13.6	237	17.38
Port	48.7	2724	55.96
JNL	0.0	2	1

Wairoa

Sub.	LV Line length (km)	Customers	Customer density
Tuai	9.9	368	37.33
Wairoa	0.0	1	1.00
Kiwi	128.5	3382	26.32
Tahaenui	27.7	871	31.48
Blacks Pad	17.3	276	15.97

LV Switchgear for control and protection of the LV underground network is generally housed in Transformer enclosures as an LV Frame, In Link boxes or as part of a Distribution box. For overhead installations the switchgear typically exists in the form of pole mounted fuses at transformer sites. The underground enclosures are installed with the LV reticulation usually at the subdivision development stage.

ENL has the following Distribution boxes and Link Boxes as part of the LV Network…

Type	Number
DB Other	2503
DB Black Plastic	954
DB Central Metering	100
DB Concrete SS Lid	55
DB Fibreglass Box	107
DB Galvanised Box	594
DB Green Shear	817
DB In-Ground Pit	569
DB Meter box-Metal	22
DB Verandah Box	5
Link Box Other	219
Link Box Aluminium	210
Link Box Black Plastic	33
Link Box Built-In	1
Link Box Concrete	1
Link Box Fibreglass	9
Link Box Galvanised Box	6
Link Box Green Shear	32
Link Box Montrose Box	19
Link Box Polycarbonate	7
Link Box Verandah Box	4
PoC Point	253

TOTAL	6520

2.2.8 Customer connection assets

ENL has 25,567 consumer connections - ENL gets its income by providing electricity conveyance services to these connections for the energy retailers. All of the network assets are used to convey energy to these consumer connections, and essentially are a cost that has to be matched by the revenue derived from the consumer connections. The control points at the consumer connections generally involve assets ranging in size from a simple fuse on a pole or in a suburban distribution pillar to dedicated lines and transformer installations supplying single large consumers. Quantities of customer owned private line quantities are summarized as follows…

11kV Overhead lines	377km
11kV Underground Cables	17km
400V Overhead Lines	314km
400V Underground Cables	33.4km

In most cases the fuse forms the demarcation point between ENL's network and the consumers' assets (the "service main"), and this is usually located at or near the physical boundary of the consumers' property. However in some cases a single consumer is supplied by a length of line or cable (often on public land) configured as a spur off ENL's network which is referred to as a "service line" (noting that successive revisions of the Electricity Supply Regulations in the late 1970's and early 1980's confused the two definitions). In such cases ownership of the service line has been passed to consumers, who are now responsible for funding and maintaining its safety and connectively to ENL's network.

Type of service	Gisborne	Wairoa

connection		
Domestic	16483	3367
Non Domestic	4243	1474
Total	**20726**	**4841**

2.2.9 Load control assets

ENL currently owns and operates the following three load control transmitter facilities for control of ripple relays...

Valley Road –11kV injection at 315 Hz (not in service).
Makaraka – 50kV injection at 315Hz.
Wairoa – 11kV injection at 1,250Hz.

Historically the majority of controllable load in the urban Gisborne area was controlled by a cascade pilot wire network consisting of 10 pilot feeders.

Due to issues related to the pilot systems functional inflexibility, reliability and expense, in 1992 a ripple load control system was installed on the Gisborne network. The pilot and ripple systems were operated in tandem.

As reliability has become more of issue due to age deterioration of the pilot assets, ENL has phased out the existing Gisborne city overhead pilot system in favour of ripple relays installed at customer's premises. This has been achieved through a ripple receiver installation program started in 2002 and completed in 2008. ENL owns the signal receivers installed on the Gisborne network. An opportunity to replace some pilot with ripple recievers in conjunction with an energy retailer initiated metering upgrade program, (smart meter install), commencing in 2014/15 is being currently being considered.

The Wairoa urban centre uses a pilot wire system with a small quantity ripple relays deployed in the wider area. The customer relays are owned by the incumbent energy retailer. The retailer has decommissioned the load control relays used in Mahia due to signal attenuation issues. The 8 channel pilot wire system in the urban centre is triggered via SCADA from a central point at the A-Park substation which was installed in 2009. The remaining controllable load operated by the ripple transmitter is insufficient to justify replacement of the transmitter hence it is likely that the focus will be on maintaining the pilot wire system in the urban centre only.

An approximate assessment of the controllable capability of the system is shown in the following table…

Channel		Interruptible load (kW)
1	Te Araroa	300
2	Ruatoria	600
3	Tokomaru Bay	400
4	Tolaga Bay	500
5	Wainui/Whangara	700
6	Tamarau	1,000
7	Kaiti #1	900
8	Kaiti #2	600
9	Town	500
10	West End #1	1,100
11	West End #2	700
12	Te Hapara #1	600
13	Te Hapara #2	500
14	Matawhero/Makaraka	400
15	Whataupoko #1	500
16	Whataupoko #2	600
17	Mangapapa #1	900
18	Mangapapa #2	700
19	Westpark/Matokitoki	300
20	Patutahi/Waipaoa	400
21	Waimata	600
22	Muriwai/Te Arai	600
23	Pehiri	200
24	Ngatapa	200
25	Matawai	300
26	Puha	500
	Wairoa 00	381
	Wairoa 01	216
	Wairoa 02	327
	Wairoa 03	352

	Wairoa 04	308
	Wairoa 05 Night store (not used)	25
	Wairoa 06	311
	Wairoa 07	345
	Wairoa 08	319
	Wairoa 09 (not used)	37
	Wairoa 16 Night store (not used)	48
	Wairoa 17 (not used)	168
	Wairoa 18 (not used)	179
	Wairoa 19 (not used)	197
	Wairoa 30 Flood Pump (not used)	118
	Wairoa 31 Spa Pool (not used)	30
	Wairoa 32 Cold Store (not used)	60

2.2.10 Protection & control

2.2.10.1 Key protection systems

ENL's network protection includes the following broad classifications of assets…

CB protection relays which have always included over-current, earth-fault, sensitive earth-fault and auto-reclose functions. More recent equipment also includes voltage, frequency, directional; distance and CB fail functionality in addition to the basic functions.

Transformer and tap changer temperature sensors.

Surge sensors

Explosion vents.

Oil level sensors.

There is a mix of electro-mechanical, discrete component and microprocessor based equipment on ENL’s network.

2.2.10.2 Voltage control equipment

Tap changer controls for dual transformer installations, are configured in a master-follower arrangement at older substations and balancing load IsinØ control algorithms are used for new installations. The controllers are predominantly microprocessor based. Voltage regulator controls are predominantly mechanical and are being progressively replaced with PLC controllers that allow operation of voltage regulators in either direction where appropriate.

Controls are an area in which technology advances make such controls a viable option even for the smallest substations.

2.2.10.3 DC power supplies

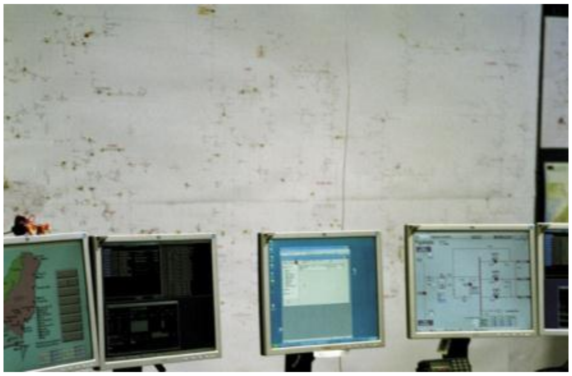
Batteries, battery chargers, and battery monitors provide the DC supply systems for CB control and protection functions as follows…

110V DC supplies are primarily required for 50kV CB operation and in a number of substations are used for 11kV CB operation and protection.

24V DC supplies are typically used for SCADA RTU’S emergency lighting, protection and CB control at newer installations.

The radio communication systems are typically supplied via 12DC systems.

2.2.11 SCADA & Communications



The SCADA system is used for real-time monitoring and control of the network. Frequency Voltage Current and temperature information is obtained from remote sites, and stored at 30 minute intervals. This information is used to report load trends for planning and alert operations staff of abnormal conditions.
Real-time status information is collected to alert operations staff of faults and potential issues with the network. Controls are available to turn sections of the network on or off, to minimise outage times, eliminating delays associated with manual switching.
Point of supply load control functions are also carried out using the SCADA.

2.2.11.1 Master station

ENL's SCADA master station is located at the head office in Carnarvon St and comprises an Abbey Systems dual master / backup master station configuration which was installed in 1999. Regular upgrades have been made to the master station and software updates to improve functionality include.
DNP and Modbus support for intelligent devices in 2001
SMS Text Messaging upgrade to replace paging system for remote alarming in 2002
Remote access upgrade 2003.
SQL database linking for historical trend storage in 2005.
Aspex Gui interface upgrade incorporating improved windows look and feel, improved graphics and improved real-time/historical graphing and trending in 2006.
Support for communications via TCPIP networks in 2007.
Support for historical data storage at remotes with occasional forwarding to the Master Station in 2010.
Addition of a Network TCPIP monitoring system in 2011.

Renewal of Computers, Software and Master Station communication ports hardware in Jan 2013 incorporating IP connectivity.
Support for TCPModbus in 2013
Substation Management System was installed in 2013/2014. The system provides direct IP connectivity to intelegent devices in the substation. For older devices that do not support IP directly IP to serial connectivity has been established.

There are 8 communication ports in use from the Master Station:

Port 1 - Cable circuit (Gisborne city).

Port 2 - UHF Radio repeater (Gisborne city).

Port 3 - Makaretu circuit (Puha / Matawai area).

Port 4 - Coast radio circuit (Tolaga – Tokomaru).

Port 5 - Kinikini/Mahia radio circuit

Port 6 - Cable and Fiber circuit (Gisborne city).

Port 7 - Wairoa radio circuit (Gisborne city).

Port 8 - Coast radio circuit (Eastcape from Tokomaru Bay.

2.2.11.2 Remote stations

There are 16 Abbey Systems Full RTU installations located at each of ENL's major substations and 155 Abbey Systems Topcat installations at remote control switches or monitoring and control sites. The majority of Topcat installations were established between 1999 and 2008 as part of the rural automation program which was completed in 2008. The rural automation program covered in previous AMP's was developed and successfully implemented giving the following results…

Enhanced data for improved planning and operational decisions

Reduced outage times

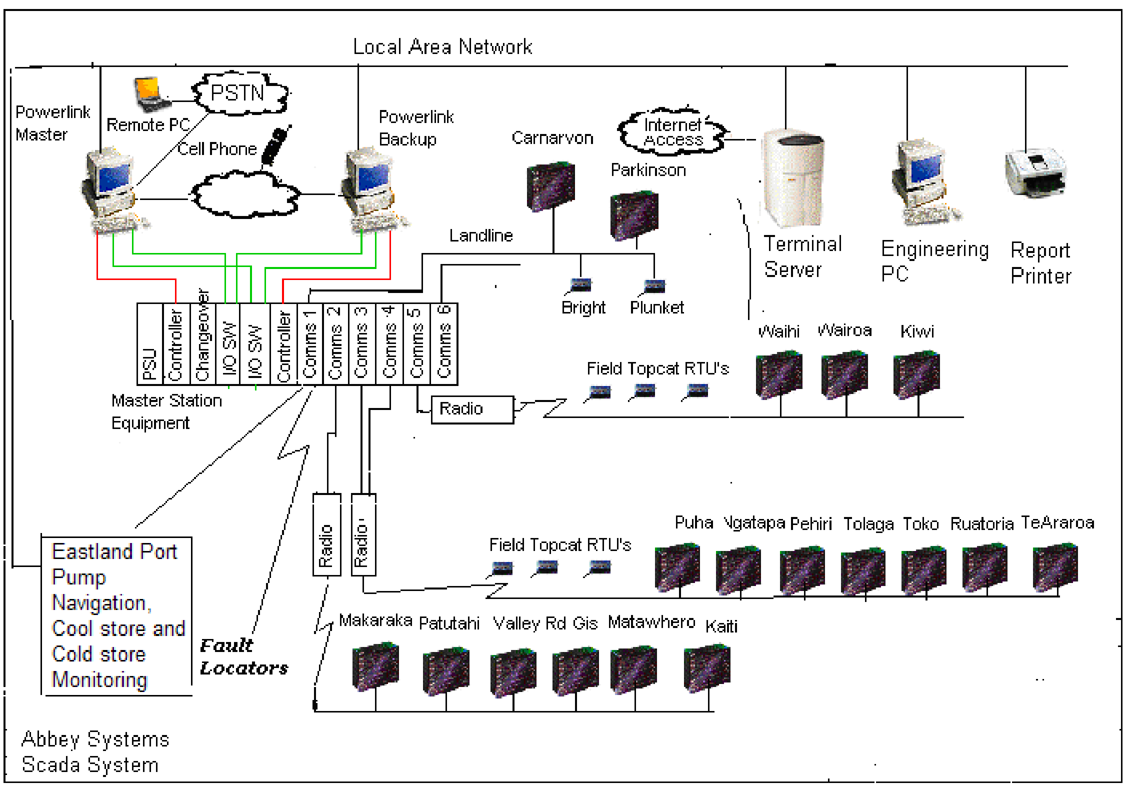
Optimised restoration times

Reduced costs associated with manual switching operations in the field.

Incorporated into the system are 4 sites linked to Fanuc PLC RTU's located in the Gisborne Port area, 10 Generators (2 Portable), and 4 Wind/Water Monitoring sites.

A summary of remote Input and Output information passing through the system excluding virtual I/O is as follows.

Digital Inputs	13000
Built-in Digital Inputs	2049
Control Outputs	4795
Measurements	3235
Analog Outputs	243



Current issues associated with the SCADA system are…

Limited redundancy in equipment on a per site basis.

A high dependence on the communications network.

2.2.11.3 Communications

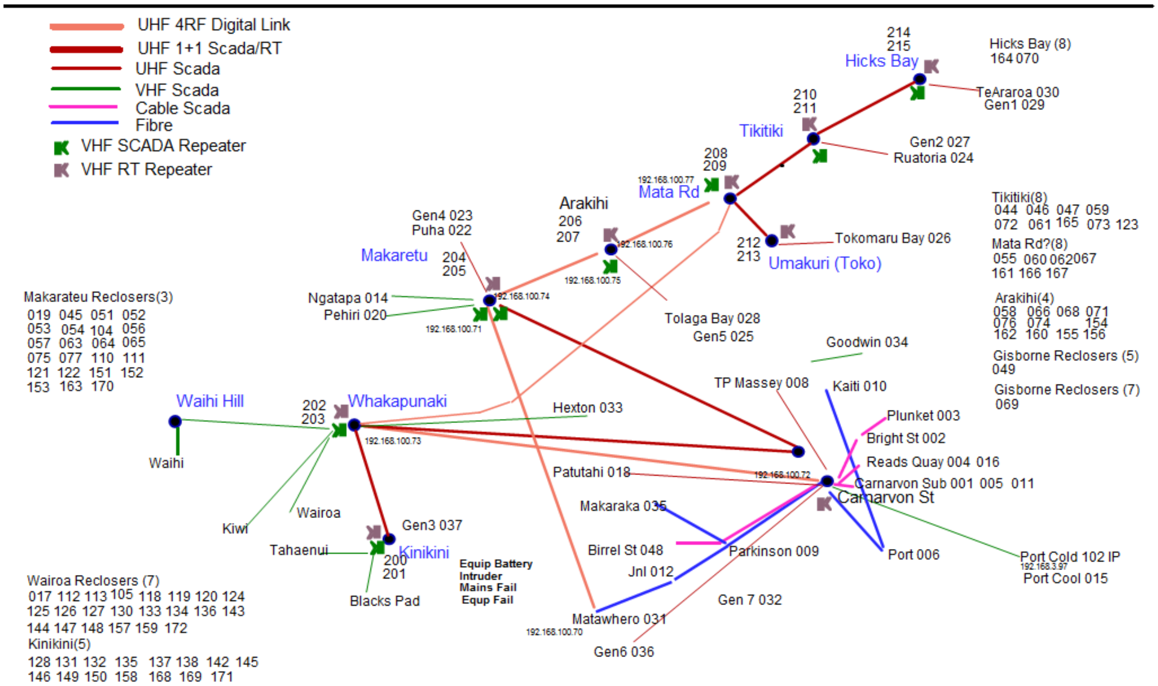
A number of communications media and protocols are used to provide voice and data information for operation of the network.

Systems include VHF Radio, UHF Radio and Copper or Fibre Cable.

Data communication is via IP, RS232/485/422Serial and Audio.

Protocols associated with data communication include , Modbus, DNP3, Abbey Systems (HTLC).

Communications Overview



Backbone Links
ENL currently owns and operates the following communications links…

Digital Links from 4RF are installed, forming the main back bone.
-Between Matawhero Sub Fiber termination to Makaretu -2002
-Between Carnarvon Street to Whakapunaki -2003
-Between Makaretu to Arakihi -2009
-Between Arakihi to Mata Rd -2010
-Between Mata Road to Whakapunaki 2011
-Between Mata Rd to Tikitiki 2012
-Between Tikitiki to Hicks Bay 2012
-Between Whakapunaki to Kinikini 2012

These Digital Links are generally configured with a single Channel for linking the original analog voice repeaters incorporating E and M signalling interface circuits, 1 to 8 Channels for Scada traffic and the remainder of the Bandwith is available for low speed IP Data.
The 4RF Digital Link installed between Whakapunaki and Mata Rd can be used to facilitate contingent rerouting.

One 1+1 link between Mata Rd and Umakuri, installed in 1993 is the only remaining part of the back bone of the system.

Two UHF 1+1 links are currently maintained for contingency support to Makaretu and Whakapunaki. This support is currently limited to the RT voice channel and a Single Scada channel.

A short UHF point to multipoint link established in 2002 to provide SCADA coverage to the Waihi Power station and a remote switch site.

Fiber optic Communications cables were installed in 2005 between Carnarvon Street and Kaiti, Port, Parkinson, Makaraka, JNL, Matawhero substations. The cables provide SCADA, Telephone, Protection and IP services for the Substation Management System.

Scada Repeaters

Eight VHF and Two UHF point to multipoint repeaters are also used for SCADA communications to substations and field recloser sites. This equipment was installed between 1999 and 2001 and consists of a mix of new and reused equipment.
-Makaretu VHF1
-Makaretu VHF2
-Arakihi VHF
-Mata Rd VHF
-Tikitiki VHF
-Hicks Bay VHF
-Whakapunaki VHF
-Kinikini VHF
-Waihi Hill UHF (Connects to Waihi and Remote Switch W1040)
-Makaretu-Puha UHF
-Carnarvon, Gisborne City UHF

Wifi Network

A network of WiFi 2.4GHZ radios was deployed in 2005 and integrated to the ENL Scada system, which provides monitoring of PLC controllers for access security, sewer-pumps, Navigation systems, Cranes and compressor cooling systems relateing to operations associated with Eastland Port.

Voice Radio Telephone Network

The existing voice communications system consists of Nine VHF E-band 25W repeaters. The repeaters are all coupled together via one channel of the 4RF backbone links between Gisborne and Te Araroa. One repeater operates from Carnarvon St primarily for coverage around ENL's offices. Each repeater can be remotely disconnected from the trunk network in the event of a failure. This system is scheduled for removal in 2015/2016. At this time the Voice allocation on the 4RF backbone links will be reconfigured increasing the IP bandwidth.

In 2010 Radio Frequency Services announced a requirement to change all wide band VHF frequencies to narrow band. The changes required replacement of all Voice repeaters and Mobile Radios used by ENL, with completion required by 2015/16.

In 2014 four digital Teir 3 Tait repeaters were installed with the remainder being scheduled for 2015. The repeaters are connected via the IP backbone provided by the 4RF links.

A Sun Server central controller was installed to manage the digital RT network in 2014, with a second redundant unit planned in 2015.

Approximately 100 Vechile Digital radios ans 20 Portable radios were installed in 2014 replacing the old analog wideband RT's. a futher 40 Vechile RT's and 20 Portable radios are scheduled for 2015.

All RT units are fitted with a GPS receiver and provide GPS positioning and logging which is presented in real time on Google maps or Google Earth along with GIS asset data. This allows improved staff response and coordination associated with faults dispatch.

The new GPS capabile digital system also provides one tier of ENLs working alone monitoring system for employees.

Substation Management System

The Substation Management System is complementary to the SCADA system and provides the ability to access Intelegent devices to fine tune configuration and operating parameters or retrived detailed logs and event data when necessary. The system uses an IP based communications network which has been established using a mix of inhouse and third party communications links. The Network allows connectivity for Camera Monitoring development, Intelligent (SMART Grid) Protection equipment, Access to information systems and Meter reading. There are approximately 169 Intelegent devices with direct IP connectivity currently deployed.

The following locations have back up communications via third party Internet service providers to support the substation management system function:

-TeAraroa Substation (Gisborne.net.nz)

-Ruatoria Substation (Gisborne.net.nz)

-Tokomaru Bay Substation (Gisborne.net.nz)

-Tolaga Bay Substation (Gisborne.net.nz)

-Puha Substation (Gisborne.net.nz)

-Ngatapa Substation (Gisborne.net.nz)

-Pehiri Substation (Gisborne.net.nz)

-Kiwi Substation (Gisborne.net.nz)

-Mahia Generator Site (Vodafone)

This Substation Management System communications network is separate in terms of utilising different equipment but common dependencies exist at transmitter sites which share common power supplies and masts with ENL’s communications equipment.

Current issues associated with the various communications system are…

Limited redundancy in equipment and communication routes.

Occasional interference in adverse weather. eg snow build up on antenna.

2.2.12 Other assets

2.2.12.1 Land and Buildings

In addition to the land and buildings associated with Zone substations, Distribution substations, Overhead lines and Underground cables ENL utilises the following significant Land and Building assets.

- North Clyde Wairoa, Land owned by ENL for Zone Substation Growth.(refer Development Plan)
- Wairoa Depot, This site was traditionally owned by Wairoa Electric Power. The site was operated as a depot until around 2009. The facility is partially occupied by tenants and available for leasing opportunities. The site is considered strategic in terms of Emergency preparedness and in the long term it has potential to re-establish it as an operational Depot. This facility is owned by the Eastland Group with the cost of ENL's tenancy incorporated into Business Support allocated costs.
- Tokomaru Bay Depot. The site was operated as a depot until around 1993. The facility is occupied by tenants. The site is adjacent to the Tokomaru Bay substation and serves as an environmental barrier in terms of noise and safety from domestic dwellings in the vicinity.
- Carnarvon Street Depot and Office facility. This facility is owned by the Eastland Group and partially occupied by tenants of which ENL is one.. Due to the close integration of the buildings with the adjacent Zone substation the ability to lease the entire facility is limited. As the current tenants contract services to ENL maximum efficiencies in terms of communication and asset management functions are realised. The cost of ENL's tenancy incorporated into Business Support allocated costs.

2.2.12.2 Generators

Small diesel Standby generators are installed at critical locations to ensure ENL's SCADA and Communications network can be sustained in contingent events. A 12kVA unit is installed at Carnarvon Street Substation for the Control Centre and smaller units ranging from 1.5 to 8KVA are located at Hicks Bay, Tikitiki Mata Rd, Arakihi,Makaretu, Whakapunaki, and Kinikini radio repeater Sites.

2.2.12.3 Software

ENL commissioned the Powerview GIS mapping System in 2002 which contains the network Line, cable, Distribution Substation, Switchgear and connection location, connectivity inspection and condition information.

Quickmap software is used to integrate Powerview GIS data with aerial photography and Google earth data to aid with planning and design.

ENL maintains network modeling design software including Load flow and protection coordination using the PSS Sincal software package.

Low voltage design is carried out by engineering staff using LV Drop software.

The Visim line design package was initially purchased from Foleys in 1997 and is used to validate Structure and line design. ENL has developed in house software to replace the Visim line design software.

Design drawings and plans are prepared using Bentley Microstation products.

ICP and billing information is managed via the Talgentra Gentrac system. This system was upgraded in 2010-2011.

Fault dispatch functions are carried out using Microsoft exchange and Gmail to provide the link between Retailers, the Dispatcher and Fault contractors. Garmin products are used to assist with dispach in the field. A tier3 Tait RT system is used to provide real time tracking and location feedback of fiels staff.

PLC Configuration Software is used to Analyse and setup intelligent devices installed on the network

Financial Reporting and Works management functions are carried out using a combination of Sage Accpac ERP and Microsoft Access database applications

Activa Software is used to Manage the Financial Fixed assets register.

Miscellaneous communication and data storage functions are predominantly carried out using Microsoft products linked to open value software assurance to maintain currency.

Sharepoint is used for electronic document control covering process flow control and approval for policies and procedures that have been transferred from the paperbased documentation systems.

Impac Riskmanager is used to manage Health and Safety activities including – Risk identification and control, Incident reporting, Contractor authorisation and competentancy, Safety equipment management and testing and Health and safety reporting.

Payroll and Property management software packages are used to manage the payrolle and property management functions of Eastland Group.

Powerlink and Aspex Software packages enable the Real time Supervisory Control and Data Acquisition functions of the Abbey system SCADA system.

In general specialised software specific to ENL's operation is managed by the ENL Engineering team. Software related to financial activities, general business activities and general communication is provided and managed by Eastland Group's corporate services business, with cost allocations divided over the various Eastland Group businesses and incorporated in Business Support allocations.

2.2.12.4 IT Infrastructure and Business communications

The specialised infrastructure specific to ENL's operation is covered in section 2.3.13 SCADA and Communications. The IT and Business communication systems include equipment under the following categories:

- Personal Computers
- Functional Computers
- Servers
- Switches / Hubs /Routers /Firewalls
- PABX systems
- Telephones
- Office Security and Access Systems
- Cameras and calculators
- Meeting and conferencing equipment (Screens Projectors etc)

The management functions associated with IT and Business communication assets are carried out by the Eastland Group's corporate services business, with cost allocations divided over the various Eastland Group businesses and incorporated in Business Support allocations.

2.2.12.5 Test Equipment

Key test equipment maintained by ENL to ensure availability when required includes:

- Cable fault location equipment
- Insulation testing Equipment
- Voltage monitoring loggers
- Protection testing Equipment
- High voltage phasing equipment
- Communications testing Equipment
- Equipment for testing and calibration of transducers
- Equipment for testing ripple injection performance
- Switchgear test attachments

2.2.12.6 Safety Equipment

A minimum level of Safety equipment is maintained by ENL at key locations to ensure availability when required. The equipment is considered as key in terms of emergency preparedness.
Equipment includes:

- Personnel protective equipment
- Portable earthing equipment
- Barriers and Warning Signs
- Specialised Lifting Equipment
- Water/food storage (basic emergency preparedness)
- Medical and first aid equipment
- Fire fighting equipment

2.2.12.7 Plant and equipment

A minimum level of specialised plant is maintained by ENL at key locations to ensure availability when required. The equipment is considered as key in terms of emergency preparedness.
Equipment includes:

- Fuel and oil Storage facilities
- Fuel and oil handling equipment
- Oil separation facilities to ensure environmental compliance
- Survey Equipment
- Cable location equipment.
- Portable Generators
- Specialised hand/power tools and equipment used for asset construction and maintenance.

2.2.12.8 Furniture and fittings

In order to maintain the business operation ENL owns and utilises non network assets such as:

- Office furniture, Desks Chairs.

- File storage facilities
- Office fittings, partitioning systems and Window coverings
- Food and drink preparation/storage equipment

The equipment is considered key in terms of maximising staff productivity.
These assets are supplied by the Eastland Group as part of a Business Support operational expense allocation.
In general the management functions associated with these assets are carried out by the Eastland Group's Corporate Services Business.

2.2.12.9 Transportation assets

ENL utilises a fleet of vehicles to enable efficient management of the Network assets. These vehicles are supplied by the Eastland Group as part of a Business Support operational expense allocation.
There is currently a mix of leased and owned vehicles. The vehicles utilised by ENL are generally specialised to meet needs associated with emergency preparedness.
The management functions associated with these non-network assets are split between ENL engineering team and Eastland Group's Corporate Services Business. There are 8 Vehicles in this category of non-network assets.

2.3 Age & condition of assets by category

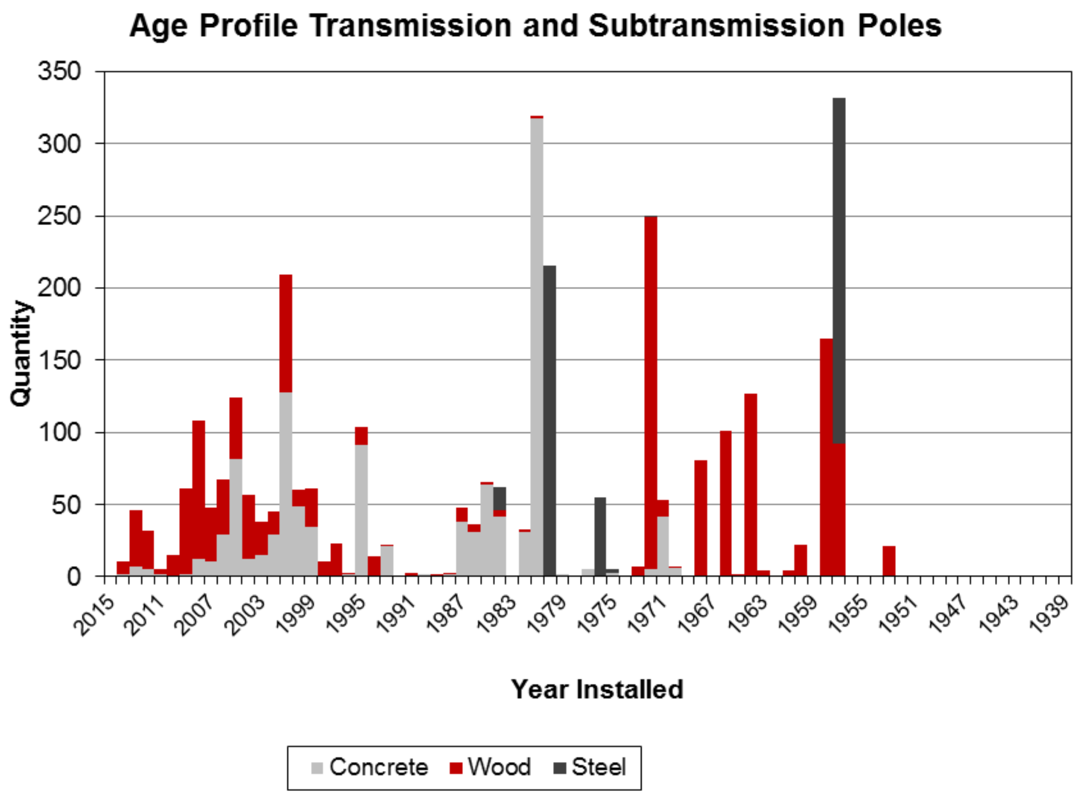
ENL approximates asset condition by age for asset categories with large populations and similar performance characteristics. The life cycle activities described in Section 5 of this AMP qualify the relevance of the age/condition approximation and ultimately determine the rate at which each asset category ages. A summary including average age and values for each asset category is provided is section 2.3.15.

2.3.1 Bulk supply assets

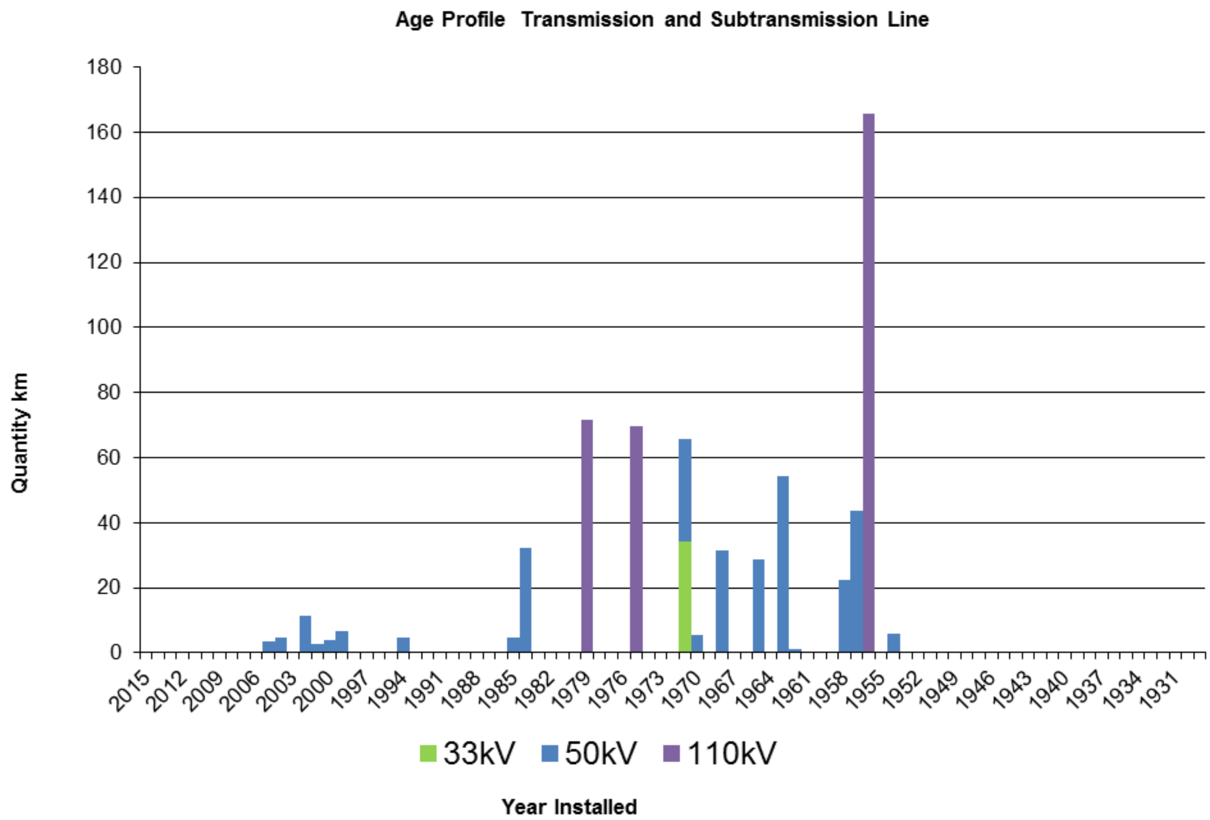
The Bulk supply Transmission assets described in Section 2.2.1 are owned and operated by Transpower in accordance with their asset management policies and procedures. Generation Assets used for supply of energy are managed by the owners of the assets.

2.3.2 Transmission and Sub-transmission Lines

The age of sub-transmission poles is as follows…



The age of sub-transmission conductor is as follows…



The high growth period between 2003 and 2006 is associated with urban reinforcement.
Conductor is lasting longer than poles in terms of condition however Growth and Security triggers have prompted conductor size increases. Poles are well into their age replacement period while conductor is predominantly showing the initial installation pattern. Note some conductor is second hand, explaining the less smooth and more spread installation profile.
As the assets are considered critical replacement is planned before the in service failure rate becomes high.
The poles in replacement zone are wooden.
The replacement rate for poles from 1988 indicates the replacement cycle is already in progress.

Tower 204 on the Gisborne Tokomaru 110kV Line has a foundation stability issue

Despite some conductor being old, there are no identified corrosion or strength issues predicted. Some vibration damage has been identified during inspections. Conductor and bindings are repaired and vibration clamps are fitted as identified. Vibration damage is initially picked up by visual inspection of binders.

Glazing is failing on OB insulations. This is believed to be the result of age, agricultural chemical and sun damage. It results in TV interference complaints, which we are obligated to repair in an acceptable time frame. This is more expensive than coordinating replacement with other planned work. Approximately 5 sites p.a. are identified and corrected.

There is past problem of pole fires caused by failures NGK 10 skirt insulators. These are only rated at 45kV and problem is more prevalent in areas close to the coast. Between 2000 and 2008 the majority of the problem insulators were replaced. No allowance is made for further replacement until problem sites are identified.

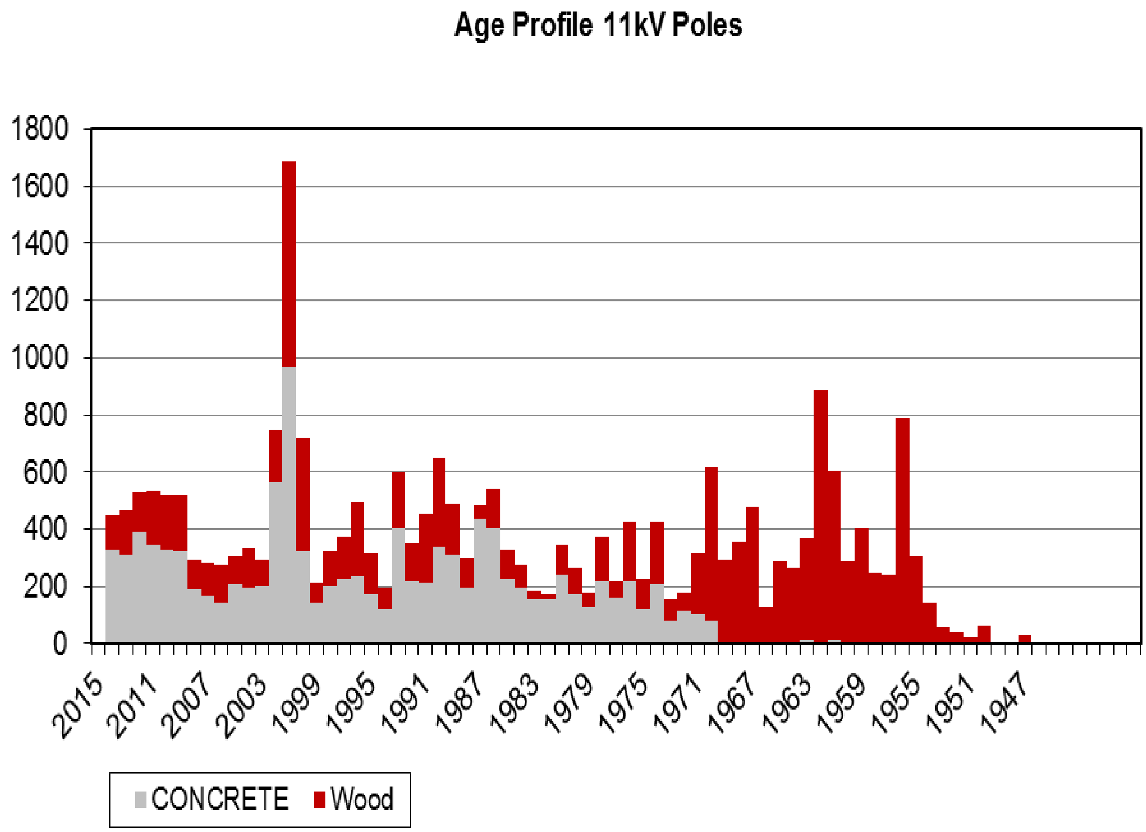
There are approximately 750 strings of blue and brown ceramic insulators that are in the order of 80 years old. These insulators were received in 1960, 2nd hand from NZED. Industry experience indicates that we cannot expect much more life out of this type of insulator.

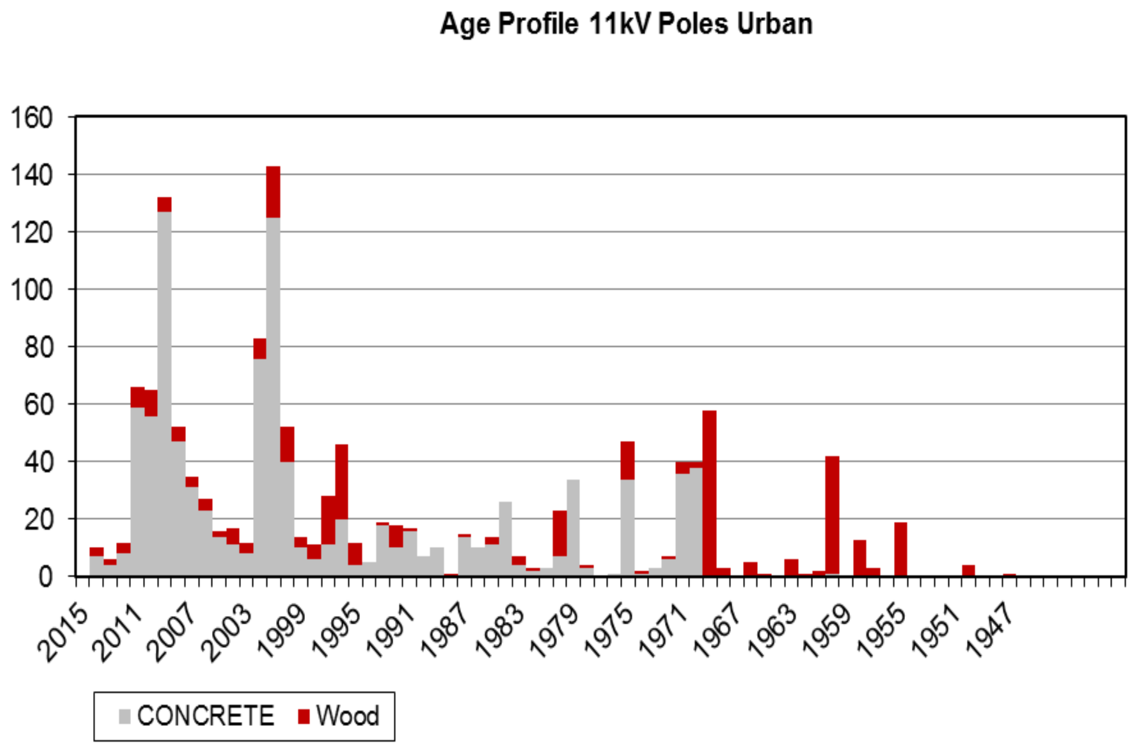
The original suspension strings on the Mahia Line were discovered to have severe wearing on the top hook (40% worn through) in 2001. They had also been stressed through incorrect operating voltage (corrected in 2000). A majority of these insulators were replaced between 2001 and 2003. The Mahia line also has no amour rods fitted to protect the conductor which may shorten conductor life. Remaining problems will be addressed as identified.

All other hardware is believed to be in adequate condition to survive the pole.

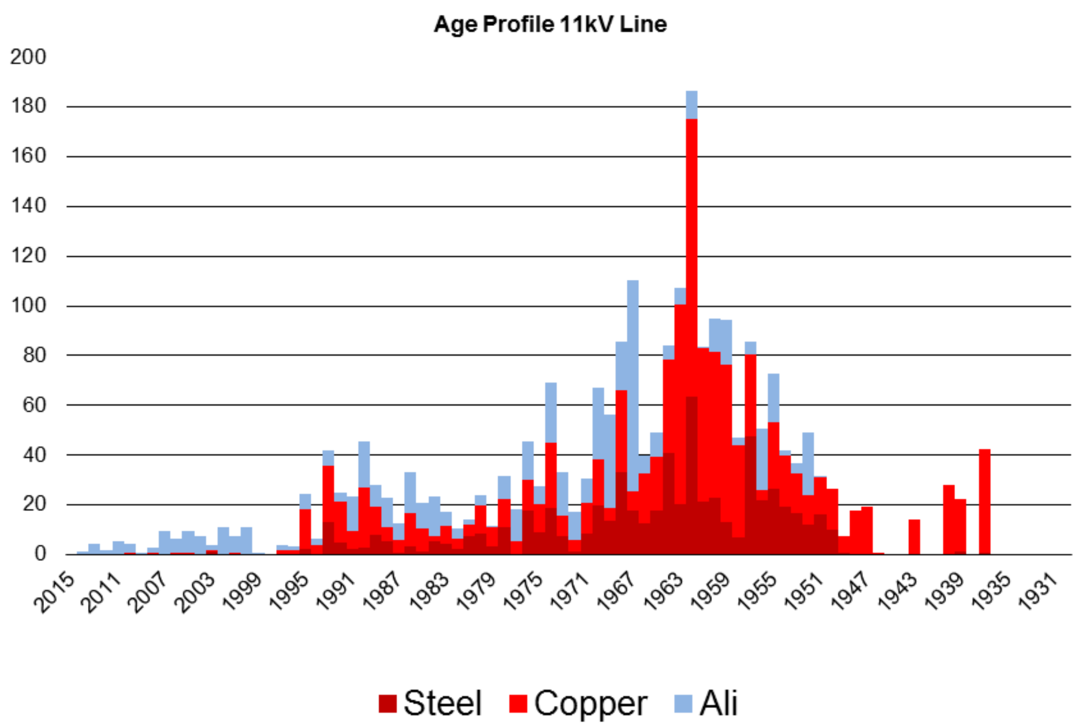
2.3.3 Distribution Lines and Cables

The age of 11kV poles is as follows…


Age Profile 11kV Poles
1800
1600
1400
1200
1000
800
600
400
200
0
2015
2011
2007
2003
1999
1995
1991
1987
1983
1979
1975
1971
1967
1963
1959
1955
1951
1947
CONCRETE
Wood



The age of 11kV conductor is as follows…



The profiles indicate that poles are well into a replacement program.

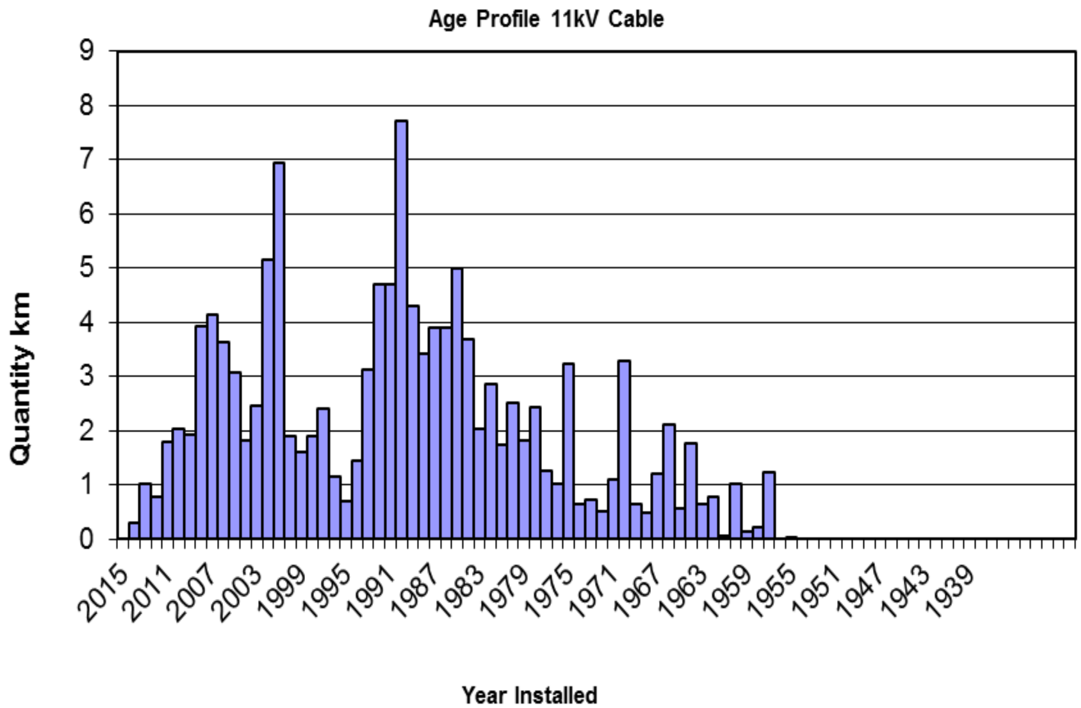
The nominal 60-year life represents the end of the age failure period, which is more applicable to wooden poles, not the start.

The urban pole age profile shows the newer population of mainly concrete poles.
The conductor population is older than the pole population which reflects the expectation that conductor will exceed the 60 year life expectation. Analysis of conductor failures generally indicate underlying causes e.g. Falling Trees, foreign interference and hardware failure, have contributed to the perceived overall conductor condition
The installed 11 kV conductors consist of aluminum (22%), steel (27%) and copper (51%) construction.

Approximately 30% of conductor population and 50% of the pole population is in the failure portion of the life cycle.

78% of the conductor used is copper or steel. The conductor size is typically small due to lack of historical capacity upgrades.
There is 661km of galvanised steel conductor on the network. Approximately 125km is rusting badly to the point where breakages are becoming difficult to repair. Currently repair costs are below the replacement threshold however sections of this conductor will require replacement over the next 10 years.

The age of 11kV cable is as follows…



Due to sample size of cables and the relative new age of the asset the profile is showing an installation pattern rather than renewal.
In general capacity upgrades are sufficient to mitigate age replacement

2.3.4 Major Substation Transformers

The age of Major Substation Transformers is tabulated as follows

Zone Substation Transformers			
Location	**Type**	**KVA**	**Manufacture date**
01 Te Araroa Sub	50/11 - 3 Phase	2500	1/01/1998
02 Ruatoria Sub	50/11 - 3 Phase	5000	1/01/2001
03 Tokomaru Bay Sub	50/11 - 3 Phase	2500	8/08/1997
04 Tolaga Bay Sub	50/11 - 1 Phase O/Hauled 1996	1667	1/01/1965
04 Tolaga Bay Sub	50/11 - 1 Phase O/Hauled 1996	1667	1/01/1965
04 Tolaga Bay Sub	50/11 - 1 Phase O/Hauled 1996	1667	1/01/1965
04 Tolaga Bay Sub	50/11 - 1 Phase Spare Unit	1667	1/01/1965
05 Kaiti Sub	50/11 - 3 Phase	12500	1/01/1987

06 Carnarvon Sub	50/11 - 3 Phase	12500	1/01/2003
06 Carnarvon Sub	50/11 - 3 Phase	12750	1/01/1995
07 Parkinson Sub	50/11 - 3 Phase	12500	1/01/1986
07 Parkinson Sub	50/11 - 3 Phase O/Hauled 2004	12500	1/01/1971
08 Makaraka Sub	50/11 - 3 Phase	12750	1/01/2001
09 Patutahi Sub	50/11 - 1 Phase	1667	1/01/1948
09 Patutahi Sub	50/11 - 1 Phase	1667	1/01/1948
09 Patutahi Sub	50/11 - 1 Phase	1667	1/01/1948
09 Patutahi Sub	50/11 - 1 Phase Spare Unit	1667	1/01/1948
09 Patutahi Sub	50/11 - 1 Phase	1667	1/01/1941
09 Patutahi Sub	50/11 - 1 Phase	1667	1/01/1941
09 Patutahi Sub	50/11 - 1 Phase	1667	1/01/1941
09 Patutahi Sub	50/11 - 1 Phase Spare Unit	1667	1/01/1941
10 Pehiri Sub	50/11 - 3 Phase	2500	8/07/1996
11 Ngatapa Sub	50/11 - 3 Phase	2500	1/01/2007
12 Puha Sub	50/11 - 1 Phase	1667	1/01/1949
12 Puha Sub	50/11 - 1 Phase	1667	1/01/1949
12 Puha Sub	50/11 - 1 Phase	1667	1/01/1949
13 Gisborne Sub	110/50 – 3 Phase	60000	1/1/2006
13 Gisborne Sub	110/50 – 3 Phase	60000	1/1/2006
13 Gisborne Sub	110/50 – 1 Phase Not in Service	10000	1/11954
13 Gisborne Sub	110/50 – 1 Phase Not in Service	10000	1/11954
13 Gisborne Sub	110/50 – 1 Phase Not in Service	10000	1/11954
14 Matawhero Sub	50/11 - 3 Phase	5000	1/01/1997
14 Matawhero Sub	50/11 - 3 Phase	5000	14/08/2000
15 Port Sub	50/11 - 3 Phase	12750	1/01/2001
16 JNL Sub	50/11 - 3 Phase	12750	1/1/2004
20 Tuai Sub	110/11 – 1 Phase	766	1/1/1946
20 Tuai Sub	110/11 – 1 Phase	766	1/1/1946
20 Tuai Sub	110/11 – 1 Phase	766	1/1/1946
20 Tuai Sub	110/11 – 1 Phase Spare	766	1/1/1946
31 TPWairoa Sub	33/11 - 3 Phase	12500	1/01/2007
31 TPWairoa Sub	110/11 – 1 Phase O/Hauled 2007	3333	1/1/1954
31 TPWairoa Sub	110/11 – 1 Phase O/Hauled 2007	3333	1/1/1954
31 TPWairoa Sub	110/11 – 1 Phase O/Hauled 2007	3333	1/1/1954
31 TPWairoa Sub	110/11 – 1 Phase O/Hauled 2007	3333	1/1/1954
31 TPWairoa Sub	110/11 – 1 Phase O/Hauled 2007	3333	1/1/1954
31 TPWairoa Sub	110/11 – 1 Phase O/Hauled 2007	3333	1/1/1954
32 Kiwi Sub	50/11 - 3 Phase	6300	1/01/1983
33 Blacks Pad Sub	33/11 - 3 Phase	1500	14/05/2000
34 Tahaenui Sub	33/11 - 3 Phase	1500	14/05/2000
35 Waihi Sub	50/11 - 3 Phase	6300	1/01/1983
Spare - Mahia	33/11 - 3 Phase Spare Unit	2500	14/5/2000

The general expectation for transformer life is 60 years if the load has generally been low and overhaul work has been undertaken at 30 years alternatively 45 year life is expected if no life extension work has been carried out.

These transformers are considered critical equipment as the lead-time for replacement or repair can be months and they are generally too expensive to warrant holding spares. For this reason it is important that they are replaced before there is any risk of in-service failure

Tap changers are the weak link in transformer reliability. ENL carries a spare OLTC unit for its IMP transformers, Regular overhauls and checks are carried out to ensure optimum performance. A range of other spares such as bushings are also carried.

There is a surplus of single phase units currently in service for the single phase transformer banks. Therefore a number of units can be allowed to fail in service before total replacement is required.

Dual transformer installations can also avoid early replacement due to the higher security provision.

Known performance issues and past events that have limited transformer life include the following: -

Tuai

The tapchanger is not operational. The Transformers are scheduled for age replacement. One transformer bushing has a low insulation test.

Wairoa

The Transformers are scheduled for age replacement.

Gisborne

The old 30MVA transformer bank has been removed from service but has been kept onsite as a contingency.

Patutahi

Blue phase transformer on T2 bank has a low test, but it is to be removed from service if it fails.

Puha

The alternative to defer T1 replacement is to construct a tie line to Puha, improving the security support to Puha and reducing the area affected in the event of an outage. Currently the generator at Puha is providing the necessary security provision.

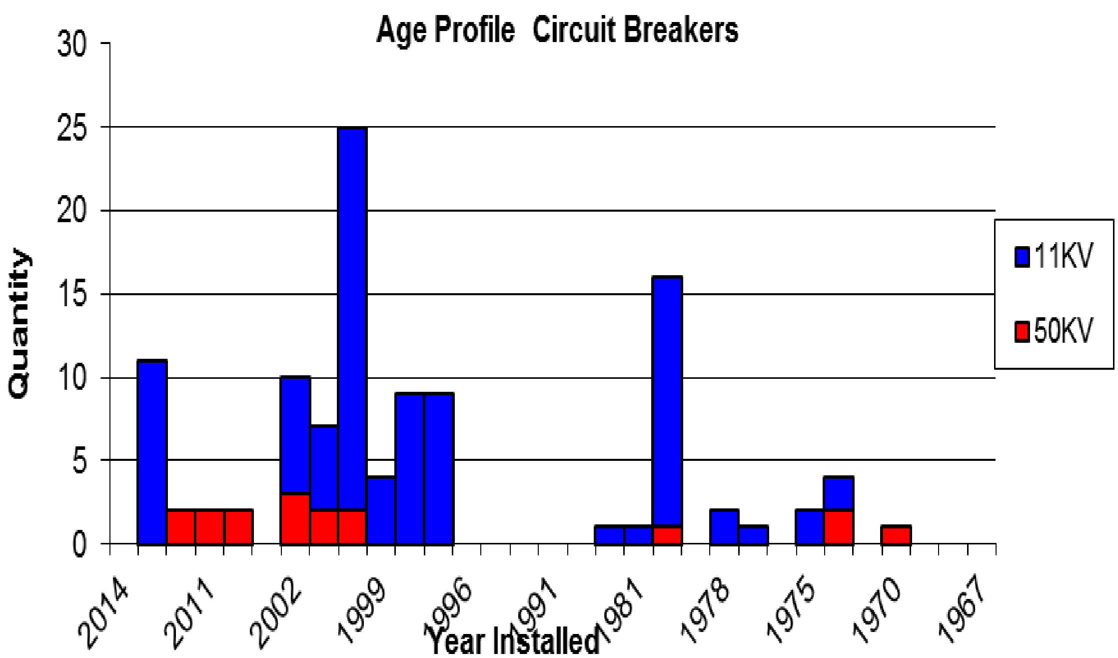
Tolaga

The T1 transformer bank has had a major overhaul in 1996. A number of the radiators have had repairs in 2010 and 2011.

Renewal forecasts show the planned replacement dates for the transformers above. It is possible that Matawhero substation will require larger transformers allowing the existing units to be moved to Tolaga and Puha.

2.3.5 Circuit Breakers

The age of Circuit Breakers is as follows…



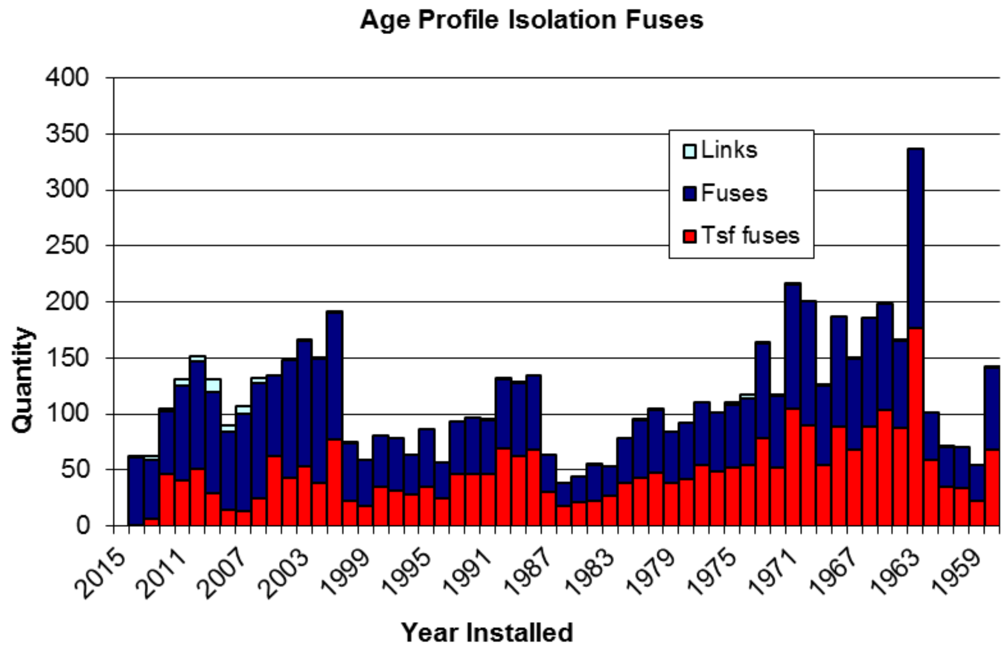
The data includes all 110kV 50kV, 11kV, indoor and outdoor equipment located within Major Substations and installed in the wider Network. There is insufficient population of any single type to draw conclusions. The period from 1999 to 2004 reflects rural CB installation and Substation renewal programs.

All circuit breakers are equipped with SCADA remote control systems.

11kV switchboard reliability is critical and therefore early replacement is desirable.

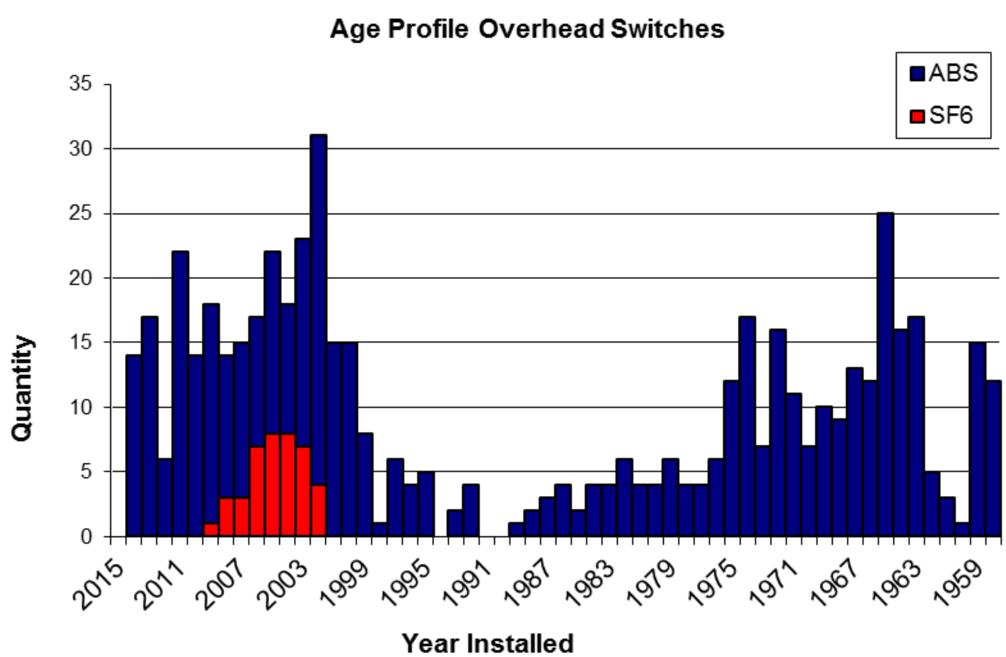
2.3.6 Pole Mounted Isolation Equipment

The age of 11kV fuses is as follows…



The transformer fuses are indicating a pattern which is into a replacement cycle which generally coincides with transformer replacement.

The age of 11kV pole mounted Switches is as follows…



The ABS units initially were installed during construction with minimal attention or operational use. More recently as pole replacement has commenced the use of switches has increased. Any issues with operation are identified and corrected when found.

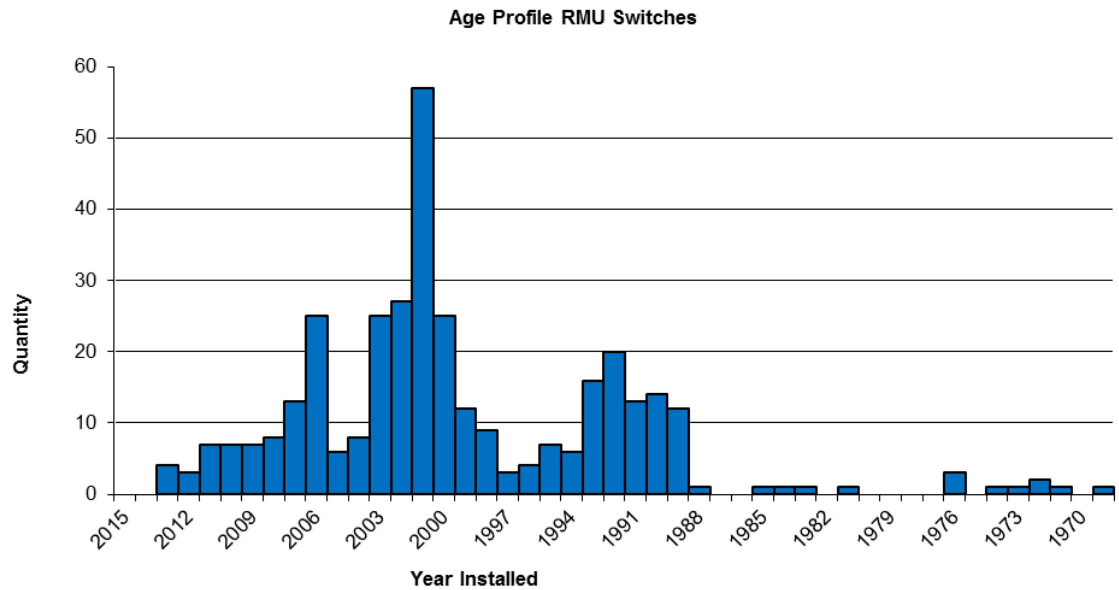
50kV ABS’s are well maintained and are relatively new. Therefore they are expected to deliver a service life equivalent to the ODV life of 35 years.

Quadrant ABS’s with a wire operating system have been identified as potentially problematic should the operating wires break during operation and come into contact with live LV. The proportion of 200Amp Quadrant wire operated Air break switches installed on the network is estimated at 50% exact quantities are being established as part of line inspection programs. These switches have a priority for replacement where they are located on poles with LV or at locations where the consequence of failure is high. The characteristics of these ABS’s that make them less suitable than the current ABS standard are…

While it meets the minimum standard the open contact spacing is closer than newer switches. The requirement is a gap of 150mm minimum.
The switches are not rated to break load (10A maximum). Controllers and operators risk making errors in identifying this limitation as it is not identified on site or on the system diagram. Given the maximum load on most rural feeders and spur lines is well below 10A the switches are adequate for these locations. Switches on higher loaded feeders are systematically being identified and replaced.
They are wire operated. Should the operating wires break during operation they may come into contact with live LV where it exists on the same structure.

2.3.7 Switchgear Ground Mounted

The age of 11kV Ground Mounted switches is as follows…



The quantities are based on complete assets containing multiple switching units as opposed to individual switching units.

Most of the equipment in use is either ABB Oil filed SD series or ABB SF6 Safelink Switchgear.

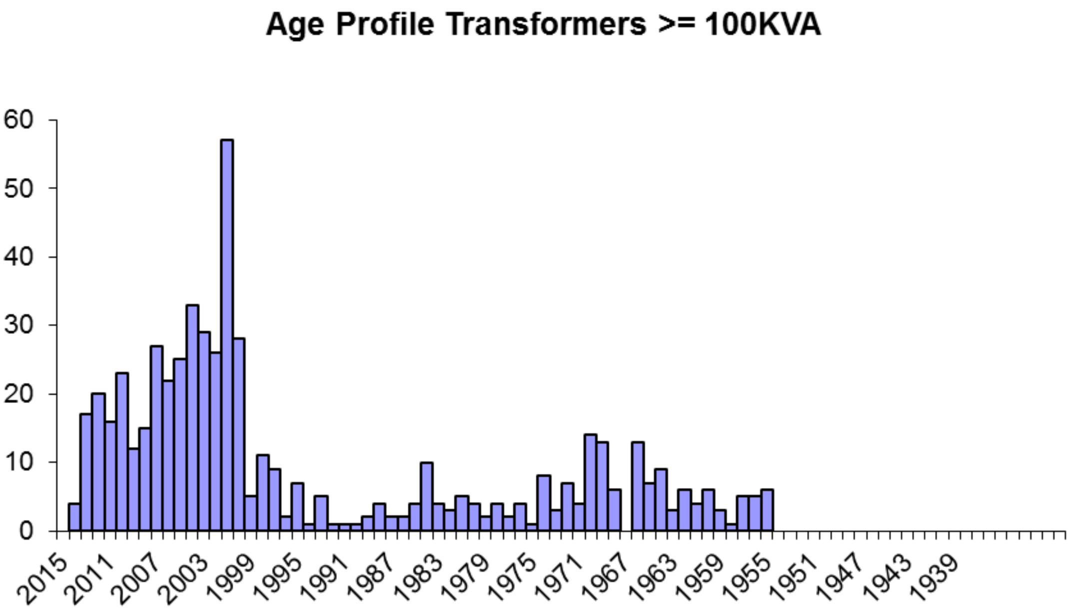
The design deficiencies in older units have largely been eliminated by upgrades.

The population is relatively young largely due to early replacement due to older designs not meeting the necessary safety, performance and reliability requirements. These types include a small remaining quantity of series 1 Andelect units.

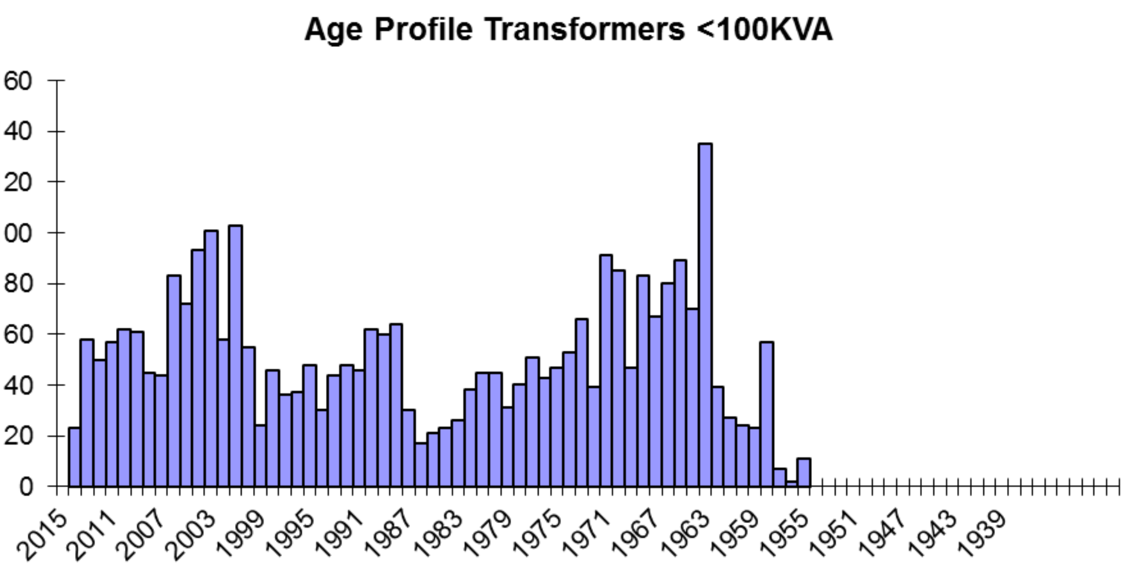
Installation quantities are generally dependent on other work such as under-ground reticulation or installation of new large transformers.

2.3.8 Distribution substations

The age of transformers rated at 100kVA or greater is as follows…



The age of transformers rated at less than 100kVA is as follows…



Transformers have a reasonably fast roll-off in survival spanning a 5-10 year period indicating sudden total failure mechanisms (e.g. tank rusting through, lightening strike, structure collapse or fault overload.) The transformers therefore have high reliability and good overall condition. Due to the rapid decline in condition over a period less than the inspection cycle for smaller units below 50kVA the optimum replacement time for these units is post failure. Opportunistic replacement in conjunction with structure replacement is also carried out where appropriate in terms of the Transformer age/condition.

Large transformers (>=100kVA) have an even installation profile. On average 12 were installed per year from 1960-1985, and 5/yr after 1985- 2000.

The Compliance program in 2000 eliminated the majority of the older group of pole mounted 250kVA units.

Smaller transformers have been in a replacement cycle since 1988 at an average rate of around 60/yr.

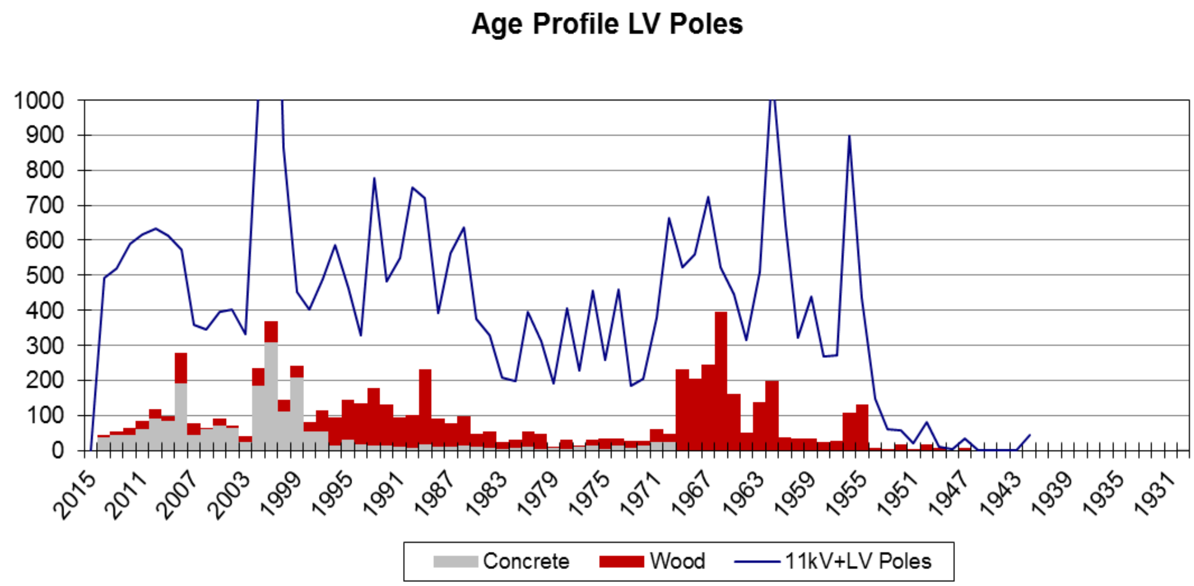
Residual survival is considered negligible as it is only evident in large transformers which reflects the past maintenance attention they have received.

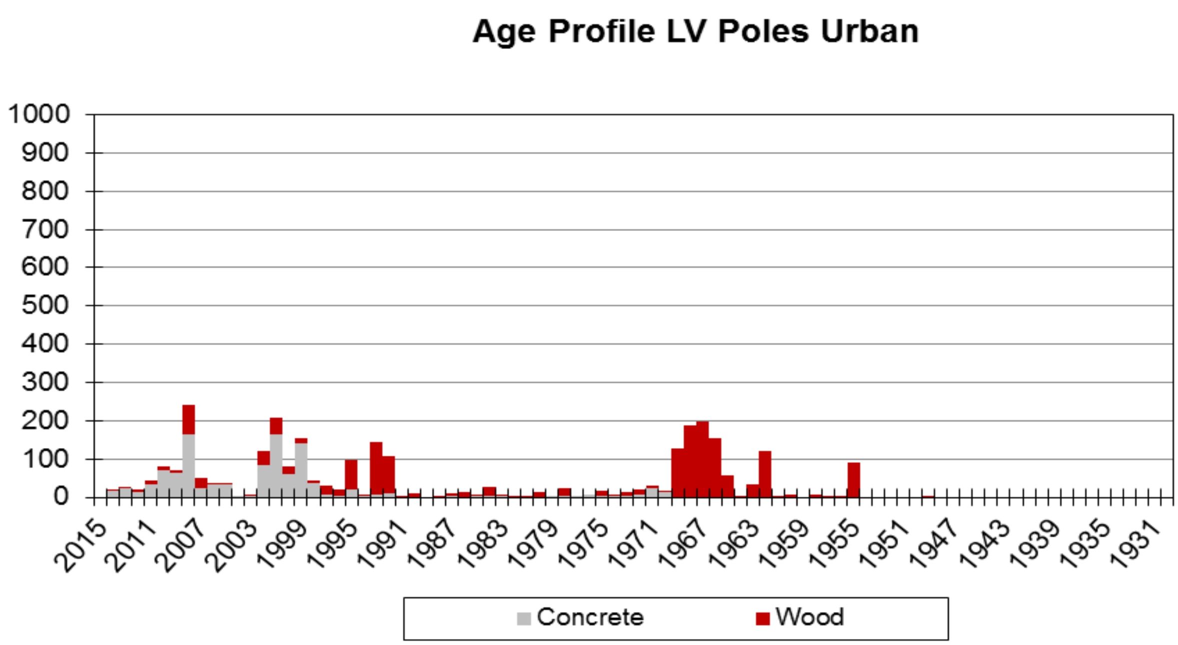
Ground-mount multi-fin transformers have been identified through inspections, to have rust issues around the fins and have the potential to develop leaks. The units have been identified and incorporated into replacement programs.

Failure analysis shows that the predominant cause of in service failure is tank life being reduced by rust. For this reason age is generally a good indicator of condition with units situated in costal locations being a secondary factor.

2.3.9 LV network

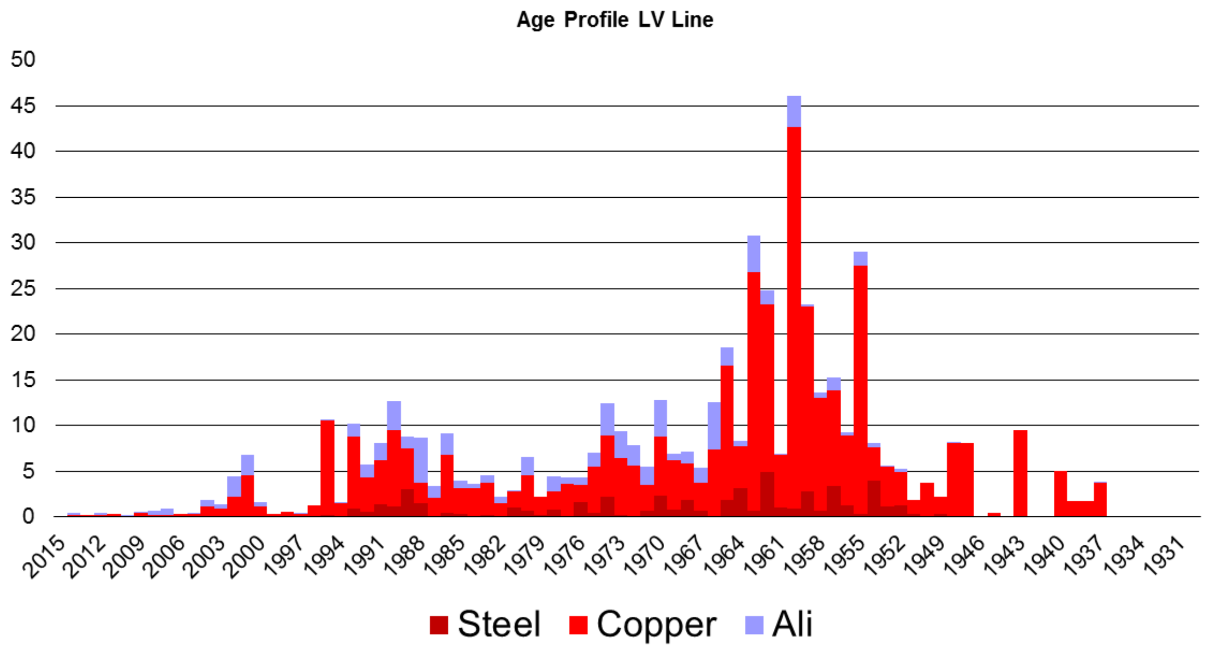
The age of LV poles is as follows…





The urban population indicates the majority of poles are in the new population with an older population located in the urban fringe areas.

The age of LV conductor is as follows…



The LV overhead network generally is below design standards in terms of conductor size and length of circuit.

This low standard of LV construction has arisen due to a policy of not upgrading capacity unless age replacement is required. The historical reluctance to avoid capital renewal unless coordinated with under-grounding activity has also contributed. However it is a valid business strategy to trade off capital expenditure for increased technical losses but this becomes sub optimal in the long term. In urban networks where annual load growth in domestic installations is approximately 1%, the 20% security capacity contingency for overhead lines will be consumed in 20 years.

Conductor tends to be replaced far sooner than poles due to capacity upgrades.

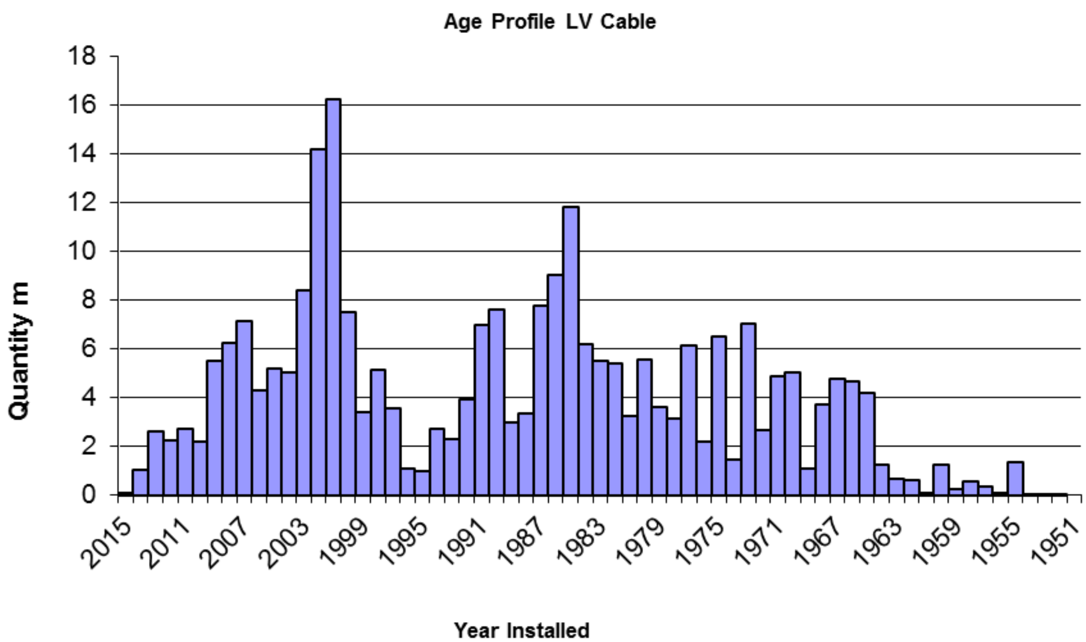
Poles tend to be left until in-service failure or need for replacement associated with new connections or conductor upgrade.
The low pole installation in recent years has some correlation with under-grounding and use of 11kV under building.
Average span in urban area very short at 30m allowing more lea-way before design criteria is compromised.
The main performance issues are related to age or condition and minimal maintenance practices. These issues include…

Failing connectors causing conductor burning
Breaking conductor after clashing or external interference.

Stretched and sagging conductor vulnerable to wire wraps and being caught by high vehicle loads

LV overhead lines are managed in a reactive mode when fuses overload and voltage complaints are received. LV conductor is fused to full duty rating. Often during faults this rating is exceeded for short periods, particularly on overhead open lines. Where this has occurred regularly there is evidence of conductor life being shortened due to annealing of HD Cu., i.e. loss of tensile strength resulting in breakages.

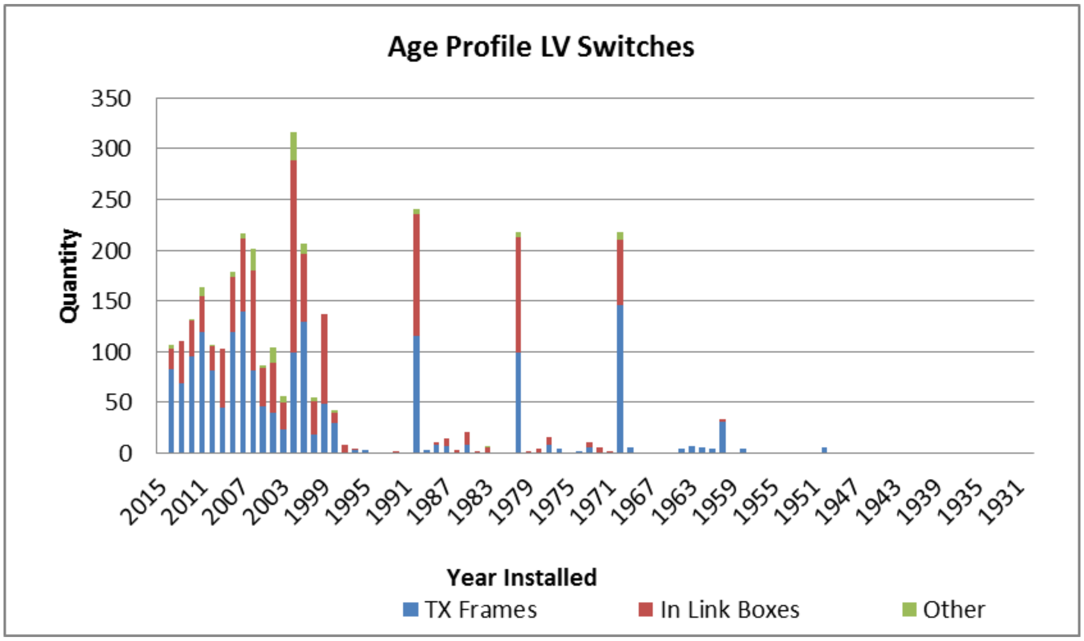
The age of LV cable is as follows…



The cable installation rate shows a strong correlation with reduction in overhead line installation.
Minimal replacement levels are evident but the age profile is driven more by capacity upgrade.

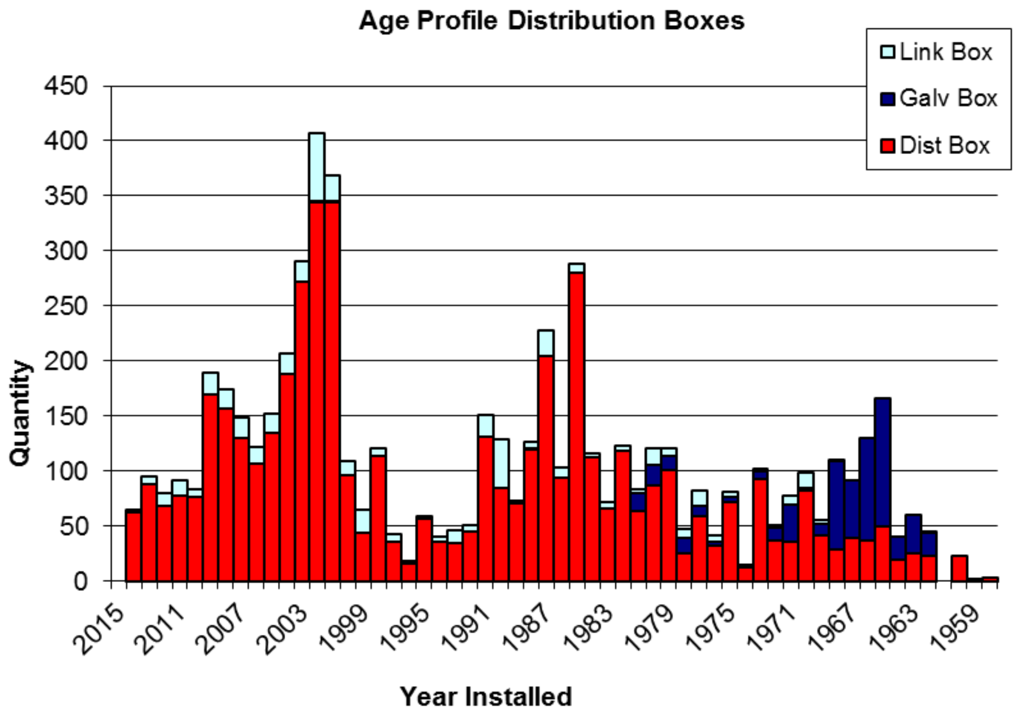
Generally transformers overload before cables and this is allowing issues to be overcome through increasing transformer density thus reducing LV run lengths. This approach will be adequate until transformer capacity is not needed for the load density it is more economic to re-conductor.

The average age of LV switches is as follows…



The dataset for LV switchgear including Transformer and Link box frames shows an incomplete pattern and approximate age as past documentation was not considered necessary. This equipment has a relatively young average age because its installation is associated with cables and ground-mount transformers. Therefore it has to be aged to the point where survival can be accurately assessed. Safety standards and performance of early installations is driving replacement. Most of this is undertaken in conjunction with other work such as transformer renewal.

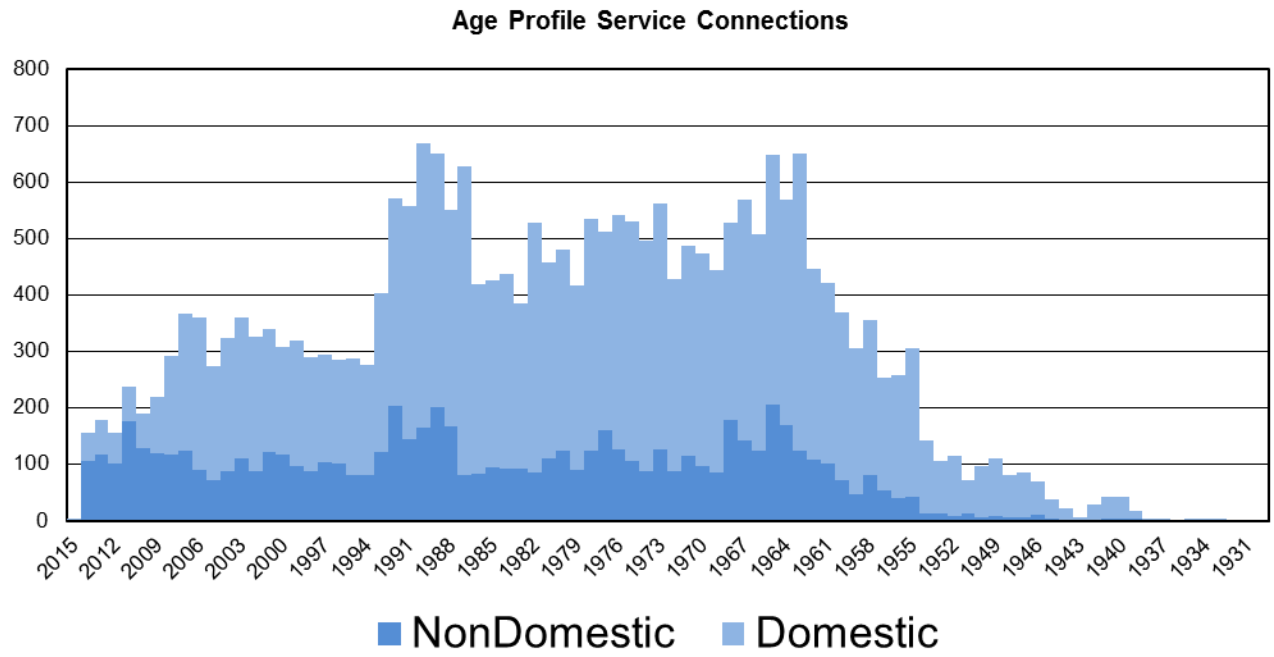
The age of Distribution Boxes is as follows…



Replacement of the older galvanised boxes is underway as overall deteriation is identified during inspection.

2.3.10 Consumer connection assets

The age of consumer connections is as follows…



Failure of service fuses and connectors are the main faults. No preventive replacement programs are undertaken due to difficulty in predicting aging as this is dependent on loading conditions.

Approximately 25% of fuse bases require replacement when the fuse needs replacing. This is caused by burning on the terminal of loose jumper connections or corrosion. The problem is related to quality of the product and installation.

Service failures are treated as non-critical because they affect only one connection.

In some urban areas of the network service fuses are housed in metal clad meter boxes located on the front property boundary. These boxes were installed in the 1960's as a substitute to the traditional meter box. Many of these (approx. 300) boxes have become deteriorated with age or have been otherwise damaged and are in an unsafe state. The current ownership of these boxes is not clear cut and as such a scheme is in place where the cost of replacement of the box is shared between ENL, the customer's energy retailer and the property owner. In addition ENL is segregating its equipment from the replacement meter boxes and relocating into new service fuse boxes.

An age deterioration and damage issue also exists with similar issue with sun damaged fiberglass service fuse boxes. ENL has a program in place to replace these boxes with new service fuse boxes.

Voltage drop in the customers' service main is the main reason for poor performance. ENL has not actively managed this in the past as it generally only affects the service of the consumer responsible for it. The higher losses however do reflect into the costs of the network and are ultimately shared by all customers.

Poor power factor also affects service connection performance driving the need to invest in transmission capacity. Offending installations will be notified to owners and failure to correct issues will result in penalty charges generally by way of increased kVA assessments.

Harmonic generation will be handled via penalty charging where it only affects ENL equipment. If it affects other consumers then disconnection and compensation to those consumers will be enforced.

2.3.11 Load control assets

Approximate numbers of remote load control devices are…

Description	Number
Ripple relays installed in Gisborne between 1990 and 2009.	10,875
Pilot-wire controlled loads in Gisborne.	2,755
TrustPower-owned installations in Wairoa.	Approx. 2,000
Total	

The Wairoa system operates at 1250 Hz, which is subject to high signal attenuation which potentially results in unreliable control. As a result of having high sensitivity receivers installed and issues relating to cost responsibility for Retailer owned receiver upgrading, the effectiveness of the load control system in rural areas has diminished to the point that it is no longer viable to renew the ageing injection plant. Urban control in Wairoa is via a pilot wire system.

The Gisborne frequency injection plant operates at 317HZ and signal attenuation issues at this frequency have proven to be less common.

As the age of the Injection plants increases the frequency of breakdown has increased. The Gisborne injection plant is nearing maximum capacity. To overcome the capacity issue will require the installation of a new Injection transmitter facility. Investigation is continuing into the required timing and cost of this installation.

The age profile of ENL's relays averages 13 years due to the recent replacement of the pilot wire contactors with ripple relays in the

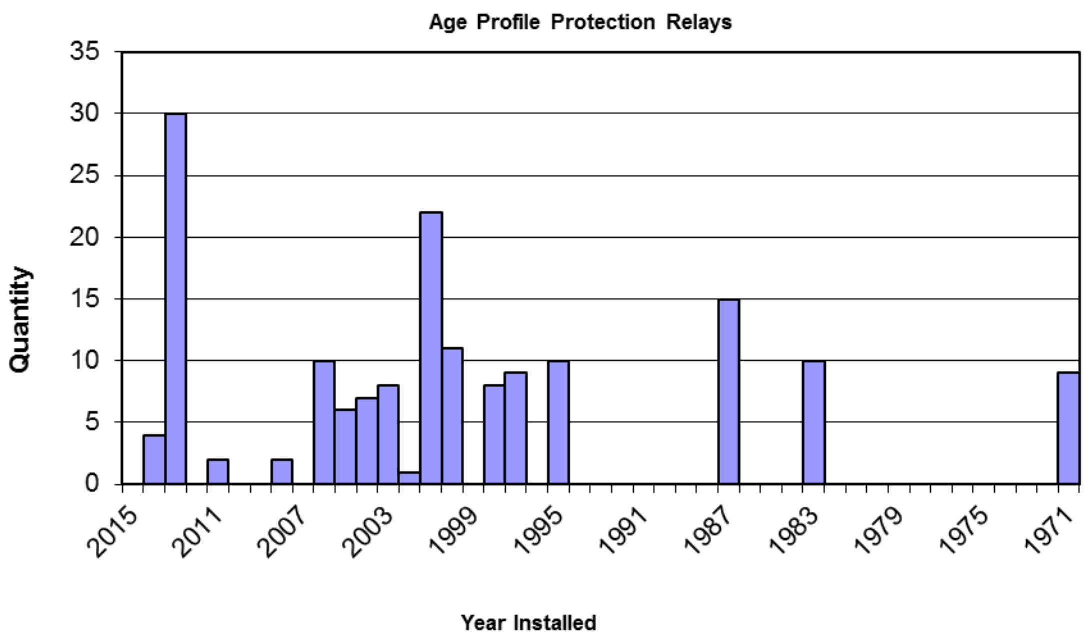
Gisborne city. Renewal programs for ripple relays are reactive in nature and are triggered by failure of the units to operate.

2.3.12 Protection & control

The protection and control equipment used predominantly at Zone Substation sites is varied in terms of functionality and performance characteristics for this reason condition and performance are assessed on a case by case basis. Due to the small population and variety of systems used age analysis provides an indication of the appropriateness of technologies to provide the desired performance rather than condition.

2.3.12.1 Key protection systems

Protection equipment was traditionally expected to last the life of the device it protected. However newer electronic equipment is unlikely to perform adequately after 10 to 15 years. This equipment is required to co-ordinate across the network and therefore must maintain compatibility with ENL's and Transpower's latest technology. Generally technology upgrade is required before renewal.



2.3.12.2 Voltage control equipment

Tap change control relays provided by IMP with earlier transformer purchases have proved unreliable between 2001 and 2007 the units were replaced with RegD control relays and no further issues have been identified.

Older voltage regulators are currently fitted with mercury filled switch mechanisms. Replacement with PLC controls is planned when the existing units show signs of miss-operation due to mechanical wear.

2.3.12.3 DC power supplies

The DC power supplies have been progressively replaced from 1999 as older charges have become noisy and unstable. The equipment has an average age of 3 years.

24 and 12 volt battery banks are generally less than 5 years old as renewal is more economic than regular testing due to the distances to sites. The condition of batteries installed in pole mounted automation installations deteriorates at a greater rate due to summer temperatures generally achieving a maximum 3 year life.

110V Battery banks are replaced at intervals of 6 to 10 years depending on condition testing hence the age of these installations averages around 8 years.

2.3.13 SCADA & Communications

As the Abbey Systems SCADA (Supervisory Control and Data Acquisition) system was purchased in 1999 the average age of the components is approximately 9 years. The communications systems in place at the time of the SCADA system purchase were re-used for the new system with progressive replacement of links and repeaters in progress over a 15 year cycle.

2.3.13.1 Master station

SCADA systems have an ODV life of 15 years as equipment ages support becomes expensive and replacement technology becomes attractive.

Replacement systems generally cost less, are smarter, less proprietary, etc. Like other computer based systems replacement is frequent and continual.

2.3.13.2 Remote stations

To maintain functionality and compatibility with master station functionality the age of RTU's follows a similar pattern to the master station equipment influenced only by new rural automation sites.

2.3.13.3 Communications links

The age of communications equipment is tabulated as follows…

Repeater (Multipoint)	Description	Manufacture/ Install date
Whakapunaki	VHF Voice	1987/1990
Whakapunaki	VHF Abbey	2000/2000
Kinikini	VHF Voice	1987/1990
Kinikini	VHF Abbey	1993/2000
Carnarvon St	VHF Voice	2014/2014
Carnarvon St	UHF Abbey	1999/1999
Umakuri (Tokomaru)	VHF Voice	1993/1993
Tikitiki	VHF Voice	1993/1993
Tikitiki	VHF Abbey	2002/2002
Hicks Bay Hill	UHF Abbey	2001/2001
Hicks Bay Hill	VHF Voice	2010/2011
Mata Rd	VHF Voice	1993/1993
Mata Rd	VHF Abbey	1993/2000
Makaretu	VHF Abbey	1993/2000
Makaretu	VHF Voice	1993/1993
Makaretu	VHF Abbey2	2001/2001
Arakihi	VHF Voice	1993/1993
Arakihi	VHF Abbey	2001/2001
Waihi Stn on hill	UHF Abbey	2001/2001
Waihi Power Station- Waihi Hill/W1040	UHF Data	2010

Link (point to point)	Type	Manufacture Date
Gisborne - Makaretu	UHF 1+1 Backup	1993
Gisborne - Whakapunaki	UHF 1+1 Backup	1993

Gisborne(Matawhero) - Makaretu	4RF Digital Link /IP	2003
Makaretu - Arakihi	4RF Digital Link /IP	2009
Arakihi – Mata Rd	4RF Digital Link /IP	2010
Mata Rd – Umakuri	UHF 1+1 Data Voice	1995
Mata Rd – Tikitiki	4RF Digital Link /IP	2011
Tikitiki – Hicks Bay Hill	4RF Digital Link /IP	2012
Gisborne - Whakapunaki	4RF Digital Link /IP	2007
Whakapunaki – Kini Kini	4RF Digital Link /IP	2013
Whakapunaki - Mata	4RF Digital Link /IP	2001

Communications cable (Note Significant circuits only)		Installed Date
Carnarvon St - Gisborne		1987
Gisborne - Kaiti		1986
Carnarvon St - Makaraka		1986
Carnarvon St – Bright St/ Plunket		1986
Carnarvon St Reads Quay		1986
Carnarvon St – Parkinson St / Birrel St		1986
Fibre Optic Circuits		
Makaraka - Parkinson St		2005
Parkinson St - JNL		2005
Port-Kaiti		2006
JNL - Matawhero		2005
Carnarvon St – Reads Quay		2005
Carnarvon St – Parkinson St		2005
Reads Quay – Gladstone Office		2013
Port Sub –Port Office		2010
Reads Quay - Port		2005
RT's	Quantity	Ave purchase date
Handheld Simplex Narrow band Analog	10	1995-2010
Handheld VHF Narrow band Digital	20	2014

Vehicle VHF Narrow band Digital	100	2014
Substation/Automation sites UHF Analog	9	2001
Substation/Automation sites VHF Narrow Band Analog	100	2005

Pilot Isolation Facilities	No. of Circuits	Service	Installed Year
Carnarvon Street	9	Voice(4)/Data(5)	1995
Valley Rd	3	Not Used	1990's
Kaiti	2	Not Used	1990's
Parkinson St	2	Not Used	1990's
Makaraka	1	Not used	1990's
Wairoa	1	Telecom	2000
Kiwi	1	Telecom	1990's
Ngatapa	1	Telecom	1990's
Patutahi	1	Telecom	1990's
Pehiri	1	Telecom	1990's
Puha	1	Telecom	1990's
Ruatoria	1	Telecom	1990's
Te Araroa	1	Telecom	1990's
Tokomaru	1	Telecom	1990's
Tolaga	1	Telecom	1990's
Plunket Sub	1	Data	1980's
Bright St	1	Data	1980's
Reads Quay	1	Data	1980's
Birrel St	1	Data	1980's

The standard ODV maximum life assigned to communications equipment is 15 years. Modern equipment with more stable components and self-tuning capability generally perform well during this life. Antennas and cables exposed to weather need more regular replacement (10 years). Usually technology advances make earlier system replacement desirable. The Wide-Band VHF Repeaters and

The isolation equipment is required to isolate telecom connections and ENL's communication circuits from earth potential rise in fault conditions at major substations. The isolation facilities are designed to ensure safety of personnel and protection of connected equipment. Use of this equipment will be phased out as fiber-optic circuits replace the need for copper communications circuits.

The wireless broadband 2.4G and 5G communications network was installed between 2005 and 2006 the relationship between age and performance of this system has not been determined at this stage.

2.3.14 Other assets

The assets in this category typically have well established condition standards in line with historically adopted practises comparable with all New Zealand business practises. A brief summary of the condition and issues if any, for these assets by category is provided below.

2.2.12.1 Land and Buildings

The general condition of Land and building assets identified in section 2.2.12 above is as follows.

- North Clyde Wairoa, Land. This property is in good condition with minimal fencing. The grass surface is maintained on a regular basis in accordance with contract specifications. No services are installed on the property hence no renewal plans are required for the site.
- Wairoa Depot. While the land is in good condition, the buildings and structures are old and are in a below average state of repair. Roofing on sections to the buildings was replaced in 2010. As the buildings have minimal use there is currently no need to redecorate the interior.Exterior cladding and painting work is undertaken when inspections identify breaches in the integrity of the structures. Fencing is old but intact and the overall exterior condition is in keeping with the standards of general infrastructure in the area. Currently no upgrade plans have been developed pending discussions with potential tenants to determine their requirements.
- Tokomaru Bay Depot. The land is in good condition and maintained in line with semi-rural standards applied in the district. The buildings are maintained to above average condition

and are of a modern construction. No development or renewal projects have been identified other than routine cosmetic maintenance as a result of inspection and certification activities.

- Carnarvon Street Depot and Office facility. The facility is in very good condition due to regular re development projects undertaken over the life of the buildings. The Garage and Board room facility was built in 2006 and is a modern steel frame skyline garage construction in excellent condition.The Work shop facility is leased to Contractors and is structurally sound with a concrete/timber construction and steel clad. Some maintenance issues exist due to leaking skylights which are progressively being replaced.The Store facility is leased to tenants and is in similar condition and of the same construction as the workshop facility.The Office facility is concrete/wooden construction with Aluminium windows. The building was initially a work shop and was refitted in 2000.The former Carpenters workshop houses the test equipment and IT department. The aged building was refurbished in 2001 and included relining of the interior, replacement of the asbestos roof with steel.The former Garage workshop facility was converted to an office facility and leased to a contractor in 2001. The buildings are maintained inspected and certified to the commercial standards required by regulation. No development expenditure is programmed for the site. Minor adjustments are made to the buildings as needs arise.

2.3.14.1 Generation

The age of standby generation assets is tabulated as follows…

Generators	Rating kVA	Manufacture Date	Controller Date/Type
Carnarvon St	12	1960's	2008 Fanuc28pt
Makaretu	3	1960's Refurbished 2012	2014 DSE7420
Arakihi	4	2011	2011 DSE7310
Mata Rd	4	2014	2013 DSE7420
Kinikini	1.5	1960's	2015 DSE7420
Whakapunaki	8	2015	2014 DSE7420
Tikitiki	1.5	1960's	1990 DSE 5220
Hicks Bay	1.5	1960's	1990 DSE 5220

Condition is influenced by usage patterns and maintenance undertaken.
As the units are all air cooled maintenance is minimal.
All fuel and safety systems for the generator installations were updated to align with regulatory changes in 2007.
Note Larger Standby Generation Units are owned by Eastland Generation Limited. Asset Management strategies for these units are outside the scope of this plan.

2.3.14.2 Software

The software assets are in a constant state of renewal and upgrade hence age of these systems is generally current. Currently all of the software systems in use are meeting the desired performance requirements and no significant upgrade is planned over the next 3 years. The GIS system is not compatible with 64 bit Windows 7 operating systems. This can be overcome by virtualisation software when necessary.

Software	**Latest Version/Installed Year**
Gentrack Billing System	2011
Powerview GIS	2001
Finance –Accpac	2011
Fixed Assets- Activa	2011
Cognos –Financial Reporting	2012
Abbey Systems Scada	2014
Microsoft Operating Sys Servers	2013
Substation Management System Monitor Mikrotik Dude	2015
Microsoft Exchange	2013
Microsoft Server (Files)	2010
GMAIL (redundancy)	2012
Microsoft Operating Sys PC's	Win7 -Win8
Microsoft Office	2010 -2013
PSS Sincal	2014
Protection software SEL	2000 and 2014
Protection Software Uniserve	2014
Battery Charger Software	2014 Ice / DCtools
PLC Software Fanuc	2010 Proficy 2006 VersaPro
PLC Software Cscape	2014
Metering Software Email	2011
Loggers Codam DOS	1996

Loggers Polylogger	1998
Loggers Eberlee	2014
PLC Software Rockwell	2011
Radio Software Aprisa	2002
Relays Enermet	2008
Relays Microtrip DOS	1998
Relays Polarr	1999
Relays Reg D	2012
Transducers Weidmuller	2012 XP only
Security Milestone	2013
Security Innerrange	2013
Config Software Moxa	2014
Config Software Mikrotik	2014
Controller PicAxe	2009
Config Software Adam	2010
Config Software Harris RTU	XP only
Radio Software Mikrotik	2015
H and S/PSMS Software	2015 Web Provider
Payroll	2013
Share Point (Forms/Policy Document Library)	2012

2.2.12.4 IT Infrastructure and Business communications

As the IT and Business communications assets are collectively integrated into a system the degree of utilisation of shared components of the system for ENL verses other Eastland Group businesses is calculated using ratios of personnel and functions performed. In General all assets in this category are owned by Eastland Group and utilised by ENL as appropriate. Costs resulting from allocations are provided in disclosed financial information.
The average age of assets in this category is 3 to 4 years for electronic equipment and 10 years for cabling systems. To maximise business efficiency the systems are designed and maintained to a standard that provides 99% operational availability hence the assets are in very good condition.

2.2.12.5 Test Equipment

In general the test equipment is between 15 and 30 years old. Key items include:

- Protection test set
- Baur Cable Fault locator

- Variable DC power supply
- Ductor
- 5kV Megger
- High Voltage Phasing Equipment
- High Voltage Testers
- Cable Location Equipment

4 x Voltage recorder loggers were purchased in 2011 to replace aged chart recorders.
Older equipment is built into varnished wood or leather cases and is used infrequently.
While the equipment is old the condition is very good and all items are fit for purpose.
Minimal expenditure is planned in the short term other than an investigation into purchase of a second acoustic detector for cable fault location.
Test attachments for switch gear have an age and condition profile similar to the switchgear as these assets were purchased with the initial purchase of each type of switchgear. There are approximately 15 different test attachments required to cover the switchgear assets used on the network.

2.2.12.6 Safety Equipment

All ENL supplied safety equipment is replaced on an on-going basis generally in accordance with the expiry dates on equipment.
Inspection processes and safety tests are undertaken at prescribed intervals. Items that fail tests are replaced as necessary hence the average age of safety equipment is generally 50% of the prescribed life of the equipment.
Equipment Includes:
Hard hats
Switching Suits
Gloves
Overalls
Safety Boots/Shoes
Climbing Harneses
Portable Earthing Equipment
Highvoltage Test attachments

2.2.12.7 Plant and equipment

The nature, range and aging characteristics of plant and equipment vary significantly. Due to the low population size e.g. (1 or 2 of each item) trends and expected useful life is difficult to predict. As issues are identified during use or as a result of workplace inspection programs, equipment is retired or renewed on the basis of case by case. No significant expenditure is programmed for assets in this category.

Equipment Includes:
Safety Ropes
Cones and Area Delineators
Power Tools
Motorised Tools
Hydrolic Equipment
Generators
Pumps
Oil and Fuel Tanks
Crane attachments
Lifting Equipment

2.2.12.8 Furniture and fittings

In general the furniture and fittings including partitioning systems were purchased between 2000 and 2010 as staffing levels increased over time. The assets are maintained in a condition fit for purpose. The Board room table was refurbished in 2000 when it was relocated to the site and is in good condition.

2.2.12.9 Transportation assets

The average age of the transportation assets owned by Eastland Group and used by ENL is approximately 5 years. Asset life targets 8 to 9 years or 200,000 km to minimise cost of refitting. Due to the road conditions distances travelled and terrain the average condition is generally below that typically expected from vehicles of the same age. In some cases vehicles can achieve the targeted distance trigger with 3 or 4 years where the role of the user involves significant travel.

2.3.15 Summary of assets with values

The assets are summarised in Table 2.3(a).

Table 2.3(a) – Summary of assets by category including value

Asset description	Approx Quantity	Unit	Average age	Condition summary	RAB 2014 ($000)	Book Value 1/4/14 ($000)
01. Subtransmission Line	335	km	41	Ageing	$2,671	$3,014
02. Subtransmission Poles	2388	each	36	Average	$8,035	$9,127

03. Subtransmission Cable	1	km	11	Good	$1,438	$396
04. Other Subtransmission Assets		total	13	Good	$87	$71
05. Zone substation assets		total	19	New/good condition	$6,479	$7,083
06. Major Transformers		total	33	Average	$3,386	$4,665
07. Distribution Line	2400	Km	48	Ageing	$8,915	$9,431
08. Distribution Poles	25010	each	35	Average	$31,820	$29,013
09. Distribution Cable	134	km	27	Above Average	$11,956	$10,722
10. Distribution Substations	3629	each	33	Average	$4,314	$5,220
11. Distribution transformers	3629	each	31	Average	$10,644	$12,454
12. Switchgear	1820	each	34	Average	$11,159	$11,2724
13. Load Control Equipment		total	9	Average	$2,461	$2,239
14. Other Distribution Assets		total	13	Average	$458	$454
15. LV Lines incl Streetlighting	538	Km	46	Ageing	$3,649	$4,599
16. LV Poles	6575	each	40	Average	$4,518	$4,938
17. LV Cable incl Streetlighting	258	km	29	Average	$8,918	$9,344
18. Connection assets		total	37	Customer Drives upgrades	$2,689	$3,324
19. Communications		total	17	Technology determines Condition	$923	$831
20. SCADA & System Control		total	11	Technology determines Condition	$358	$500
21. Non System		total	8		$711	$600
Total			27		$125,598	$129,307

In addition at 31 March 2015, Transmission Assets having an RAB value of $13.497 m were acquired from Transpower. This value is excluded from the above figures

2.4 Justification for assets

ENL creates stakeholder service levels by carrying out a number of activities (described in Section 5) on its assets, including the initial step of actually building assets such as lines and substations. Some of these assets obviously need to deliver greater service levels than others e.g. Carnarvon substation in industrial Gisborne has a higher capacity and security level than Tahaenui substation in rural Wairoa.

Hence a greater level of investment will be required that generally reflects the magnitude and nature of the demand.

Ideally an asset can be justified if the service level it creates is equal to the service level required. In a practical world of asymmetric risks, discrete component ratings, non-linear behaviour of materials and uncertain future growth rates ENL considers an asset to be justified if its resulting service level is not significantly greater than that required subject to allowing for demand growth and discrete component ratings.

ENL matches the level of investment in assets to the expected service levels required as follows…

Designs are developed by personnel with an understanding of how asset ratings and configurations create service levels such as capacity, security, reliability and voltage stability.

The asymmetric nature of under-investment and over-investment is considered in line with relevant risk factors identified in section 6.2.3 to obtain an optimum balance. i.e. Over-investing creates service levels in excess of what is needed, but under-investing can lead to service interruptions (which typically costs about 10x to 100x as much as over-investing).

Standards are used that define discrete "sizes" of the many classes of components that need to be recognised. The use of a minimum range of standard sizes for transformers poles and conductors reduces costs associated with stock holdings and spares and maintenance, which is also factored into the overall investment cost. In some cases capacity can be staged through use of modular components.

Experienced personnel are involved to confirm predictions made to accommodate future demand growth, (noting that the ODV Handbook now prescribes the number of years ahead that such growth can be accommodated).

A key practical measure of justification is level of optimisation required in the derivation of ENL's ODV. The ratio of ENL's ODRC to DRC from ENL's 2009 Valuation was 0.99, with a ratio close to 1 indicating a high level of justification. In addition the levels of investment in growth performance and security between 2000 and 2007 indicate a catch up suggesting insufficient investment previously.

Areas where over investment have previously required optimisation as per ODV definitions were:

The predominant optimisation relates to Distribution Transformer capacity to obtain 0.3 demand capacity ratio. As there are a large number of small transformers in the rural network and the minimum economic size of each item is higher than that required to provide the required service levels the actual installed capacity results in a ratio lower than the allowable limit.

Some 300mm cables (Heavy) were technically optimised to 185mm (Medium) however the cost difference between the two sizes at the time of installation was so small the actual over investment had been negligible.

3. Service levels

3.1 Consumer-oriented service levels

ENL's overriding objective in setting service levels is to deliver customer value by matching the performance of its assets and all asset activities to the performance customers expect and are willing to pay for, and the returns on investment required by the shareholder. The targets are established to reflect average performance within a benchmark group of utilities of similar size, customer density, urban/rural split, and transmission remoteness.

As part of on-going engagement with its customers, ENL formally surveys and consults with stakeholder and customer representative groups on an annual basis. The primary required outcome of the consultation process is for ENL to receive feedback from customers on which attributes of supply are important to them, preferences for price and reliability and how well ENL is delivering those attributes and/or preferences. Responses received are then considered by Eastland Group's management team and significantly influence the setting of service levels.
To ensure objectivity is maintained, the consultation process is undertaken by an independent consultant.

Stakeholder/customer groups included in consultation were;

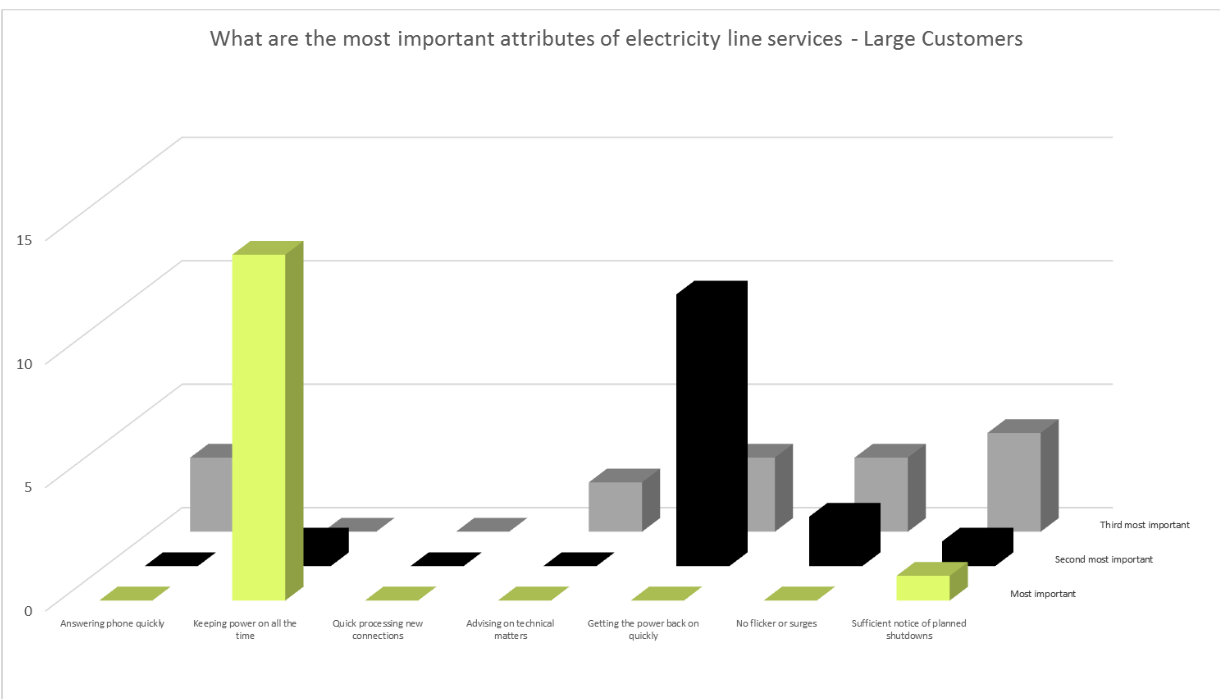
ENL's 25 largest customers, (by energy consumption)
A random selection of 2 %, (367), of the mass market consumers pro-rated between Gisborne and Wairoa.

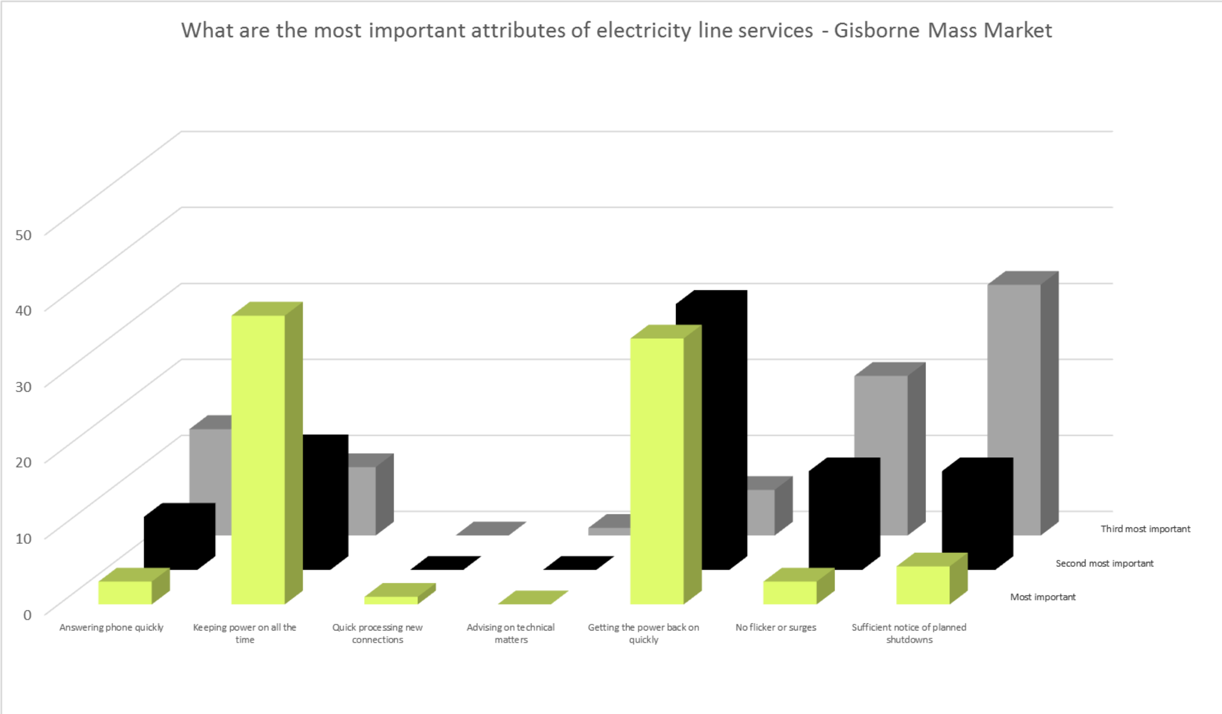
The following groups were also consulted

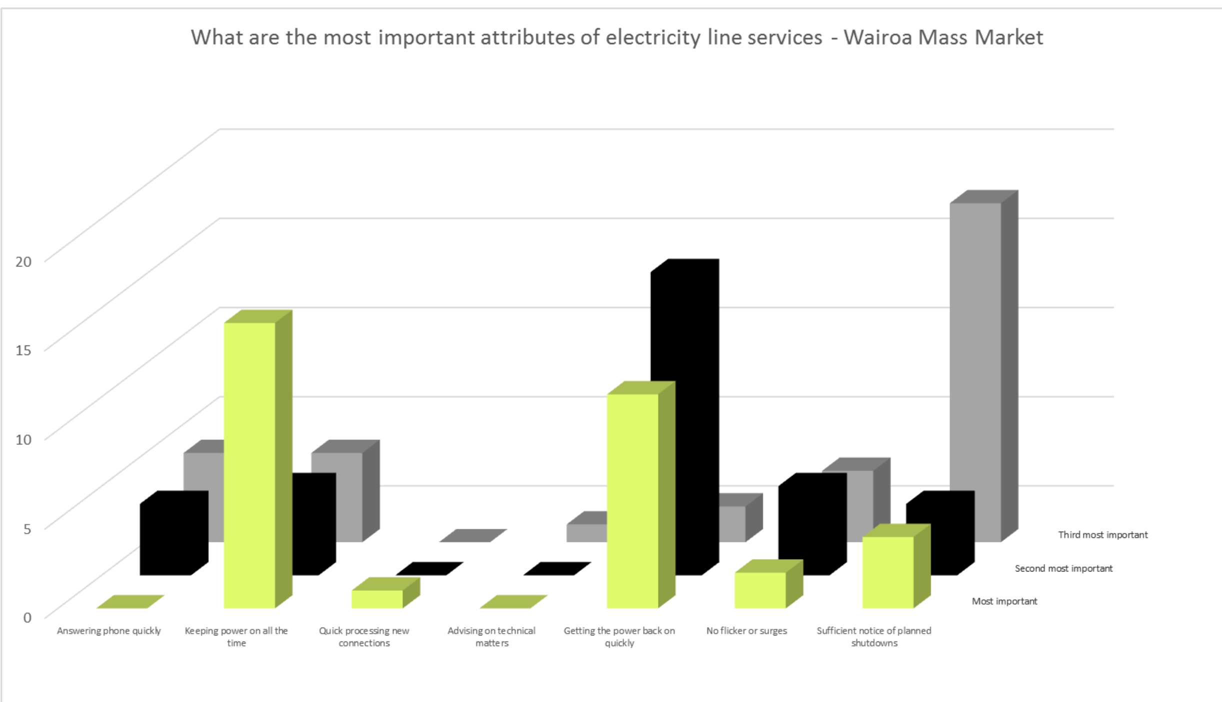
Representative group	Interest
Gisborne District Council	Ensuring that economic development initiatives are supported by a reliable and reasonably priced electricity supply.
Gisborne Chamber of Commerce	Ensuring that the business sector's interests of reliability and reasonable prices are looked after.
Gisborne Greypower	Ensuring that the elderly's (especially

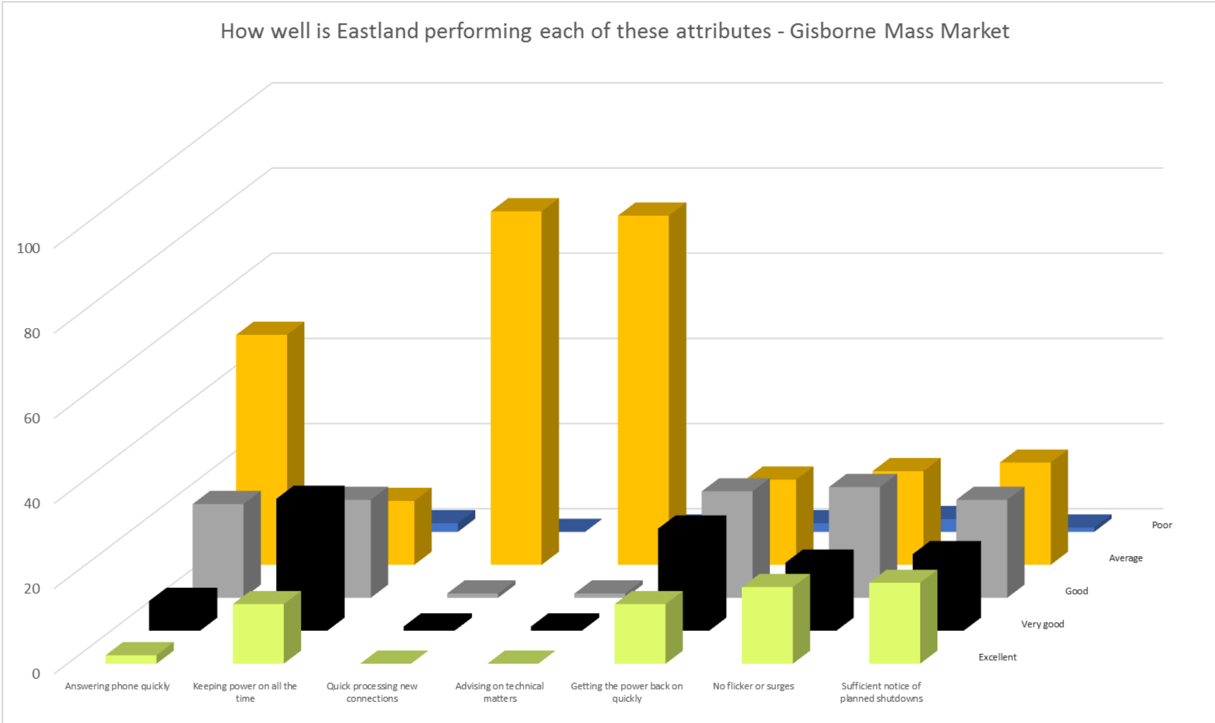
	those on fixed incomes) interests of low prices are looked after.
Wairoa District Council	Ensuring that economic development initiatives are supported by a reliable and reasonably priced electricity supply.
Wairoa Greypower	Ensuring that the elderly's (especially those on fixed incomes) interests of low prices are looked after.
Te Rununga O Turanganui A Kiwa	Ensuring that development initiatives are supported by a reliable and reasonably priced electricity supply.
Te Runanga O Ngati Porou	Ensuring that development initiatives are supported by a reliable and reasonably priced electricity supply.
Federated Farmers	Ensuring that the farming sector's interests of reliability and reasonable prices are looked after.

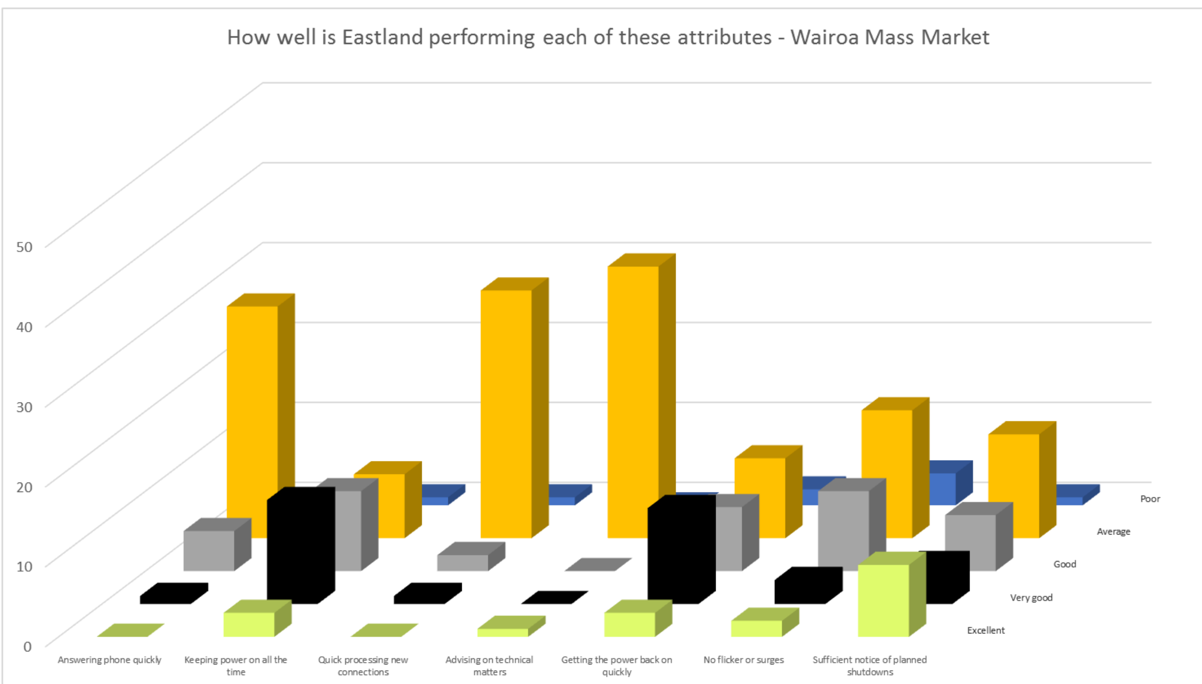
The following charts summarise the responses received from the 2012 consultation round.

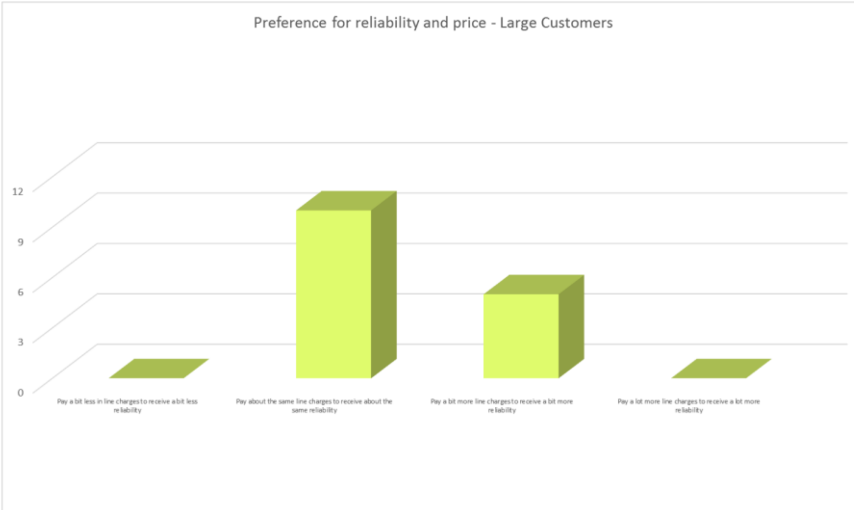



What are the most important attributes of electricity line services - Gisborne Mass Market
50
40
30
20
10
0
Answering phone quickly
Keeping power on all the time
Quick processing new connections
Advising on technical matters
Getting the power back on quickly
No flicker or surges
Sufficient notice of planned shutdowns
Third most important
Second most important
Most important


What are the most important attributes of electricity line services - Wairoa Mass Market
20
15
10
5
0
Answering phone quickly
Keeping power on all the time
Quick processing new connections
Advising on technical matters
Getting the power back on quickly
No flicker or surges
Sufficient notice of planned shutdowns
Third most important
Second most important
Most important

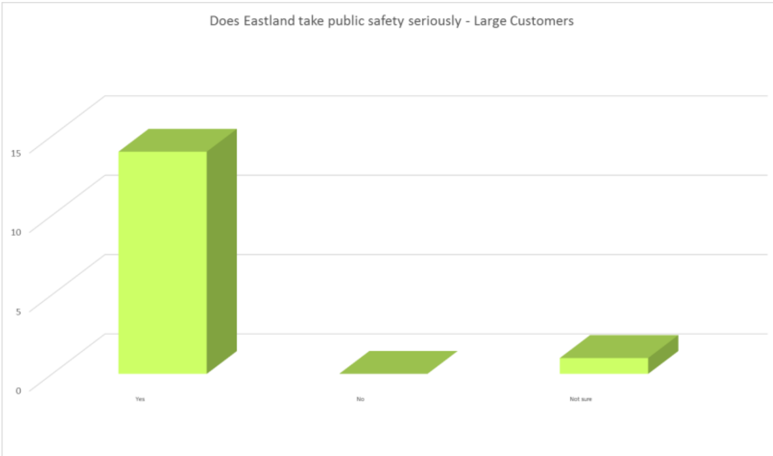

How well is Eastland performing each of these attributes - Gisborne Mass Market
100
80
60
40
20
0
Answering phone quickly
Keeping power on all the time
Quick processing new connections
Advising on technical matters
Getting the power back on quickly
No flicker or surges
Sufficient notice of planned shutdowns
Poor
Average
Good
Very good
Excellent

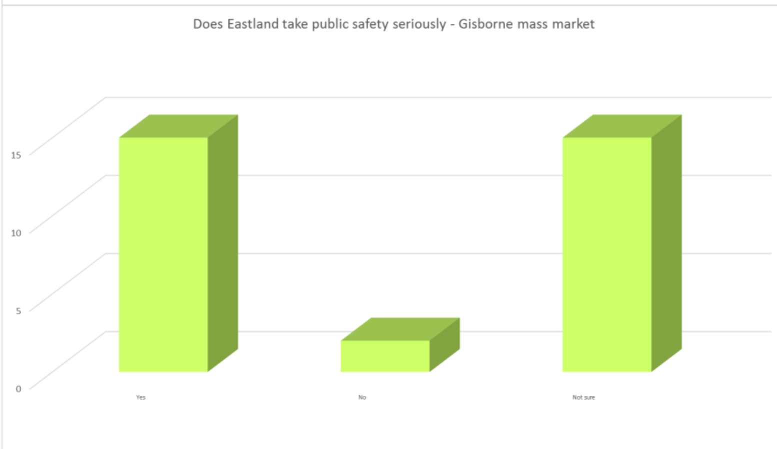

How well is Eastland performing each of these attributes - Wairoa Mass Market
50
40
30
20
10
0
Answering phone quickly
Keeping power on all the time
Quick processing new connections
Advising on technical matters
Getting the power back on quickly
No flicker or surges
Sufficient notice of planned shutdowns
Poor
Average
Good
Very good
Excellent

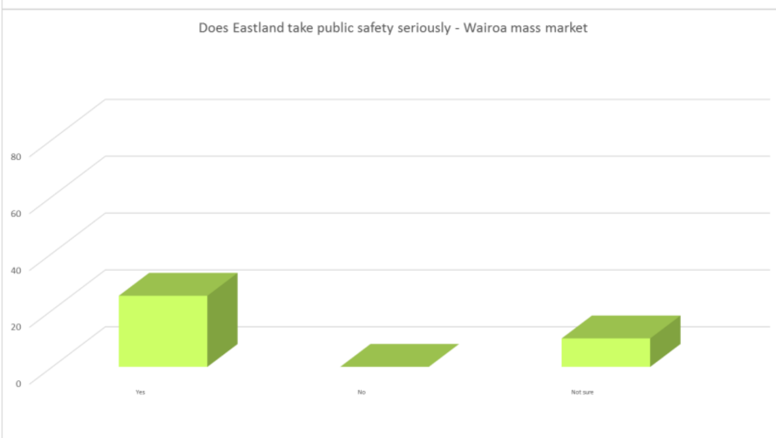

Preference for reliability and price - Large Customers
12
9
6
3
0
Pay a bit less in line charges to receive a bit less reliability
Pay about the same line charges to receive about the same reliability
Pay a bit more line charges to receive a bit more reliability
Pay a lot more line charges to receive a lot more reliability


Preference for reliability and price - Gisborne Mass Market
80
60
40
20
0
Pay a bit less in line charges to receive a bit less reliability
Pay about the same line charges to receive about the same reliability
Pay a bit more line charges to receive a bit more reliability
Pay a lot more line charges to receive a lot more reliability


Preference for reliability and price - Wairoa Mass Market
30
20
10
0
Pay a bit less in line charges to receive a bit less reliability
Pay about the same line charges to receive about the same reliability
Pay a bit more line charges to receive a bit more reliability
Pay a lot more line charges to receive a lot more reliability







ENL's interpretation of the results from completed surveys, indicate the Primary focus needs to be on supply interruptions and restoration times. Whether ENL improves or simply maintains these areas and whether line charges are increased to do so are addressed as follows… Continuity should be maintained at about the current levels or improve where it can without increasing line charges. ENL definitely shouldn't let continuity decline.

ENL should maintain restoration performance at about the current levels, improve where it can without increasing line charges, but definitely shouldn't let restoration performance decline.
ENL should maintain its timeliness and addressing accuracy of planned shutdown notices, improve where it can without increasing line charges, but it definitely shouldn't let performance decline.
Customers feel that Eastland Network takes Public Safety seriously but do not wish to pay more for improved safety.

3.1.1 Primary customer service levels

ENL's customers have clearly signalled that continuity and restoration are the two operational performance attributes that they value the most and at a minimum ENL needs to maintain current levels of performance without increasing its line charges.
Operational Performance
To measure operational performance with respect to continuity and restoration, ENL in accordance with industry standard practice and the Information Disclosure and Electricity Distribution Threshold regimes, sets targets for the next five years against the following key indices;

SAIDI – system average interruption duration index. The measure of how many system minutes of supply are interrupted per year.
SAIFI – system average interruption frequency index. The measure of how many system interruptions occur per year.

In 2014 the Regulator completed a review of historical performance for the primary customer service levels and determined new targets for the next regulatory period 2015-2020.
The new targets have been linked to financial and future target incentives for distribution lines businesses that do not have exemptions.

The determination significantly amended the treatment of reliability performance measurement and reporting.

Three of the key changes resulting from the Default Price Path reset were:

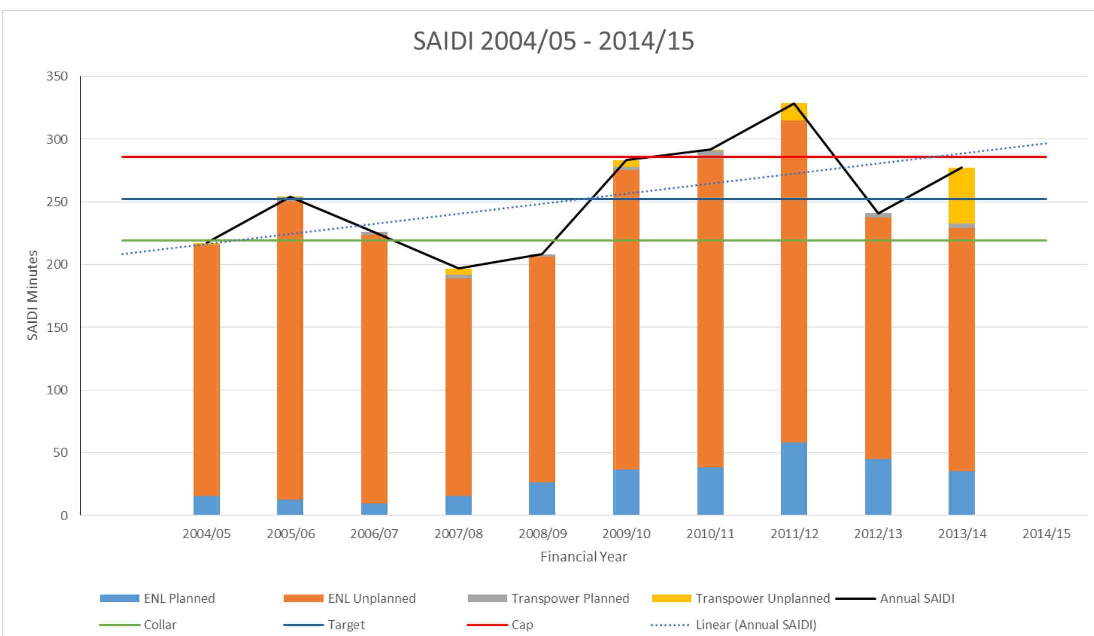
- The establishment of SAIDI and SAIFI daily boundary values derived from the past 10 years of network reliability data
- The determination that outages that are planned will only count for half as much when calculating SAIDI and SAIFI totals

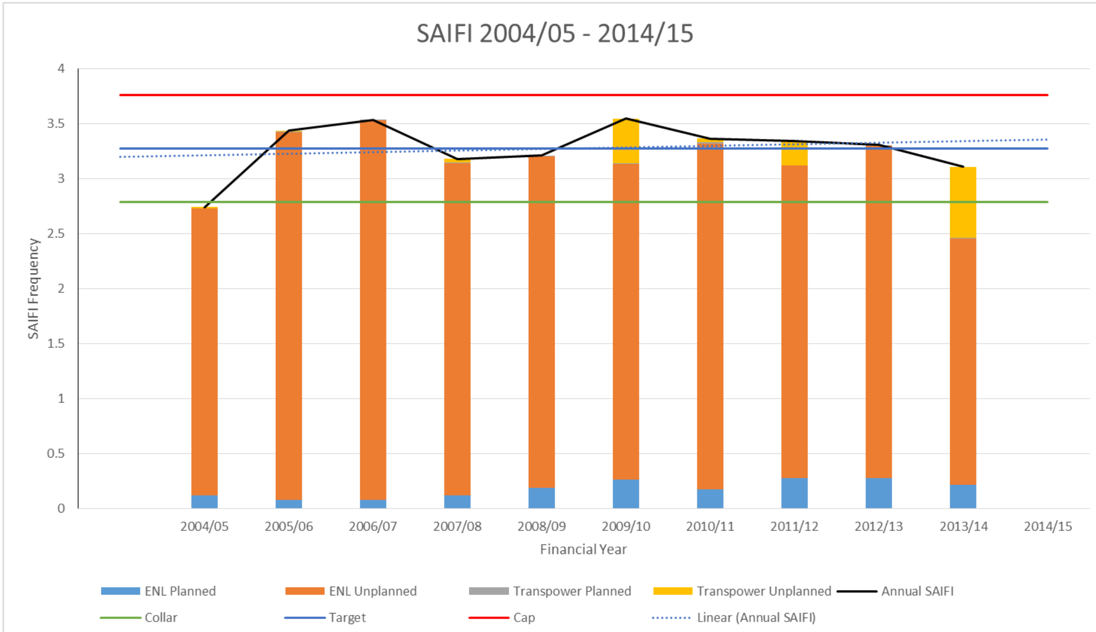
- The introduction of cap, collar, and target SAIDI and SAIFI performance values linked to financial incentives

The incentive linked performance values were adjusted from the figures given in the determination to account for the outages of the Transmission assets being acquired; they are shown in the table below:

	SAIDI	SAIFI
Boundary Value	13.390	0.208
Limit	285.776	3.766
Target	252.450	3.277
Collar	219.125	2.787
Cap	285.776	3.766

To better understand how these changes will impact Eastland Network the 2004–2014 network outage data has been applied, together with 10 years of outage data relating to the Transmission assets acquired in March 2015, according to the new methodology. The results are shown in the charts below.





An analysis of the results show Eastland Network would likely have breached SAIDI compliance in 2010/11 and 2011/12 as it had under the old standards. It also indicates that in some years Eastland Network may have run over the targets that are to be introduced for SAIDI and SAIFI, this would likely have resulted in financial penalties under the new incentive system.

As the targets have been determined based on historical performance they do not allow for changes in industry guidelines or work practises. E.g. changes in guidelines for reclosing circuits after faults may increase outage times when physical inspection of the entire line prior to re-livening is required.
With these results in mind ENL has forecast that the new quality targets may be exceeded and budgeted conservatively, allowing for the maximum penalty each year. This would result in an approximate $227,000 reduction in revenue each year that SAIDI and SAIFI reach their respective Cap values.

To meet the determined targets ENL has considered the following options:

A) Changes to existing design. To reduce unplanned events caused by failure of assets, the common failure modes and outage times shows that the best improvements for asset design include.
    a. Increased levels of automation to provide fast backfeed in meshed networks. Current levels of automation have been optimised to avoid over automation and additional unneccesary automation maintenance.

b. Replacement of rural overhead lines with underground. The investmant to acheve this option is of the order of 3 or 4 times current network valve.
c. Development of radial networks into meshed networks. The investment to achieve this option is approximately 1.8 time the current network value.

B) Significant increased expenditure on tree control. The analisis of tree faults to date indicate little improvement will be made from a disproportional value investment unless tree regulations allow trees to be removed from falling distance of the lines.
C) Installation of standby generation on radial feeders/segments of the network. ENL is developing this strategy which is incorporated into plans.
D) Significant increases in Manpower including fault response and repair crews. Identified as an issue refer 1.5.6
E) Establishment of additional Depots, stock holdings and Plant to reduce repair delays. Potentially a step following option D above.

Primary Service levels conflict

A potential conflict between the stakeholders linked to the primary service levels has emerged.

On one side of the conflict, regulated service level targets have been set to reward improvement of security standards for network designs, maintenance, response and restoration of supply.

On the other hand regulated incomes are in place which limit the rate at which improvement to the current security standards can be made. In addition results of surveys from consumers strongly indicate a preference to maintain current security levels rather than increase costs to acheve improved security sevels.

ENLs' prioritys for managing this conflict are identified in section 1.4.5.

ENL is commited to improvements to current and future security standards where this can be achieved within current financial criteria.

From analysis of the design standards, life cycle management, historical performance and current future strategies it is possible that ENL will be unable to achieve the regulated targets in each year of the next 5 year regulatory period.

In addition should ENL wish to increase maintenance and design changes requiring outages to implement, an insufficet margin exists within the set targets to achieve the work without exceeding the targets.

Key reliability and efficiency performance targets for the next 10 years are indicated:

Performance measure	Actual 2013-14	Forecast 2014-15	Target 2015-16	Target 2016-17	Target 2017-18	Target 2018-19	Target 2019-25
SAIDI: B ENL Planned	71.3	46.0	40.0	40.0	40.0	40.0	40.0
SAIDI: C ENL Unplanned	213.5	256.0	232.0	232.0	232.0	232.0	232.0
SAIDI: Total(B + C)	284.8	302.0	272.0	272.0	272.0	272.0	272.0
SAIDI ½B + C (ComCom target)	NA	NA	252.0	252.0	252.0	252.0	252.0
SAIFI B	0.4	0.4	0.54	0.54	0.54	0.54	0.54
SAIFI C	2.3	3.8	3.00	3.00	3.00	3.00	3.00
SAIFI: (B + C)	2.7	4.2	3.54	3.54	3.54	3.54	3.54
SAIFI ½B + C (ComCom Target)	NA	NA	3.27	3.27	3.27	3.27	3.27

If ENL were to set the targets to align with the forcast development program the targets set would be above the regulated targets hence the lower of the two assessments has been used.

The SAIDI and SAIFI targets are used to drive a steady state level of performance that considers network asset design, age, location, configuration, financial implications and customer expectations. Investment to improve service beyond steady state and regulated levels is seen as over investment and as such cannot be justified. Given the relatively small asset base there is high degree of uncertainty in the validity of the forecast predictions.

Complimentary to key operational performance targets are targets for the restoration of faults which affect the supply to customers. ENL's targeted performance is to meet the targets as prescribed in current Use of System Agreements entered into with energy retailers. These minimum targets are;

Fault Restoration

Urban	4 hours
Rural	8 hours

An exception to these targets can occur where private lines have failed or where hazards exist that prevent private lines from being restored, until the hazards have been corrected. This situation typically occurs where trees have encroached into the safety zone on private lines.

The control operations staff and/or faults service contractor record response times and the causes for the network outages defined by the disclosure rules, in the System Outage database which facilitates analysis and disclosure reporting. For outages that are excluded from the disclosure requirements information is recorded on the fault response documentation. An Engineering officer is responsible for reviewing the recorded figures and implementing improvements or corrective action when necessary. Comparisons of the response times are made with benchmark values to indicate trends. Outage duration and repair time components are incorporated into the performance indices for industry benchmarking.

Line Function Services Charges

Customer consultation has determined that in general ENL's customers are satisfied with the current level of network operational performance and are unwilling to pay for improved performance. However, ENL is faced with two significant issues that fundamentally affect how the business will be operated and managed in the future to deliver even the minimum levels of service:
It has a network that has been identified as being relatively old, with a significant level of assets nearing the end of the lives;
It has faced on-going and erosion of the businesses Return on Investment (ROI) due to regulation.

Eastland Network has identified a developing gap, for some asset categories, between required renewal rates to maintain asset age and current targeted rates, primarily limited by available funding. This is compounded by a distribution network that is spread over a large geographic area and characterised by a low density of less than seven connections per kilometre of line.

ENL's service level with respect to lines charges is that lines charges need to be sufficient to provide for the correct level of investment and return on the network, which in turn allows customer service level requirements to be met. ENL's annual regulated revenue is set in accordance with the allowable maximum revenue, as determined by the Electricity Information Disclosure Determination 2012. ENL's revenue requirements are implemented in accordance with Commerce Commission pricing methodology requirements and Electricity Authority Pricing Principles.

Lines businesses are able to apply for a customised price path that may allow prices to be set which are higher than allowed under the current regulation. If ENL's ROI continues to degrade, a customised price path is likely.

3.1.2 Secondary customer service levels

Secondary service levels are the attributes of service that ENL's consumers ranked below the attributes of supply continuity and restoration, and line function services charges. A key point to note is that most of these service levels are process driven which has two implications…

They tend to be cheaper than fixed asset solutions e.g. someone could work a few hours overtime to process a back log of new connection applications.

There are heterogeneous in nature i.e. they can be provided exclusively to consumers who are willing to pay more in contrast to fixed asset solutions which will equally benefit all consumers connected to an asset regardless of whether they pay.

The attributes of service which customers have ranked as secondary in importance and which ENL sets and monitors performance against targets are;

Shutdown notification and coordination.
To provide notification timing and shutdown advice in accordance with current Use of System Agreements, ENL has implemented the industry standard pro-forma email notification process. This process identifies affected ICPs and standardized information is emailed to relevant energy retailers. The energy retailers in turn advise their customers accordingly.
When organizing a shutdown, ENL directly contacts large and significant customers, (e.g. rest homes) to discuss and negotiate outage times which as much as possible are set to accommodate the preferences of those customers.

How quickly ENL processes Network Alteration applications for new connections, changes in required capacity or total disconnection.

How promptly and how well ENL provides technical advice to consumers on network asset related issues.

How promptly and how well ENL responds to quality of supply issues. The quality of supply is measured in terms of voltage flicker complaints, low voltage issues, harmonic content in supply, interference to telecommunication assets and radio interference.
The legislation and regulations that determine ENL supply quality requirements include The Electricity Act 1992, Electricity Regulations 1997 and The Commerce Act 1986.
Deviations from regulatory limits and poor supply quality levels are recorded in the network defects database as soon as they are identified. Corrective actions are carried out as soon as practicable. Issues requiring longer term supply quality improvement to the network asset are incorporated into the company design standards and management plans for the affected asset categories.

How prompt and effective ENL's Complaint and Dispute Resolution Process is.
ENL is an electricity company member of the complaints scheme administered by the Electricity & Gas Complaints Commission. Accordingly ENL is compliant with the Commission's Code of Practice for Electricity Companies and its Complaint and Dispute Resolution Procedure. ENL performance targets are aligned with those of the Commission.

ENL secondary customer service level performance targets for the next 10 years are;

Attribute	Measure	2012-2023
Notification of Planned Outages	Number of planned outages not notified to energy retailers at least 10 working days in advance.	0
	Number of individual ICP omissions or errors in outage notification to energy retailers.	0
	Number of large or significant customers not consulted directly during outage planning.	0

Processing of Network Alteration applications	Number of working days to process correctly completed applications for a new domestic or small commercial supply where infrastructure, capacity or resource consent issues do not exist.	5
	Number of working days to process correctly completed applications for load increases/decreases for existing domestic or small commercial ICPs where infrastructure, capacity or resource consent issues do not exist.	5
Provision of technical advice	Number of working days to acknowledge inquiry.	2
	Number of working days to investigate and respond to a customer inquiry.	20
Supply Quality issues	Number of working days to acknowledge a customer reported supply quality issue and initiate an investigation.	5
Complaints Procedure	Number of working days ENL has to acknowledgement that a complaint has been received from a customer.	2
	Number of working days to when an unresolved dispute is deemed deadlocked.	20
	Number of working days to when an unresolved dispute is deemed deadlocked. (with ENL having advised that additional investigation time is required)	40

3.1.3 Other Stakeholder service levels

In addition to the service levels that are of primary and secondary importance to consumers, ENL has safety and environmental management service levels that benefit stakeholders.

3.1.3.1 Safety

Eastland Group is committed to providing and maintaining a safe and healthy environment for all of its employees, contractors, customers and the public.

Eastland Group's regulatory and corporate responsibilities for health & safety management across the businesses it manages are described in the Eastland Group Health & Safety Manual. This manual also determines for each business the health & safety management policies and procedures required to be implemented to meet those responsibilities. In addition a safety management system required under regulation exists to ensure specific processes are in place to ensure prevention of serious harm to the public and/or significant damage to property.

In all over 100 documents have been identified that contain compliance requirements associated with operation maintenance and reporting for the Network Assets.

The key regulations and industry codes of practice that ENL has a responsibility to comply with are;

Health & Safety in Employment Act 1992.
Electricity (Hazards from Trees) Regulations.
Maintaining safe clearances from live conductors (NZECP34:2001).
Power system earthing (NZECP35:1993).
Safety Manual –Electricity Industry
Electricity Act
Electricity (Safety) Regulations

Key elements of the Eastland Group Health & Safety Manual and Safety Management system which ENL implements are;

Workplace Hazard Management
Contractor Health & Safety Management
Public Safety – Asset Hazard Management

As drivers to achieve the Eastland Group safety policy standards of safety performance, ENL has set the following targets for every year of the planning period and beyond;

Event / Incident Description	Target
Serious Harm Employees Contractors /Lost Time	0
Serious Harm Public	0
Serious Damage Company Property and Equipment	0

Serious Damage Public Property	0
Near Miss Harm Employees Contractors	NA
Near Miss Harm Public	NA
Near Miss Damage Company Property and Equipment	NA
Near Miss Damage Public Property and Equipment (HV Power faults)	NA

Safety performance reporting to the ENL Board of Directors is undertaken at every monthly Board Meeting.

3.1.3.2 Environmental management

In planning and undertaking activities which have implications for the environment, Eastland Group is committed to managing and operating its businesses in a manner which meets the community's environmental expectation. For ENL this requires a balance be met between the community's need for electricity and that of effective environmental management.
ENL has the environmental management performance target of full compliance with all laws, regulations, resource consent and local authority District Plan conditions.

3.2 Industry and Business performance targets

As a monopoly lines business ENL is required to disclose a range of internal performance and efficiency measures as required by the Electricity (Information Disclosure) Requirements. ENL aligns future performance targets against the Disclosure measures. The measures which are applied to target asset management performance are described below;

The peer/benchmark values for the industry are published annually by Price Waterhouse Coopers (refer www.pwc.co.nz)

3.2.1 Asset performance

Complimentary to the primary customer service levels for SAIDI, SAIFI, Section 3.1.1, ENL also forecasts and monitors network performance via the number of faults per 100km for both overhead and underground assets at per asset voltage category. This targeted performance for the next ten years is;

	SERVICE PERFORMANCE TARGETS							
	2013/14 Actual	2013/14 Forecast	2014/15	2015/16	2016/17	2017/18	2018/19	2019-2025
Interruptions								
B Planned	165	180	180	180	180	180	180	180
C Unplanned	263	280	280	280	180	180	180	180
Faults/100km								
110 kV	NA	NA	NA	0.9	0.9	0.9	0.9	0.9
50 kV	2.32	3.64	3.64	3.64	3.64	3.64	3.64	3.64
33 kV	14.5	5.81	5.81	5.81	5.81	5.81	5.81	5.81
11 kV	9.89	12.2	12.2	12.2	12.2	12.2	12.2	12.2
Total	9.14	11.27	11.27	11.28	11.28	11.28	11.28	11.28
Underground								
110 kV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
50 kV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33 kV	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11 kV	8.86	8.31	8.31	8.31	8.31	8.31	8.31	8.31
Total	8.77	8.22	8.22	8.22	8.22	8.22	8.22	8.22
Overhead								
110 kV	0	0	0	3	3	3	3	3
50 kV	2.33	3.66	3.66	3.66	3.66	3.66	3.66	3.66
33 kV	14.57	5.82	5.82	5.82	5.82	5.82	5.82	5.82
11 kV	9.95	12.46	12.46	12.46	12.46	12.46	12.46	12.46
Total	9.17	11.41	11.41	11.41	11.2	11.2	11.2	11.2

Notes

1. 2014/15 Actual values are not yet available
2. Data excludes Private and Transpower outages

3.2.1 Financial efficiency measures

ENL's projected financial efficiency measures are shown below. These measures are…

Operational Expenditure per km of line

Operational Expenditure per ICP

Where operational expenditure is the expenditure incurred in the operation of the distribution business, and that is not Capital

Expenditure and excludes depreciation, tax, expenditure on transmission and expenditure relating to financing the business.

Financial Efficiency Measure	Actual 2013-14	Forecast 2014-15	Target 2015-16	Target 2016-17	Target 2017-18	Target 2018-19	Target 2019-25
Operational expense ($/km)	$2,139	$2,065	$2,607	$2,487	$2,643	$2,659	$2,647
Operational expense ($/icp)	$307	$324	$408	$389	$412	$414	$411

2013/14 Information Disclosure industry averages, Operational Expenditure per km = $3,598, Operational Expenditure per ICP = $349/ICP.

While other measures are directly associated with performance of the network assets these targets are determined from both impacts relating to asset management activities and the impact of other strategic and business initiatives unrelated to asset management.

3.2.2 Energy delivery efficiency measures

ENL's projected energy efficiency measures are shown below. These measures are…
Load factor – [kWh entering the network during the year] / [[max demand for the year] x [hours in the year]].

Loss ratio – [kWh lost in the network during the year] / [kWh entering the network during the year].

Capacity utilisation – [max demand for the year] / [installed transformer capacity].

It should be noted that the energy delivery efficiency parameter values achieved are predominately determined by the network configuration and assets required to supply the demand profiles of customers. Over the planning period ENL expects to maintain a sustainable steady state position with respect to energy delivery efficiency delivery. Tactics to achieve this are described in Section 5.0.

Energy Delivery Efficiency Measure	Actual 2013-14	Forecast 2014-15	Target 2015-16	Target 2016-17	Target 2017-18	Target 2018-19	Target 2019-25
Load factor ENL	57%	59%	59%	57%	55%	53%	53%
Loss ratio ENL	7.0%	7.0%	9.5%	9.5%	9.5%	9.5%	9.5%
Capacity utilisation ENL	22.8%	22.8%	23.0%	23.0%	23.0%	23.0%	23.0%

2013/14 Information Disclosure industry averages, Load Factor = 59.7%; Loss Ratio = 5.6%; Capacity Utilization = 31.7%.

The average load factor indicates that the load characteristic of the region is consistent with other areas. The above average loss ratio reflects the low density long line length characteristic of the region. The increase to 9.5% forcast from 2015 is due to inclusion of 110kV transmission losses following relocation of the Metering to Tuai GXP. For companies with no Transmission and Subtransmission assets the loss ratio is expected to be lower. The below average capacity utilisation reflects the low density connections using minimum size transformers that are larger than necessary. In general the results are in line with expected levels.

3.3 Justification of service levels

Historical trends for key service levels in Section 8 of this plan show the extent of variation between good and bad years can be in the order of 50%. While comparison of targets over a short time base may suggest little incentive is in place for improvement ENL has considered the entire asset life cycle and short term variance when setting the steady state targets. When the targets are aligned over a time frame equivalent to the asset life there is a significant incentive in place to improve designs and methods to improve service levels where possible.
ENL’s service levels are justified through consideration of the following;

By what is achievable and sustainable within current revenue boundaries. This is the primary consideration affecting the ability to set and achieve marked improvement in future performance. In line with customer survey conclusions improvements to the availability and reliability of supply to customers with no increase in cost significantly limits options for improvement of the asset to a level that dramatically enhances service levels, hence performance improvement will be gradual and lower than the levels of annual variation.

By the physical characteristics and configuration of the assets which comprise the network and which are difficult and expensive to significantly alter (but which can be altered if a consumer or group of consumers agrees to pay for the alteration). As with other lines businesses ENL has legacy decisions which have established service levels that would require significant additional investment to alter. Examples include the use of second hand 50kV insulators in the 1960's that are now impacting on reliability and the construction of distribution lines across country as opposed to alongside accessible roads.

Through consideration of customer consultation results and the subsequent analysis to determine the customer's primary service level requirements and their agreement to pay.

Achieving compliance with all legislative and regulatory requirements applicable to the ownership and operation of the network. This includes when an external agency imposes a service level on ENL (or in some cases an unrelated condition or restriction that manifests as a service level such as requirement to place new lines underground)

When establishing performance levels ENL carried out a comparison against other lines businesses for the purpose of determining its desired position in the market.

Analysis and consideration of previous information disclosures published annually is undertaken to confirm ENL is aligned with its peers.

In general service levels have been set to maintain ENL in an average industry position.

4. Development plans

ENL's development plans are driven almost totally by demand but on occasions may be influenced by other drivers, primarily security of supply.

At the most fundamental level, demand is created by each individual consumer, using energy via their individual connection. The demand at each connection aggregates "up the network" to the distribution transformer, then to the distribution network, then to the Subtransmission/Zone substation, then via the sub-transmission network to the Transmission Substation/Lines to the Grid Exit Point and ultimately through the grid to a power station.

4.1 Planning approach & criteria

4.1.1 Planning unit

ENL has adopted the 11kV distribution feeder as its fundamental planning unit which typically represents one or perhaps two of the following combinations of consumer connections…

An aggregation of up to 1,000 urban domestic consumer connections.
An aggregation of up to 300 urban commercial consumer connections.
An aggregation of up to 20 or 30 urban light industrial consumer connections.
An aggregation of anywhere from 20 to 100 rural domestic or farm consumer connections.
A single large industrial consumer connection.
Injection of up to 5MW of generation (e.g. Waihi and the diesel generators).

Physically this planning unit will usually be based around the lines or cables emanating from an 11kV switchboard.

4.1.2 Planning approaches

ENL tends to plan development of its assets in three different ways (strategically, tactically and operationally) as shown below…

Planning approaches

Attribute	Strategic	Tactical	Operational
Asset description	Sub-transmission lines & cables. Major substation assets. Load control injection plant. Central SCADA & telemetry. Generation Connections Distribution configurations e.g. Decision to link or divide feeders.	Minor substation assets All individual distribution lines (11kV) All distribution line hardware. All on-network telemetry and SCADA components. All distribution transformers and associated switches. All HV consumer connections.	All 400V lines and cables. All 400V consumer connections. All consumer metering and load control assets.
Number of consumers supplied.	Anywhere from 500 to about 7,500	Anywhere from 1 to about 500.	Anywhere from 1 to about 50.
Impact on balance sheet and asset valuation.	Individual impact is low. Aggregate impact is moderate.	Individual impact is moderate. Aggregate impact is significant.	Individual impact is low. Aggregate impact is moderate.
Degree of specificity in plans.	Likely to be included in very specific terms, probably accompanied by an extensive narrative.	Likely to be included in specific terms, and accompanied by a paragraph or two.	Likely to be included in broad terms, with maybe a sentence describing each inclusion.
Level of approval required.	Approved in principal in annual business plan. Individual approval by board and possibly shareholder.	Approved in principal in annual business plan. Individual approval by chief executive.	Approved in principal in annual business plan. Individual approval by GM - Operations.
Characteristics of analysis.	Tends to use one-off models and analyses involving a significant number of parameters and extensive sensitivity analysis.	Tend to use established models with some depth, a moderate range of parameters and possibly one or two sensitivity analyses.	Tends to use established models based on a few significant parameters that can often be embodied in a "rule of thumb".

To further guide its thinking ENL has developed the following "investment strategy matrix" shown in Figure 4.1.2(b) which broadly defines the nature and level of investment and the level of investment risk implicit in different circumstances of growth rates and location of growth.

Figure 4.1.2(b) – Investment strategy matrix

Location of demand growth	Lo	Hi
Outside of existing network footprint	**Quadrant 3** • CapEx will be dominated by new assets that require both connection to existing assets and possibly upstream reinforcement. • Likely to absorb lots of cash – may need capital funding. • Easily diverts attention away from legacy assets. • Likely to result in low capacity utilisation unless modular construction can be adopted. • May have high stranding risk.	**Quadrant 4** • CapEx will be dominated by new assets that require both connection to existing assets and possibly upstream reinforcement. • Likely to absorb lots of cash – may need capital funding. • Easily diverts attention away from legacy assets. • Need to confirm regulatory treatment of growth. • May have a high commercial risk profile if a single customer is involved.
Within existing network footprint	**Quadrant 1** • CapEx will be dominated by renewals (driven by condition). • Easy to manage by advancing or deferring straightforward CapEx projects. • Possibility of stranding if demand contracts.	**Quadrant 2** • CapEx will be dominated by enhancement rather than renewal (assets become too small rather than worn out). • Regulatory treatment of additional revenue arising from volume thru' put as well as additional connections may be difficult. • Likely to involve tactical upgrades of many assets

Prevailing load growth

ENL's current demand growth falls mainly in Quadrants 1 and 2 as follows…

Quadrant 1

Areas such as Matawai, Raupunga, Waikaremoana and the semi-rural areas around Wairoa are quite clearly in this quadrant – there is little if any growth so investment tends to be dominated by Renewal i.e. assets "wear out" rather than get "too small". The potential for the population to decline particularly in the Wairoa District increases the risk of stranding assets.

Quadrant 2

Areas such Makaraka, Matawhero, the Gisborne industrial estate, the Kaiti / Port area of Gisborne and the Mahia Peninsula are clearly in this quadrant – growth is high but it is largely within or very close to the existing network footprint. As ENL further examines in section 4.3.2 the impending forestry maturity cycle could drive very significant growth around Matawhero over the next 5 to 20 years if the logs are processed in the district instead of simply exported.

Investment in this quadrant tends to be dominated by Up-sizing rather than Renewal i.e. Assets get "too small" rather than "wear out".

4.1.3 Trigger points for planning new capacity

Because new capacity has ODV, balance sheet, depreciation and ROI implications, ENL will meet demand by other, less investment-intensive means. This discussion also links strongly to the discussion of asset life cycle in section 5.1.

The first step in meeting future demand is to determine if the projected demand will exceed any of the defined trigger points for asset location, capacity, reliability, security or voltage. These points are outlined for each asset class in Table 4.1.3(a).

If and only if a trigger point is exceeded does ENL then move to identify a range of options to bring the assets' operating parameters back to within the acceptable range of trigger points. These options are described in section 4.2 which also defines a preference for avoiding new investment unless a commercial return is certain.

Table 4.1.3(a) – Summary of planning "trigger points"

Asset category	Location trigger	Capacity trigger	Reliability trigger	Security trigger	Voltage trigger
LV lines & cables	Existing LV lines and cables don't reach the required location.	Not applicable – tends to manifest as voltage constraint.	Operational performance/reliability outside industry stds.	Not applicable.	Voltage at consumers' premises consistently drops below 0.94pu.
Distribution substations	Substation is not efficiently located in relation to load.	Where fitted, MDI reading exceeds 80% of nameplate rating.	Operational performance/reliability outside industry stds.	Excursion beyond triggers specified in section 4.2.2	Voltage at LV terminals consistently drops below 1.0pu.
Distribution lines & cables	Load cannot be reasonably supplied by LV configuration therefore requires new distribution lines or cables and sub.	Conductor current consistently exceeds 66% of thermal rating for more than 3,000 half-hours per year. Conductor current exceeds 100% of thermal rating for more than 10 consecutive half-hours per year.	Operational performance/reliability outside industry stds.	Excursion beyond triggers specified in section 4.2.2	Voltage at HV terminals of transformer consistently drops below 10.5kV and cannot be compensated by local tap setting.
Zone substations	Substation is not efficiently located in relation to load.	Max demand consistently exceeds 100% of nameplate rating.	Operational performance/reliability outside industry stds.	Excursion beyond triggers specified in section 4.2.2	Distribution voltage depression cannot be compensated for locally
Sub-transmission lines & cables	Load cannot be reasonably supplied by distribution configuration therefore requires new sub-trans lines or cables and zone sub.	Conductor current consistently exceeds 66% of thermal rating for more than 3,000 half-hours per year. Conductor current exceeds 100% of thermal rating for more than 10 consecutive half-hours per year.	Operational performance/reliability outside industry stds.	Excursion beyond triggers specified in section 4.2.2	Voltage depression that cannot be compensated for at substations.

4.2 Prioritisation methodology

Development projects are prioritised in the following order of precedence…

Projects to address a short fall in demand from existing connections.
Projects to re-establish security levels following increases in demand.
Projects to provide for new load at existing connections
Projects to provide for new connections.

Where development projects are linked with other work the order of precedence above is qualified by consideration of the Action Plan Priorities Ranked by Risk Reduction Outcomes assessment in section 6.2.3.

4.2.1 Development Options for meeting demand

Table 4.1.3(a) defines the trigger points at which the capacity of each class of assets needs to be increased. Exactly what is done to increase the capacity of individual assets within these classes can take the following forms (in a broad order of preference)…

Defer while monitoring risk and simply accept that one or more parameters have exceeded a trigger point. This option would only be adopted if the benefit-cost ratio of all other reasonable options were unacceptably low and if assurance was provided to the chief executive that the option to defer did not represent an unacceptable increase in risk to ENL. An example of where this option might be adopted is where the voltage at the far end of a remote rural feeder is unacceptably low for a short period at the height of the holiday season – the benefits of correcting such a constraint are simply too low.

Operational activities, in particular switching on the distribution network to shift load from heavily-loaded to lightly-loaded feeders to avoid new investment or winding up a tap changer to mitigate a voltage problem. The downside to this approach is that it may increase line losses, reduce security of supply, or compromise protection settings.

Influence consumers to alter their consumption patterns so that assets perform at levels below the trigger points. Examples might be to shift demand to different time zones, negotiate interruptible tariffs with certain consumers so that overloaded assets can be relieved, or assist a consumer to adopt a substitute energy source to avoid new capacity. Currently the ability to implement Demand Side Management initiatives is somewhat hampered by lines companies not having direct relationships with end user customers.

Construct distributed generation so that adjacent assets performance is restored to a level below their trigger points. Distributed generation would be particularly useful where additional capacity could eventually be stranded or where primary energy is going to waste e.g. Waste steam from a process.

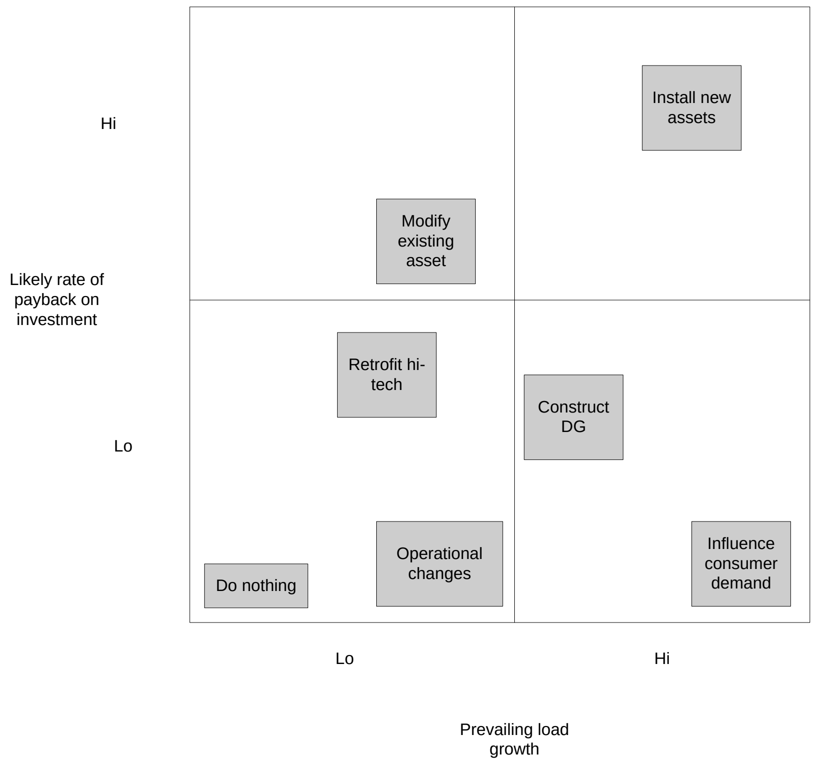
Modify an asset so that the assets trigger point will move to a level that is not exceeded e.g. by adding forced cooling. This is essentially a sub-set of the above approach, but will generally involve less expenditure. This approach is more suited to larger classes of assets such as 50/11kV transformers.

Retrofitting high-technology devices that can exploit the features of existing assets (including the generous design margins of a bygone era). Examples might be using remotely switched air-breaks to improve reliability, or using advanced software to thermally re-rate heavily-loaded lines.

Install new assets with a greater capacity that will increase the assets trigger point to a level at which it is not exceeded. An example would be to replace a 200kVA distribution transformer with a 300kVA so that the capacity is not exceeded.

In identifying solutions for meeting future demands for capacity, reliability, security and voltage ENL considers options that cover the above range of categories. The benefit-cost ratio of each option is considered (including estimates of the benefits of environmental compliance and public safety) and the option yielding the greatest benefit is adopted. ENL uses the model in figure 4.2.1(a) to broadly guide ENL’s adoption of various approaches…

Figure 4.2.1(a) – Options for increasing capacity



4.2.2 Development options for meeting security requirements

A key component of security is the level of redundancy that enables supply to be restored independently of repairing or replacing a faulty component. Typical approaches to providing security to a zone substation include…

Provision of an alternative sub-transmission circuit into the substation, preferably separated from the principal supply by a bus-tie.

Provision to back-feed on the 11kV from adjacent substations where sufficient 11kV capacity and interconnection exists. This obviously requires those adjacent substations to be restricted to less than nominal rating.

Use of local generation.

The most pressing issue with security is that it involves a level of investment beyond what is obviously required to meet current demand. In general it is necessary to allow increases in demand to erode security levels beyond trigger levels thereby increasing risk, then invest in new asset to restore the security levels and allow for future growth. Hence demand growth and security essentially overlap throughout the development cycle.

4.2.2.1 Prevailing security standards

The commonly adopted security standard in New Zealand is the EEA Guidelines which reflect the UK standard P2/5 that was developed by the Chief Engineer's Council in the late 1970's. P2/5 is a strictly deterministic standard i.e. It states that "this amount and nature of load will have this level of security".

Deterministic standards have largely given way to probabilistic standards in which and the failure rate of supply components is estimated to determine the impact on performance targets providing comparative investment levels between multiple projects, to avoid interruption. The disadvantage of this approach is that, in terms of investment cost to performance improvement, investment in remote groups of connections rather than a single large industrial connection is favored. This is balanced by weighting the decisions based on the importance of the load to the wider community eg. Pumps, Hospitals and Schools and the contribution/income provided by the large single customer loads. The risk matrix approach shown in section 6.3 is used to assess or balance the decisions relating to security standards.

4.2.2.2 Issues with deterministic standards

A key characteristic of deterministic standards such as P2/5 and the EEA Guidelines is that rigid adherence generally results in at least some degree of over investment.

4.2.2.3 Contribution of local generation to security

To be of any use from a security perspective, local generation would need to have 100% availability which is unlikely from a reliability perspective and even less likely from a primary energy perspective such as run-of-the-river hydro, wind or solar. For this reason the emerging UK standard P2/6 provides for minimal contribution of such generation to security.

4.2.2.4 ENL's security standards

ENL's security standards below provide the base security criteria applied to all network design.

Class	Range of group peak demand (GPD) MVA	No. of customers effected	Security Level	Contingent Capacity	Time to restore after 1st event	Time to restore after 2nd event
D	More than 25MVA i.e. transmission, or sub-transmission rings .	15,000 or more	n-1	100%	Maintain 100% GPD less 12MVA. Remaining 12MVA restored within 3 hours.	Repair time.
C	Between 12 and 25 MVA ie. small GXP, primary CBD & urban substations	7,000 to 15,000	n-1	100%	Maintain 100% of GPD.	Restore 90% of GPD within 3 hours and remaining 10% in time to repair.
B1	Between 6 and 12 MVA ie. Primary urban or industrial substations.	3,500 to 7,000	n	100%	Restore 75% of GPD within 15 min, restore 90% within 3 hours, and remaining 10% in time to repair.	Within 3 hrs restore 90%, repair time 100%
B2	Between 3 and 6 MVA ie. single transf subs and urban meshed feeders	1,750 to 3,500	n	80%	Restore 75% of GPD within 30 minutes, 90% within 3 hours and remaining 10% in time to repair.	Restore 100% in time to repair.
B3	Between 1 and 3 MVA ie. rural zone substation, meshed feeders.	500 to 1,750	n	67%	Restore 50% of GPD within 1 hour, 90% within 3 hours, and remaining 10% in time to repair.	Restore 100% in time to repair.
A	Less than 1MVA ie. rural feeders, urban spurs, distribution transformers	Less than 500	n	Note 1	Restore 100% in time to repair.	Restore 100% in time to repair.

Note 1 - refer to ENL's Customer Service Standards for LV Network backup, dual distribution transformer capacity or temporary supply criteria. Temporary options include construction of prefabricated OH lines, HV or LV flexible surface jumpers or 300kVA generator supplies.

The following table confirms that ENL's target security levels are being met at Major substation level, for the forecast loads over the planning period…

Sub.	Applicable security level	Projected 2021/22 load	Additional provision for security
Gisborne Transmission Substation	D	Load is projected to exceed the 110kV line around 2018 in shoulder periods. Transformer capacity is not forecast to be exceeded until 2023	Further detailed investigation is planned in respect of the actual level of security and capacity provided by the 110kV lines.
Carnarvon Substation	C	Load well within 11kV back-feeding capacity from Parkinson & Port.	None required
JNL Substation	B1	Load within 11kV support capacity from adjacent Matawhero and Parkinson Substations.	None required
Kaiti Substation	C	Load within 11kV support capacity from adjacent Port Substation.	Possibility that in the long term not all Kaiti load could be back-fed on the 11kV from Port. Single transformer is a recognised point of weakness.
Makaraka Substation	B1	Expected load not expected to exceed transformer capacity	In Medium term opportunities to provide additional support capacity from Matawhero/JNL are a consideration.
Matawhero Substation	C	Expected load well within capacity	None required
Ngatapa Substation	B3	Expected load well within capacity	None required
Parkinson Substation	C	Expected load well within capacity	None required
Patutahi Substation	B1	Expected load well within capacity of either transformer.	None required.
Pehiri Substation	B3	Expected load well within capacity	None required.
Port Substation	C	Expected load well within capacity	None required.
Puha Substation	B2	Expected load within capacity but only 1 transformer	Security provisions will be required potentially from Ngatapa
Ruatoria Substation	B3	Expected load well within capacity of diesel generator and 11kV back-feeding capability.	None required.
Te Araroa	B3	Expected load can be totally	None required.

Substation		supplied by diesel generator.	
Tokomaru Substation	B3	Expected load well within capacity of diesel generator and 11kV back-feeding capability.	None required.
Tolaga Substation	B3	Expected load well within capacity of diesel generator and 11kV back-feeding capability.	None required.
Blacks Pad Substation	B3	New substation planned	Sub-transmission development
Wairoa Substation	C	Load is project to exceed transformer firm capacity by 1MW in 2015 under an n-1 scenario	The current load can be managed operationally via load control and generation. The Wairoa assets are approaching end-of-life and are being scheduled for replacement and additional capacity will be provided at this time.
Kiwi Substation	B2	Expected load will require reconfiguration	Upgrade feeder assets
Tahaenui Substation	B3	Expected load well within capacity	None required
Waihi Substation	B2	Expected load within capacity	None required
Tuai Substation	A	Expected load will never merit any alternative supply other than the possibility of re-locating a diesel generator if an outage looked prolonged.	None required.

4.2.2.5 Guiding ENL's security policy

The following philosophies are fundamental to meeting ENL's security standards in the design of any network component…

ENL's network is a low density, lightly loaded, distribution network. In a network of this character the provision of security via full redundancy can rarely be justified, is not cost efficient, and does not offer the best fault tolerance.

Having said that, the preferred method of providing contingency supply will be via excess capacity in adjacent network components.

Transformer loading for both zone and distribution transformers shall comply with IEC 354 which permits short duration overloads beyond nominal ratings under specified ambient and cyclical conditions.

Alternative supply options will be built at the lowest voltage practical due to better inherent fault tolerance and flexibility with respect to interconnection.

Cables will not be loaded into duty cycle levels of loading. Legacy jointing practices and installation design do not provide for this mode of operation.

Preference will be given to ring design for an alternative route instead of double spur circuits.

In rural spur networks the density of isolation points will be used to localize the effects of faults, to achieve customer service standards.

4.2.2.6 Specific security provisions

Transmission and Sub-transmission

(n-1) circuit security will be provided for all lines, cables, and equipment where loading exceeds 12MVA.

Breakers' will be rated at 2x expected max demand to enable carrying of adjacent feeder loads.

33kV and 50kV CB's shall only be fitted with bypassing arrangements when supplying a spur line. This is to allow maintenance or repairs with the substation(s) on-line.

Transmission/Subtransmission Substations

Transformer loading is to comply with IEC354. This permits overloading beyond nominal ratings under specified ambient and cyclical conditions. Thus the duration of restoration following a first interruption will result in no ageing beyond design provisions. Overloading of transformers such that ageing occurs will only be permitted for a second contingent event of up to 1 hour.

Loading shall never exceed 120% of the transformers design rating or the lesser of limits imposed by cabling.

All connections and auxiliary equipment shall be rated for continuous operation at maximum load levels.

Transformers will be rated to support a minimum of half the loading of neighbouring zones.

Installation of forced or assisted cooling will be used in preference to dual transformer installations or capacity upgrades where overload is required beyond IEC354 for contingent events.

Substations carrying normal load in excess of 12MVA will be of dual transformer designs if it is unlikely that neighboring substations or feeder circuits will be able to support that substation after allowing for 10 years growth.

11kV switch panels will have a split bus arrangement where maximum demand is likely to exceed 6MVA. In single transformer substations the incomer and the tie line to the adjacent substation shall be connected on opposite sides of the bus-tie. This ensures that at least one side of the 11kV bus can be energised.

Urban 11kV feeder CB's shall not be normally loaded beyond 4MVA to allow sufficient capacity to pick up 2MVA from an adjacent feeder. The tie feeder between Carnarvon St and the Port area requires an 8MVA rating.

Feeder cables from CB's must be rated to match CB excess capacity requirements which will typically be 6MVA in the urban, CBD or industrial area. In rural areas feeder cables shall be rated to 3MVA.

All feeder circuits must have a tie switch external to the substation to another circuit from the opposite side of the bus or ties to a feeder from an adjacent substation.

Distribution

11kV circuits provide security via excess capacity, interconnection and isolation ability i.e. the focus is on restoration speed and contingency provision as opposed to un-interruptible supply. Generally excess capacity and provision of mobile generation provide LV circuit security. In key commercial and industrial areas LV interconnection may be appropriate. Generally the installation of remote or automatically operated equipment shall be governed by the response times determined in section 4.2.2.4.

11kV pad mounted switchgear provisions…

No more than 3 transformers supplied from 1 switchboard without bus section.

Not more than 1MVA fed from switchgear supplied from a single cable circuit (excluding industrial situations).

No more than 1MVA of installed transformers and associated switchgear cascaded with no back feed.

Not more than 1 cable circuit connected directly to the bus of a switchboard arrangement.

In rural areas an air break switch will be installed to provide an isolation point every 50 customers or 25km of downstream circuit.

Cables will be designed with 33% excess capacity to enable sharing of half the load of the connecting circuit where there are two alternative supply routes.

Where overhead lines have back-feed capability they will be permitted to operate to 120% capacity in emergencies. Therefore they will be designed for sag and clearances appropriate to the maximum conductor operating temperature rather than 50^0C provided this does not exceed 75^0C.

Lines will not be permitted to have more than 2% losses at installation.

Spur assets (lines, cables, transformers) that cannot be supported via the LV network will have provisions for quick connect standby generation if normal loading exceeds 200kVA.

Distribution transformers (less than 1,000kVA) will be permitted to overload to the ratings of IEC354.

In commercial and industrial areas…

General distribution transformers will normally be 500kVA units. All cables shall be rated to allow loading of the transformer to 120%. This would provide overload capacity for 6 hours in winter peak areas at 20^0C (10 hours at 10^0C) and for 3 hours in summer peak areas at 30^0C given an initial loading at 80%. Actual load profiles for a given transformer where initial loading is less than 80% will enable extension to the period of overload.

LV interconnection shall normally be specified to allow for an out of service condition of an intermediate transformer. Where LV-interconnected, transformers should not exceed (other than for short duration's of less than 1 hour) 80% of their rating under normal operating conditions.

LV runs from transformer to an open tie point should not exceed 200m (400m from transformer to transformer).

Loads in industrial areas greater than 50kVA should have a dedicated LV feed.

In urban domestic supply areas including small commercial areas located predominantly within an urban area…

Transformer size should be standardised to 200kVA in winter peak areas with cables rated to allow loading of the transformer to 133% and to 300kVA in summer peak areas with cables rated to allow loading of the transformer to 100%.
Each LV feeder should not be supporting more than 25 domestic supplies assuming an ADMD of 3kVA.

LV interconnection would normally only be provided where a small commercial shopping center is located within a predominately urban area. 300kVA transformers may be required.

Provision of quick mobile substation connections to the LV is preferred to the provision of LV interconnection.

Transformers must be able to be isolated from LV bus bars via incomer links where LV interconnection to another transformer is provided.

4.2.3 Development Funding

There are a number of options available to ensure ENL is able to fund and resource development projects. Typically new load and network extension projects are funded by the requesting company or developer who has the option of selecting local or national resources to establish the required assets. This arrangement usually applies to projects in categories 3 and 4 above and in some cases to category 2 hence the likelihood that ENL will be faced with insufficient funding or resources to achieve projects in category 1 is very low. Should the rate of development ever increase beyond ENL's capabilities then deferral of new load is a final option.

4.2.4 Choosing the option

The level of analysis is guided by the bottom row of Table 4.1.2(a). In particular, the underlying principles will be reused for sufficiently similar circumstances, whilst for new situations previous principles with suitable modifications are applied.

Broadly the cheapest option that meets minimum consumer needs, safety and environmental standards and revenue constraints will be chosen and modified to suit particular circumstances such as likely future load growth. The asset management risk assessment tool (refer 6.2.3) is used to determine the relative priority of both development options and renewal plans in terms of activity category and identified projects.

4.3 Demand forecast

4.3.1 Current demand

ENL's current after diversity maximum demand (ADMD) at the Tuai GXP Substation for the 2013/2014 financial year was 53.32MW. This demand is disaggregated to the Gisborne and Wairoa Region demands below.

The system demand figures including embedded generation are-

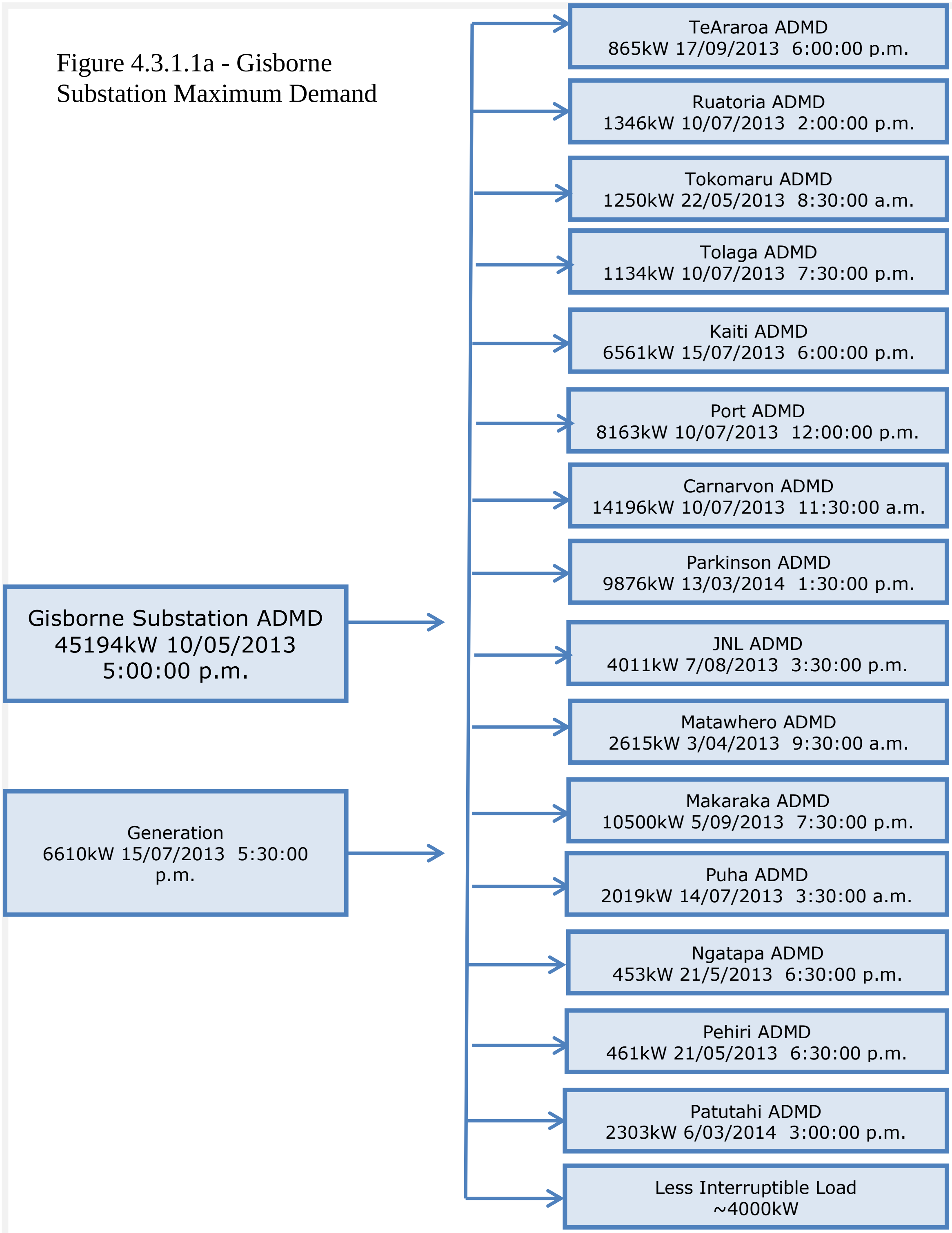
Gisborne Region	50.296MW	10/07/2013	5:00:00 p.m.
Wairoa Region	10.604MW	29/11/2013	11:30:00 a.m.

System Total 59.851MW 10/07/2013 5:00:00 p.m.

4.3.1.1 Gisborne Region

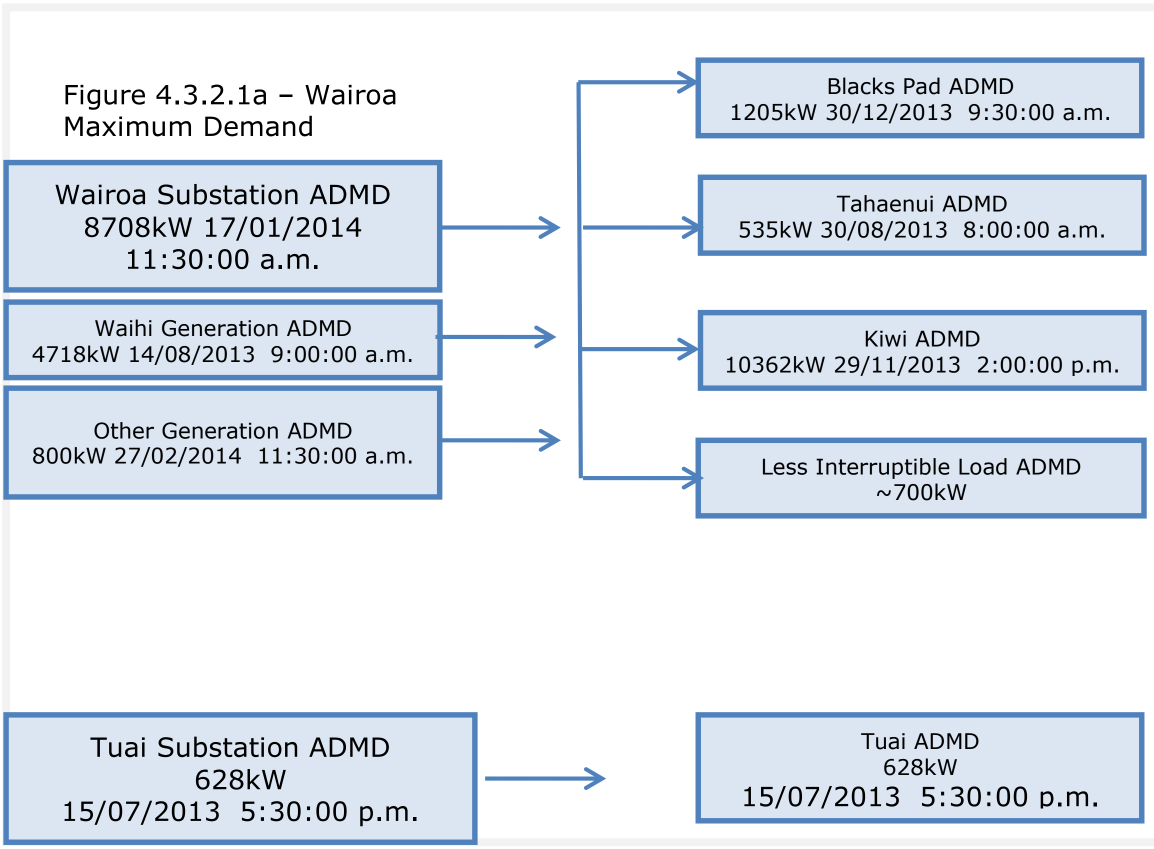
The current after diversity maximum demand (ADMD) at Gisborne Substation for the 2013/2014 financial year was 45.194MW, This demand is disaggregated in Figure 4.3.1.1(a).

Figure 4.3.1.1a - Gisborne Substation Maximum Demand



4.3.1.2 Wairoa

ENL's current after diversity maximum demand (ADMD) at Wairoa Substation for the 2012/2013 financial year was 8.708MW and for the Tuai Substation 0.628MW, which is disaggregated in Figure 4.3.1.2(a).



4.3.1.3 Demand Management Initiatives

The main initiatives that have had a measurable impact on the Gisborne and Wairoa Substations is the use of embedded generation and the Load control plant.

Use of embedded distributed generation has reduced the GXP peak demand by 10MW at the GXP. Given the installed capacity of generation totals 13MW this indicates less than 65% of the generation potential was able to be realised.

Use of load control to manage demand is likely to have contributed less than 2MW of reduction to the total peak demand. As metering equipment is not setup to measure the demand that wasn't supplied

the measurement of load control demand effectiveness can only be determined by extrapolation of the daily demand profile curves (refer section 4.7.1.3) over the flat area for times where load control was active.
Demand management initiatives that do not have a measurable impact are generally undertaken by customers with external Energy consultants providing the technical expertise. As ENL wishes to encourage any initiatives no notification barriers are imposed on the activities. Hence ENL is often not advised of activities been undertaken. Examples of three initiatives ENL is aware of are…
Replacement of the compressor drives with variable speed drives on Eastland Groups cool store. This initiative produced only a slight demand reduction but the reduction in energy usage was of the order of 20%.
Solar hot water cylinder upgrades at TePuia Springs. This project involved the installation of a solar hot water system with traditional element backup. While there was a resulting reduction in energy usage there was an increase in demand as the original hot water cylinders with 1kW elements were replaced with cylinders containing 3kW backup elements. As the backup elements are typically needed at times coincident with the maximum demand the expectation of reduced demand was not realised.
The Mahia Sewage schemewas installed in 2013. The scheme uses small pumps on each installation to take advantage of diversity and avoid peak loading often seen when large pumps are used.

As the following forecasts provided in this section rely heavily on historical trends and involve a high degree of aggregation, minimum and maximum demand forecasts are provided which take into account any demand reduction initiatives that may occur.
As discussed in the development section 4.7.1.4 there is a limit to the extent that demand initiatives can be effective which occurs when the demand profile flattens.
Future demand initiatives targeting a shift in consumption from day to the period between 12:00am and 4:00am at night will have the biggest impact on demand. Currently no initiatives to achieve this have been identified.

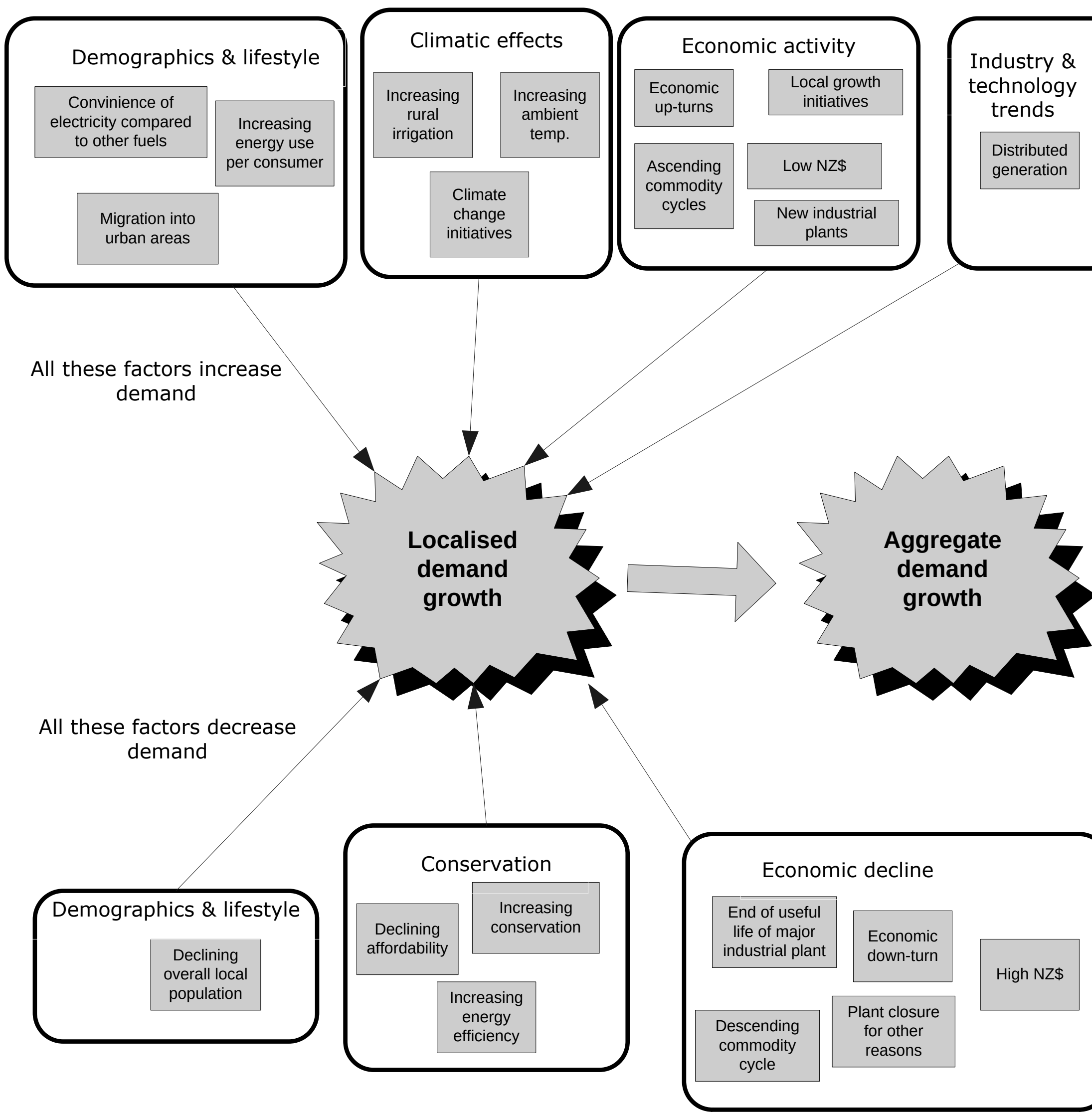
4.3.1.4 Demand Management Impact on Forecasts

As described in 4.3.1.3 above measurable Impacts on demand initiatives to date equate to approximately 10% of the regional peak demands. As the natural variation due to environmental conditions is of this order no impact on demand forecasts has occurred.

4.3.2 Drivers of future demand

Key drivers of demand growth (and contraction) are depicted in Figure 4.3.2(a) below.

Figure 4.3.2(a) – Drivers of demand



At a localised level (11kV feeder) one or two of these issues will generally predominate, will be predictable and manageable, and can be aggregated into a reasonably reliable feeder demand forecast. The estimates of future demand are described in section 4.3.3 below.

The following section examines in detail what ENL believes will be the most significant drivers of its network capacity and configuration over the next 15 to 20 years…

4.3.2.1 Maturing forestry

Expected processing volumes

The predominant economic growth for the region is expected to be linked to forest harvesting. The Ministry of Agriculture and Forestry's forecasts of the total recoverable volume of logs through to 2040 indicate current log volumes are expected to triple to around 2.5 million m^3 within 5 years, and increase still further to around 3.5 million m^3 approximately 10 years after that.

Likely distribution requirements

The existing JNL mill can be expanded to accommodate approximately 36% additional throughput but beyond that additional harvest volumes will require additional mills. On the assumption that the ratio of raw log exports to the total harvest volume remains approximately the same further mills may be required, A large mill would probably have a combined heat & power ("CHP") unit fuelled primarily by waste wood and boosted by gas to deliver the larger part of its gross energy requirements.

The electricity load requirements associated with new plants in close proximity are likely to be between 7 to 10 MW if they are similar to the existing JNL mill. The network around Matawhero where processing plants are most likely to locate will therefore need to supply an additional 10 MW.
ENL are not aware of any expansion plans at this time.

Likely sub-transmission requirements

Impacts on the sub-transmission network would of course be greater and reflect the aggregated regional load increase, perhaps in the order of 25 to 30MW. This additional demand could be minimised through embedded CHP plants exporting surplus power to the distribution network.

Knock-on community economic growth

The Tarawhiti Development Taskforce report estimates that forest harvesting and processing could ultimately over time generate 15,000 – 20,000 additional jobs in the region. Additional connections and community prosperity would be almost certain to drive increased domestic consumption.

Possible investment risks

On a final note, the regional benefits and anticipated increases in load will be limited if most logs are exported unprocessed, and this constitutes a real investment risk to ENL given that historically the New Zealand forestry sector has exported raw logs.

4.3.2.2 Regional natural gas reserves

Undeveloped gas resources existing in the region could be a source of relatively cheap electricity generation in the Gisborne and Wairoa regions and radically alter net power flows. New gas-fired generation could also significantly reduce net power imports at Gisborne Substation. Given the high costs of augmenting the double circuit 110kV line supplying Gisborne Substation, the Vector high-pressure gas main from Opotiki, local gas supplying local generation could provide cheap and stably-priced electricity.

Current issues associated with the development of gas-fired generation is difficulties associated in securing price surety for long term gas supply and current EIRA restrictions on distribution company involvement in generation and retailing.

4.3.2.3 Changes In Technology

Advances in generation technology that replace the need for network capacity are already emerging and will almost certainly be a commercial reality by 2017. The need for investment in network assets with an economic 40 year life (but a practical life of about 70 years) is therefore clearly subject to challenge. This is particularly true of capacity investment in the remote rural network, where small scale distributed generation is potentially more economical.

Transmission and distribution lines exist for the sole purpose of transporting electricity from where it is generated to where loads are located. Logically, if generation could be moved closer to loads, then there would be less need for transmission and distribution. In this sense, new generation "competes" with electricity lines businesses/investments. This is particularly true of distributed generation (and direct substitutes such as direct solar water heating). Larger embedded generation plants are less of a threat for distribution networks, but pose a significant risk of bypass for transmission networks. These technologies can also be used as substitutes for network upgrades.

Potential new generation around Gisborne includes new biomass generation to accompany additional forestry mills, larger biomass plant(s) that would produce more power than required by the mills, gas generation plant to take advantage of surplus capacity in the Vector pipeline or new gas discoveries, small gas turbines and hydro that could be operated as peaking plant to reduce peak demand, and other renewables such as the high wind and solar resources in the region.

ENL may have the opportunity to use embedded and distributed generation to reduce the need for transmission and distribution upgrades, and can also re-engineer its network during the current upgrade program so that it is more suitable for a distributed generation environment. These issues are the subjects of a development strategy in preparation to minimise investment risk and lower electricity supply costs.

Conversely where the scale of any distributed generation is greater than the local load the generation surplus at any location may require line upgrades and/or distribution or transmission solutions in addition to the existing lines. While this would not result in a reduction in the local region long term benefits remain at the transmission or national level.

Introduction of smart metering systems by some Energy Retailers active in the region is progressing. The impact of this technology is currently too small to identify the effects on energy and demand measurements.

While smart meters are expected to reduce energy and demand, any benefit will require end users to change their behaviour patterns before any change will occur. This is particularly true for the domestic market.

4.3.3 Estimated Distribution Feeder demands

As outlined in detail in the remainder of section 4, ENL expects its future demand to vary from the current demand as follows…

Some growth within the existing network footprint in the Kaiti / Port area, the Gisborne industrial estate and the Mahia Peninsula.

A low rate of growth within or very close to the existing network footprint at Matawhero if the impending forest harvest is processed locally.

Possible contraction of demand along the east coast north of Gisborne.

Possible contraction of demand in the rural parts of the Wairoa District other than Mahia.

ENL's collective experience strongly indicates that it would be rare to ever get more than a few months confirmation (sufficient to justify significant investment) of definite changes in an existing or new major consumers demand. This is because most of these consumers operate in fast-moving consumer markets and often make capital investment decisions quickly themselves, and they generally keep such decisions confidential until the latest possible moment. Probably the best that ENL can do is to identify in advance where the network has sufficient surplus capacity to supply a large chunk of load, but as experience shows industrial location decisions rarely if ever consider the location of energy supply – they tend to be driven more by land-use restrictions, raw material supply and transport infrastructure.

This section examines each of ENL's Subtransmission substations at a feeder level in regard to the issues identified above and provides a 10 year projection of demand, determined using ENL's collective experience, for each sub and what provision for growth if any is required.

4.3.3.1 Gisborne Reigon

Carnarvon St Substation

Feeder	Rate & nature of growth	Provision for growth

Aberdeen	Typical domestic commercial mix Medium	None required
Anzac	Typical domestic commercial mix Medium	None required
Awapuni	Typical domestic commercial mix Medium	None required
Childers	Typical domestic commercial mix Medium	None required other than for security
City	Swings in growth due to cyclic prosperity in CBD	None required other than for security
Gladstone	Typical domestic commercial mix Medium	None required other than for security
Kahutia	Swings in growth due to cyclic prosperity in CBD	None required
Palmerston	Typical domestic commercial mix Medium	None required other than for security
Watties	Commercial subject to lumpy change	None required
Sub	High, less lumpy than industrial subs but still dependent on retail cycles. Likely to exhibit load shifts between feeders.	None required – projected 10 year load is expected to be only 65% of capacity.

JNL Substation

Feeder	Rate & nature of growth	Provision for growth
JNL	Large step changes Moderate	Non required
Matawhero Tie	Provides for security only	Non required
Sub	Moderate	Non required

Kaiti Substation

Feeder	Rate & nature of growth	Provision for growth
Dalton	Domestic Medium	Non required
Delatour	Domestic load increases rather than new load	Non required
Hershell	Domestic Medium	Non required
Tamarau	Domestic Medium	Non required
Wainui	Domestic Medium	Non required
Whangara	Domestic Rural Low to Medium	Growth constrained intermediate zone sub considered
Sub	Moderate, reasonably diverse and predictable as this is largely domestic.	Projected 10 year load is expected to be about 95% of capacity, Expect to off-load 3MW or 4MW to Port. If large growth in Wainui possibly establish Whangara substn (2.5MVA), 2013 -15.

Makaraka Substation

Feeder	Rate & nature of growth	Provision for growth
Bushmere	Lifestyle Rural medium	None required
Campion	Lifestyle domestic High	None required
Haisman	Lifestyle domestic High	None required
Nelson	Lifestyle domestic High	None required
Sub	High	Projected 10 year load just exceeds 100% of capacity. Off-loading 2MW or 3MW to Patutahi is an option. If high subdivision growth in Linton West/Nelson Rd possibly establish Mangapapa substn (12.5MVA) 2017 -2020.

Matawhero Substation

Feeder	Rate & nature of growth	Provision for growth
Bell	Industrial Rural medium	None required
Dunstan	Industrial Rural medium	None required
JNL A	Security Tie	None planned
Manutuke	Industrial load new load forecast	None required
Waipoa	Industrial load new load forecast	None required
Sub	Very high	Projected 10 year load is expected to be 85% of capacity. Offset by and secures JNL sub.

Ngatapa Substation

Feeder	Rate & nature of growth	Provision for growth
Ngatapa	Rural minimal	None required
Tahora	Rural minimal	None required
Totangi	Rural minimal	None required
Sub	Low, vulnerable to single large load being a high percent of existing surplus capacity.	Security Provision planned – projected 10 year load is expected to be only 60% of capacity under existing normal conditions

Parkinson Substation

Feeder	Rate & nature of growth	Provision for growth
Cedenco	Industrial Low	None required
Chalmers	Domestic Low	None required
Elgin	Domestic Low	None required

Innes	Industrial Steady but Lumpy increases	None required
Lytton	Domestic Low	None required
Solandis	Domestic Low	None required
Willows	Security Tie Low	None required
Sub	Low, potentially lumpy and uncertain due to medium sized industrial loads.	None required – projected 10 year load is expected to only be 65% of capacity.

Patutahi Substation

Feeder	Rate & nature of growth	Provision for growth
Lavenham	Rural Mix Low	None required
Muriwai	Rural Mix Low	None required
Te Ari	Rural Mix Low with large load	No needs identified
Waimata	Rural Mix Low	None required
Sub	Low.	None required – projected 10 year load is expected to be only 33% of capacity. Could take about 3MW of load from Makaraka and Matawhero if necessary.

Pehiri Substation

Feeder	Rate & nature of growth	Provision for growth
Parikania	Rural Mix Low	None required
Tahunga	Rural minimal Rural Mix Low	None required
Tiniroto	Rural Mix Low	None required
Warenga	Rural minimal	None required
Sub	Low.	None required – projected 10 year load is expected to be only 30% of capacity.

Port Substation

Feeder	Rate & nature of growth	Provision for growth
Crawford	Domestic Low	None required
Esplanade	Commercail load new load forecast	None required
Harris	Domestic Low	None required
Port	Industrial load Low	None required
Sub	Low.	None required – projected 10 year load is expected to be only 15% of capacity, so there is scope to shift about 9MW on to Port from Kaiti or Carnarvon.

Puha Substation

Feeder	Rate & nature of growth	Provision for growth
Kanikania	Rural growth generally low. Small increases significant in terms of total load one significant load at end of line.	None Required
Matawai	Stable Township no growth	None Required
Te Karaka	Stable township possible decrease offset by outlying lifestyle blocks	None Required
Whatatutu	Rural growth generally low. Small increases significant in terms of total load	None Required
Sub	Low. Large step increase in load experienced in 2009 due to addition of distributed generation with var requirement.	None required – projected 10 year load is expected to be only 45% of capacity.

Ruatoria Substation

Feeder	Rate & nature of growth	Provision for growth
Makariaka	Rural growth generally low. Small increases significant in terms of total load	None Required However security support limited.
Ruatoria	Stable Township. Growing slowly	None Required
Tikitiki	Rural growth generally low. Small increases significant in terms of total load	None Required
Sub	Low.	None required – projected 10 year load is expected to be only 33% of capacity.

Te Araroa Substation

Feeder	Rate & nature of growth	Provision for growth
Awatere	Rural growth generally low. Small increases significant in terms of total load	None Required
Hicks	Rural growth generally low. Small increases significant in terms of total load	None Required
Te Araroa	Stable Township	None Required
Sub	Low, vulnerable to single large load being a high percent of existing surplus capacity.	None required – projected 10 year load is expected to be only 35% of capacity.

Tokomaru Bay Substation

Feeder	Rate & nature of growth	Provision for growth
Inland	Rural growth generally low. Small increases significant in terms of total load	None Required however security support necessary.
Mata	Rural growth generally low. Small increases significant in terms of total load	None Required however security support necessary.
Seaside	Rural growth generally low. Small increases significant in terms of total load	None Required
Sub	Low, vulnerable to single large load being a high percent of existing surplus capacity.	None required – projected 10 year load is expected to be only 45% of capacity.

Tolaga Bay Substation

Feeder	Rate & nature of growth	Provision for growth
Rototahi	Rural growth generally low. Small increases significant in terms of total load	None Required
Tauwhare	Rural growth generally low. Small increases significant in terms of total load	None Required
Tokitie	Rural growth generally low. Small increases significant in terms of total load	None Required however security support necessary.
Town		
Sub	Low.	None required – projected 10 year load is expected to be only 37% of capacity.

4.3.3.2 Wairoa Reigon

Blacks Pad Substation

Feeder	Rate & nature of growth	Provision for growth
Mahia feeder	High, spread amongst life-style blocks, holiday homes and dairy conversions. Holiday homes add a peaky aspect to the load which makes recovery of investment awkward.	Already using one 1MWe diesel generator to support both load and voltage. Plans to provide additional network capacity by moving Blacks Pad closer to the Mahia load and install a larger 33/11kV transformer in place.
Sub	High, spread amongst life-style blocks, holiday homes and dairy conversions. Holiday homes add a peaky aspect to the load which makes recovery of investment awkward.	Already using one 1MWe diesel generator to support both load and voltage. Plans to provide additional network capacity by moving Blacks Pad closer to the Mahia load and install a larger 33/11kV transformer in place.

Wairoa Substation

Feeder	Rate & nature of growth	Provision for growth
Kiwi A	Low Growth Region	At capacity 33kV upgrade necessary
Kiwi C	Low Growth Region	At capacity 33kV upgrade necessary
Sub supply to Mahia	Low Growth Mahia	None required
Sub	Low Growth Region	

Kiwi Substation

Feeder	Rate & nature of growth	Provision for growth
AFFCO	Unpredictable	At limit
Borough 1	Low Growth Township	Approaching secure limit
Borough 2	Low Growth Township with industry	Approaching secure limit
Brickworks	Little if any	Voltage constrained at far end, so any remote growth would require either re-conductoring or adopting of 22kV.
Kiwi B	Supplies Mahia	None required
Nuhaka	Little if any	Voltage constrained at far end, so any remote growth would require either re-conductoring or adopting of 22kV.
Waihi	Generator - no increase expected	None Required
Sub	Non Required Supplies Waihi Substation	None Required

Tahaenui Substation

Feeder	Rate & nature of growth	Provision for growth
Morere feeder	Minimal if any growth. Load can peak if used to back feed Blacks Pad or the Nuhaka feeder.	None required
Sub	Minimal if any	Non required.

Tuai Substation

Feeder	Rate & nature of growth	Provision for growth
Lake	Little if any	None required
Ruatikuri	Little if any	Distance main issue Voltage regulator or capacitors beyond current planning period
Sub	Minimal if any.	Non required.

Waihi

Feeder	Rate & nature of growth	Provision for growth
Waihi Sub	Nil – takes injected generation from	None required.

	Waihi hydro.	

4.3.4 Estimated demand aggregated to Transmission and Subransmission Substation level

4.3.4.1 Gisborne Region

Sub.	Rate & nature of growth	Provision for growth
Gisborne 110kV/50kV	Low	Load is projected to exceed the 110kV line supplying the Gisborne 110kV during shoulder periods. Transformer capacity is not forecast to be exceeded until 2023. Development options identified in Development Program. Need another 110kV circuit from Tuai to Gisborne to provide (n-1) security at current demand, and will require a second additional 110kV circuit to meet demand growth. Would be useful to build a new Subtransmission Substation near Matawhero or Makaraka instead of terminating any new lines at Gisborne Substation.
Carnarvon	Low, less lumpy than industrial subs but still dependent on retail cycles. Likely to exhibit load shifts between feeders.	None required – projected 10 year load is expected to be only 65% of capacity.
JNL		
Kaiti	Low, reasonably diverse and predictable as this is largely domestic.	Projected 10 year load is expected to be about 95% of capacity, so expect to off-load 3MW or 4MW to Port.
Makaraka	Low	Projected 10 year load just exceeds 100% of capacity. Off-loading 3MW or 4MW to Patutahi would be a key option.
Matawhero	Low	Projected 10 year load is expected to be 85% of capacity. JNL new sub
Ngatapa	Low, vulnerable to single large load being a high percent of existing surplus capacity.	None required – projected 10 year load is expected to be only 60% of capacity.
Parkinson	Low, potentially lumpy and uncertain due to medium sized industrial loads.	None required – projected 10 year load is expected to only be 65% of capacity.
Patutahi	Low.	None required – projected 10 year load is expected to be only 33% of capacity. Could take about 6MW of load from Makaraka and Matawhero if necessary.

Pehiri	Low.	None required – projected 10 year load is expected to be only 30% of capacity.
Port	Low.	None required – projected 10 year load is expected to be only 15% of capacity, so there is scope to shift about 9MW on to Port from Kaiti or Carnarvon.
Puha	Low.	None required – projected 10 year load is expected to be only 45% of capacity.
Ruatoria	Low.	None required – projected 10 year load is expected to be only 33% of capacity.
Te Araroa	Low, vulnerable to single large load being a high percent of existing surplus capacity.	None required – projected 10 year load is expected to be only 35% of capacity.
Tokomaru	Low, vulnerable to single large load being a high percent of existing surplus capacity.	None required – projected 10 year load is expected to be only 45% of capacity.
Tolaga	Low.	None required – projected 10 year load is expected to be only 37% of capacity.

4.3.4.2 Wairoa Region

Sub.	Rate & nature of growth	Provision for growth
Wairoa 110kV Substation	Low	Load can exceed transformer firm capacity under an n-1 scenario. The current load can be managed operationally via load control and generation. The Wairoa assets are approaching end-of-life and are being scheduled for replacement and additional capacity will be provided at this time. Replacement with110/33kV Transformers likely.
Wairoa 33kV Substation	Linked to Mahia Growth	Non Required
Blacks Pad Substation	Low at limit, spread amongst life-style blocks, holiday homes and dairy conversions. Holiday homes add a peaky aspect to the load which makes recovery of investment awkward.	Already using one 1MWe diesel generator to support both load and voltage. First step to provide additional network capacity has been to move Blacks Pad closer to the Mahia load, next step will be install a larger 33/11kV transformer.
Kiwi Substation	Likely growth is almost totally big industrial and therefore lumpy and difficult to forecast.	Additional growth complication is that the Nuhaka - Frasertown and Brickworks - Raupunga feeders are very long (and hence voltage constrained) so any significant load growth on either of these feeders would

		require 11kV reinforcement as well as augmenting Kiwi.
Tahaenui Substation	Minimal if any growth. Load can peak if used to back-feed Blacks Pad or the Nuhaka feeder.	Non required.
Waihi Substation	Nil – takes injected generation from Waihi hydro.	None required.
Tuai Substation	Minimal if any.	No provision for growth is required and no constraints on growth exist.

4.3.4.2 Subtransmission Substation Growth

Transmission and Subtransmission substation capacities and present loads are shown in the following table. The loads shown are half hour maximum demands with normal load control policy in effect. Reductions at some sites compared with previous years are caused by imbedded generation reducing the burden on the substation Transformer assets. As the expected life of the generation assets is shorter than that of the Transformer assets and the reliability/availability is lower the capacity of the transformers is set to provide for peak demands should the generators be unavailable.

Forecast peak power demands for the installed transformer capacity by the end of the planning period are also indicated.

Growth forecasts have been averaged on a 10-year prediction to smooth out step increments introduced by new loads.

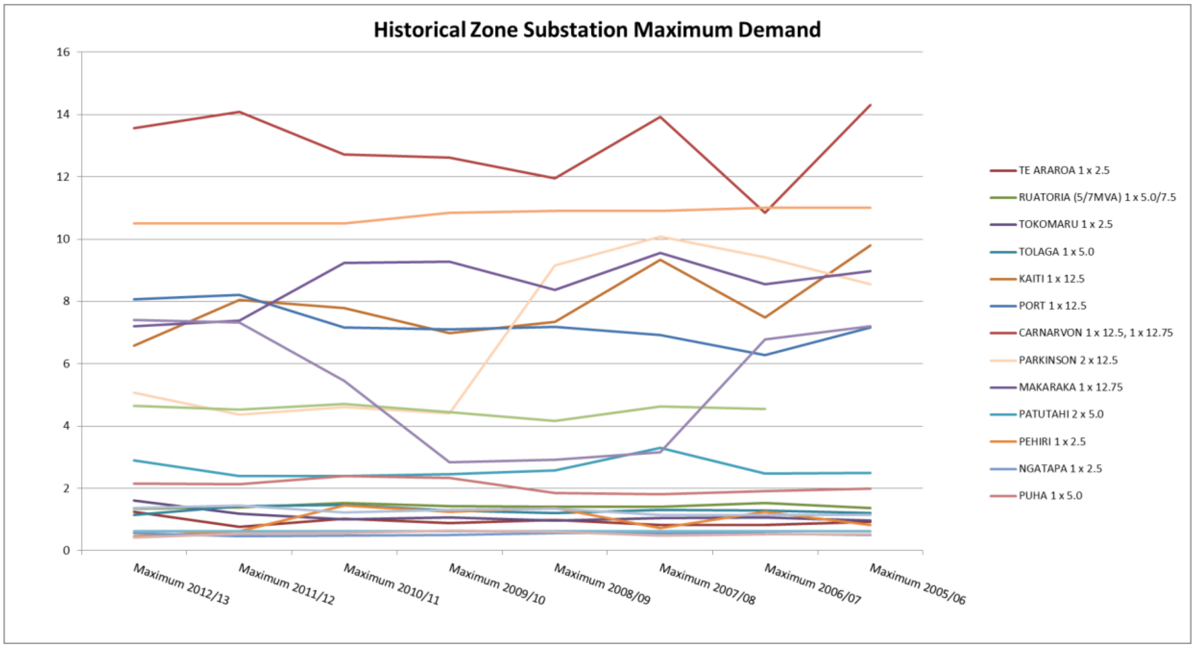
A year by year forecast has not been provided as the exact timing and nature of future loads in is not known hence the information would be inaccurate and misrepresent the general predictions provided.

Substation	Transformer Capacity (MVA)	Maximum 2013/14 (MW)	%of Installed Capacity	Growth (%)	Load 2025 (MW)	%of Installed Capacity
TE ARAROA	1 x 2.5	0.865	35%	0%	1.31	53%
RUATORIA	1 x 5.0/7.5	1.346	27%	0%	1.41	28%
TOKOMARU	1 x 2.5	1.25	50%	0%	1.70	68%
TOLAGA	1 x 1phase 5.0	1.134	23%	0%	1.21	24%
KAITI	1 x 12.5	6.561	52%	0%	6.91	55%
PORT	1 x 12.5	8.163	65%	0%	8.48	68%
GISBORNE	2 x 60 (110kV/50kV)	45.1	28%	2%	48	40%

Substation	Transformer Capacity (MVA)	Maximum 2013/14	%of Installed Capacity	Growth	Load 2025	%of Installed Capacity
CARNARVON	1 x 12.5, 1 x 12.75	14.196	57%	0%	14.26	57%
PARKINSON	2 x 12.5	9.876	40%	0%	5.33	21%
MAKARAKA	1 x 12.75	10.5	82%	1%	7.64	60%
PATUTAHI	2 x 1phase 5.0	2.303	23%	0%	3.04	30%
PEHIRI	1 x 2.5	0.461	18%	0%	0.48	19%
NGATAPA	1 x 2.5	0.453	18%	0%	0.59	24%
PUHA	1 x 1phase 5.0	2.019	40%	0%	2.26	45%
JNL	1 x 12.75	4.011	31%	0%	4.90	38%
MATAWHERO	2 x 5.0/7.5	2.615	17%	1%	7.86	52%
TUAI	1 x 1 phase 6 (110/11)	0.628	10%	0%	0.66	11%
WAIROA	2 x 1 phase 10 (110/11)	10.4	52%	0%	11.04	55%
WAIROA MAHIA	1 x 12.5 (11/33)	2.1	16%	1%	2.23	18%
KIWI	1 x 6.5 (11/50)	4.8	74%	0%	4.8	74%
BLACKS PAD	1 x 1.5 (33/11)	1.205	80%	1%	1.46	97%
TAHAENUI	1 x 1.5 (33/11)	0.535	36%	0%	0.44	30%
WAIHI	1 x 6.5 (50/11)	4.8	74%	0%	4.8	74%

Notes
- Gisborne is a Transmission Substation
- Kiwi and Waihi are a Generation Infeed
- Wairoa Mahia is an outfeed to Blacks pad and Tahaenui

The graph below indicates the historical maximum demand for each major substation. The variation from year to year for a number of substations represents contingent events where the reserve capacity has been utilised to supply adjacent substations during maintenance activities.



Disclosure Requirement
The Electricity Disclosure Determination 2012 Report on Capacity Forecast, (Schedule 12b.) is provided in an appendix of this plan. Due to rounding requirements the figures provided round to the nearest 1MVA which does not accurately reflect demand at small substations with peak demands below 800kW. The detail figures can be seen in the table above.
In the disclosed report the definition of firm capacity does not recognise the existence of the transformer in a single transformer zone substation. Details of the transformers are shown in the asset description section of this plan and in the table above.

4.3.5 Overall System Growth – Demand Aggregated to GXP

By projecting growth trends forward, coincident system peak demand has been forecast to grow from 60 MW in 2012/13 to a worst case of 80 MW in 2023. This gives an overall growth rate of approximately 1.4% p.a.

Alternatively the conservative scenario indicates minimal if any growth to 60 MW in 2023 which equates to a rate of 0% p.a.

When making development decisions related to capacity requirements for long life assets, ENL considers the high load forecast and a prudent planning margin, to ensure investment covers the worst case scenario. To avoid over investment, the investment in capacity is deferred as long as possible. For other decisions the low or medium forecasts are used as appropriate.

Wairoa Transmission Substation – Prudent Planning Margin

When considering the firm capacity at Wairoa Substation a 2 MW 'prudent planning margin' has been included in the assessment of the adequacy of future capacity. This assessment is in addition to other planning assessments outlined in this AMP.

The margin is considered appropriate for regional planning purposes to ensure that ENL is capable of supplying a step-change increase in industrial load. The planning margin is necessary given the very long lead-time to increase supply capacity in respect of 110kV Substations and 110kV transmission lines.

The planning margin has been estimated at 2 MW and represents a new small to medium industrial site, or the expansion of an existing industrial site.

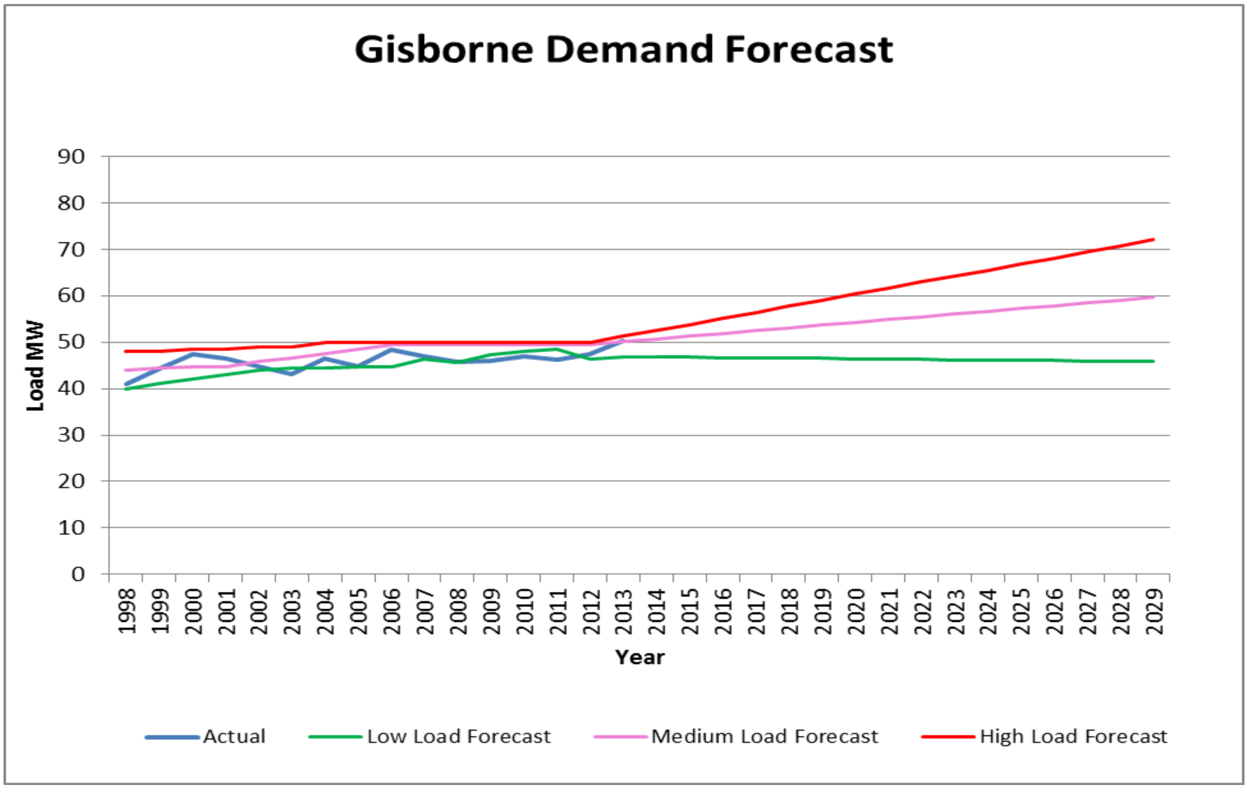
The results of this assessment indicate that Wairoa Substation and the distributed generation provide suitable firm capacity beyond the end of current planning horizon.

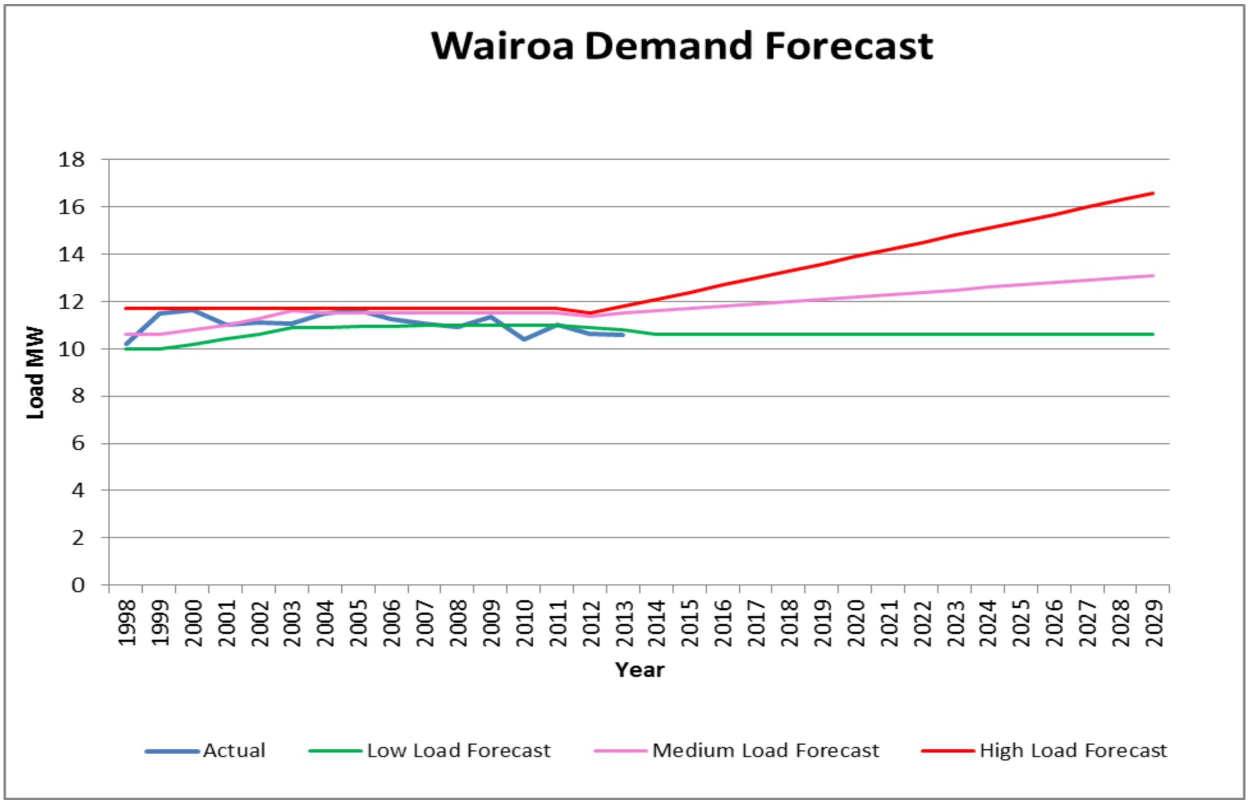
Gisborne Transmission Substation – Prudent Planning Margin

When considering the firm capacity at Gisborne Substation a 6 MW 'prudent planning margin' has been included in the assessment of the adequacy of future capacity. This assessment is in addition to other planning assessments outlined in this AMP.

The margin is considered appropriate for regional planning purposes to ensure that ENL is capable of supply a step-change increase in industrial load. The planning margin is necessary given the very long lead-time to increase supply capacity in respect of 110kV Substations and 110kV transmission lines. Having headroom in the capacity is considered to be of particular importance in the Gisborne region given the unpredictability in growth associated with wood harvesting and related industrial activity.

The results of this assessment indicate that Gisborne Substation and the distributed generation provide suitable firm capacity to 2022.





The forecast demand growth trends are -1% to +2% p.a. the historical trend shows an annual variation of up to 3% largely due to changing factors such as load control strategies, energy saving drives arising out of national energy shortages and weather patterns.

Disclosure Requirement

The Electricity Disclosure Determination 2012 Report on Forecast Demand, (Schedule 12c) is provided in an appendix of this plan. To determine the system growth in terms of GXP demand, an extrapolation of the high Load forecast for the Wairoa and Gisborne regions was modified slightly by the diversity to provide an approximate coincident value. The expected contribution of known embedded generation at 11kV was then separated out to provide a total GXP figure.
In 12c(i) of the report the embedded generation figures reflect the expectation of additions as per the required definitions. The predictions are based on current trend of 5 x 2kW solar installations p.a. , a progressing distributed hydro generator approx. 100kW and the possibility of additional diesel generation discussed in the development options of this plan. From 2015 relocation of the GXP metering from

Gisborne and Wairoa substations is forcast to increase demand by 2-3% due to the additional losses in the Transmission Assets.

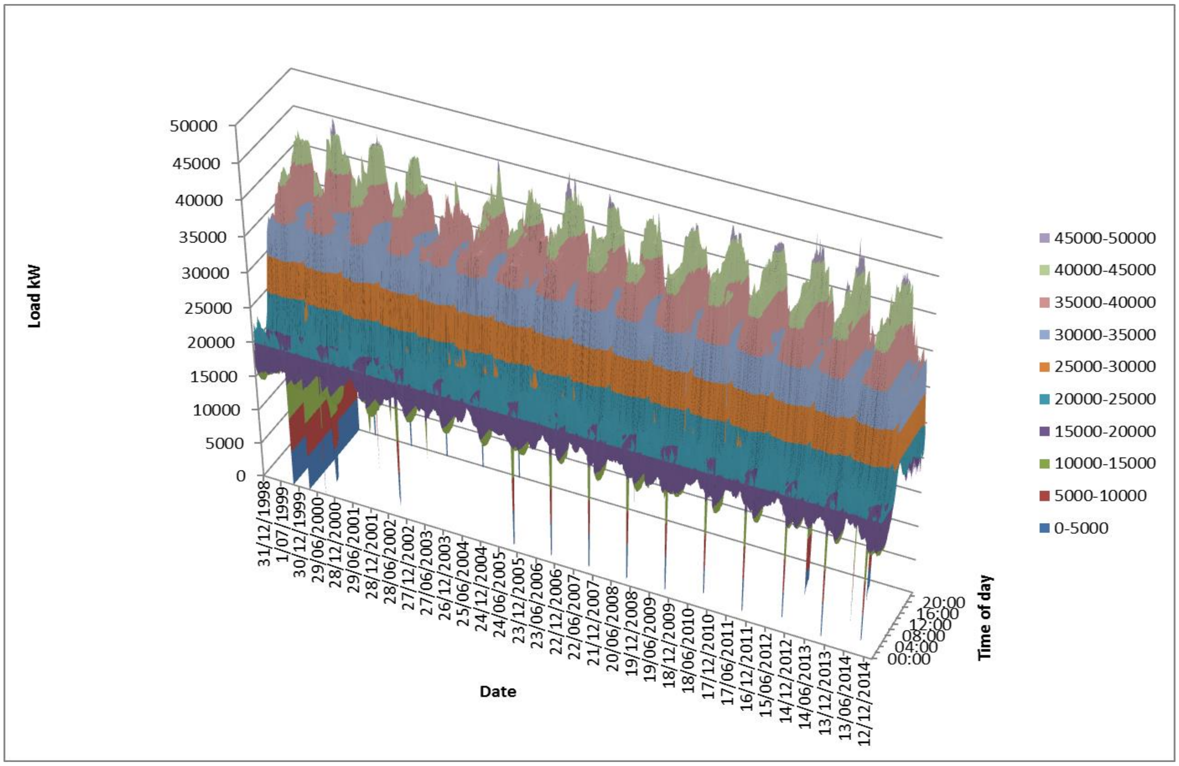
4.3.6 Forecast Accuracy and Variations

ENL has used a Load Forecasting Model to help predict the impact of accumulated load growth on its capacity requirements and security standards. The model allows scenario planning for investigating the impact of large loads associated with new processing plants and other industrial loads when applied at specific locations in the network. Forward projections of growth rates are obtained from historical trends at feeder level, or sub feeder level where data is available. There is significant dependence on the experience of the personnel establishing the correct growth rates and their understanding of the patterns in the region.

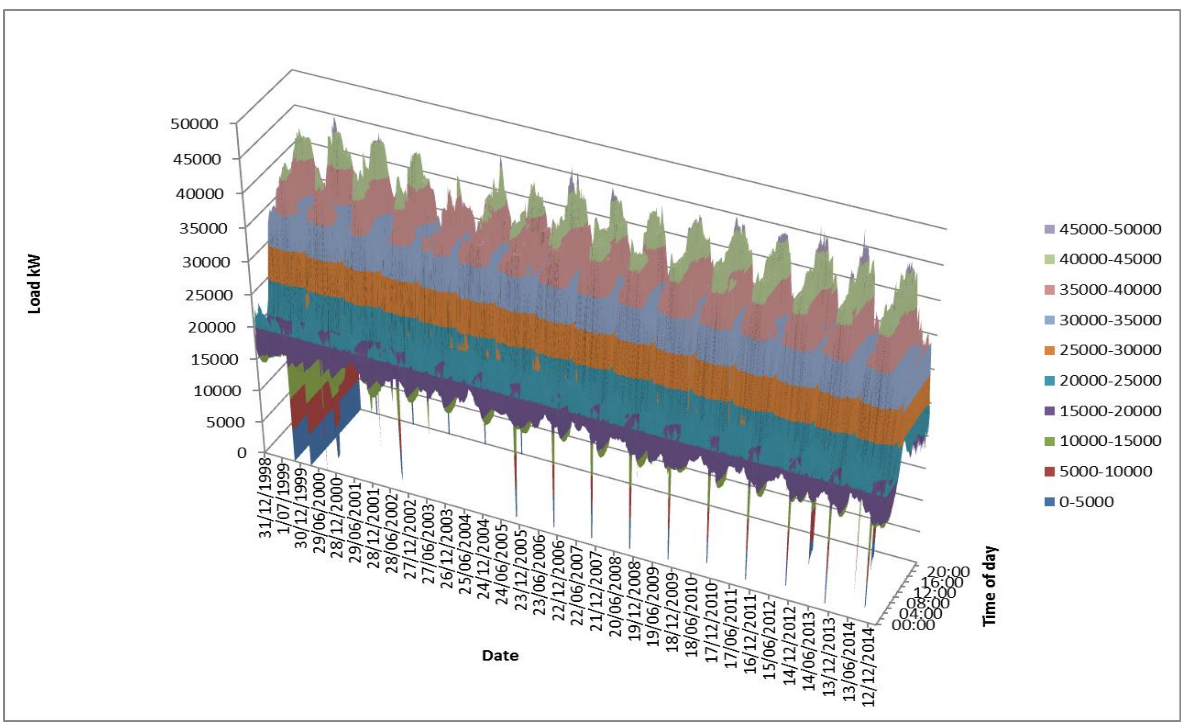
The model achieves this via the following method…
Profile Builder: Feeder load data is obtained from the SCADA system. Load profiles are created for domestic, non-domestic, and specific industrial consumers and reconciled so that they sum to known feeder level data.
Zone/Subtransmission substation, sub transmission line, Transmission Substation and GXP profiles can then be built up which take into account diversity.
Load Forecasting: The number of connections and an assumed annual growth rate can vary each profile for each class of consumer.
Scenario planner: Large loads and generation can be inserted at any sub-transmission node. i.e. Zone/Subtransmission Substation. Resulting loads and their profiles can be applied to load flow analysis software to determine voltage, loss and security issues.

ENL has also considered historical and national trends and has found that they provide the most effective method for load forecasting. Consideration is made of regional developments via use of the Load model however past experience has shown that load forecasts provided by end users do not take diversity into account. Only a small proportion of the developments eventuate and in general the forecasts have proven to be inaccurate. To compensate for inaccuracy in load forecasting the security standards in place provide a buffer to accommodate load growth and allow appropriate time frames to compensate and re-establish the appropriate security.

Gisborne System Historical Load 1999 to 2014



Wairoa System Historical Load 2001 to 2014



Shown by the charts above all demand forecasts are subject to variation as a result of externalities such as weather and economic growth. Annual variations in these factors will create demand variations in the short term, whilst sustained trends are likely to cause more persistent departures from the forecast. The Gisborne trend above shows a sudden change in the demand profile from 2002 periods. This change was due to a change in load control strategies from 2002 and the national campaign to save energy due to water storage levels in 2003.

Varying the timing of planned work can accommodate forecast variances. Lower than expected load growth can be accommodated by deferral and faster than expected load growth by acceleration. Adequate notice is generally available for the type of work involved to undertake such acceleration, although major items of equipment can have long lead times and constrain the extent to which work can be performed 'just in time'. ENL's basis for network planning and operations is sufficiently rigorous and conservative to avoid serious capacity shortages and un-served demand.

4.3.7 Issues arising from estimated demand

No issues from the estimated demand have been identified.

4.4 Capacity constraints

4.4.1 Transmission constraints

Gisborne Transmission Substation
The Gisborne Substation transformer upgrade completed in March 2007 addressed immediate issues related to capacity constraint, meeting future load growth and ENL's security standards.

The worst case forecast is that the 60MVA firm capacity at Gisborne Substation, (at Class D security of supply), is sufficient to meet increasing maximum demands until approximately 2022. Whilst the 110kV lines from Tuai to Gisborne meet current demand their firm capacity , (at the required Class D security), is insufficent to meet forecast demand, (including the prudent planning margin). Eastland is presently utilising 4MW of firm distributed generation capacity to provide the necessary capacity to meet forecast demand, (including the prudent planning margin).

Wairoa Substation

There are currently no constraint issues at the Wairoa Substation. The contingency rating of the 110kV lines from Tuai is 57MW. The normal/contingency rating of the 2x 10MVA 110/11kV transformers is 20/12 MVA. The maximum coincidental demand of the Wairoa network is 11MW. After the application of load control, Waihi generation and Mahia generation the maximum demand at Wairoa Substation is 8.0MW.

Wairoa issues and development proposals relate to sub-transmission assets to Mahia and distribution assets only.

The 10MVA fixed capacity at Wairoa Substation, (at Class C security standard), is insufficient to meet forecast demand, (including the prudent planning margin). Eastland is presently utilising 3.5MW of firm distributed generation capacity to provide the necessary capacity to meet forecast demand, (including the prudent planning margin). It is proposed that the current 110/11kV transformers due to age/condition considerations will be replaced with 110/33kV units prior to 2025. Development plans for the Wairoa sub-transmission network are being progressed to coordinate this upgrade.

ENL Tuai Substation

There are no current or forecast capacity constraint issues arising at the Tuai Substation. If any significant growth were to occur over time additional security measures will be required. Development of standby generation options to meet the necessary security levels is the most viable option at this time. To improve connection economics an option exists to extend the 11kV distribution from Tuai to the Frasertown feeder and supply 2 to 3MW of the Wairoa Substation load from the Tuai Substation. This option would defer the timing of the Wairoa Substation development to around 2027 given the worst case growth scenario.

Tuai GXP Transmission Supply

Operationally at Tuai the 110kV lines to the Gisborne, Wairoa and Tuai Substations are connected to a ring bus. Previous security constraints relating to the ring bus circuit breaker were eliminated when was equipped with bus protection in 2011.

4.4.2 Transmission /Sub-transmission constraints

The failure of a double circuit 110kV tower on either the Gisborne or Wairoa Lines will interrupt the entire supply to the respective Region. Previously Transpower managed this risk in line with their National standards.
These circuits are now managed by ENL.
Addition of a third line from Tuai to Gisborne on separate towers would address this constraint for Gisborne.
Sufficient embedded generation capacity to allow independent operation from the grid in the Gisborne and Wairoa Networks would improve the security levels.
The Mahia 33kV line which is currently limited to 1.5MW, by the Transformener Capacity at Blacks Pad. Following the 33kV extension project the limit will be 2.5MW.

4.4.3 Distribution constraints

In ENL's overhead network the constraint is generally driven by voltage drop. A nominal design standard of 3.0% is applied to new lines or connections to the existing lines. Voltage drop is permitted to reach 5% before reinforcement is considered or application for new load is declined. Other factors such as the need for contingent capacity to meet security needs are also considered.

Cable network tends to be more constrained by thermal ratings. Therefore underground systems are less tolerant of constraints.

ENL has identified the following distribution constraints…

Tikitiki Feeder Ruatoria – Limited transfer capacity between substations
Inland Feeder Tokomaru Bay– Limited transfer capacity between substations
Mata road feeder Tokomaru Bay – Very long feeder
Tauwharepare Feeder Tolaga Bay - Very long feeder
Dalton Feeder Kaiti Anarua Bay feeder is voltage constrained over holiday periods. Hence only isolated new loads could be supplied.
Nelson Road Feeder Makaraka

TeArai Feeder Patutahi - Very long feeder
Tiniroto Feeder Pehiri - Very long feeder
Tahora Feeder Ngatapa - Very long feeder
Whatatutu Feeder Puha- Very long feeder
Matawai Feeder Puha Additional load would require a voltage regulator and ultimately a 50/11kV zone substation.
Muriwai feeder Patutahi can only supply around an additional 200kVA of load, up to halfway along the feeder otherwise the voltage would be unacceptably low.
Frasertown and Raupunga feeder's remote connections are currently limited by voltage. This will preclude all new load other than isolated single dwellings.
Mahia Feeder Blacks Pad – High point loads at ends of feeder
Ruatakuri Feeder Tuai - Very long feeder
Hicks Bay Feeder TeAraroa - Very long feeder
Kiwi A and B feeders from Wairoa Substation to Kiwi Substation at Limit
Borough1 and Borough2 Feeders in Wairoa near security limit.

Relief of all of these constraints typically requires significant customer contribution as the required investment is unlikely to be covered by the allowable revenue. ENL is developing the option of installing Diesel Generation to support voltage at peak loading to relieve the constraints. Note the generation would not provide for significant growth if 24 hour generation was required. The generation solution when used during planned and unplanned shutdowns will contribute to improvement of key performance indicators for the feeders identified above.

4.4.4 Significant consumer constraints

In general significant consumers have supplies tailored to their requirements. Consumers requiring increases in capacity are effectively constrained by the minimum investment they initially undertook.

4.5 Use of non-asset solutions

Covered in section 4.2.1 ENL considers a range of non-asset solutions including smart technologies, third party generation and network reconfiguration. ENL's preference is for solutions that avoid or defer new investment.

4.5.1 Distributed Generation

ENL believes that in part a solution to improve security and defer investment to overcome constraint is the development of additional embedded generation throughout its distribution network. The following generation possibilities in the Gisborne and Wairoa Region have been identified;

-Medium scale, (80MW) hydro generation
-Small scale , (70-2000KW) hydro generation
-Bio-mass fuelled combined heat & power plants
-Gas-fired cogeneration plants.
-Wind Generation
-Gas engines

Eastland Groups' Business Plans contain initiatives to investigate the feasibility of potential generation, both inside and outside the region, and develop those projects as appropriate.

In September 2008, Government passed the Electricity Industry Reform Amendment Bill under urgency in the House. This was the culmination of review of the EIRA designed to relax the rules regarding ownership and operation off generation by Lines Companies.
A key part of these changes were changes to the restrictions on renewable energy sources. Renewable energy sources are defined as:

solar, wind, hydro, geothermal, biomass, tidal, wave, ocean current sources, or any other energy source that occurs naturally and the use of which will not permanently deplete New Zealand's energy sources of that kind, because those sources are generally expected to be replenished by natural processes within 50 years or less of being used.

While clearly this has relaxed the rules regarding the amount of generation a lines company can own, in particular renewable generation and generation outside its geographic area, arm's length rules still apply to a lines company with generation and retail functions as shown in the table below:

	Electricity Lines Company	
	Generation Division	**Retail Division**

Renewable Generation	In region	Unlimited	Information separation >10MW: Separate Co. Separate Board >30MW Separate Company Separate Board Separate Mgt
	Outside region	Unlimited	
Non-renewable Generation	In Region	50MW or 20% of max demand	
	Outside Region	Unlimited	

The remaining restrictions, specifically those regarding the arms-length rules, could be a significant impediment to the development of generation/retailing opportunities.

Ultimately, each Generation Opportunity must be assessed against the criteria of creation of Shareholder value and regional prosperity before the decision to proceed is made. While this is can be subjective in terms of regional prosperity, all projects will be assessed on a Discounted Cash Flow basis, that incorporates all project costs and revenues, and only those projects which are expected to have a positive Net Present Value against a hurdle rate that is deemed acceptable for the project will proceed.

However, based on Eastland Network's previous experience, a key factor to the success of these projects is the ability to retail. As discussed above, the changes to the EIRA still present significant challenges and restrictions on the ability to retail. This may significantly undermine the value of many generation opportunities.

4.6 Policies for distributed generation

ENL clearly recognises the value of distributed generation in the following ways…
-Reduction of peak demand at the Transpower GXP.
-Reducing the effect of existing network constraints.
-Avoiding investment in additional network capacity.
-Making at least a small contribution to supply security.
-Making better use of local primary energy resources thereby avoiding line losses.

-Avoiding the environmental impact associated with large scale power generation.

As many of these benefits are only realised if the generation can reliably and consistently perform when needed, wind, solar and run of river hydro generation are generally not able to make any significant contribution. Where there is no guarantee that the generation can offset transmission costs ENL is usually unable to contribute to the benefits until savings have been identified.

ENL also recognises that distributed generation can have the following undesirable effects…
-Increased fault levels, requiring protection and switchgear upgrades.
-Increased line losses if surplus energy is exported through a network constraint.
-Stranding of assets, or at least of part of an assets capacity.
-Reduction in asset utilization without the ability to remove the asset
-Instability of the network during faults and interaction with existing generation
-Deviation of voltage beyond allowable limits and voltage stability issues.
-Increased loading on assets to accommodate power factor requirements of induction generators
-Harmonic interference
-Automatic reclosing creating synchronising issues

Despite the potential for some undesirable effects, ENL actively encourages the development of distributed generation that will benefit both the generator and ENL. As per the Electricity Industry Participation Code 2010 Part 6 (Connection of Distributed Generation), details on the processes necessary and information required to enable connection of DG to ENL's assets are available in the Eastland Network section of the Eastland Group website, (www.eastland.co.nz).

The priority's for fault restoration and repair work are determined on the basis of the nature and number of customers affected, the available resources, locations, environmental conditions and estimated repair times. In general generation only connections are expected to have a lower priority assigned than load using customers with greater dependence on their electricity supply. Hence outage/repair times for generation may be greater than disclosed averages for outages and service levels may be lower.

The key requirements for those wishing to connect distributed generation to the network broadly fall under the following headings.

Connection terms & conditions (commercial)

Connection of distributed generation to an existing connection will not incur any additional line charges if the capacity of the connection does not alter. Connection of distributed generation requiring capacity greater than the existing connection may incur additional costs to reflect network reinforcement.

Distributed generation that requires a new connection to the network will be charged a standard connection fee, and may also be charged a fee to reflect reinforcement of the network back to the next transformation point.

Variable and fixed line charges will be payable by the connecting party to ENL.

Installation of suitable metering (refer to technical standards below) shall be at the expense of the distributed generator and its associated energy retailer.

ENL recognises and shares the benefits of distributed generation that arise from reducing ENL's costs (such as transmission investment costs, or deferred investment in the network) provided the distributed generation is of sufficient size to provide real benefits. Separate contracts for recognition of benefits will generally be fixed term and renewable if the benefits still exist. Penalties will apply to contracts if the benefits are not realised.

Those wishing to connect distributed generation must satisfy ENL that a contractual arrangement with a suitable party is in place to consume all injected energy.

Safety standards

A party connecting distributed generation must comply with any and all safety requirements promulgated by ENL.

ENL reserves the right to physically disconnect any distributed generation that does not comply with such requirements.

Technical standards

Prior to connection of an installation ENL will require evidence that all matters relating to regulatory compliance have been met. This may include but is not limited to

Easements

Resource consents

Building consents

Asset Capability Statement and approval from the System Operator

Safety Management Systems

Electrical compliance certificates

Metering capable of recording both imported and exported energy must be installed. If the owner of the distributed generation wishes to share in any benefits accruing to ENL, such metering may need to be half-hourly.

ENL may require a distributed generator of greater than 10kW to demonstrate that operation of the distributed generation will not interfere with operational aspects of the network, particularly such aspects as protection and control.

All connection assets must be designed and constructed to technical standards not dissimilar to ENL's own prevailing asset management standards.

While specific analysis is required on a case by case basis, the maximum injection into the network before voltage limits are exceeded is indicated in the following table.

Location	Nominal Maximum export
Urban 50kV sub-transmission	8 - 20 MW
Rural 50kV sub-transmission	2 - 8 MW
Urban 11kV distribution	3 - 6 MW
Rural 11kV distribution	50% of the typical feeder load 50 - 500kW
Rural 11kV distribution near Major Substations	1 - 2 MW
Urban 400V Reticulation	100 - 200kW
Rural 400V Reticulation	8 to 50kW

In accordance with the Electricity Industry Participation Code 2010 Part 6 (Connection of Distributed Generation), details of the processes necessary and information required to enable connection of distributed generation to ENL assets is available from the ENL section of the Eastland Group web site.

4.7 Development program

4.7.1 Options considered for major initiatives

As identified in section 1.6 the Wisdom and Understanding inherent in ENL's processes and systems continually filters numerous ideas and options for development initiatives. While many options can be quickly considered and discounted the following options for major initiatives have developed as a result of the process. A ranking of success outcomes and risk factors for the following development initiatives in this section provided in section 6.2.3.

4.7.1.1 Transmission Development

The acquisition of transmission spur assets from Transpower in 2015 provided the following benefits.

- Enhanced operation of the 110kV supply to the Gisborne and Wairoa regions through ENL gaining full indication and control of all the substation equipment
- Material reduction in the cost of managing and operating the spur assets and operational efficiencies through coordination with other ENL activities in the region;
- Optimisation of capital expenditure across, transmission, Subtransmission, distribution and local generation, which will achieve the necessary supply security at a lower cost than if the assets were separately managed;
- Reduced regional coincident peak demand, resulting in reduced transmission interconnection charges.

Following acquisition of these Transpower Transmission Assets described in section 2 of this plan completion of the asset transfer is programmed over 2015 and 2016.

Approximately $770,000 of transfer project costs is forecast. The transfer projects include:

- Transfer of telemetry and control from Transpower SCADA system to ENL's SCADA system and establishing new

communication links between ENL's control room to Tuai, Wairoa and Gisborne 110kV substations;
- The purchase of 110kV line and station spares; and,
- The purchase of temporary tower equipment (non-network assets).

Gisborne Substation

Options available to incrementally increase the transmission capacity to Gisborne to accommodate growth are;

a. 110kV Line Thermal Upgrade

Worst case load forecasts for the Gisborne Substation predict that the 110kV lines summer contingent capacity becomes a constraint in 2018.
A study in 2010 indicated that a thermal upgrading of the line to 75 degrees C would increase the thermal capacity from 59MW to 77MW (winter rating). It is important to note that the voltage constraint would become the limiting constraint and additional capacitors on the 50kV bus at Gisborne would be required. The study indicated that installing 4 x 6MVAr capacitor banks would be necessary to achieve 67MW on the line. The cost of this option is likely to range from $2-10+ million.

A detailed investigation into the scope and of work required to achieve the thermal upgrade is required to validate this option.

It should be noted that the deferral of demand growth may be achieved through development of a significant amount of network connected generation if it occurs first.

b. Full re-conductoring and partial re-conductoring

The 2010 study investigated both partial and full re-conductoring. Re-conductoring overcomes both the capacity and voltage constraints on the line. Line capacity ratings of between 65 and 70MW can be achieved with these options.

A detailed investigation into the scope and of work required to reconductor the line is required to validate this option. As the two circuits share the same towers on some sections of the line there is likely to be material safety issues to contend with. The cost of this option is likely to range from $2-10+ million.

c Third transmission Line

As a potential solution to the eventual 60MW constraint, the possibility of reconductoring the Tuai – Gisborne 110kV line and installing additional transformer capacity, (a 3rd 60MVA transformer) at the Gisborne Substation. Estimated costs of the re-conductor work and additional transformer capacity are $30 - $50mill.

It is expected that this solution will not be optimum as the ENL sub-transmission network supplied from the Gisborne Substation will have become constrained. Being installed in predominantly urban areas means that these constraints will not easily be resolved through enhancement of, or additions to the existing sub-transmission lines also consenting issues will be significant.

The construction of a third transmission line from Tuai is therefore proposed. This 40MW line would terminate at Patutahi where a Transmission Substation would be established at the existing ENL subtransmission substation site. Potentially the Gisborne Substation would be transferred to this location and the existing 110kv lines from Patutahi to the Gisborne Substation would be converted to 50kV. The Patutahi location facilitates the "easy" construction of new sub-transmission lines to the Matawhero industrial area where the majority of demand increase is expected to occur. The estimated cost of the new line is $60mill and the new GXP $20mill.

ENL has previously identified a line route from Tuai to Patutahi which can share an existing 11kV line route. The 11kV would be overbuilt with 110kV on concrete poles. A preliminary concept report has been completed in 2008 and a process relating to the obtaining of necessary easements is the next stage.

The three 110kV line scenario will provide a transmission contingent capacity to the Gisborne region of 100MW.

Scheduled for 2023-2027 - dependant on growth triggers

Wairoa Substation

Previously it was proposed that the ENL security for Wairoa Substation be reduced to from a C to a B1 classification. This would require only an "n" level of security with 100% contingency capacity such that 75%

of the load could be restored within 15 minutes, 90% within 3 hours and 100% restoration dependent upon repair time. Optimisation of the Wairoa Substation to this security level would have halved the quantity and value of assets required and save approximately $40,000 pa in connection charges. It was proposed that the use of 1.5Mw of load control and 6MW of embedded generation, (5MW Waihi Hydro + 1MW Mahia Diesel) would compensate for the reduced service levels.
This proposal has now been discounted as it would result in an unacceptable divergence from ENL's security standards. Waihi Hydro only has 3 days storage capacity and cannot be relied upon to deliver 5MW on call. This was demonstrated in March/April 2002 when due to lack of rainfall Waihi was unavailable for evening peak reduction. Under the proposal should an event coincide with Waihi unavailability then a shortfall in contingent capacity would exist which could only be counted through the rationing of supply. The reduction of Wairoa Substation asset also would restrict the availability of capacity for growth.

Under changes in the 2004 ODV Handbook the Wairoa 110kV assets which had been optimised to 50kV were required to be reinstated to 110kV. This resulted in a 7.8%, ($71,000) reduction in ENL connection charges at that time.

Transpower has identified the age/conditioned based replacement of the 110/11kV transformers is due in 2015. As the detailed design of this project progresses replacement with 110/33kV transformers is a consideration.

While no development actions are scheduled as the assets are currently operated by Transpower, the age replacement of the transformer is identified in the Acquisition of Transmission Assets option below.

4.7.1.2 Transmission/Sub-transmission Development

Transmission

The 110kV lines from Tuai to Gisborne and Wairoa are predominantly a double circuit tower construction. Failure of a single tower is likely to interrupt both circuits (n – 2 electrical). While the likely hood or frequency of this risk is low given the maintenance, inspection and robust design of the lines the consequence is very high.

The only option currently identified to eliminate this risk is construction of a new110kV line from Gisborne to Wairoa which provides both a contingent route and complements growth options in 4.7.1.1. To date the risk has not been considered significant and the levels are aligned with risk levels acceptable to other NZ lines businesses. Options considered for growth incorporate plans to eliminate this risk in the long term.

Gisborne Sub-transmission

Within the urban Gisborne sub-transmission network previously identified demand growth triggers have been reached and associated investments have been made to accommodate the expected minimum load growth projections. With the concentration of loads restricted to blocks of less than 12MW, n-1 security is provided without the requirement of dual transformers or large transformers in neighbouring substations being needed to cover contingent events. Sufficient flexibility exists in key parts of the distribution system such as Matawhero, to accommodate forecast industrial load growth. Further development of the 11kV network is on-going but is only undertaken in response to meet firm load growth requirements.

In the long term the ability to upgrade the urban sub-transmission system to address security or capacity constraints is limited and will coincide with transmission constraint requiring a 3rd transmission line and new Transmission Substation.

Rural loadings are lower than the installed capacities of the sub transmission system. The daily load profile is reasonably flat, and there are few commercial and industrial loads. As the rural loads are relatively low growth is extremely sensitive to even small subdivisions or commercial developments. The ability to accommodate growth too far out from rural substations is also limited.

From an economic viewpoint, high levels of sub transmission investment made in the rural area cannot be justified, but long distances require high voltage and bulk supply has to be concentrated. Security provision would therefore normally require large, redundant assets. ENL has adopted a design approach where security is provided by standby generation support. This approach has the potential to deliver better service, reduce Transmission/Subtransmission substation asset investment, and avoid 11kV network reinforcement cost. Actions undertaken as a result of the installed generation in 2003 have included removal of high maintenance 2nd transformer banks and replacement of outdoor switchyards with indoor 11kV switchboards providing room for generators on existing sites.

Should the rate of growth exceed the expectations the following provisional projects have been identified that are considered sufficient to accommodate medium growth expectations.

- Provisional Whangara Substation 2.5MW. Situated between Kaiti and Tolaga bay substations this substation may be necessary to meet load growth and support requirements in the Wainui Beach area. While medium scale generation prospects in the area may negate the need to establish this substation large scale generation options will potentially require a substation with up to 10MW export capacity in this area. Provisionally scheduled for 2023/24-2024/25.

-Provisional 50kV/11kV 12.5MW Transformer. Situated at the Gisborne substation. An option has been identified to extend the Gisborne Substation 50kV Bus creating 2 additional Bays. The 50kV line to Kaiti and the Coast can then be separated utilising 1 of the additional Bays and a short 50kV line to a new substation can be established to reduce load and increase support for the Makaraka, Carnarvon and Kaiti Substations. Provisionally scheduled for 2021/22-2022/23.

-Provisional Patutahi Zone Substation capacity increase 12.5MW. Situated close to the Matawhero area an option has been identified to upgrade the capacity at this site should a short fall develop in the Matawhero area. The need for this is unlikely however provision is scheduled for 2023/24.

Matawai Supply

The Matawai area supplied from the Puha Substation is exposed in terms of ENL's security standard by the single 11kV line from Puha to Otoko hill run over rugged inaccessible terrain. Currently Puha Substation is linked to Patutahi via the 11kV network and supported by a 1MW generator to enable regular maintenance on the ageing transformers.

To accomidate growth and/or improve security in the Matawai Area installation the following options have been identified:

A. 50/11kV Substation Matawai. A Zone substation at Matawai combined with conversion of the 50kV line from Otoko to Matawai, currently operating at 11kV, back to 50kV has been considered. Two possible locations for the substation have been considered, Site 1 is at Matawai township on ENL owned land, Site 2 is near Olivers Road approximately halfway between Puha and Matawai and coinsides with an 11kV embedded generation connection to the line that would be used at 50kV currently operated at 11kV.

B. Generator Relocation: Relocation of the Generator at Puha Substation to A site at Otoko past the single 11kV line bottleneck to the Matawai Area would overcome the security constraint but would not provide for benefits the other options would provide.

C. New 11kV Line Section: The Ngatapa substation has been identified as a key site in terms of location to provide security and support to the Matawai area currently supplied from Puha substation. Construction of a section of 11kV line from the end of the Ngatapa feeder to Otoko Hill under the existing 50kV line route. while being close to the value of a new substation at Matawai will not only provide for the security requirements of Matawai but will provide the additional benefit of capacity support for both the Ngatapa and Puha substations.

The Ngatapa/Otoko 11kV feeder project is scheduled in the distribution development section of this plan.

Scheduled for 2017/18.

Wairoa Sub-transmission

Wairoa sub-transmission development considers the Capacity constraint at Mahia, Capacity availability for the forecast Wairoa CBD growth, Rationalisation of Wairoa and Kiwi Substations and Tuai Substation Supply.

Mahia

Mahia is currently supplied at 11kV from a 33/11KV 1.5MVA transformer at Blacks Pad. This transformer is not fitted with on load tap changing capability. This coupled with the length of the 11KV line and current conductor size results in voltage stability issues occurring when demand exceeds approximately 800KVA.

Demand requirements at Mahia have increased due to the growth of dairy farming at Mahunga, beach property subdivisions and installation of sewage treatment schemes in the area. The current rate of growth is forecast to continue due primarily to continuing subdivision activity. To date demand requirements exceed the capacity of the Mahia transformer and are very seasonal in nature. It is expected that over time this seasonality will not be as evident as more people take up permanent residence at Mahia.

Increasing demand requirements also result in increased voltage stability issues.

Since 2002 a generator has been installed and operated at Mahia during high demand holiday seasons to overcome capacity and voltage issues. However with the level of demand growth forecast to increase at Mahia and the expected change in demographics it is expected that the generator solution is a medium term solution.

Investigation has shown the upgrading of the 11kV Mahia network will not be sufficient to resolve current issues and accommodate increasing demand requirements. The optimum solution is to relocate the Mahia transformer closer to the load source and increase its capacity. This involves extending the 33kV line approximately 6.5km to Opoutama and establishing a small zone substation. The substation would comprise of a 2.5MVA transformer fitted with an on load tap changer.

The cost of this option is estimated at $1.5 mill. As this expenditure will result in little additional returns to ENL and additional financial contribution is being sourced from the developers in the form of contributions linked to the capacity being developed and their specific requirements.

Implementation of the Mahia development project has been delayed due to continuing challenges with the project including obtaining a suitable substation site and achieving easements over private property for the 33kV line extension.

Scheduled for 2015 – 2017.

AFFCO & Wairoa CBD

AFFCO's current approximate maximum demand of 4MW is 35% of the total maximum demand (11.6MW) of the Wairoa network. Load increases at AFFCO have a significant influence on the Wairoa 11kV network as a whole. AFFCO is currently supplied at 11kV from Kiwi substation. The maximum capacity limit of this supply is 5MW, after this limit is exceeded the supply to AFFCO will be required to be at 33kV.

AFFCO have advised that in the medium term, expansion of their plant may result in a maximum demand increase to 6.5MW. In 2008 new load associated with sawmilling in Wairoa was introduced however this venture is no longer operating. Any future growth will take up the remaining contingent capacity of the 11kV network supplied from Kiwi substation.

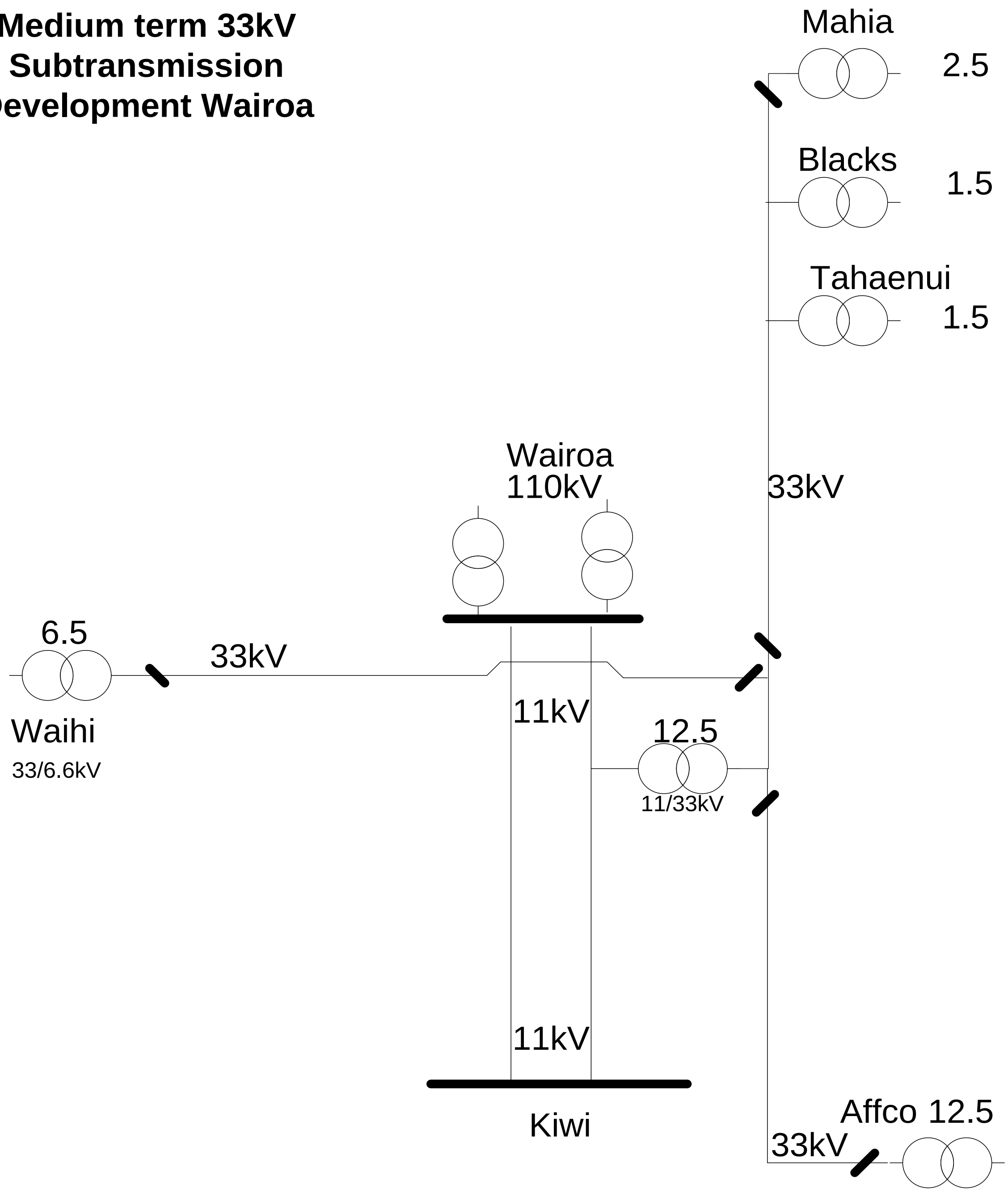
The following options have been identified:

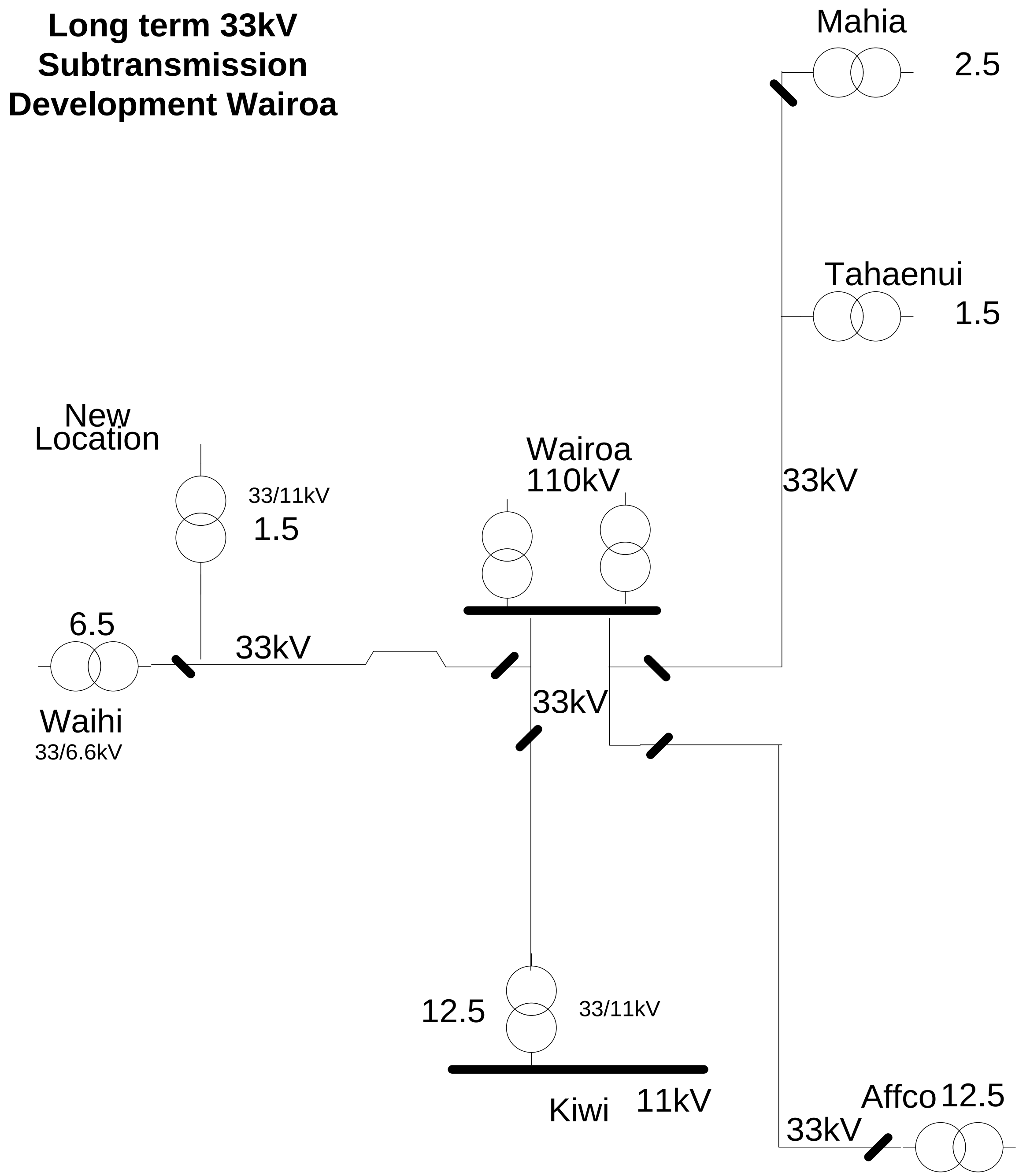
A. Embedded Generation Affco. Eastland Group/ENL continue to investigate embedded generation opportunities.
B. 33kV Supply to Affco. In the medium term AFFCO could be supplied at 33KV by converting the Waihi 50KV line to 33kV and connecting to the 33kV Transformer at Wairoa instead of Kiwi. This will improve contingent 11kV capacity to Kiwi and be available to supply other Wairoa growth including sawmilling.
C. 11kV Feeder Reconfiguration Wairoa Substation. A reconfiguration of the Frasertown feeder, Mahia Supply TX , Raupunga Feeder and KiwiB Feeder at the Wairoa Substation (acquired Apr 2015) will improve contingent 11kV capacity to Kiwi as per option B and reduce Customer minutes ie SAIDI for outages on Fasertown feeder as a result of splitting the feeder from the connections in the Nuhaka Whakaki area
D. The long term option for the sub-transmission development of Wairoa is that the current 110/11KV transformers be replaced with 110/33KV transformers. This option provides for splitting of the Borough1 and Borough2 feeder load/connections to maintain contegent capacity on these two feeders crossing the Wairoa River.

The medium and long term options for sub-transmission development in Wairoa are shown on the following schematics. While the first stage of development is underway it should be noted that the final stage will be deferred until necessary.

Scheduled for 2020- 2024.

Medium term 33kV Subtransmission Development Wairoa





Tuai Substation

The maximum demand Tuai is not forecast to exceed 0.65MW during the planning period.
The age/conditioned based replacement of the 110kV transformer is now due.

The potential to supply Waikaremoana load from alternative sources to avoid replacement of the 110kV transformer and allowing it removal has been investigated.

The alternative supply options allowing removal of the Tuai Transformer include.

A) Tuai/Wairoa 11kV Link. Building a line to Waikaremoana from the end of the existing Wairoa 11kV network which comes within about 1km of Waikaremoana. Because of the 11kV reinforcement/upgrade required all the way from Wairoa. It is also considered that consent and/or easement issues associated with this option would be considerable. The additional load and line length on the Frasertown feeder would incur a corresponding decline in primary performance figures.
B) A variation to this option could include converting the 50kV Waihi line to 33kV and provide a 6.6/11/33kV transformer at Waihi. This option will be further investigated when the Wairoa development plan is implemented.
C) Taking an 11kV supply straight from the generation bus at Tuai. This option was discounted due to loss of supply issues associated with planned and unplanned generation bus outages. The generator at the site has been approached but has declined proposals on both technical and operational grounds. Liability relating to obligation to supply and for damage to customers equipment were also identified as issues, preventing successful implementation, by the generator.
D) Standby Generation Development: The installation of standby generation, refer 4.7.1.5 ffers a solution to the issue of contingency capacity while addressing distribution performance enhancement at the same time. This option does not provide for removal of the transformers but allows for replacement of the existing transformer with a single 3 Phase unit at lower cost than 2 units or a single phase bank with spare unit.

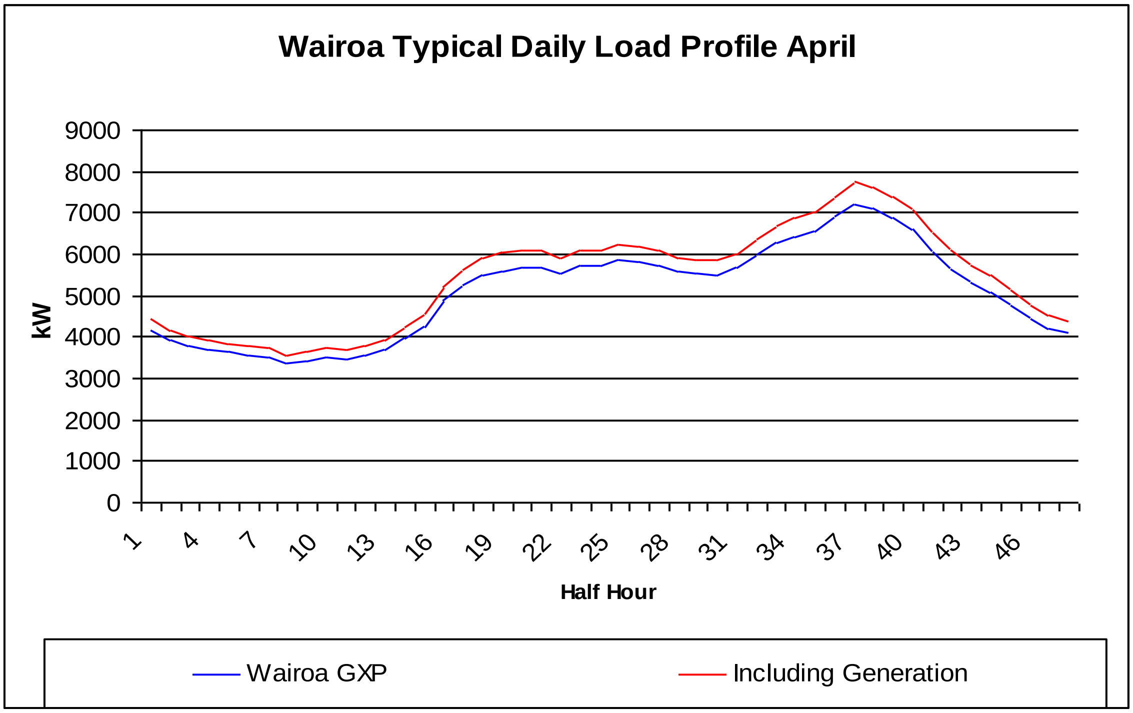
ENL has investigated the above options however, options A to C are not economically or commercially viable, hence a supply from the Tuai GXP to a Substation at or near this site will be required for the foreseeable future.

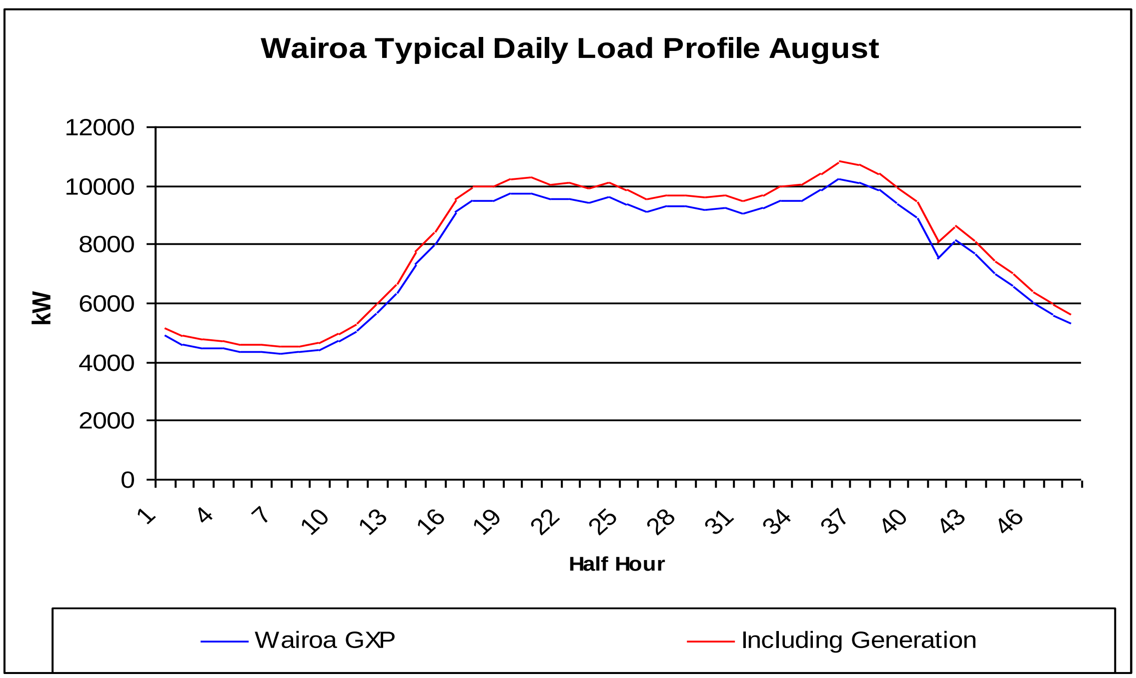
4.7.1.3 Generation Development

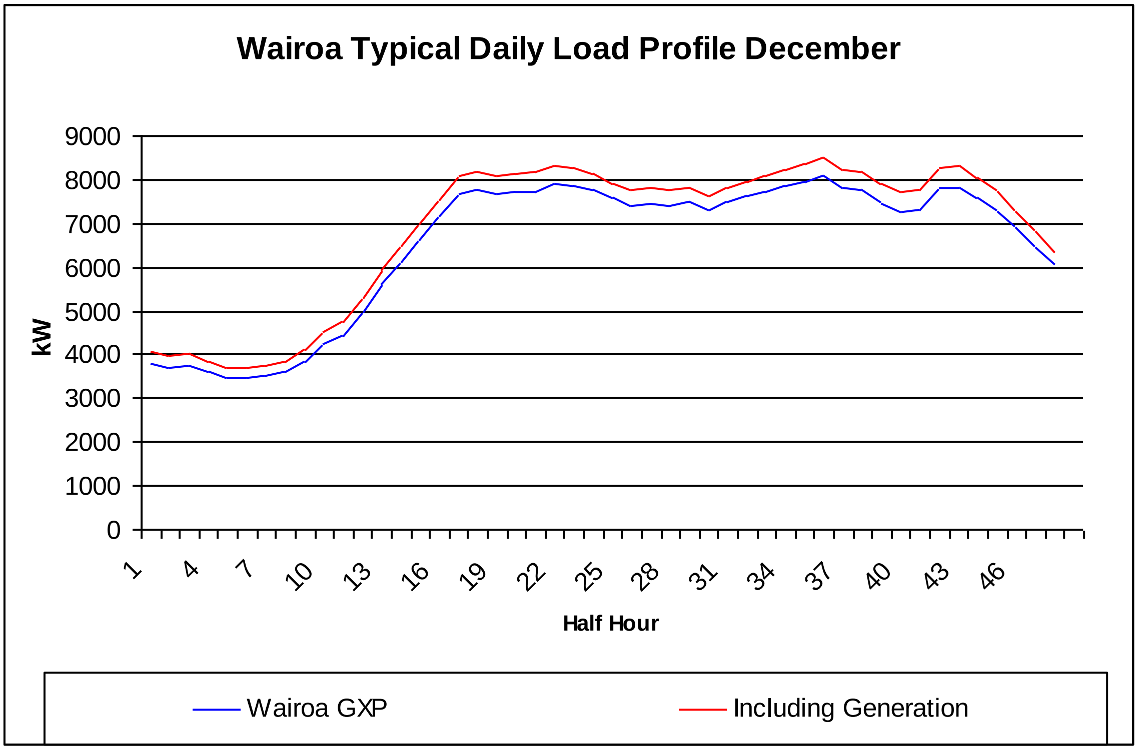
Investment in generation by Eastland Generation Limited presents a business diversity option as well as being a least cost substitute for expensive transmission and/or sub-transmission investment.

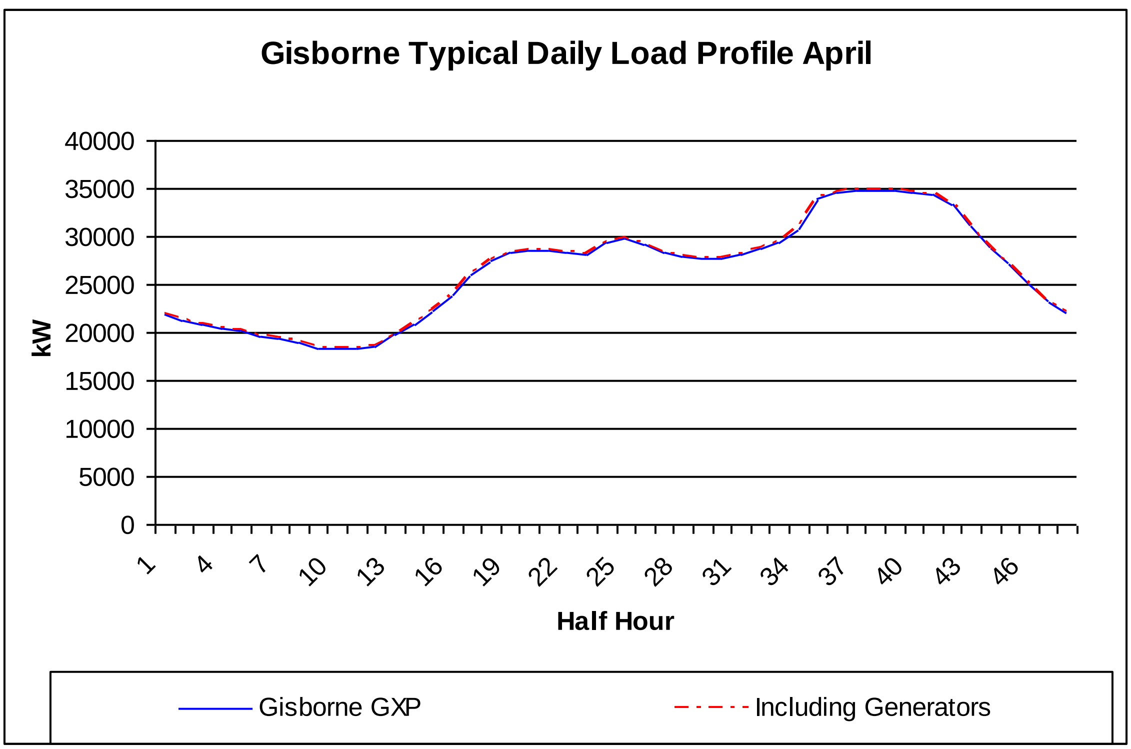
For each development need identified which involves an asset solution, ENL considers alternative solutions including distributed generation. Working with Eastland Generation Limited and other partnerships non-asset solutions are incorporated into development actions where appropriate. The work undertaken in conjunction with Generation partners includes: Water monitoring, Wind Monitoring and Engineering analysis activities. As the activities of Eastland Generation Limited include development opportunities outside the ENL region the internal processes used to develop these alternatives are outside the scope of this plan.

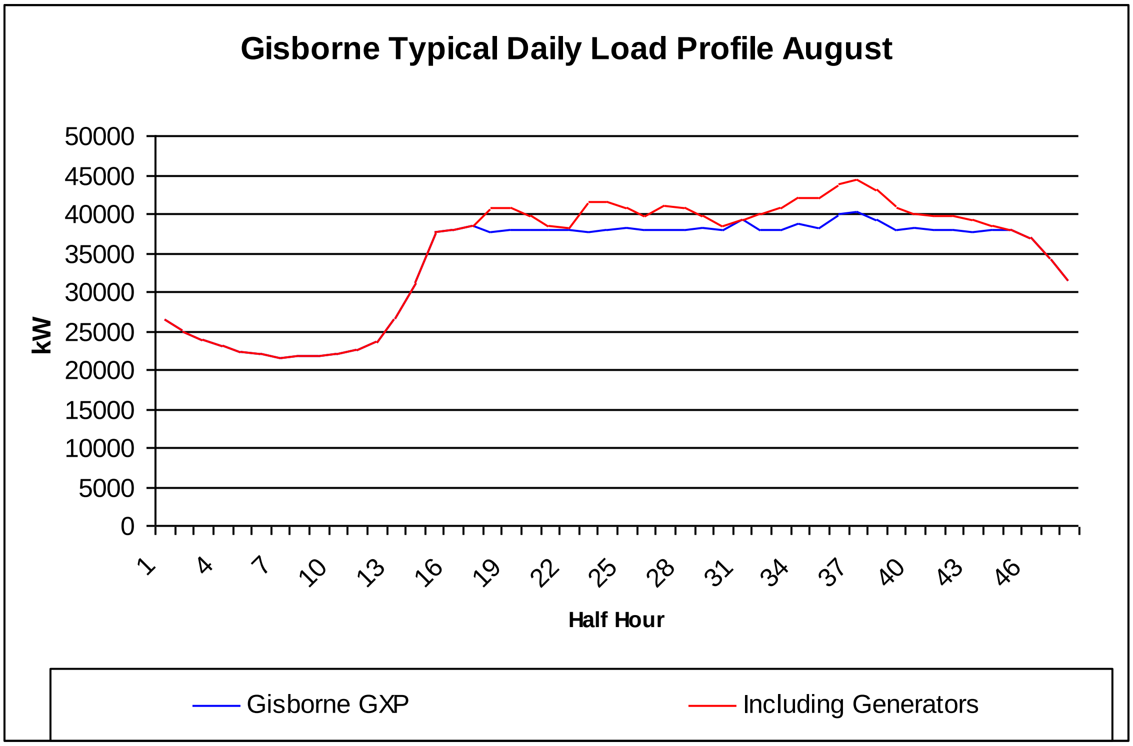
The following daily load profiles show how the use of ENL's existing embedded generation when operated in conjunction with load control can effectively manage peak load periods creating a flat daily profile. These profiles indicate that there is little scope for additional peaking generation benefiting the overall demand side management of the assets. The contribution of base load generation opportunities is the preferred method to minimise further transmission and sub-transmission investment.

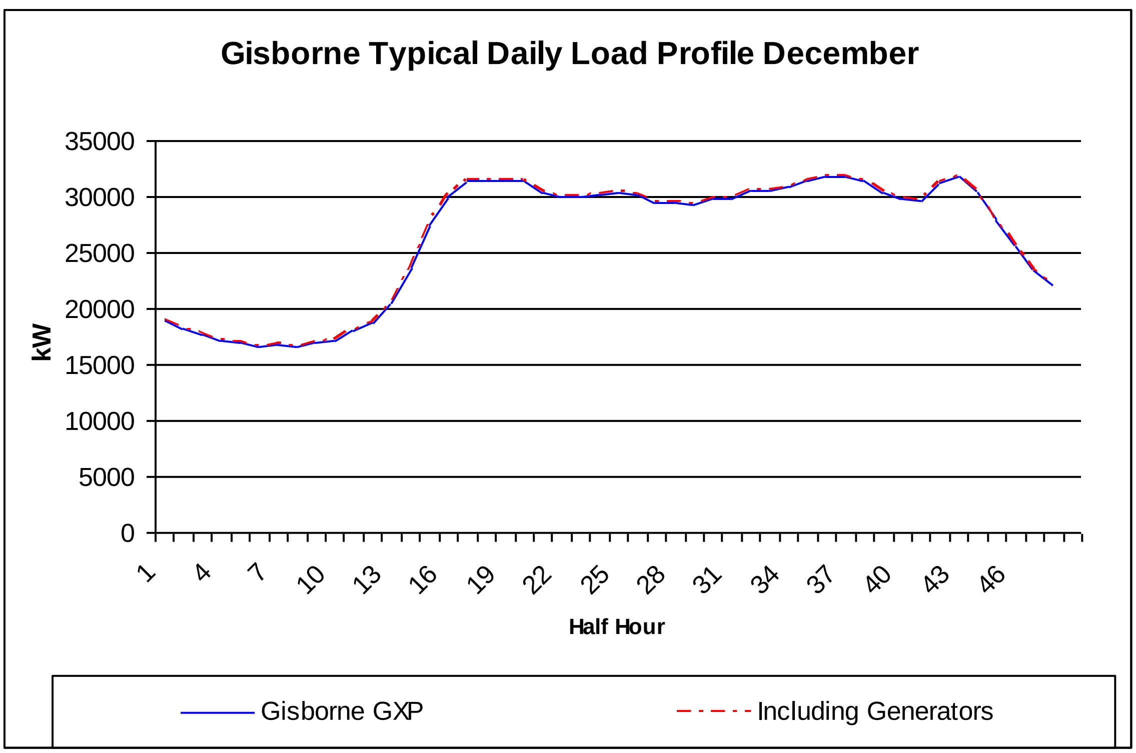

Wairoa Typical Daily Load Profile April
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
kW
1
4
7
10
13
16
19
22
25
28
31
34
37
40
43
46
Half Hour
Wairoa GXP
Including Generation


Wairoa Typical Daily Load Profile August
12000
10000
8000
6000
4000
2000
0
kW
1
4
7
10
13
16
19
22
25
28
31
34
37
40
43
46
Half Hour
Wairoa GXP
Including Generation


Wairoa Typical Daily Load Profile December
kW
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
1
4
7
10
13
16
19
22
25
28
31
34
37
40
43
46
Half Hour
Wairoa GXP
Including Generation


Gisborne Typical Daily Load Profile April
kW
40000
35000
30000
25000
20000
15000
10000
5000
0
1
4
7
10
13
16
19
22
25
28
31
34
37
40
43
46
Half Hour
Gisborne GXP
Including Generators





Regular review of alternative generation schemes previously investigated on the East Coast is undertaken. The various schemes investigated included Hydro, Wind, Biomass and Co-generation (utilising natural gas). The reviews are carried out in order to assess the viability of previously investigated generation options with regard to the increasing cost of energy and identify those worthy of implementation.

Wind

Monitoring is currently being undertaken at Mokairau, Makarori and Whakapunaki. These sites were thought to show potential; however lack of wind and proximity to the existing distribution network is the primary constraint affecting economic viability. Large scale options have the additional logistical issues associated with road access from Gisborne. Another issue is that should significant development of wind generation occur, further base load generation would have to be introduced. This is to ensure network stability and provide contingent capacity support.

A Provisional allocation to establish wind generation has been identified in Eastland Generation Limited's development program should any option become viable.

Biomass Generation

A number of proposals to install a biomass plant using waste from forestry and timber industries have been investigated. A site in the Matawhero area would supply the developing large scale industry with both electricity and process steam. Options of this plant are yet to be determined by Eastland Generation Limited and will be based around the requirements of the mill operators.
Studies into residue volumes and delivered price at Matawhero have been completed. The studies identify an economic line within which residue could be delivered to a bio-mass generation facility. The studies indicate some level of forest residue collection is viable. It is likely that this opportunity will be taken up by a third party in conjunction with the development of a new large scale industry.

Hydro

In the 1970s and 80s a number of potential hydro schemes on the East Coast were investigated by Eastland Energy. With changes in the economic environment with respect to generation Eastland Generation Limited continues to reviewing these opportunities.

In addition to its own investigations, Eastland Generation Limited is liaising with private investors who have identified other potential hydro schemes within the Gisborne and Wairoa regions.

Waihi Power Station improvements include the possibility of increasing the storage capacity of the dam by dredging sediment from the lake floor, and/or by raising the height of the existing dam wall. Investigations have proven both these proposals to be uneconomic at this time.

Gas Co-generation

Investigations into Gas Cogeneration have shown it to be uneconomic without process heat off take. There are also constraints on the regions gas supply, limiting any generation to around 6MWe. To make this type of generation cost effective it is imperative that an industry capable of utilising the process heat is found (e.g. timber drying). Also access to long term supply of gas with price certainty is required. Eastland Generation Limited continues to review any opportunities should they arise.

Customer installed Standby generation

Some opportunity exists for ENL to utilise customer installed standby generation as peaking plant. This opportunity is however limited as few industrial customers in the region have at this time felt it necessary to make provision for or invest in security of supply. Currently the existing customer generators are not suitable for use in a peaking role without significant upgrade cost. The reduced life expectancy and increased maintenance cost in a peaking role when compared with the targeted life of the equipment in a standby role are additional issues affecting the viability of these options currently.

4.7.1.4 Distribution Development

Security reinforcement due to Growth

Section 4.4.3 of this document identifies when growth will or has caused 11kV capacity constraints either in terms of demand or more commonly in terms of voltage stability over distance.

Feeders selected for duty as tie feeders providing contingency capacity to other feeders/substations need to maintain spare capacity.

CBD expansion necessitates the upgrading and development of reticulation in specific areas of the Gisborne and Wairoa CBD's. This upgrading includes the undergrounding of existing overhead circuits on the CBD fringe with allowance for capacity upgrade.

In cases involving upgrade of existing lines or cables the justification for the identified projects incorporates a renewal component that has not been included in the renewal projections. Refer section 5.4.

11kV Lines and Cables that need to be upgraded for growth within the next 10 Years are indicated below. The cable projects are small in nature involving upgrades of old cables to a larger size.

As these projects have similar success outcomes and risk assessment factors the rating of these options are the same and identified as having a reasonably high priority in section 6.2.3.

Year	Location	Existing Size	New Size	Cost	
2024/25	Ngatapa to Otoko Hill (50kV Underbuild line) 8km	N/A	Dog	$	279,208
2019/20	Stanley Rd cable link for Anzac and Awapuni Road	N/A	300mm Al	$	167,525
2017/18	Wainui link Sponge Bay to Lloyd George line, 1.55km	7/14cu	300mmAl/Dog	$	150,772
2024/25	Moana Rd Bypass Dalton Feeder 1.4km	N/A	300mm Al	$	268,039
2018/19	Plunket Sub to Ormond Rd (Peel St Bridge)	70mm Cu	300mm Al	$	111,683
2018/19	Kahutia St Feeder cable (Carnarvon-Barry)	70mm Cu	300mm Al	$	307,128
2022/23	City Feeder cable (Carnarvon-Pac'N'Sav)	70mm Cu	300mm Al	$	156,336
2020/21	Gladstone to Hirini Street cable	95mm Al	300mm Al	$	89.346
2025/26	JNL to Makaraka link , line	N/A	300mmAl/Dog	$	210,000

Allowances to accommodate growth triggered 11kV line network extension work typically arising and completed during the financial period are as follows.

Lines	1.0km p.a. @ $100,515/km = $100,515
Cables	0.5km p.a. @ $222,000/km = $111,683

Development of Load Control System

Identified as an opportunity to optimise network performance and defer investment in demand side growth, options for development of the load control system has been considered. The main disadvantage identified is the inability to provide reliable control and achieve the necessary benefits. In addition there is a lack of incentive for consumers to invest in energy storing appliances which limits the effectiveness of any investment. Without products that are tailored to, for example, hot water cylinders of different sizes, there is no incentive to install storage capacity.

Control in the non-domestic sector is at present virtually non-existent. There is a potential market for controlled products specific to dairy sheds, irrigation and freezer loads. A further option that can be offered to businesses is supply with lower security levels, for example, a “first off – last on” priority load control for non-essential load such as air-conditioning.

Since ENL is dependent on retailers passing through pricing to consumers, there is a major barrier to optimise load control. Concerns in the industry over this perceived lack of retail sector maturity are likely to be addressed at some point.

In 2000 the Gisborne city load control system included a significant amount of outdated pilot control. This was a hardwired cascaded relay system that had high maintenance costs. Because the system could only support one control option it could not be tailored to different loads. The system had no potential to capture the entire controllable load.

From 2000 to 2008 the Gisborne pilot system was replaced with ripple receivers to minimise on-going costs. While the project successfully eliminated the high maintenance costs the entire system relies on a single injection transmitter.

Wairoa has a particular problem due to the frequency selected for its ripple control system. High frequency signals have difficulty propagating through networks and therefore control is very unreliable for the rural portion of the Wairoa controllable load. Load control development in Wairoa is further complicated in that the incumbent energy retailer owns the signal receiving equipment.

The Wairoa CBD and township operates on a pilot system with a centralized control point. Investigation of options for replacement of the existing Wairoa plant do not realise sufficient benefits currently. The best option at present is to maintain the pilot wire system with a view to shutting down the injection plant when it fails.

Bypass the existing Wairoa load control plant providing direct control to the pilot system in the CBD.

Summary of Actions

Install 2nd Injection point Gisborne deferred indefinitely until sufficient benefits improve viability.

Monitor the viability of a new load control plant and frequency change at Wairoa while maintaining the pilot wire system.
Monitor opportunities to implement demand side management. Currently no effective opportunities identified

Network Loss Reduction

Distribution network companies do not suffer any significant cost penalty for high losses. Hence there is little investment signal for reducing losses. This would imply that if voltage standards can be maintained in line with the regulations then it is a valid commercial approach to minimize capital upgrades by not maintaining low loss levels. Where security provision by way of interconnectivity is prominent and reserve capacity is built into the network for growth, overall loss figures are likely to be lower.

It can also be argued that it is more economically efficient for the community to pay for losses than to fund capital expenditure on conductor size and/or voltage upgrades to decrease losses, particularly on rural feeders with poor economics. Where transmission is constrained the value of reducing losses can be measured against:

1) The cost of kWh of avoided transmission (i.e. imbedded generation)
2) The cost of new investment to increase transmission capacity

Networks also have an obligation to manage their networks to good industry practice.

While voltage problems are not widespread on the network they do exist. An indicator of high losses is voltage sensitivity to load regulation. These issues are regularly evident in the following areas within ENL's network.

Frasertown-Raupunga ring
Essentially distance is beyond the capability of 11kV reticulation and sub transmission support is required.

Mahia
A large seasonal load at the end of the feeder suggests conductor reinforcement and sub transmission extension is required.

Matawai

Load, distance and voltage contribute to marginal performance.

Whangara
The long distance between Kaiti and Tolaga substations combined with high growth at Wainui is exceeding the conductor capacity and the Tatapouri voltage regulator limits.

Ormond
Load, distance and voltage contribute to marginal performance

While losses are higher in certain other locations the number of supplies affected is small and load diversity may mitigate this to some degree. If the areas identified above were to see significant load growth, voltage performance would quickly become unsatisfactory.

When designing new or replacement networks the following loss standards are applied.

Design Loss Standards	Design %	Max. %
Transmission/Sub transmission Lines	1	2
Zone Transformers	1	2
Distribution Lines	3	5
Distribution Transformers	2	4
LV Distribution	3	6
TOTAL	10%	19%
Non-network losses		
Service Line	3%	
Metering	2%	
Installation	3%	
TOTAL	8%	

Loss Analysis

Prior to April 2015 ENL's total system losses were around 8.2%. From April 2015 following relocation of Transpowers GXP Metering from Gisborne and Wairoa Substations to the Tuai GXP the losses increased by a futher 2%. The cost of these transmission Losses previously allocated via Transpowers pricing model were allocated to the Electricity Retailers suppling Customers in the Gisborne and Wairoa Regions.
The losses can be broken down to technical and non-technical losses. While the dynamics of the network load makes calculation of technical

losses impractical use of load flow analysis applied to a snapshot of the network may provide a relative comparison or distribution of losses for the network segments. Using a snapshot load of 1 standard deviation above the normal average load and a load distribution based on installed transformer capacity, the total loss for the Eastland Network's high voltage network was determined to be 3.1 %. This figure being made up of 50 kV line losses of around 0.8%, 11 kV line/cable losses of around 1.1% and the losses from the zone substation transformers of around 1.2%. The average loss of the Eastland Network's Low Voltage network was determined to be in the region of 2 %.

Old zone transformers offer the greatest opportunity to reduce losses on ENL's network. There are 4 banks of 4 single-phase units on the network. These transformers have losses in the order of 6% as a result of the following factors:

High loss iron (all pre-1964 development using steel alloy).
4 separate units contain more iron to magnetize.
Sub-optimal load.

In all cases savings in losses and reduced maintenance justifies replacement with modern 3-phase IMP units within a 25 year pay-back period.

Location	Capacity MW	Losses kW	Value p.a. $
Tolaga T1	5	300	30,000
Puha T1	5	300	30,000
Patutahi T1	5	300	30,000
Patutahi T2	5	300	30,000

The following table indicates the calculated high voltage losses in terms of load per feeder. When compared to the design standard it shows that there is considerable diversity in losses of components and load (of which loss is a function). High % losses for a given feeder can be an indicator of either low utilisation or an under-designed/overloaded feeder. Hence consideration of each feeder in terms of length, location and purpose is necessary when interpreting the information.

SUBSTATION	FEEDER	Feeder I (A)	Feeder Length (km)	Feeder Vdrop (V)	Vdrop (V/km)	load (KVA)	line loss (KVA)	% losses
Te Araroa	AWATERE	4.49	48.76	180	3.7	99.8	16.0	16.1
	HICKS BAY	13.73	73.52	590	8.0	252.1	21.5	8.5
	TE ARAROA	7.51	13.95	50	3.6	143.1	4.0	2.8

		25.73	**136.23**					
Ruatoria	RUATORIA	23.78	21.88	50	2.3	467.4	22.1	4.7
	MAKARIKA	9.90	53.47	290	5.4	186.2	19.1	10.2
	TIKI-TIKI	15.98	123.15	380	3.1	324.1	40.5	12.5
		49.65	**198.50**					
Tokomaru	INLAND	10.55	55.06	400	7.3	217.1	18.6	8.6
	SEASIDE	6.29	6.09	30	4.9	118.5	5.0	4.2
	MATA RD	14.32	129.08	380	2.9	268.3	39.2	14.6
		31.15	**190.23**					
Tolaga Bay	TOKO-TIE	3.93	38.66	90	2.3	85.9	15.0	17.5
	TOWN	13.84	2.61	10	3.8	259.5	5.0	1.9
	ROTOTAHI	11.88	43.08	120	2.8	227.4	20.0	8.8
	TAUWHAREPARE	8.03	113.78	420	3.7	162.9	35.2	21.6
		37.68	**198.13**					
KAITI	HERSCHELL	8.92	0.68	0	0.0	160.0	7.0	4.4
	DALTON	45.33	93.18	740	7.9	875.7	37.2	4.2
	TAMARAU	74.75	14.17	230	16.2	1451.2	41.6	2.9
	WAINUI	37.36	3.07	30	9.8	720.1	13.2	1.8
	WHANGARA	34.11	22.26	280	12.6	649.4	30.3	4.7
		200.47	**133.36**					
CARNARVON	KAHUTIA	35.01	3.68	70	19.0	684.1	33.4	4.9
	CITY	72.16	2.19	40	18.3	1374.9	15.3	1.1
	WATTIES	65.40	3.01	30	10.0	1242.1	35.1	2.8
	ANZAC ST	23.72	2.31	20	8.6	480.0	27.0	5.6
	CHILDERS RD	55.59	5.73	60	10.5	1100.6	51.2	4.7
	AWAPUNI RD	44.36	5.40	50	9.3	855.9	33.1	3.9
	GLADSTONE RD	72.18	6.36	140	22.0	1393.9	72.1	5.2
	ABERDEEN RD	70.62	10.25	160	15.6	1283.8	47.4	3.7
	PALMERSTON RD	68.10	3.04	30	9.9	1290.1	28.1	2.2
		507.13	**41.96**					
PARKINSON	LYTTON RD	50.08	2.90	60	20.7	951.9	17.4	1.8
	WILLOWS RD	4.45	10.18	10	1.0	88.9	31.0	34.9
	ELGIN	77.91	7.96	140	17.6	1484.2	32.5	2.2
	CHALMERS	56.64	5.43	40	7.4	1098.0	31.1	2.8

	CEDEN CO	94.92	1.16	20	17.3	1800.0	13.3	0.7
	SOLANDIS	44.93	1.54	10	6.5	825.1	21.0	2.5
	INNES ST	10.74	0.84	0	0.0	165.0	12.0	7.3
		339.66	**30.01**					
MAKARAKA	CAMPION	60.57	9.35	190	20.3	1004.3	46.1	4.6
	NELSON RD	106.38	14.77	450	30.5	1940.6	51.7	2.7
	HAISMAN RD	64.92	38.22	360	9.4	1117.5	46.5	4.2
	BUSHMERE RD	53.84	136.97	720	5.3	964.0	57.5	6.0
		285.71	**199.31**					
PATUTAHI	LAVENHAM RD	9.77	33.35	90	2.7	192.4	10.0	5.2
	WAIMATA	33.40	65.18	230	3.5	618.0	30.2	4.9
	MURIWAI	24.48	68.79	340	4.9	461.8	34.7	7.5
	TE ARAI	22.67	82.20	350	4.3	425.1	23.8	5.6
		90.31	**249.52**					
PEHERI	WARENGAO Kuri	9.81	18.10	80	4.4	183.9	4.1	2.2
	PARIKANAPA	1.04	27.01	40	1.5	23.1	6.0	25.9
	TINIROTO	7.29	76.19	510	6.7	138.2	20.3	14.7
	TAHUNGA	3.20	30.93	260	8.4	63.8	9.0	14.1
		21.33	**152.24**					
NGATAPA	NGATAPA	4.91	30.88	210	6.8	96.5	7.0	7.3
	TAHORA	9.02	84.55	610	7.2	172.4	22.3	12.9
	TOTANGI	0.41	12.06	110	9.1	19.5	4.0	20.5
		14.34	**127.48**					
PUHA	WHATATUTU	14.07	95.62	380	4.0	284.7	28.5	10.0
	KANAKANAIA	12.95	43.23	260	6.0	249.4	17.0	6.8
	TE KARAKA	12.66	28.22	140	5.0	245.8	9.1	3.7
	MATAWAI	26.07	230.17	450	2.0	503.2	59.8	11.9
		65.75	**397.24**					
JNL	JNL	192.28	2.68	40	14.9	3604.3	11.7	0.3
MATAWHERO	DUNSTAN	59.13	3.26	80	24.5	1115.3	9.2	0.8
	JNLA	117.86	4.78	130	27.2	2172.7	18.2	0.8

	WAIPOA	41.65	1.22	40	32.8	787.5	18.1	2.3
	BELL RD	21.95	18.75	80	4.3	410.3	19.0	4.6
		240.59	**28.01**					
PORT	PORT	6.15	2.28	0	0.0	130.1	29.0	22.3
	CRAWFORD	44.30	7.43	30	4.0	841.7	15.1	1.8
	ESPLANADE	92.53	7.06	30	4.2	1749.9	81.1	4.6
	HARRIS	97.33	7.82	60	7.7	1796.8	38.4	2.1
		240.31	**24.60**					
KIWI	BRICKWORKS/ RAUPUNGA	36.98	217.83	750	3.4	614.9	59.9	9.7
	AFFCO	148.29	8.81	280	31.8	2651.3	85.7	3.2
	NUHAKA/ FRASERTOWN	50.66	252.58	630	2.5	952.2	76.1	8.0
	BOROUGH 1	73.59	10.81	160	14.8	1332.0	51.5	3.9
	BOROUGH 2	103.87	12.13	180	14.8	1823.7	63.9	3.5
		413.40	**502.15**					
WAIROA	BLACKS	33.72	95.09	300	3.2	592.9	23.8	4.0
	TAHAENUI	17.49	64.29	280	4.4	328.8	23.4	7.1
		51.21	**159.38**					
TUAI	TUAI	23.94	133.77	1040	7.8	465.3	60.9	13.1

Despite losses being high in terms of percentage, on some rural feeders the cost of re-conductoring is prohibitive unless needed for other reasons or attended to as part of a renewal program.

While ENL does not bear the cost of network losses it does bear cost of increased demand and transmission upgrade if losses are significant.

Reducing ENL losses is a relatively expensive although justifiable option for gaining 1MW of transmission capacity. Economics favor concentration on reduction of losses contributed by the older zone transformers on the system.

Power Factor Correction

Identified as an opportunity to optimise network performance and defer investment in capacity upgrades, options for improving levels of power factor correction have been considered.

ENL pricing conditions require all network connections to maintain a power factor of 0.95 lag or better. Consequences of not meeting this requirement is that ENL reserves the right to apply a higher demand tariffs fixed daily charge to the ICP until the power factor issue is remedied.

Power Factor is poor in most rural areas of the network and correction would increase capacity at the 50 kV Gisborne bus by approximately 900 kW. This poor performance is the result of inadequate policing of standards for connection of motors.

The approaches to addressing this are…

Installations are reviewed on a regular basis and customers notified of the need to add capacitors/correction. ENL believes that the most effective approach for dealing with non-compliance is penalty payment via pricing rather than attempting disconnection.

Selected feeders can be corrected in bulk via the installation of static capacitors. As identified in the loss analysis, approximately 7 feeders on the network are considered suitable for the application of reactive compensation by capacitors. This viability of this option is generally restricted to rural feeders where loads are less than 400KW. And losses exceed 5%. The capacitors are expected to cost in the order of $40,000 per site. There is currently no commitment to this option as distributed generation strategies are expected to provide for voltage support, reducing losses at high load times.

Additional capacitance could be installed as an option at the Transpower substation but this is the most expensive option and does not realise the benefit of reduced network losses. This option is not being pursued at this time.

Uneconomic Rural Lines and Connections

Twenty percent of ENL distribution lines, are considered uneconomic. Calculation of value objectives has indicated the need to reduce value in remote and rural areas and hence improve the economic performance of these network segments or current levels of subsidisation by urban customers will need to be maintained or increased in the future. The option of disconnection of uneconomic lines will have negative potential social and economic effects on rural

customers and communities hence ENL is currently discounting this option.
ENL has been developing the following strategies for the management of uneconomic lines.

Assets classed as rural and remote will be allowed to age to an average remaining life of 25 to 30 years. Following this the lines will be maintained at this minimum level via a combination of renewal at lower cost, service line handover and cost contribution strategies.

Alternative energy supply options are also expected to be part of the economic outcome and ENL has supported investigation into this technology. Further, ENL supports investigation into embedded generation options.

Renewal of the remote assets at a lower cost design solution can be achieved via reduction to single-phase in place of 3-phase construction. This is limited to lines where the existing customers are prepared to convert 3 phase equipment to single phase or operate it using converter equipment.

Investigation of a number of construction options and voltages has been considered. The most economical solution for the terrain on ENL's network appeared to be 22kV single wire earth return. However other factors including new easement negotiation, telecom interference issues, and re-insulation costs, have now been considered and suggest conversion to single phase 11kV is the most practicable in terms of a viable and sustainable solution.

300km of network in the Gisborne region in uneconomic zones has provisionally been identified as suitable for conversion. Preliminary communications indicate that customer contribution options to fund the rebuild work are unacceptable. In addition there is no mechanism under the Targeted Control Regime to recover costs via specific price schedules. ENL is continuing to monitor options on an appropriate mechanism to address the viability of having uneconomic lines.

The current approach to determining the best mix of options is to manage the risk and failures in a lowest cost manner.

4.7.1.5 Performance Enhancement

Overhead to Underground Conversion

ENL recognises that renewal of overhead lines with underground cables can provide benefits in the areas of public safety and reliability.

Projects of this nature are generally not considered due to funding constraints. However where growth projects are undertaken in urban areas, upgrades in conjunction with the undergrounding option are considered.

Ground Fault Neutralisers

An option exists to use Ground Fault Neutraliser technology, which reduces the amount of electrical arcing at the point a fault occurs on the network. This reduces the level of threat to human life and risk of fire. It also allows the power supply to be maintained to homes and businesses, while repair crews are dispatched to fix the fault. Transient or momentary faults can be neutralised as well, eliminating most cases of flickering lights and short term interruptions to power supply. The estimated cost to install units at 8 rural zone substations averages $250,000 per site or a total of $2,000,000. The system is effective on avoiding a single earth fault per substation which is up to approximately 5% of SAIDI. The cost of establishing this technology is currently prohibitive given regulated revenue constraints and increased reliability at a cost to the customer is not signalled from customer surveys. Currently service level improvements of this nature are a lower priority than inspection and maintenance activities associated with safety.

Urban/Rural Automation

Previously ENL has invested in automation of approximately 80 key sites in the region to minimise disruption times to areas outside the immediate fault area. A small allocation of the Performance and improvement funding is allocated to increasing the level of automation over the life of this plan. Sites are selected that provide the greatest benefit after considering where faults are occurring and who is affected. As faults in the urban area are rare and response times in urban areas are low, rural automation projects are generally favoured over urban projects.

Standby Distributed Generation

In partnership with Eastland Generation Limited ENL has established sites used to enhance performance of the network in contingent events and for maintenance activities. ENL is reviewing options to increase the level of distributed generation targeting vulnerable rural and remote lines that have performance issues identified from analysis of Distribution performance in section 8.2.4.

Areas include:

–Frasertown

-Raupunga

-Matawai

-Hicks Bay

-Rukaturi

-Mata road

At an estimated cost of $300,000 per installation, reduced SAIDI for both planned and all types of unplanned outages can be achieved on the feeder where the generation is connected. Operational costs can also be recovered from delivered energy in some cases and demand management benefits exist. If the generation is supplied under contract via a third party up front capital costs are avoided. Currently service level improvements of this nature are a lower priority than inspection and maintenance activities associated with safety

Portable/Emergency Generation

ENL uses small portable generators to supply customers during planned work and in emergencies. The use of the generators is dependent on criteria of availability, cost, assessed need, duration of need, and size of load. The emergency generator portfolio comprises 3 units as follows.

-500kW Crane and Trucks (Currently not in service) Replacement options are being considered

-200kW Truck mounted

-60kW Trailer mounted (new 2011)

Additional units are being considered in the medium term. As the equipment is considered mobile plant funding is via existing allocation in the maintenance/operational budget. Currently service level improvements of this nature are a lower priority than inspection and maintenance activities associated with safety.

4.7.2 Development Co-ordination

Capacity and security constraints impact different components of the transmission and distribution system and vary with growth expectations. Growth cannot be excluded at transmission level because it has the ability to outstrip the best laid development plans.

A high degree of co-ordination exists to implement approved transmission, sub-transmission and generation options so that investment is complimentary and supports the strategic objectives. Also it is preferable that development options are where possible implemented incrementally so that adjustments can be made in response to changing circumstances.

4.7.3 Development program

Expenditure forecasts based on the options considered for major initiates are given below. The lack of significant development actions for major initiatives supports the minimal growth trends experienced and forecast in the region.

Year	Action	Cost
2014 -2015	Transmission – Completion work for acquisition of the Eastland transmission spur assets, including	1.0m
	Transmission - Purchase of line and station spares $150,000	
	Purchase of temporary tower equipment $150,000	
	Transmission - Install new RTUs and communication equipment at Tuai, Wairoa and Gisborne 110kV substations and associated communication equipment to transfer control and indication to ENl's control room $530,000	
2015-2017	Information systems review (refer 1.7.5)	$1.5m
2015-2017	Mahia 2.5MW substation and 33kV Line extension	$1.1m
2020-2024	Wahi/AFFCO/Wairoa 33kV Supply & Rationalistion	$1.3m
2023-2025	Provisional Mangapapa Zone Substation 12.5MW	$1.1m
2021 -2023	Provisional Whangara Zone Substation 2.5MW	$1.1m
2020-2025	Provisional Tuai – Gisborne 110kV Line Reconductor	$10 - $20mill
2019 - 2021	Provisional Patutahi Zone Substation Capacity increase 12.5MW	$950,000
2023-2027	Provisional Tuai – Gisborne 3rd 110kV Line & new Transmission Substation at Patutahi	$80mill
As needed	Provisional Embedded Generation, (Hydro, wind,biomass, gas)	$100,000
As needed	Provisional Connection of Customer installed Generation	$50,000

5. Managing the assets lifecycle

All physical assets have a lifecycle, and ENL's electricity assets are no exception. This section describes how ENL manages its assets over the entire lifecycle from "conception" to "burial".

5.1 What is the lifecycle of an asset

The lifecycle of an existing asset is outlined in Figure 5.1(a) below…

Figure 5.1(a) – Asset lifecycle

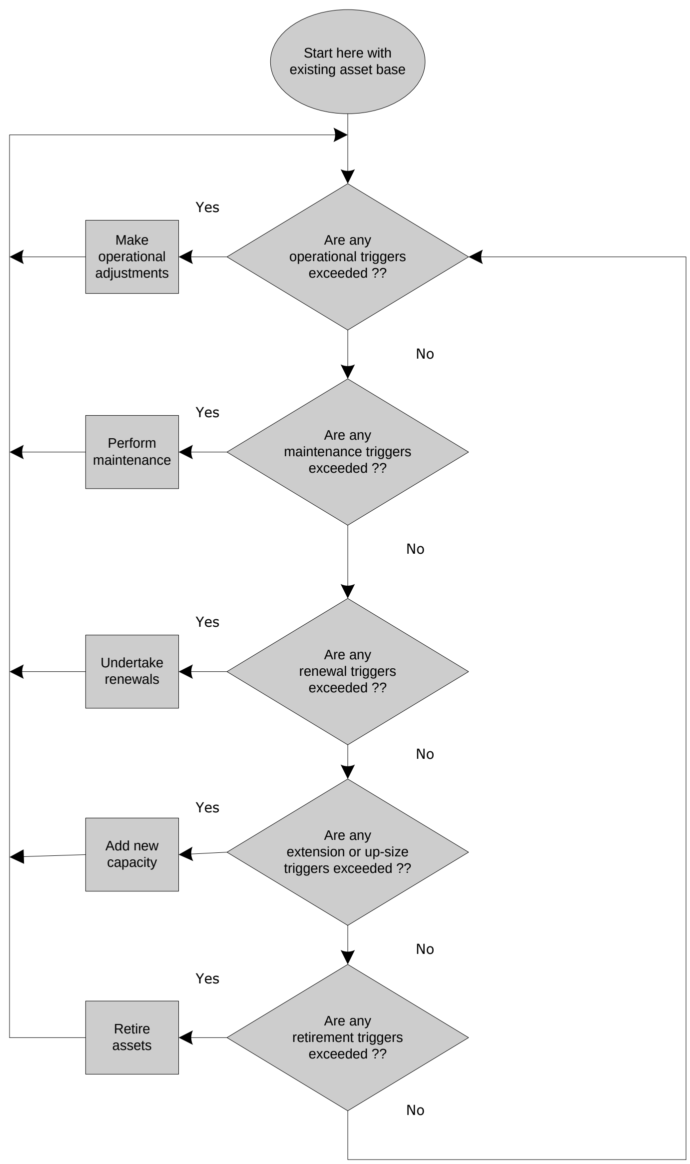


Table 5.1(b) below provides some definitions for key lifecycle activities…

Table 5.1(b) – Definition of key lifecycle activities

Activity	Detailed definition
Operations and Support	Involves altering the operating parameters of an asset such as closing a switch or altering a voltage setting. Doesn't involve any physical change to the asset, simply a change to the assets configuration that it was designed for. In the case of electrical assets it will often involve doing nothing and just letting the electricity flow. Involves systems and management functions necessary to monitor record and measure trends and generally manage the assets from conception to removal.
Maintenance	Involves replacing consumable components like the seals in a pump, the oil in a transformer or the contacts in a CB. Generally these components will be designed to wear out many times over the assets design lifecycle and continued operation of the asset will require such replacement. There may be a significant asymmetry associated with consumables such as lubricants in that replacing a lubricant may not significantly extend the life of an asset but not replacing a lubricant could significantly shorten the assets life.
Renewal	Generally involves replacing a non-consumable item like a pole or transformer with a replacement item of identical functionality (e.g. strength, capacity). Such replacement is regarded as a significant mile-stone in the life of the asset and may significantly extend the life of the complete asset (e.g. the section of line and poles). Renewal also includes the replacement of components or items that no longer comply with initial design criteria, regulatory requirements or safety standards.(e.g. a rotten poles cannot support conductor design load, new regulatory standards for earthing, new safety requirements for switchgear operation) Renewal tends to dominate the CapEX in low growth areas (Quadrant 1 of Figure 4.1.2(b)) because assets will generally wear out before they become too small. The most typical criteria for renewal will be when the capitalised costs of ops and maintenance exceed the cost of renewal (including any loss of availability). Key issues with renewal are technological advances that generally make it impossible to replace assets such as SCADA with equivalent functionality, and creeping regulation that make certain assets (e.g. compressed air vessels over 100psi) unviable.
Up-sizing	Generally involves replacing a non-consumable item like a conductor, busbar or transformer with a similar item of greater capacity but which does not increase the network footprint ie. Restricted to Quadrants 1 and 2 in Figure 4.1.2(b).
Extensions	Involves building a new asset where none previously existed because a location trigger in Table 4.1.3(a) has been exceeded eg. building several spans of line to connect a new factory to an existing line. This activity falls within Quadrants 3 and 4 of Figure 4.1.2(b). Notwithstanding any surplus capacity in upstream

	assets, extensions will ultimately require up-sizing of upstream assets.
Retirement	Generally involves removing an asset from service and disposing of it. Typical guidelines for retirement will be when an asset is no longer required. Retirement can be considered "replacement with nothing".

5.2 Operating the assets

5.2.1 System Operations

The long term planning function undertakes asset planning and design work and Technical support services. The function includes the systems to achieve the monitoring recording and reporting of asset information.

The short term system operations function implements work programs, and manages contractors. This function ensures delivery of reliability, budget cost, and safety performance by implementation of specific capital and/or maintenance activities and budgets as determined in the AMP.

The real time operations function operates the network and involves monitoring of the electricity flow from the supply points to consumers' premises, with intervention when a trigger point is exceeded.

Intervention usually involves carrying out or coordination of activities to reconfigure the asset in real time on a short or medium term basis to address the trigger point.

As outlined in Figure 5.1(a) the first efforts to relieve excursions beyond trigger points are control room operational activities and may include…

Operating a tap-changer to correct voltage excursions (which generally occurs automatically).

Opening and closing ABS's or RMU's to relieve an over-loaded asset.

Opening and closing ABS's or RMU's to reconfigure the power flow, to shut down or restore power (which can be either planned or fault related).

Operating load control plant or dispatching embedded generation to reduce demand.

Activating fans or pumps on transformers to increase the cooling rate.

Control electricity consumption or demand in accordance with the Security of supply outage plan.

5.2.1.1 Security of Supply Outage Plan

The Security of supply outage plan has been produced to comply with the Electricity Commission requirements. The plan documents procedures for reducing demand or consumption in response to a shortage of generation or failures of the National Transmission Grid. In extreme events the plan documents priorities for disconnection of supply to consumers.

5.2.1.2 Operational Triggers

Table 5.2(a) outlines the key operational triggers for each class of ENL's assets. Note that whilst temperature triggers will usually follow demand triggers, they may not always e.g. an overhead conductor joint might get hot because it is loose or rusty rather than overloaded.

Table 5.2(a) – Operational triggers

Asset category	Voltage trigger	Demand trigger	Temperature trigger
LV lines & cables	Voltage routinely drops too low to maintain at least 0.94pu at consumers switchboards. Voltage routinely rises too high to maintain no more than 1.06pu at consumers switchboards.	Consumers' pole or pillar fuse blows repeatedly.	Signs of burning or melting.
Distribution substations	Voltage routinely drops too low to maintain at least 0.94pu at consumers switchboards. Voltage routinely rises too high to maintain no more than 1.06pu at consumers switchboards.	Load routinely exceeds rating where MDIs are fitted. LV fuse blows repeatedly. Short term loading exceeds guidelines in IEC 354.	Inspection reveals signs of heating
Distribution lines & cables	Load flow analysis identifies sections in the danger zone, followed by verification from recorders	Load flow analysis identifies sections in the danger zone, followed by verification from loggers. SCADA set point alarms routinely triggered	Joint fails or shows signs of heating
Zone substations	Voltage drops below level at which SCADA set point alarms triggered. OLTC can automatically raise taps.	Load exceeds guidelines in IEC 354.	Top oil temperature exceeds manufacturers' recommendations. Core hot-spot temperature exceeds manufacturers' recommendations. Infra-red survey reveals hot joint Gas analysis indicates burning in Transformers
Transmission, Sub-transmission lines & cables	Load flow analysis identifies sections in the danger zone, followed by verification from loggers. SCADA set point alarms triggered	Load flow analysis identifies sections in the danger zone, followed by verification from loggers. Load alarms triggered Analysis of load data shows excessive levels	Infra-red survey reveals hot joint Joint fails in service

5.2.2 Business Support and System Operations Network Support

Business Support

Business support activities to ensure efficient operation of the assets include:

Finance management
Management of IT systems
Management of Human Resources
Management of non-network assets
Coordination and communication with stakeholders

Business Support expenditure is accounted for via an annual shared service fee and associated service provision agreement details the allocation of Business Support costs to ENL from EGL.

For the planning period the total $31.37m Business Support expenditure is 31% of the total operational expenditure forecast for the period.

Business Support costs have been forecast 'steady state' for this plan. These business support costs include charges in relation to the 'backbone' IT platform and financial system (which are supplied by Eastland Group to ENL). Eastland Group have recently commenced work on investigating the replacement of their legacy financial system, and the replacement of this system will likely result in an increase in Business Support costs (and an associated improvement in services). ENL intends to update the Business Support costs in the 2015 AMP.

System Operations Network Support

System Operations and Network Support expenditure includes expenditure where the primary driver is the management of the network.

For the planning period the total $29.83m System Operations and Network Support expenditure is 29% of the total operational expenditure forecast for the period.

Increases in System Operations and Network Support expenditure has been driven in part by an increase in engineering and associated support staff as a result of the increase in regulatory compliance and additional transmission assets. ENL is embarking on a strategy to increase its resourcing to improve its asset management practices (in conjunction with the replacement of its core asset management systems). It is expected that this investment will improve the AMMAT scores over the coming 2-3 years.

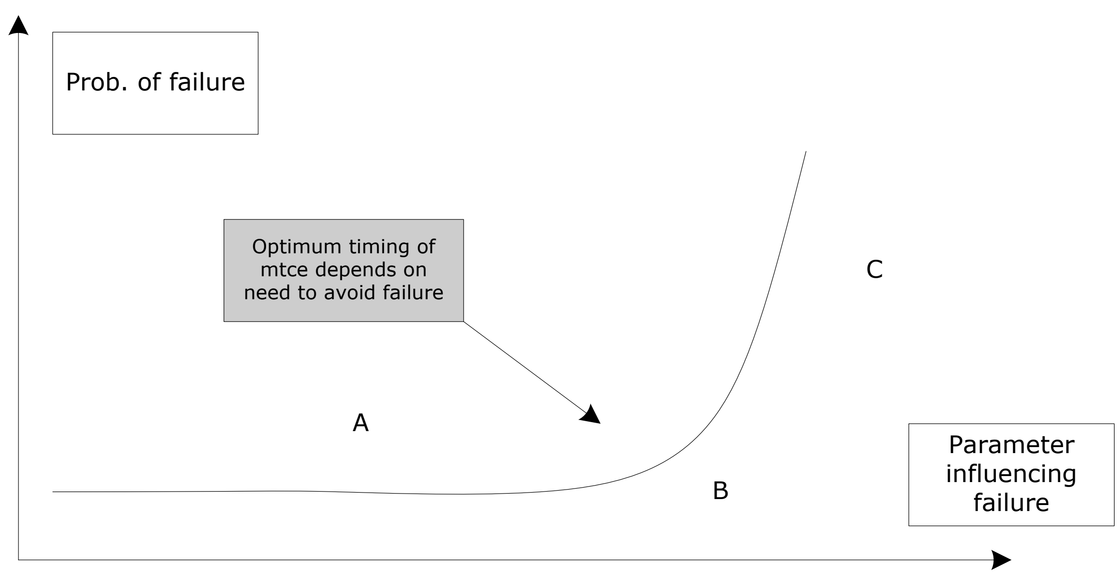
Also contributory to the increase in System Operations and Network Support expenditure is the forecast additional ACOD expense from 2015 to

2024 of $9.4m. The forecast ACOD payment is made to network connected distributed generation in recognition of avoiding investment, (in additional distribution assets and the upgrading of transmission assets), so as to meet required network service and performance standards. The exact value of any future ACOD is dependant on the final outcome of the proposed Transpower asset transfer project. Accordingly greater clarity regarding ACOD will be able to be provided in future versions of the AMP.

5.3 Maintaining the assets

As described in Table 5.1(b) maintenance is primarily about replacing consumable components. Examples of the way in which consumable components "wear out" include the oxidation or acidification of insulating oil, pitting or erosion of electrical contacts, and wearing of pump seals. Continued operation of such components will eventually lead to failure as indicated in Figure 5.3(a) below. Failure of such components is usually based on physical characteristics, and exactly what leads to failure may be a complex interaction of parameters such as quality of manufacture, quality of installation, age, operating hours, number of operations, loading cycle, ambient temperature, previous maintenance history and presence of contaminants – note that the horizontal axis in Figure 5.3(a) is not simply labelled "time".

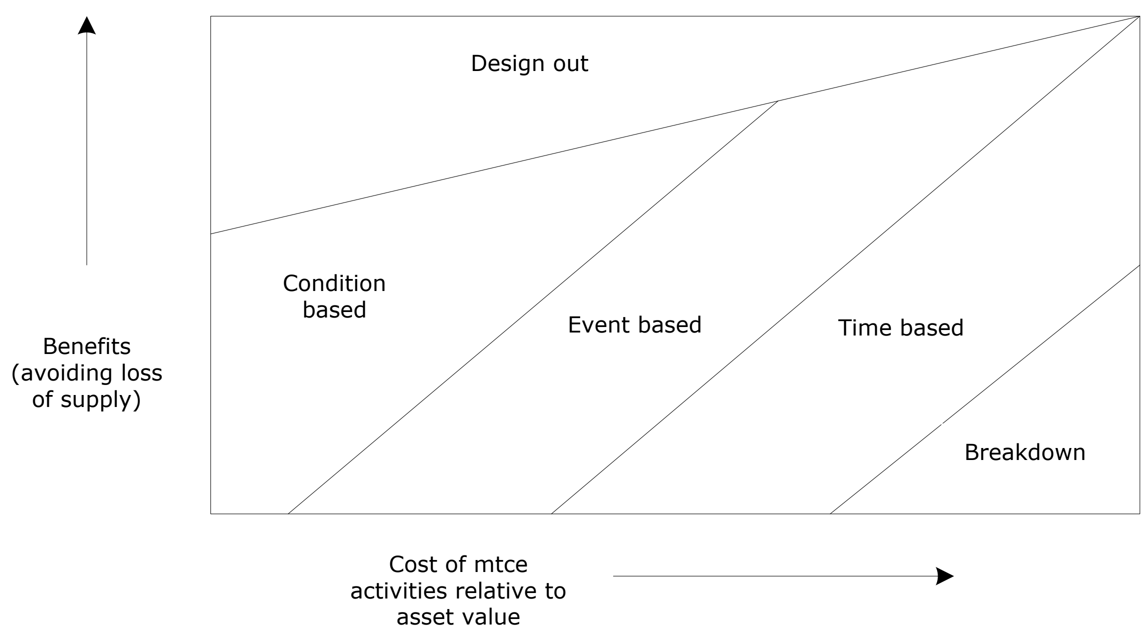
Figure 5.3(a) – Component failure



Exactly when maintenance is performed will be determined by the need to avoid failure. For instance the need to avoid failure of a 15kVA transformer supplying a single consumer is low, hence it might be operated out to point C in figure 5.3(a) whilst a 50/11kV substation transformer may only be operated to point B due to a higher need to avoid failure. In the extreme case of, say, turbine blades in an aircraft engine it would be desirable to avoid even the slightest probability of failure hence the blades may only be operated to point A. The obvious trade-off with avoiding failure is the increased cost of labour and consumables over the assets lifecycle along with the cost of discarding unused component life.

Like all ENL's other business decisions, maintenance decisions are made on cost-benefit criteria with the principal benefit being avoiding supply interruption. The practical effect of this is that assets supplying large consumers or numbers of consumers will be extensively condition monitored to avoid supply interruption whilst assets supplying only a few consumers such as a 15kVA transformer will more than likely be run to breakdown. The maintenance strategy map in Figure 5.3(b) broadly identifies the maintenance strategy adopted for various ratios of costs and benefits.

Figure 5.3(b) – Maintenance strategy map



This map indicates that where the benefits are low (principally there is little need to avoid loss of supply) and the costs of maintenance are relatively high an asset should be run to breakdown. As the value of an asset and the need to avoid loss of supply both increase ENL relies less and less on easily observable proxies for actual condition (such as calendar age, running hours or number of trips) and more and more on actual component condition (through such means as DGA for transformer oil).

Component condition is the key trigger for maintenance. However the precise conditions that trigger maintenance are very broad, ranging from oil acidity to dry rot. Table 5.3(c) describes the maintenance triggers ENL has adopted…

Table 5.3(c) – Maintenance triggers

Asset category	Components	Maintenance trigger
LV lines & cables	Poles, arms, stays & bolts	Evidence of dry-rot or spalling. Loose bolts, moving stays. Displaced arms. Foundation/erosion issues Location Safety Issues
	Pins, insulators & binders	Obviously loose pins. Visibly chipped or broken insulators. Visibly loose binder.
	Conductor	Visibly splaying or broken conductor. Poor clearances Visibly Uneven sag Trees in lines
	Cable	Failure of insulation
Service connections	Distribution Pillars	Visible Rust Graffiti/Vandalism Safety issues
Distribution substations	Poles, arms & bolts	Evidence of dry-rot or spalling. Loose bolts, moving stays. Displaced arms. Foundation/erosion issues
	Enclosures	Visible rust. Cracked or broken masonry. Overgrown access Safety issues Graffiti/Vandalism
	Transformer	Excessive oil acidity (500kVA or greater). Visible signs of oil leaks. Excessive moisture in breather. Visibly chipped or broken bushings.. Visible rust Earthing issues Safety issues
	LV Switches & fuses	Build up of contaminants

		Operations at recommended maintenance levels Failure of fuse elements Alignment or lubrication issues Safety issues
Distribution lines & cables	Poles, arms, stays & bolts	Evidence of dry-rot. Loose bolts, moving stays. Displaced arms. Foundation/erosion issues Location Safety Issues
	Cables	Failure of insulation Oil leaks Depth/clearance issues
	Pins, insulators & binders	Obviously loose pins. Visibly chipped or broken insulators. Visibly loose binder. Radio interference
	Conductor	Visibly splaying or broken conductor. Poor clearances Signs of clashing Visibly Uneven sag Trees in lines
Distribution Switchgear	Ground-mounted switches	Detectable discharge Detectable hot spots Buildup of contaminants Oil/Gas leaks Visible Rust Graffiti/Vandalism Access and Location Safety Issues
	Fuses ABS's, Switches	Loose mechanisms Binding Mechanisms Earthing issues Visibly burnt contacts Oil/Gas leaks Corrosion
Voltage Regulators	Transformer	Excessive oil acidity (500kVA or greater). Visible signs of oil leaks. Excessive moisture in breather. Visibly chipped or broken bushings.. Visible rust Binding mechanisms
	Control Equipment	Inaccurate readings Miss operation
Zone substations	Fences & enclosures	Visible damage Visible rust Leaks Safety issues
	Buildings	Visible damage Leaks Visible deterioration Backed up pipes Leaking taps Visible Rot Broken fittings
	Bus work & conductors	Visibly splaying or broken conductor. Poor clearances Signs of clashing Visibly Uneven sag Corrosion of Fittings Insulation Failure
	33kV/50kV switchgear	Detectable discharge Detectable hot spots

		Failure to operate Operations at recommended maintenance levels
	Transformer	Excessive oil acidity Visible signs of oil leaks. Excessive moisture Visibly chipped or broken bushings.. Visible rust Excessive noise Excessive gas content
	11kV switchgear	Detectable discharge Detectable hot spots Failure to operate Operations at recommended maintenance levels
	Instrumentation	Unreadable Inaccurate readings Miss operation
	Poles, arms, stays & bolts	Evidence of dry-rot or spalling. Loose bolts, moving stays. Displaced arms.
Sub-transmission lines & cables	Pins, insulators & binders	Obviously loose pins. Visibly chipped or broken insulators. Visibly loose binder. Radio interference
	Conductor	Visibly splaying or broken conductor. Poor clearances Signs of clashing Visibly Uneven sag Trees in lines
	Radios and repeaters	Communications fade or unavailability over limits Levels out of allowable limits Frequencies out of range
Communications	Radios	Non operational Loss of signal Levels out of allowable limits
SCADA	RTU's	Loss of data False indication occurs Fails to indicate Measurements suspected as being out of valid range Equipment Lockup Controls fail to function Miss operation Nuisance alarms

Maintenance Activities

The following maintenance sub sections of the lifecycle management plan describe details of the regular on-going work that is necessary to keep assets operating to their minimum design levels, maintain the assets to an acceptable condition (e.g.no graffiti) and ensure the assets are performing safely. The details include the basis for condition monitoring, equipment standards, planned activities and provisions for unplanned actions in response to faults or incidents. Condition monitoring activities have been developed that are appropriate for each type of asset. These are presented by individual asset category using the same nomenclature as the CapEx plans. Maintenance inspection and testing work relating to safety is generally based on regular time intervals and for condition assessment the time interval period varies over the life of the asset. Other maintenance activities are driven from condition and reliability monitoring.

Maintenance Management Process

During annual planning budgeted activities identified for each asset category are time lined for completion over the year to optimise resources. The Asset management team members are allocated the activities to complete. The works management system is used to manage the contracts for the maintenance activities. Paper based systems are used to obtain the information relating to asset condition and maintenance completed. Pertinent details relating to condition and maintenance undertaken are entered into the GIS system for reporting. Schedules of defects and corrective actions are prepared from the field returns and fed back into the works management system and dispatched to field contractors for correction. Separation of the GIS and Works database entry/reporting functions, ensure that all required condition assessments are obtained and the defects identified are rectified. Field audits and periodic changes to the allocation of activities to both Asset management and field staff ensure the maintenance procedures and activities are being carried out correctly.

5.3.1 Service Interuptions and Emergencies

All fault response work is contracted to two service providers.
Firstly the provision of 24 hr x 7 day dispatch service is currently contracted to a company based in Hastings. This contract covers the receiving of fault calls and the direct dispatch of fault response resources.
A second contract for the provision of field resources for fault restoration and minor repairs is currently held by Eastech Limited which in order to service the contract provides resources in Wairoa, Gisborne, and Tokomaru Bay. As specified in the contract any renewal required following the initial fault response is determined as maintenance or capital in accordance with ENL accounting policies.

The annual Fault Management cost of $3,029,168 associated with these contracts is allocated, (in proportion to the faults forecast by extrapolation of historical trends), across asset classes as follows;

50kV Lines	$ 20,306
11kV Lines & Cables	$ 241,236
400V Lines & Cables	$ 19,291

Load Control	$	4,061
Zone Substations	$	6,092
Transformers (Distribution)	$	6,102
11kV GM Switches	$	4,307
Pole Mounted Isolation Equip	$	1,523

The annual Fault Management cost includes costs of the third party dispatch centre.

5.3.2 Transmission and Sub-transmission lines

Minor and Major inspection schedules are used for 110kV Lines.
A visual patrol of every urban 50 and 33 kV pole and the conductors is carried out every twelve months. A helicopter patrol of every rural 50 and 33 kV line is carried out every twelve months. The patrols are often incorporated into the patrols necessary as a result of a fault occurring. The following points are included in the inspection:

Structure foundation erosion (weather or excavator work)
Structure movement and conductor clearance
General hardware, insulator and conductor condition
Early signs of cross-arm burning
Damaged or broken binders
Monitor vibration dampener performance
External interference (e.g. trees)
Sabotage
Safety Issues e.g. buildings/structures/road widening

While detailed 110kV lines are inspected at regular scheduled frequencies the detailed inspection is carried out on 50 & 33 kV poles at an increasing frequency as the lines near their forecast end of life. This inspection includes updating safety index information on the poles through pole testing and/or visual inspection techniques. Visual inspection includes excavation and/or climbing to categorically determine the poles below ground and/or head condition. Any components on the poles, identified from the inspections that require renewal are categorised in terms of risk and scheduled for correction typically within 1 year.

Discharge detection and thermo scans of selected areas of line close to terminal points at zone substations are undertaken 3 yearly, corresponding with the checks at zone substations. Repairs required as a result of the scans are categorised in terms of risk and scheduled for correction typically within 1 year.

Pole Assessment Criteria

Every pole has a safety index record which rates the poles current strength capabilities against the required pole strength. This information is held in database. The safety indices for wooden poles are updated following inspection and qualified where necessary by ultrasound scan tests.

Poles with a safety index less than 1.0 are red tagged to signify that the pole could fail under normal loads. The targeted replacement time frame for red tagged poles is 3 months.

Poles where the safety index has declined to below 1.2 are identified with a blue tag which signifies that the pole is capable of supporting normal loads but not ultimate design loads. The targeted replacement of blue tagged poles located in populated areas or other risk areas is within 12 months. Other blue tagged poles are targeted to be replaced within 2 years.

Poles with a safety index of 1.5 and above have repeat visual inspections and assessments every 5 to 10 years (based on previous condition assessments) to determine remaining strength.

The inspection process generally manages the poles in sections of line to give optimum cost efficiency. The line sections are chosen based on terrain, significance/importance and levels of public exposure. Over the period 1990 to 2005 a number of ultra-sound or quantitative methods were used to identify at risk poles. Since 2005 qualitative assessments by suitably qualified and competent inspectors have been used to classify poles in terms of risk. This method has been more effective at ensuring poles identified for replacement will provide the best overall outcome when considering safety, reliability, performance and value.

The pole inspection and testing regime used to assess sub-transmission lines, is also used to assess and rate 11kV and 400V distribution poles.

The strategy for any corrective actions identified from inspections is to carry out the work necessary to achieve the standard pole/conductor standard life, rather than extend the life beyond the standard life. Where viable when corrective actions are required the standard of the asset is brought into line with current standards adopted for new/replacement assets.

The assessed funding required to carry out the maintenance activities is as follows;

Planned Actions	Total	Quantity
110KV Tower/foundation/conductor/access track inspection & maintenance	$304,000	
Patrols 50 & 33kV (Ground & Heli)	$24,367	2000
Inspection 50 & 33kV	$20,306	135
Testing of Poles 50 & 33kV	$10,153	200
Component Renewal/Maint 50kV	$50,765	50

Unplanned Actions	
110kV tree control	$90,327
110kV fault response/defect /fault repairs	$80,000
Tree control 50kV (refer 11kV Lines and Cables)	N/A
Defect / Fault repairs 50kV	$12,691
Fault response (incl. Helicopter) 50kV	$20,306
Radio Interference correction	$6,918

5.3.3 11kV lines and cables

A visual patrol of every pole and its associated line hardware and conductors is carried out at a maximum interval of two years. Poles and lines located in urban areas and rural townships are inspected every twelve months. The patrols are often incorporated into the patrols necessary as a result of a fault occurring.

A more detailed inspection is carried out every five years as the lines near their end of life. This inspection includes updating safety index information on the poles through pole testing/inspection techniques. Visual inspection includes excavation and/or climbing as necessary to categorically determine the poles below ground and/or head condition. Any components on the poles, identified from the inspections that require replacing are categorised in terms of risk and scheduled for correction within 1 year. Renewal of partial pole components e.g. cross-arms is not capitalised.

As with sub-transmission poles the mechanical strength requirements for all individual 11kV poles have been determined and recorded. The safety indices for wooden poles are updated as a result of inspection and where necessary ultrasound scan tests.

At risk poles are identified from the inspection returns and updated in pole database records, using the same criteria as for sub-transmission poles. Replacement and monitoring strategies are as per the Pole Assessment in Sub-transmission Lines section.

Note concrete poles only require a visual inspection per the above as below ground rot does not occur.

A tree control program consisting of hazard identification and notification in accordance with the Electricity (Hazards from Trees) Regulations 2003 has been developed. Elements of this program include…
Patrolling of the network to identify and record tree interference/ hazards. These patrols are undertaken on 12-18 month cycles.

The identification of tree owners whose trees are a hazard and the issuing of Hazard Warning Notices or Cut/Trim Notices and subsequent negotiations.

The engagement of accredited contractors to undertake ENL funded first cuts and/or the removal of "no interest" trees.

In 2010 a specific program to target tree control associated with commercial forestry blocks was commenced. The program is expected to eliminate the associated hazards over the next 3 years.

No planned cable maintenance activities are deployed. Replacement is programmed in capital works budget from analysis of performance from fault statistics.

Due to the unavailability in the market of insurance cover for significant events affecting distribution network assets, ENL has in place;

- Storm/significant event contingency funding of at $101,530 per year
- A $1.0mill borrowing provision reserved in EGL's annual funding plan.

Transformers, Switches and line sections the become surplus to requirements through changes to land use and load are identified during patrols and reporting systems. Specific funding is allocated to the removal of this unnecessary equipment.

Planned Actions	Total	Quantity
Patrols and General maintenance	$203,060	40feeders
Pole Inspection and testing	$81,224	1600
Tree control program	$609,181	1200
Forestry Tree control program	$203,060	10
Equipment Removal	$40,612	

Unplanned Actions	Total	Quantity
Defect / Fault repairs	$263,978	
Fault response	$147,219	120
Control and Switching costs	$20,208	
Trees forced cutting	$101,530	250
Storm contingency	$101,530	

From previous years an increase in expenditure in Defect/Fault repairs (+$50k) and Fault Response (+$25k) has been allowed for. This increase in expenditure is to fund the impliementation of a standby Line Mechanic roster which will improve fault response and repair times and address health & safety concerns related to Faultmen working alone.

5.3.4 LV lines and cables

A visual patrol of every pole and the conductors is carried out at a maximum interval of two years. Poles and lines located in urban areas and rural townships are inspected every twelve months. Should any mechanical strength defects be discovered then a full below ground inspection will be done within a year.

Safety indices for all 400V wooden poles are known and recorded. These are updated via visual inspections, on a five yearly basis, qualified where necessary by pole testing/inspection techniques.

At risk poles are identified from the pole database records and using the same safety index criteria as for sub-transmission and distribution poles. Replacement and monitoring strategies are as per the Pole Assessment in Sub-transmission Lines section.

Note concrete poles only require a visual inspection per the above as below ground and head rot does not occur.

Tree patrols, notification and cutting are undertaken in conjunction with the 11kV Tree Control program.

No planned cable maintenance activities are deployed. Replacement is programmed in capital works budget from analysis of performance from fault statistics.

Planned Actions	**Total**	**Quantity**
Patrols and minor maintenance	$10,153	50km
Pole Inspection/Testing	$15,230	300
General Maintenance cable	$10,153	
Tree control Program	Refer 11kV	

Unplanned Actions	**Total**	**Quantity**
Trees forced cutting		Refer 11kV
Defect / Fault repairs	$ 50,765	
Fault response	$ 25,283	100

5.3.5 Service connections

Service connections are inspected visually every five years. Where the inspection identifies problems liaison is directly with service connection owner. The repairs of the defects are the responsibility of the service connection owner within six months. In cases of high safety risk and no action by the service connection owner the service connection may be disconnected.

Inspection of private HV service connections every 5 years is the responsibility of the private owner. However problems identified during visual patrols covered in the 11kV lines section are notified to the private owner for correction within 6 months.

Compliance with Voltage levels is monitored via voltage checks. This includes the investigation of customer reported quality of supply issues. Costs associated with the rectification of customer supply issues are allocated against the assets involved.

Planned Actions	**Total**	**Quantity**	**Unit Cost**
Patrols/inspection	$ 5,077	500	$10

Unplanned Actions	**Total**	**Quantity**
Voltage Checks/Complaints	$20,306	100

5.3.6 Load Control

The Load control injection plant and coupling cells are tested and inspected each year prior to the main winter load period. Controllable load is updated prior to the main winter load period. Any defects found are repaired immediately

Injection equipment is maintained within the Manufacturers specifications for the operating frequency and voltage levels.

Planned Actions	**Total**	**Quantity**
Injection plant testing	$8,122	2

Unplanned Actions	**Total**	**Quantity**
Defect repairs / replacement costs (Excludes capital relay costs)	$5,077	
Fault response (Pilot circuits)	$5,077	20

5.3.7 Major Substations

Each Substation is inspected every four months and includes inspection and minor maintenance activities associated with…
Transformers
Circuit breakers
Switchgear including connections or terminations
Protection and control equipment
Scada and communications systems
Structures, insulators and bus work
Overhead line connections
Voltage regulators
Zone substation LV switchboards
DC switchboards and battery systems
Earthing systems
Buildings
Fences
Oil containment
Pest control measures
Drainage

Emergency and contingency systems
Signage and Safety Systems

Safety equipment inspection and testing at each zone substation is undertaken annually. Also an independent Occupational Health and Safety inspection of each zone substation is made annually.

Thermo-vision and ultrasound scans are carried out three yearly at zone substations. The earthing system resistance at each zone substation is tested every five years. All urgent defects are repaired on discovery, major non urgent defects are repaired within four months, and other minor defects will be included in the normal maintenance program.

Time based maintenance schedules are maintained for equipment at each zone substation. These schedules are modified following evaluation of inspection and condition assessment results. The typical frequencies range from 2 to 5 years. The lower 2 yearly frequencies are largely due to older equipment. Required equipment maintenance based on usage recordings, inspection and condition monitoring is then carried out. The summary below shows the average annual costs for routine adjustment, testing, calibration and preventative maintenance of the zone substation and rural voltage regulator equipment.

<u>Routine Maintenance Summary</u>

A) Transmission Substations, (includes transformers, switchgear, protection/control equipment)

Massey Road	$188,984
Wairoa	$110,437
Tuai	$32,923
Tokomaru Bay	$57,808

B) Distribution Substations

Voltage Regulators	$3,000
TeAraroa Sub	$5,000
Ruatoria	$5,000
Tokomaru bay	$3,000
Tolaga Bay	$4,000
Kaiti	$4,000
Carnarvon Street	$4,000
Port	$2,000
Valley Rd	$ 500
Parkinson Street	$3,000
Matawhero	$3,000

Makaraka	$3,000
Patutahi	$4,000
Puha	$3,000
Ngatapa	$4,000
Pehiri	$4,195
Hexton	$1,250
Goodwin Rd	$1,250
Wairoa load Control	$2,200
Kiwi Substation	$4,200
Blacks Pad	$1,200
Tahaenui	$1,200
TOTAL	$65,995

Planned Actions Distribution Subs	**Unit**	**Total**
Protection Testing (3 subs pa)		$25.383
3 Monthly Inspections (25 sites 3 Visits p.a.)		$25,383
Grounds Maintenance (20 sites 12 visits p.a.)	$183	$44,673
OHS inspection (20 sites)	$250	$5,077
Thermo or ultrasound inspections (10 sites)	$2000	$20,306
Average Routine Maintenance		$65,995

Unplanned Actions	**Total**
A) Transmission Substations	
Defect / Fault repairs	$25,353
Fault response	$10,150
B) Distribution Substations	
Defect / Fault repairs	$25,383
Fault response	$4,061

Note - work associated with circuit breakers, switching equipment, control/SCADA and protection equipment and LV / DC Systems at zone substations has been included.

5.3.8 Major Substation Zone Distribution Transformers

Activities include…

Bi-annual DGA analysis
Bi-annual Furans analysis
Thermo vision as part of substation maintenance

Painting as required
Tap changer oil flushing
Tap changer overhaul per manufacturer's recommendations
Process oil as required
Major overhaul as required

Note - major overhauls are not undertaken on aged single phase banks. Replacement with a new 3 phase transformer is more economic.

Standards

Based on BS 148, IEC 42 and Transpower standards.

Oil acidity < 0.1 mgkOH/g

Oil electrical strength > 40kV

Moisture content < 30 ppm

Resistivity 20 deg >=60 G ohms per metre

Dissolved gas limits

-Hydrogen	50 ppm
-Methane	50 ppm
-Carbon Monoxide	300 ppm
-Carbon Dioxide	3000 ppm
-Ethylene	100 ppm
-Ethane	100 ppm
-Acetylene	15 ppm

While standards concentrate on maintaining oil condition it is important not to confuse this with transformer condition. These standards must be maintained in order for the transformer to achieve standard life. Exceeding the standards results in permanent damage and shortening of transformer life. DGA analysis provides indication of developing faults and the need for internal maintenance. Trends are monitored to assess expected life/aging.

Recent asset condition surveys have revealed the premature failure of the protective coating systems on zone transformers. This has resulted in significant steel corrosion. Accordingly allowance is made from 2008 to repaint 1 zone per year using high specification products. The repaints are forecast to last a minimum of fifteen years.

Planned Actions

Transformer painting	$20,306
DGA furrow tests,	$11,574
Average tap changer overhauls	$15,230
Average oil processing	$12,184

5.3.9 Circuit breakers

Substation circuit breakers are inspected visually during four monthly substation inspections. Two yearly thermovision surveys include all substation circuit breakers. Trip testing is carried out in conjunction with protection testing. Partial discharge testing is carried out on indoor circuit breakers. The frequency of the testing cycle increases as discharge levels increase over time. This work is covered in the zone substations section. This is the main indicator of CB insulation condition and therefore CB life.

Inspection and maintenance of rural pole mounted circuit breakers and remote controlled switches is carried out yearly.

Di/dt circuit breaker wear monitoring is implemented where protection equipment has this capability. The information is recorded and assessed as part of the Zone substation inspection work.

The number of trip operations is monitored via SCADA or as part of the 3 monthly / annual inspections. Remote or field circuit breakers are inspected annually and trip testing is carried out at intervals not exceeding 3 years. Minor and major maintenance assessments are used to determine end of life and replacement triggers. Work under taken during these activities generally includes:

Oil replacement
Adjustment of travel and mechanisms
Mechanism lubrication
Contact replacement if required
Cleaning, painting
Trip testing, timing
Re-insulation, replacement of damaged or worn components.

Variation of discharge or thermo vision results from previous results triggers major maintenance of the circuit breakers

Standards

Manufacturer's specifications for each type of equipment.

Insulation levels are maintained within the manufacturer's specifications and are measured during servicing.

Standards and recommendations for minor and major maintenance frequencies are derived from industry experience.

Oil circuit breakers servicing.
-50kV CB's after 2 fault trips or 8 years
-11kV CB's after 8 fault trips or 8 years

Planned Actions	**Total**	**Quantity**	**Cost**
Rural Automation annual inspection	$13,707	90	$152
Rural Automation/CB avg routine maint	$18,275	45	$406

Unplanned Actions	**Total**
Defect /Fault repairs	$20,306

Note - work associated with circuit breakers at zone substations is included in the zone substations section.

5.3.10 Distribution Transformers

Smaller transformers generally in rural locations are inspected in conjunction with earth testing programs and line inspections. Transformers with an installed age over 35 years are specifically checked to identify units with excessive external deterioration of the tanks or 11kV tails where they are internally connected, for replacement.

In all cases the units are checked during earth testing/switchgear inspections at intervals not exceeding 5 years. Oil testing is carried out on transformers 500kVA and above the frequency of the tests varies depending on the analysis results.

Ground mount substations undergo an annual visual inspection. Items covered in the inspection include inspection of the LV panels, associated 11kV switchgear, Load readings, high voltage terminations, earthing, warning/danger notices and security equipment, (i.e. door locks and equipment covers).
General maintenance activities carried out in conjunction with inspections include painting on site, vegetation/rubbish clearing, LV panel cleaning and label upgrading.

Transformer loading on ground mount substations is monitored annually via MDI readings. Low voltage panels of all Ground style substations over 100kVA are inspected annually MDI readings are recorded.

Other than 5 yearly earth testing and inspections during the course of line patrols no maintenance activities are carried out on smaller in-service transformers.

Transformers returned from the field for service, receive minor refurbishment work where the age of the units is less than 20 years old.

Earth testing is carried out on a 5 year cycle. Earths include distribution substations, switch sites and LV earths. Earthing system repairs are undertaken on the worst 20% of earth tests. Earth tests between 0 and 50 ohms are considered adequate in terms of the expected seasonal variation in ground moisture content.

Refurbishment is only considered if the transformer condition is such that it has 15 years remaining service life and cost is less than 25% of a new transformer. Economics is limited by the frequency of relatively expensive recovery and installation.

Planned Actions	**Quantity**	**Unit Cost**	**Total**
Refurbishment <100kVA	10	$576	$5,765
Refurbishment >100kVA	2	$4,061	$8,122
Inspection and minor maint	528	$48	$25,383
Oil Handling /filtering /TX disposal			$10,153
Earth testing	1000	$25	$25,383
Earthing system repairs	100	$456	$45,689

Unplanned Actions **Total**

Defect /Fault repairs	$15,230

5.3.11 Pole Mounted Isolation Equipment

Inspection of all air break switches is carried out in conjunction with Zone substation inspections, line patrols and prior to operation. Visual inspection includes checking of the switch contacts and mechanism. Inspection and testing of the earthing is carried out as per earth testing described in the Transformer section.

Operational testing of the switches is carried out where this is possible without a shut-down. Live line methods are deployed to carry out maintenance on switches where necessary. Defects are documented as found and corrective action prioritised as necessary to prevent failure in service. This may involve nil operation until the opportunity to coordinate with other work.

Equipment maintained in accordance with Manufacturers specifications.

Costs associated with maintenance activities are included within the other asset categories. i.e. Zone substations, CB maintenance, line maintenance.

5.3.12 11kV Switchgear (ground mounted)

Ring main units, oil filled isolators, fuse units and SF6 units are inspected yearly. Items covered in the inspection include inspection of cable entry/protection, operating components, earthing, warning/danger notices and security equipment, (i.e. covers and locks).
General maintenance activities carried out in conjunction with inspections include painting on site, vegetation/rubbish clearing, LV panel cleaning, label upgrading and lubrication of operating components.
Maintenance requiring a shutdown is carried out at increasing intervals as the equipment nears end of life.

At key sites and larger industrial substations switchgear is surveyed bi-annually using thermo-vision equipment. The survey attempts to provide early warning of poor or failing connections to the switchgear and poor contacts. The frequency of monitoring will be increased if testing identifies problems developing at a higher rate.

Partial Discharge monitoring is also carried out on larger switchboards at intervals not exceeding 5 years where proximity to transformers does not cause interference. The frequency of monitoring will be increased if testing identifies problems developing at a higher rate.

Standards

Oil leaks and low oil levels are repaired within 6 months.

Rust is treated within 12 months.

Maintenance activities

For RTE switches maintenance is carried out in conjunction with refurbishment of the transformers when they are removed from service.

Routine maintenance work requiring shut downs is opportunistic. This is a major constraint on the level of confidence that can be applied to equipment reliability.

Servicing is carried out on the basis of the inspection results. Activities include:
Exterior painting on site
Oil replacement
Contact replacement
Termination inspections and cleaning where possible
Termination replacement

Planned Actions	**Total**	**Quantity**	**Unit Cost**
Inspection and minor maint	$10,153	194	$52
Average Switch maintenance p.a.	$15,230	15	$1,012
Substation Building Maint/repairs	$10,153	5 p.a.	$2031

Unplanned Actions	**Total**	**Quantity**	**Unit Cost**
Defect /Fault repairs	$10,153	5	$2031

5.3.13 LV switchgear

A general inspection of LV switchgear is incorporated into annual line patrols. A specific visual patrol of LV Disconnection and Link boxes is carried out every 5 years and larger link boxes are checked and cleaned during 3 yearly inspections. LV frames in ground mount substations are inspected in conjunction with annual transformer Inspections. No routine maintenance activities are undertaken on overhead LV equipment.

Standards

Legal compliance and pre-emption of faults.

Planned Actions	Total	Quantity	Unit Cost
Inspections/servicing	$15,230	500	$31
Inspections/servicing Shared Boxes	$ 5,077	150	$34
OH Fusebase and Carrier Replacement	$50,765	250	$203

Unplanned Actions	Total	Quantity	Unit Cost
Defect /Fault repairs	$ 10,153		

5.3.14 Control and protection

Operation of the equipment is monitored via the SCADA system all operation events are investigated to ensure the operation of devices occurred correctly. Incorrect operation of protection has been found to occur with some equipment types typically in relation to auto-reclose controls. Relay testing and CB trip testing frequencies for relays vary depending on the type and age of devices. The functionality of the tap-changers is monitored via the SCADA system.

Battery maintenance costs are minimal tests and maintenance on batteries within zone substations are included in 4 monthly zone substation inspections. No maintenance is carried out at rural automation sites as the cost to replace the batteries is lower than the cost to undertake tests.

Standards

Within manufactures specs for individual relays and equipment.

Where liquid batteries are contained within buildings separate rooms are used with good ventilation. Where this cannot be achieved batteries are housed in outdoor containers.

Maintenance activities

Tap change control – Adjustment and calibration of AVR's not exceeding 4 yearly
Transducers – calibration 6 yearly
24V battery systems – First test 2 years after initial installation, thereafter annual Load test on 24V battery systems
110V battery systems – Annual physical inspection and load test (monitoring on line)
Protection Electromechanical – Three yearly secondary tests
Protection Solid-state – 5 yearly secondary tests
Protection Microprocessor – 10 yearly tests
CB trip testing – Not exceeding 5 yearly when no operation has occurred. (refer Circuit Breaker maintenance)
Transformer protection not exceeding 10 yearly
Fire safety and intruder systems not exceeding 6 monthly

Note - work associated with protection and control equipment is included in the related asset section/budget.

5.3.15 Communications

A degree of remote monitoring of the radio systems is in place to provide early warning of equipment malfunction. Annual testing and calibration is carried out to ensure the equipment performance is within specification.

Standards

Complies with the Radio Spectrum Management Conditions and Radio Communication Regulations.

Operates within manufacturers specifications.

Power - repeaters – 25W, RTs – 5W.

Drift - no more than 2 kHz.

Frequency.

Heat levels within manufacturers specifications.

One complete spare link and 2 portable repeaters are maintained for contingency operations.

Planned Actions	**Total**
Maintenance/Calibration	$35,536
Track Maintenance	$4,061
Hut Maintenance	$4,061
Radio Licences	$13,199

Unplanned Actions

Defect/Fault repairs	$16,245

5.3.16 SCADA

In general the RTU input and output functions are tested in conjunction with maintenance of the associated equipment. During protection and switchgear testing the digital indications, analogs, measurement and control functions are verified back to the master station. General indications such as door security and fire alarms are verified during 3 monthly inspections.

Other indications such as DC battery and mains fail alarms are verified during RTU inspections at intervals not exceeding 2 years. This work is generally coordinated with other activities being undertaken at the substations.

Standards

Operates within manufacturers specifications

Planned Actions	**Total**
Support fees	$10,153
Software Licences	$5,077
SCADA maintenance allowance	$10,153
Configuration file alterations	$6,092

Unplanned Actions

Defect/Fault repairs $10,153

5.3.17 Non Network Assets

These assets are supplied by the Eastland Group as part of a Business Support operational expense allocation.
In general the management functions associated with these assets are carried out by the Eastland Group's Corporate Services Business.

5.4 Renewing assets

In accordance with Information Disclosure (2008) capital expenditure categories ENL classifies work as renewal when an asset is replaced due to physical deterioration of the asset or as a result of the obsolescence of the asset. The key criteria for renewing an asset is when the capitalised operational and/or maintenance costs exceed the renewal cost .This can occur in a number of ways…

Operating costs become excessive e.g. Addition of inputs to a SCADA system requires an increasing level of manning.

Maintenance costs begin to accelerate away. E.g. a transformer needs more frequent oil changes as the seals and gaskets perish.

Supply interruptions due to component failure become excessive (and what constitutes "excessive" will be a matter of judgment which will include the number and nature of customers affected).

Renewal costs decline, particularly where costs of new technologies for assets like SCADA decrease by several fold.

The asset does not comply with design, regulatory or safety requirements.

Because of the low growth and surplus capacity in the network, ENL capital expenditure is dominated by renewals. The rate of renewal can be used to manipulate the age of each asset category relative to its rate of depreciation. Most of ENL's asset categories are being renewed at a rate less than the depreciation but commensurate with constrained revenue, hence the overall asset is aging.

While the renewal rate manipulates the age of the population for each asset category, the historical population age profile and condition assessment information provide sufficiently accurate forecast renewal rates. The forecast renewal targets and renewal actions identified from condition assessments for each asset category are provided in the following sub-sections.

5.4.1 Transmission and Subtransmission lines

LIFE CYCLE ASSESSMENT
Includes 110kV 50kV and 33kV

	Poles	Lines
ODV Standard Life (Wood/Concrete or Steel)	45/60	60
Population Size (Wood/Concrete or Steel)	1541/1132	641km
Average Age	33/24	45
Steady state renewal rate p.a.	34/18	14km
Premature failures /Opportunistic renewal	7	0.2km
10year renewal rate p.a.	60	0
Start of failure period	35/55years	60years
Failure period duration	10 years	20years
Targeted renewal rate	60	0.2km
Rate of Growth Additions/Upgrades	0	0
Steady state less renewal/Upgrade gap	0	13.8km

These assets are critical to reliability and therefore renewal programs aim to renew asset before failure in service. In addition any known defects are to be dealt with within a year.

Transmission Lines

Renewal actions related to transmission lines are driven primarily from comprenhensive asset condition and rating surveys which target distinct/specific contributory asset parts such as tower steel work, insulators, conductors and tower foundations.

Transmission line renewal expenditure forecast for the planning period is based on asset condition survey information driven forecasts from Transpower. As ENL gains operational experience of the transmission line assets and completes its own asset condition surveys, renewal expenditure forecasts for these assets will be updated accordingly in future versions of the AMP.

Average Transmission Line renewal for 2015 – 2025 is $1.046m

Sub-transmission Lines

The renewal rate required over the next 10 years is higher than the steady state rate. Condition assessments have confirmed the need for renewal over steady state rates. Premature failures account for renewal of poles that fail due to external causes. E.g. Car-hit-pole, Land slips, Falling Trees, Severe storms.

Where insulator, cross-arm, conductor spans or partial pole condition issues are identified the entire (pole) asset or line section is replaced if the total required maintenance expenditure exceeds 50% of the cost of new asset. This is common in cases where future shutdown or travel costs to correct arising defects are likely. In addition where high outage cost or helicopter work is associated with a group of poles being renewed opportunistic renewal of associated poles approaching end of life is carried out to reduce overall costs. This is typical for the East-coast 50kV and Mahia 33kV spur line renewal work.

For transmission assets, renewal is undertake

A back log of defects identified from sub-transmission inspections has increased to a level where it is necessary to increase the short term targeted renewal rate. If the backlog of defects increases, then the planned renewal rate will need to increase.

The target renewal rate to accommodate the 10year renewal rate, premature renewal and correction of defects is set at 60 sub-transmission poles p.a.

Age renewal for conductor assumes 60 to 80 year life hence no planned replacement is currently undertaken or required.
Summary of Actions

Steady state sub-transmission pole renewal, 60 pa	$335,049
Fault replacement Line	$44,673

5.4.2 11kV Lines and Cables

LIFE CYCLE ASSESSMENT (Lines)

	Poles	Lines
ODV Standard Life (Wood/Concrete)	45/60	60
Population Size (Wood/Concrete)	13555/11220	2360km
Average Age	37/20	47

Steady state renewal rate p.a.	301/187	40km
Premature failures /Opportunistic renewal	30	1km
10year replacement rate p.a.	650	40km
Start of failure period	35/55years	60years
Failure period duration	10 years	20years
Targeted renewal rate	650	3km
Rate of Growth Additions/Upgrades	20	2 km
Steady state less renewal /upgrade gap	0	35km

The 35km p.a. gap between the 10 year renewal rate plus premature renewal and the targeted renewal rate plus the replacement due to upgrade work, is identified as a long term issue for the conductor assets. Currently the incidence of conductor fatigue failure is rare when compared with failure due to interference from birds and trees and human elements. Fatigue failures nearly always occur at connections or insulators. These failures do not warrant replacement of entire sections of conductor as the in span portion of the conductor is in good condition.

The factors influencing the ability to address this issue include: -economic justification/regulatory revenue constraint,
-the availability of physical resources
-controls on outages required to undertake the work i.e. increase in planned SAIDI

In the medium term the effect of a shortfall in investment in renewal of 11kV conductor is addressed in part by ENL's strategy for uneconomic lines described in Section 4.7.1.4 In the long term renewal investment shortfall will affect ENL's ability to achieve customer expectations of steady state performance and regulatory performance targets.

In view of the gap for conductor renewal it is necessary to determine priorities for the renewal work. This is done in accordance with the processes and policies for management of risk in section 6.2. The combination of economic, performance and other risk assessment factors for uneconomic rural lines clearly categorises this asset as the lowest priority for renewal while Population centres, Main feeders and Tie feeders have the higher priorities.

A consequence of the gap is the predicted decrease in primary customer service levels which when offset by improvement strategies form the basis for the prediction that the primary service levels will remain close to the current levels.

The conductor renewal target of 9km p.a. until 2016 increases beyond this time to 18km.

LIFE CYCLE ASSESSMENT (Cables)

ODV Standard Life	45/60
Population Size	130
Average Age	25
Steady state renewal rate p.a.	2
Premature failures /Opportunistic renewal	0.5km
10year replacement rate p.a.	0km
Start of failure period	50years
Failure period duration	20 years
Targeted renewal rate	0km
Rate of Growth Additions/Upgrades	2km
Steady state less renewal /upgrade gap	0km

As the majority 11kV reticulation in both Wairoa and Gisborne CBDs has been already undergrounded there is little undergrounding required to be undertaken during the planning period. The two exceptions are in 2016/17 and 2017/18 when an allowance of $350k per year is made to underground areas on the fringe of the Gisborne CBD. Here, domestic dwellings are being replaced by commercial buildings which protrude into the alignment of existing overhead reticulation. The undergrounding of Roebuck & Disrallei Streets and Childers & Grey Streets will also facilitate an increase in available capacity as required by the new commercial buildings.

Cable replacement is solely driven by the need for capacity upgrades and new work which is identified on a project-by-project basis. Therefore targeted replacement due to age is 0km. When multiple failures are experienced on sections of cable replacement is built into project work. Currently there are no projects specifically in this category.

Summary of Actions

Renewal Conductor 9km p.a. to 2016/17	$402,060
Renewal Conductor 18km p.a. from 2016/17	$804,117
Premature conductor replacement, 1km pa	$100,515
Pole Renewal, 650 pa	$2,088,472
Premature pole renewal, 50 pa	$335,049

Premature Cable renewal 0.5km	$111,683

5.4.3 LV Lines and Cables

LIFE ASSESSMENT (Lines)

	Poles	Lines
ODV Standard Life (Wood/Concrete)	45/60	60
Population Size (Wood/Concrete)	4225/2037	513km
Average Age	37/14	47
Steady state renewal rate p.a.	94/34	9km
Premature failures /Opportunistic renewal	30	0.2km
10year replacement rate p.a.	100	2km
Start of failure period	44years	60years
Failure period duration	10 years	20years
Targeted renewal rate	100	0km
Targeted rate of Reduction	20	1km
Rate of Growth Additions/Upgrades	0	1km
Steady state less renewal /upgrade gap	0	7km

Pole renewal will occur indefinitely until there is a need to reconductor for capacity. At this time all poles will have to meet increased strength requirements to carry the heavier conductor. Where appropriate underground conversion is undertaken at a rate of up to 1km per year. Considerations applied when selecting which streets to underground are;
The existing overhead assets are due for replacement because of age deterioration or operational constraints.
The delivery of maximum safety, amenity value and aesthetic improvement, i.e. undergrounding of main arterial urban streets on the fringes of CBDs and/or adjacent to schools and public parks.
The proportion of existing private service mains that have already been converted to underground.

The 7km p.a. gap between the 10 year renewal rate plus premature renewal and the targeted renewal rate plus the replacement due to upgrade work, is identified as a long term issue for the conductor assets. Currently the incidence of conductor fatigue failure is rare when compared with failure due to interference from birds and trees and human elements. Fatigue failures nearly always occur at connections or insulators. These failures do not warrant replacement of entire sections of conductor as the in span portion of the conductor is in good condition.

LIFE ASSESSMENT (Cables)

ODV Standard Life	45
Population Size	256
Average Age	26
Steady state renewal rate p.a.	6
Premature failures /Opportunistic renewal	1.0km
10year replacement rate p.a.	1.8km
Start of failure period	45years
Failure period duration	20 years
Targeted renewal rate	1.0km
Rate of Growth Additions/Upgrades	3.0km
Steady state less renewal /upgrade gap	0km

Summary of Actions

Pole Renewal, 100 pa	$245,703
Line renewal with underground, 1km pa	$167,525
Premature cable replacement, 1km pa	$89,346
Premature Line renewal	$44,673

5.4.4 Service connections

LIFE ASSESSMENT (Service pillars)

	(Service pillars)	OH Fuses
ODV Standard Life	45	45
Population Size	6102	29770
Average Age	24	35
Steady state renewal rate p.a.	136	661
Premature failures /Opportunistic renewal	30	-
10year replacement rate p.a.	120	661
Start of failure period	45years	45
Failure period duration	10 years	10
Targeted renewal rate	120	500
Rate of Growth Additions/Upgrades	100	-
Steady state less renewal /upgrade gap	0	-

The age profile of the service pillars indicates a required 10 year renewal rate of 80 per year plus opportunistic renewal of 30 per year. Inspections and condition assessments confirm this renewal rate.

Incorporated into the renewal rate is separation of ENL equipment from shared boundary-meter boxes by either relocating into separate new service fuse boxes and\or contributing to the relocation of the metering equipment. Primary justification for the separation work is to improve safety with age renewal being the secondary justification.

In some cases expenditure is warranted to allow other work on network assets to proceed. This is allowed for within the funding provided for the other assets.

Summary of Actions

Service Disconnect Boxes to replace shared meter box	$33,505
Service pillar renewal	$22,337
Meterboard Installation associated with GavlBox Renewal	$27,921

5.4.5 Load Control

Combined renewal and development strategies are contained in section 4.7.1.4 of this plan.

Summary of Actions

Ripple relay renewal	$11,168

5.4.6 Major Distribution Zone Substations

Renewal of fences, failing drainage, building renovations (e.g. roofing) and other significant land and building related items as identified from condition inspections is allowed for at $55,842 pa until 2016 reducing to $11,168 pa.

5.4. Major Distribution Zone Substation Transformers

Life Assessment Transmission/Subtransmission Substation Transformers	
ODV Standard Life	45
Population Size	26
Average Age	24
Steady state renewal rate p.a.	0.5
Premature failures /Opportunistic renewal	0
10year replacement rate p.a.	0.3
Start of failure period	60years

Failure period duration	20 years
Targeted renewal rate	0.3
Rate of Growth Additions/Upgrades	0
Steady state less renewal /upgrade gap	0

Life Assessment Voltage Regulators

ODV Standard Life	45
Population Size	9
Average Age	36
Steady state renewal rate p.a.	0.3
Premature failures /Opportunistic renewal	0
10year replacement rate p.a.	0
Start of failure period	60years
Failure period duration	20 years
Targeted renewal rate	0
Rate of Growth Additions/Upgrades	0
Steady state less renewal /upgrade gap	0

As Transmission/Subtransmission transformers and Voltage Regulators are considered critical assets renewal has been determined by consideration of each individual Transformer. Factors considered include external and internal condition, History of operation, development plans, losses, and age.

Transformers currently identified for renewal are as follows…

Year	Action	Cost
2015/2018	Replace T1 and T2 Wairoa	$5,466,459
2017/2018	Replace T1 Tuai	$2,008,418
2019/2020	Replace T1 at Tolaga with 1x 2.5MVA 3-Phase	$558,415
2019/2021	Replace T1 and T2 Patutahi with 1x 5MVA 3-Phase	$781,782
2017/2019	Replace T1 Puha with 1x 5MVA 3-Phase	$456,886

5.4.8 Circuit breakers

LIFE ASSESSMENT

Voltage	**110kV**	**50kV**	**11kV**
ODV Standard Life	40	40	40
Population Size	6	40	148
Average Age	16	14	20
Steady state renewal rate p.a.	0.1	0.8	4
Premature failures /Opportunistic renewal	0	0	1

10year replacement rate p.a.	0	1	2
Start of failure period	35	35	35 years
Failure period duration	10	10	10 years
Targeted renewal rate	Discrete Program	Discrete Program	Discrete Program
Rate of Growth Additions/Upgrades	0	0	1
Steady state less renewal /upgrade gap	0	0	0

Replacement of CB's is justified on the basis of maintenance savings and risks of failure. The cost of major refurbishment overhauls of the CB's has been in the order of 25% of a new unit giving an expected 25% life extension. This has allowed the CB replacement program to be managed over a more controlled timeframe. More recently new CB costs have reduced hence refurbishment is now uneconomic by comparison with life expectancies.

50 kV Circuit Breakers

Location	Function	Make	Cost	Replace
Carnarvon	T1	Reyrolle Min Oil	$89k	2020/21
Makaraka	Line to Patutahi	Reyrolle Min Oil	$89k	2018/19
Makaraka	Inject Plant	Reyrolle Min Oil	$89k	2025+

Rural automation CBs are being renewed as maintenance\replacement triggers are reached with expenditure scheduled at $25,000 bi-annually.

5.4.9 Distribution Transformers

	Small	Large
ODV Standard Life	45 years	45 years
Population Size	3062	573
Average Age	29	21
Steady state renewal rate p.a.	68	12
Premature failures /Opportunistic renewal	18	4
10year replacement rate p.a.	50	14
Start of failure period	45 years	45 years
Failure period duration	10 years	10 years
Targeted renewal rate	50	Discrete Program

Rate of Growth Additions/Upgrades	20	3
Steady state less renewal /upgrade gap	0	0

The low cost of new transformers, high cost of operating maintenance facilities and longer life expectancy of new transformers makes replacement the preferred option compared to traditional maintenance.

Renewal costs are forecast for 50 p.a. at $2100 each for small transformers and average 14 p.a. at $255,000 each for large transformers. The expenditure incorporates an allowance for replacement fuses, minor circuit alterations and earthing work to accommodate the transformer renewal.

While small transformers are only replaced as they fail or on an opportunistic basis, large transformers a programmed based on condition and needs assessments. The program for large transformer replacements is as follows…

Year	Name	Location	Rating
2015/2016	B318	Awapuni Rd (Aitkens Concrete)	250 kVA
	A416	40 Gaddums Hill	100 kVA
	B361	Grey St between Childers Rd and Gladstone Rd	250 kVA
	B430	Lowe St (Alleyway 89 FM ex masonic)	500 kVA
	W1548	Rutherford St, Wairoa	300kVA
	B379	OPP 554 Childers road ex Orange Grove	500 kVA
2016/2017	B321	Olympic Pool opp 23 Awapuni Rd	250 kVA
	W125	Garage Ngatirangi Rd Nuhaka	100 kVA
	B358	Grey St, by Gladstone Rd (T & G)	100 kVA
	W1557	39 Queen St	500 kVA
	W1536	A PARK	300kVA
	B152	Disraeli St near Gladstone Rd (sunshine breweries)	250 kVA
	B436	Solander/Banks St Cnr	300 kVA

2017/2018	B814	MacLean St, by Ormond Rd	300 kVA
	B936	Peel St and Lowe St (back alleyway behind Odeon)	250 kVA
	B359	Grey St (Back alley Salvation army)	300 kVA
	A389	Eastland Port	500 kVA
	B482	52 Centennial Cres near Endeavour St	300 kVA
	W1562	Between Marine Parade and Queen Street	50 kVA
2018/2019	B375	Rectory (end of Desmond Road)	250 kVA
	W308	Western Extension, Tuia	300 kVA
	B311	1 Roberts Road	300kVA
	D579	64 Bilham Rd, Patutahi	250 kVA
	A286	Tyndall Road	300kVA
	B908	Carnarvon/Kahutia Sts cnr Med - Lab	200 kVA
	C637	Main Road Makaraka - race course by stand	100 kVA
2019/2020	A351	Rutene Rd between Hinaki St and De Lautour Rd	250 kVA
	B440	29 Fergusson Drive	300 kVA
	W341	School Ihaka St Nuhaka	100 kVA
	W1570	Lahore St, Wairoa	300kVA
	J606	30 Barry Ave, Ruatoria	250kVA
	B323	235 Awapuni Rd, old Tip Top Factory	250kVA
	B175	47 Sunvale Crs near Fox St	200 kVA
2020/2021	B258	Bright St, Treble Court	500 kVA
	C310	Nelson Rd 'Richardson Mill'	250 kVA
	D319	93 Bilham Road, Patutahi	250 kVA
	B898	382 Childers Rd outside VTNZ	250 kVA
	J160	TUPAROA RD MANUTAHI SCHOOL	100 kVA
	B353	Off Derby St, Pak and Save Entrance	250kVA

2021/2022	B406	Solander Street	300 kVA
	F383	40 Balfour Rd, Te Karaka	200kVA
	B947	36 Disraeli Street	100 kVA
	B6225	83 Awapuni Rd	300 kVA
	W1539	Corner of Lucknow St and King St, Wairoa	200 kVA
	A249	89 Kaiti Beach Rd, Yacht Club	100 kVA
	W1579	51 Clyde St, Wairoa	300 kVA
2022/2023	B191	Childers Rd, Rural Bank Sub	250 kVA
	W1576	Colin Street, Wairoa	200kVA
	W1567	Haig Street, Wairoa	200 kVA
	A289	183 Tyndall Road	250 kVA
	C377	77 Main Rd Makaraka, Weatherall Transport	500kVA
	W1559	Queen Street	300kVA
	W1534	31 River Parade, Wairoa	200 kVA
2023/2024	W374	207 Awamate Road	300 kVA
	A483	Winifred Street, Wainui	100 kVA
	A503	233 Harris Street	250 kVA
	A532	49 Wainui Road	250 kVA
	B792	505 Aberdeen Road	250 kVA
	B902	3 Belgium Terrace	250 kVA
	A72	77 Douglas Street	250 kVA
2024/2025	B887	15 Albert Streeet	250 kVA
	J486	138 Te Araroa SH just north of Ruatoria	100 kVA
	A323	Marian Drive	250 kVA

W1577	Kabul Street, Wairoa	200kVA
B978	5 Innes Street	250 kVA
B59	267 Valley Road	250 kVA
B926	Atkinson Street	250 kVA

Summary of Actions

Transformer Renewal <100kVA 50p.a.	$111,683
Transformer Renewal >100kVA 7 p.a.	$301,544

5.4.10 Pole Mounted Isolation Equipment

LIFE ASSESSMENT (ABS and SF6 SW's)

	ABS and SF6 SW's	Fuses
ODV Standard Life	35 years	35 years
Population Size	586	6699
Average Age	28	32
Steady state renewal rate p.a.	17	191
Premature failures /Opportunistic renewal	6	20
10year replacement rate p.a.	15	50
Start of failure period	38 years	42 years
Failure period duration	10 years	7 years
Targeted renewal rate	15	50
Rate of Growth Additions/Upgrades	2	10
Steady state less renewal /upgrade gap	0	110

Expenditure for transformer fuse replacement is included in the transformer renewal allowance at a rate of 20 sets p.a.

Summary of Actions

Renew ABSs at a rate of 15/yr	$111,683 p.a.
Steady state fuse-set renewal of 50/yr	$44,673 p.a.

5.4.11 11kV Switchgear (ground mounted)

LIFE ASSESSMENT

ODV Standard Life	40
Population Size	352
Average Age	16
Steady state renewal rate p.a.	2
Premature failures /Opportunistic renewal	2
10year replacement rate p.a.	2
Start of failure period	20 years
Failure period duration	25 years
Targeted renewal rate	2 Discrete Program
Rate of Growth Additions/Upgrades	3
Steady state less renewal /upgrade gap	0

The following list details the renewal program. The costs include associated cabling and alterations.

Year	Name	Location	New Type	Existing Type
2015/2016	B781	Ormond Rd, Opp Dalrymple St	CCC	SD3
	W291	Colin St & Apatu St, Wairoa	CFC	SDAF3
	A300	Huxley Road outside Gis Hotel	CFCF	SDAF3 + SDAF
2016/2017	B778	Hospital Rd, Ormond Rd Cnr	CCC	SD3
	B618	Disraeli St near Gladstone Road	CFC CFCF	SDAF3 + SDAF + SDAF
2017/2018	A288	Tyndall Road No 183	CFC	SDAF3
	A325	Hirini St, Wainui Rd Cnr	CFCC	SDAF3
	C595	Nelson Rd, near Campion Rd	CFCF	SDAF3 + SDAF
2018/2019	A413	Wainui Rd Weighbridge	CFCF	SDAF3 + SDAF
	B992	19 Solander Street	CFC	SDAF3
	W1073	Clyde Rd, Kitchener St, Wairoa	CFCC	SDAF + SD
2019/2020	A552	Port Main Office	CFCF	SDAF3 + SDAF
	W288	Apatu St, Wairoa	CFC	SDAF3

	B697	Anzac Street/Carnarvon St	CFC	SDAF3
2020/2021	A331	Harris St, Wainui Rd Cnr	CFC	SDAF3
	J633	College Rd South, Ruatoria	CFC	SDAF3
	A98	Douglas St	CFC	SDAF3
2021/2022	B979	Childers Rd, Wharehouse	CFC	SDAF3
	A6604	Porter Street	CFC	SDAF3
	J628	College Rd South, Ruatoria	CFCF	SDAF3 + SDAF
2022/2023	B768	Stout Street Opp No175	CFC	SDAF3
	B742	Salvation Army	CFC	Rotary
	B630	Countdown Car Park	CFCF	SDAF3 + SDAF
2023/2024		Grey St, by Gladstone Rd (T & G)	CFC	Back to Back
	W255	Queen Street, Wairoa	CFC	SDAF3
	W258	Queen Street, Wairoa	CFC	SDAF3
2024/2025	B39	Roebuck Rd by Anzac St	CFC	SDAF3
	B1071	Seddon Crescent	CFC	SDAF3
	W261	Queen St, Wairoa	CFC	SDAF3

An allowance is made for planned renewal of 3 units at $251,287 p.a.

5.4.12 LV Switchgear

LIFE ASSESSMENT

ODV Standard Life	45
Population Size (Operational Switches)	3189
Average Age	16
Steady state renewal rate p.a.	70
Premature failures /Opportunistic renewal	4
10year replacement rate p.a.	14
Start of failure period	40 years
Failure period duration	10 years
Targeted renewal rate	18
Rate of Growth Additions/Upgrades	10

Steady state less renewal /upgrade gap 52

Transformers typically contain 4 to 6 Operational Switches per Frame while Link boxes have 2 to 3 operational switches per frame.

Funding for 18 LV switches which equates to approximately 6 link boxes per annum is provided at $42,000.

Funding for replacement of LV Frames is provided in transformer replacement funding.

The identified gap between steady state renewal and 10 year rate will allow the average age to increase to 24 years over the planning period.

5.4.13 Control and protection

Protection equipment traditionally lasted the life of the device it protected. However as protection schemes are required to co-ordinate across both ENL’s network and Transpower’s points of connection, protection equipment must maintain technical and functional compatibility with ENL's and/or Transpower's latest protection operating standards. Generally this results in protection equipment requiring technology upgrading before age or condition replacement.

Voltage Control

Voltage regulators are currently fitted with mercury filled switch mechanisms. Replacement with PLC controls is planned when the existing units show signs of mal-operation due to mechanical wear forecast details are as follows

Station	AVRControl Tentative Renewal Date	Cost $
Pehiri V_Reg	Complete	
Kopuroa V_Reg	Complete	
Waihua V_Reg	2015/2016	5,250
Matawai V_Reg	2016/2017	5,250
Waingake V_Reg	2017/2018	5,250
Kanakania V_Reg	2018/2019	5,250
Tatapouri V_Reg	2019/2020	5,250
Muriwai	Complete	
Mahia	Complete	

Ngatapa	Complete	

* Replacement undertaken as items fail

Battery Systems

Rural Automation sites operate either 12 or 24V DC battery systems

Substation systems include the 110V banks and 24V systems incorporating redundancy with Dual 24V chargers and Batteries. The steady state cost to maintain Batteries and Charges at these sites is $22,337 p.a.

Protection

Steady state allowance of replacement of components following Premature failure is allowed for at $11,168 p.a.

Planned replacements identified are;

AUFLS protection relay replacement/upgrade 2016 – 2018, $335,050.

5.4.14 Communications

Generally technology upgrade occurs before age or condition replacement; however ENL's strategy has been to defer the renewal until such time as the operational performance and condition of the equipment necessitates the change.

As the Radio communications network is predominantly radial in nature benefits of the new technology incorporated into the new equipment can be released sooner if the network is replaced starting at the communications hub spreading outwards to the remote regions. Equipment removed, in some cases, that has some remaining service life is relocated to the remote areas for the short term if necessary until renewal is appropriate.

Scheduled renewal and upgrade of "backbone"links and repeaters is scheduled at $11,168 pa during the planning period.

Renewal of the Voice RT network to facilitate the required change to narrow band commenced in 2014/15 will be completed 2015 at a cost of $195,445.

Cable circuits will not be renewed.

Fibre Optic circuits installed between 2002/2006 are expected to survive the planning period of this plan before renewal is required.

An allowance of $22,337 p.a. is provided for unplanned renewal as a result of premature failures.

5.4.15 SCADA

The original GPT master station and data-term RTU's were replaced between 2000 and 2002 with the current Abbey system. As the system is progressively upgraded to maintain currency no planned major upgrade or replacement for the Abbey system is programmed. Unplanned renewal of failed equipment should assume $10,500 p.a. between major upgrades.

5.4.16 Generators

Renewal timing and costs for standby generation assets associated with communication and SCADA assets are as follows…

Generator Location	Renewal Date	Cost
Carnarvon St	2016/17	$33,505
Makaretu	2018/19	$33,505
Arakihi	2020/21	$33,505
Mata Rd	2022/23	$33,505
Whakapunaki	2023/24	$33,505
Tikitiki	2024/25	$33,505

5.5 Up-sizing or extending the assets

If any of the capacity triggers in Table 4.1.3(a) are exceeded ENL will consider either up-sizing or extending the network. These two modes of investment are, however, quite different as described in Table 5.5(a) below.

Table 5.5(a) – Distinguishing between up-sizing & extension

Characteristic	Up-sizing	Extension

Location	Within or close to existing network footprint (within a span or so).	Outside of existing network footprint (more than a few spans).
Load	Can involve supply to a new connection within the network footprint or increasing the capacity to an existing connection.	Almost always involves supply to a new connection.
Upstream reinforcement	Generally forms the focus of up-sizing.	May not be required unless upstream capacity is constrained.
Visible presence	Generally invisible.	Obviously visible.
Quadrant in Figure 4.1.2(b)	Either 1 or 2 depending on rate of growth.	Either 3 or 4 depending on rate of growth.
Necessity	Possible to avoid if sufficient surplus capacity exists. Possible to avoid or defer using tactical approaches described in section 4.2.1.	Generally can't be avoided – a physical connection is required.
Impact on revenue	Difficult to attribute revenue from increased connection number or capacity to up-sized components.	Generally results in direct contribution to revenue from the new connection at the end of the extension.
Impact on costs	Cost and timing can vary, and be staged.	Likely to be significant and over a short time.
Impact on ODV	Could be anywhere from minimal to high.	Could be significant depending on length of extension and any consequent up-sizing required.
Impact on profit	Could be anywhere from minimal to high.	Could be minimal depending on level of customer contribution.
Means of cost recovery	Most likely to be spread across all customers as part of on-going line charges.	Could be recovered from customers connected to that extension by way of capital contribution.
Nature of work carried out	Replacement of components with greater capacity items.	Construction of new assets.

Despite the different nature of up-sizing and extension work, similar design and build principles are used as described in section 5.5.1.

The forecasts for new assets and asset extensions other than those identified in the development program are difficult to predict as they are generally short term customer driven activities. Section 5.5.2 identifies the predictions for these activities.

5.5.1 Designing new assets

ENL uses a range of technical and engineering standards to achieve an optimal mix of the following outcomes…

Meet likely demand growth for a reasonable time horizon including such issues as modularity and scalability.

Minimise over-investment.

Minimise risk of long-term stranding.

Minimise corporate risk exposure commensurate with other goals.

Maximise operational flexibility.

Maximise the fit with soft organisational capabilities such as engineering and operational expertise and vendor support.

Comply with sensible environmental and public safety requirements.

Given the fairly simple nature of the network ENL tends to adopt standardised designs for all asset classes with minor site-specific alterations. These designs, however, will embody the wisdom and experience of current standards, industry guidelines and manufacturers recommendations.

5.5.1.1 Transmission/Subtransmission Lines

Specific designs are used for Transmission lines and Towers

Standards used include the following:

NZS 3115:1980 for concrete poles,

AS 2209 for wooden poles.

Standard Pole types used on the network are:

- Concrete Pole 11.0m Busck
- Concrete Pole 12.5m Busck

- Concrete Pole 11.58m Firth
- Concrete Pole 12.2m Firth
- Concrete Pole 12.8m Firth
- Concrete Pole 14.4m Firth
- Softwood Pole 11.0m
- Hardwood Pole 11.0m
- Hardwood Pole 12.5m

Specific standards for conductors, line hardware and fittings.

Construction of new or replacement asset generally adhere to following standard practises;

Concrete poles (unless limited by weight for helicopter installations)
Cross-armless delta configuration, and cross-armless angles for live line compatibility
If phase separation dictates use of crossarms, then steel arms with flat post insulator construction are used
Polymer strain insulators – no strings
No LT under building
Avoid main highway line routes
Standard conductors: Cockroach – urban, Dog – rural
All poles to be fitted with possum guard
Line make-offs/staying approximately every 12th pole if there are no intermediate make-offs or angles
Conductor spacing and insulation to 66kV standard on 50kV lines.

<u>5.5.1.2 Distribution Lines and Cables</u>

Standards used include the following:

NZS 3115:1980 for concrete poles.

AS 2209 for wooden poles.

Standard Pole types used on the network are:
- Concrete Pole 11.0m Busck
- Concrete Pole 12.5m Busck
- Concrete Pole 10.01m Firth
- Concrete Pole 10.67m Firth
- Concrete Pole 11.58m Firth
- Concrete Pole 12.2m Firth

- Concrete Pole 12.8m Firth
- Concrete Pole 14.4m Firth
- Softwood Pole 11.0m
- Hardwood Pole 11.0m
- Hardwood Pole 12.5m

Standard conductors are:

- Wire “Cricket” Aluminium Overhead
- Wire “Wasp” Aluminium Overhead
- Wire “Dog” Aluminium Overhead
- Wire “Ferret” Aluminium Overhead
- Wire “Squirrel” Aluminium Overhead
- Wire “Flounder” Aluminium Overhead
- Wire 7/.044 Bare Hard Drawn Copper Overhead
- Wire 7/.044 PVC Hard Drawn Copper Overhead
- Wire 7/.064 Bare Hard Drawn Copper Overhead
- Wire 7/.064 PVC Hard Drawn Copper Overhead
- Wire 7/.080 Bare Hard Drawn Copper Overhead
- Wire 7/.080 PVC Hard Drawn Copper Overhead
- Wire 19/.064 Bare Hard Drawn Copper Overhead
- Wire 19/.064 PVC Hard Drawn Copper Overhead

Construction of new or replacement asset will adhere to following standards…

Lines

Concrete poles (hard wood poles where load/strength characteristics cannot be matched)
Crossarms mounted 200mm below top of pole
Longer crossarms (2.4m) for live line friendly spacing
Polymer strain insulators – no strings or kidney
Line routes to adhere to road reserve where possible though a continuing issue exists with Transit NZ whose minimum draft standards for pole clearance in relation to the edge of road seal, (i.e. 9m clearance in 100km/hr areas) is proving challenging.
Standard conductors - Dog – Urban and Rural ties
Insulators to minimum 15kV standard and for coastal areas 25kV
Insulators fitted 100mm in from crossarm ends
All poles to be fitted with possum guard, and pole cap if wooden

Hardwood strain pole required every 2km in straight prop pole sections of line (to break cascade failures)
Angle poles to be armless for live line capability.
Mid span jumpers not permitted
No stub poles to be used for stay anchors

Cables

No pitch terminations to be reinstated if any work undertaken
Terminations on poles to be protected with surge diverters
Standard cable sizes: 300mm 185mm 95mm AL ,16mm CU
No cable to cable T connections

5.5.1.3 LV Lines and Cables

Standards used include the following:

NZS 3115:1980 for concrete poles.

AS 2209 for wooden poles.

Standard Pole types used on the network are:
- Concrete Pole 9.5m Busck
- Concrete Pole 9.2m Firth
- Concrete Pole 10.01m Firth
- Concrete Pole 10.67m Firth
- Softwood Pole 9.0m

Various specific standards are used for line hardware and fittings.

Standard LV cable types used are:
- Cable Aluminium “Huhu” Black
- Cable Aluminium “Huhu” Blue
- Cable Aluminium “Huhu” Red
- Cable Aluminium “Huhu” Yellow
- Cable Aluminium “Beetle” Black
- Cable Aluminium “Beetle” Blue
- Cable Aluminium “Beetle” Red
- Cable Aluminium “Beetle” Yellow
- Cable Aluminium “Kutu” Black
- Cable Aluminium “Kutu” Blue
- Cable Aluminium “Kutu” Red

- Cable Aluminium “Kutu” Yellow
- Cable Neutral Screen 1/16mm Plus Pilot Copper Underground
- Cable Neutral Screen 3/16mm Copper Underground
- Cable PVC 6mm Copper Underground

Construction of new or replacement asset will adhere to the following standards…

No reinstatement of pilot
No reinstatement of O/H street lighting
Wasp PVC covered conductor for overhead
Beetle (106mm2) domestic cabled LV reticulation
Huhu (185mm2) commercial cabled LV reticulation
25mm2 NS Cu. For road crossings
No under-building on 50kV poles
Cables to be run for first span from distribution sub.
No more than 1 termination per pole.
Designs to consider elimination of road crossings, overhead crossovers, mid span jumpers and substation by-pass via overhead circuit.

LV conductors are fused to full duty capacity, i.e. no short duration duty cycle peaks are permitted. This prevents accidental overload as no monitoring is undertaken and there is little control over the load connected in customers’ installation. No de-rating is made for damage, aging or trenching conditions. This sets the upper limits on conductor capacity at rating.

The low level of protection and management of load is traded off against longevity of service.

Overhead conductor is installed with an excess contingency capacity of 20% while cables have a contingency capacity of 33%. This contingency erodes with load growth until load equals rated capacity.

5.5.1.4 Service Connections

Domestic installations have traditionally been supplied via 4 wire (2 phases, pilot, and neutral) service lines. This was a means of keeping conductor size small by meeting capacity requirement via more conductors.

Single phase connections, without pilot, are the preferred standard. This reduces the quantity of connection hardware by 66% and reduces the probability of equipment failure. This will be encouraged at the time of upgrades via a differential in fixed charges for multi phase versus single phase connections.

All new connections and upgrades will encourage under grounding by providing the point of connection in a boundary located service fuse box, i.e. installation of pole fuses will be discontinued. This cleans down the structures of hardware, aids accessibility, and prepares the way for under grounding the main line.

Pole fuses will still be permitted in rural areas however preferred connection will be via cable only to eliminate pole loading issues.

For customers not wishing to underground a UDOS pole located on their property is an alternative.

During renewal programs no pilot wire will be reinstated. The installation will be converted to ripple control.

5.5.1.5 Major Substations

Environmental standards for noise control and oil contamination levels are maintained within council specifications.
Zone substations are designed within the requirements of Health and Safety, Electricity, Environmental and Building acts, regulations and codes of practice.

Earthing at Zone substations is carried out in accordance with the codes of practice. In general 70mm2 CU conductor is used with cad-weld connections and copper-clad rods driven at each conductor intersection. The design of the grid is specific to each site and varies depending on soil re-sensitivity factors.

The requirement for containment is determined by the quantity of oil that could spill in the event of a single rupture. For equipment with low oil quantities less than 200 liters oil spill kits and spill procedures provide for containment and clean-up to minimise environmental damage. Equipment that falls into the low oil quantity category includes switchgear and distribution transformers. For high oil quantities the work comprises, installation of concrete oil containment areas and the installation of oil separators to separate oil from the storm water under normal operating conditions. The requirement for oil containment at a site is dependent on the quantity of oil that could be spilt in any single event.

New building standards include raised buildings (approx 1 metre) to reduce risk from flooding and allow cable access from underneath.

Where wooden duct covers have been used and have begun to deteriorate they are being replaced with metal covers to reduce fire risks and the chance of failure under load. Alterations carried out on the buildings, as maintenance is required include the removal of windows in buildings where indoor 11kV switchgear is used and replacement of wooden doors and window frames with low maintenance aluminum fittings.

The layout of substation yards has been designed to allow crane access for installation and removal of the large transformer without interference from the overhead 11kV and 50kV lines

Oil spill kits and handling procedures are located at all zone substations to cope with oil spills from circuit breakers with lower oil quantities.

5.5.1.6 Major Substation Transformers

Transformers are designed to comply with the following standards:

BS 171	Power Transformers
BS 148	Insulating oil for transformer and switchgear
BS 223	High-voltage bushings
BS 4571	Specification for on-load tap-changers
IEC 551	Measurement of Transformer and Reactor Sound Levels

The transformers are designed to meet the requirements of NZECP 36:1993 NZ Electrical Code of Practice for Harmonic Levels.

Specific earthquake restraint designs are provided for the transformer installations.

New transformers require secondary oil containment and oil separation equipment per District Plan.
Earthquake mountings are required to have engineering certification.
Connections to bushings are also designed for earthquake tolerance.
Noise standards as controlled to requirements of the District Plan

Standard incremental Zone substation sizes used on the network are 2.5, 5/7, 12.5MVA.

Standardisation on the purchase of low cost IMP transformers from India with on site supervision of the construction has proved successful to date.

Alterations carried out on the initial IMP design that are now incorporated into new purchases include…

Earthquake considerations include the following loads for main structural components and anchoring attachments which are applied in addition to loads present during normal operation:

- a load acting through the centre of gravity of the component in any direction corresponding to its own weight multiplied by a seismic design factor of 0.75.
- for all appendages to the main tank including radiators, conservator tank, pipe-work and electrical bushings, and for control and protection equipment a load acting through the centre of gravity of the component in any direction and corresponding to its own weight multiplied by a seismic design factor of 1.5 horizontally and 1.0 vertically

Horizontal and vertical earthquake loads are not be considered simultaneously.

Anti vibration pads between transformer and concrete pad
Separate tap changer and transformer oil compartments in conservator tanks.
Pressure relief valves in addition to the Buchholtz fitted to both the transformer and tap changer.
Less than 1.5% transformer losses
A spare tap changer is held for contingency purposes.

As opportunity permits new transformer purchases in rural locations will comprise smaller capacity 3-phase units, which allow compact substation design and reduced maintenance over the life of the units.

5.5.1.7 Circuit Breakers

The standard used for selection of CB's is AS/NZS 2650, Common specifications for HV switchgear.

Indoor 11kV circuit breakers used for all Substations where multiple feeders are necessary.

Bypass and isolation arrangements are installed for 50kV CB's where no alternative supply is available.

Incomer and bus section configurations are used where dual transformer configurations exist.

All circuit breaker/feeder ratings are twice the normal feeder load to allow support of adjacent feeder loads.

50 kV Circuit Breakers

Bulk oil circuit breakers are located within bunded containment areas.

Outdoor CB's are used for all 50kV applications.

New 50kV CB purchases have been standardised for compatibility and reduced long term costs. Standard features include:

SF6 outdoor
66kV rated minimum
DC 24 volt operation (reduces 110V DC battery costs currently incurred due to older CB designs)

11kV Circuit Breakers

Min 400A rating and 12kA short time fault rating
SF6 or Vacuum
Indoor configurations for multiple feeder substations.
Bursting discs fitted to outdoor reclosers (requirement from previous failure issues)
Electronic protection with fully configurable curve types and settings including DNP3 or Modbus communications capabilities.
24v DC operating mechanisms
Live line installation standard with bypass features using hot stick techniques
SCADA control fitted to all remote recloser installations.
Inclusion of Fault locators into recloser and protection schemes is also planned to optimise the overall network performance

The co-ordination density criteria for CB’s, reclosers, sectionalisers, and fuses are as follows...
Feeder CB per each substation feeder
Field CB not more than 2 cascaded from Feeder CB
Sectionaliser not more than 1 cascaded from Field CB

Fuses Branch fusing on private spur lines

5.5.1.8 Distribution Transformers

All transformer installations are designed to allow restoration within 8 hours.

In most cases portable generation is temporarily used to supply load during replacement of larger transformers.

The security standards adopted by ENL do not allow for temporary supply of loads as a result of smaller transformer failure.

Earth resistances step and touch and equal potential bonding standards are in accordance with the electricity act and regulations.

To upgrade earths a maximum of 6 rods (2 banks) are driven before an earth is abandoned as impractical to lower resistance. These situations are reviewed on a case by case basis as the occurrence is rare.

Strength requirements for pole mounted substations are in accordance with the outcomes of the Visim design tool.

Replacement of transformers with ground mount mini sub style units is the standard practice for transformers over 100kVA Smaller ground mount transformers are also used for replacements in rural locations where the supply is via underground 11kV cables.

Standard transformer sizes used are 15 kVA for 1 phase supplies 30, 50,100, 200, 300, 500, 750, 1000 kVA for 3 phase.
All transformers above 100kVA to be ground mounted.
All new urban substations to be ground mounted regardless of size.
LV isolation to be provided.
All Urban LV connections to be cable.
Transformers greater than 500kVA shall have 3-Phase switching provided for connection and disconnection, on the HV

5.5.1.9 Pole mounted Isolation equipment

Standards for Air Break Switches include…

installations that accommodate live line replacement and maintenance techniques
900mm Phase separation on 11kV
1400mm phase separation on 50kV
arc suppression fitted if connected capacity >1MVA on 11kV
50kV not used to break load unless fitted with suppression

load break fault make rating on all new purchases

No transformers greater than 500kVA are installed using fusing protection in overhead areas.

Where sectionalisers or similar equipment are not present on rural lines air break switches are considered necessary at distances not exceeding 10km with typical connection densities of 20 to 30 per section.

Standards for Ground-mount switch installations include…
No more than 3 transformers supplied from 1 switchboard without bus section

Not more than 500kVA fed from switchgear supplied from a single cable circuit (excluding industrial situations)

No more than 2 transformers and associated switchgear cascaded with no back feed

Not more than 1 cable circuit connected directly to the bus of a switchboard arrangement.

SF6 or Vacuum type equipment used for replacement to reduce maintenance.

11kV switchgear standards

Extendable
Extra height for termination ground clearance
Independently mounted from transformer.
3 phase operation
Fault make /load break
200A fuse tee off rating min.
400A Bus bar rating min.
12kA short time fault rating min.

5.5.1.10 LV Switchgear

New LV panel installations are constructed using DIN style equipment which is mounted independently from the transformer. Incomer links are fitted to provide the ability to isolate between the transformer and the LV bus bars. This facilitates easy removal and replacement of failed transformers or connection of mobile generators.

LV tie switches are not normally installed on overhead networks interconnections are made using portable jumper sticks in fault conditions. In underground domestic reticulation boltable tie connections are made available at the open points of the LV runs.

5.5.1.11 Control and Protection

New purchases of protection relays include standardisation in terms of flexibility in protection scheme design, communication using standard serial I/O protocols and interchangeable hardware.

It is desirable to keep protection equipment and design consistent across the entire network. Therefore replacement programs need to be concentrated into a 5-year timeframe.

For Transformers up to 5MVA Overcurrent /Earth Fault protection is sufficient.

Transformers over 5MVA are to have Restricted Earth fault and Differential Protection.

110V battery banks installed as single unit.

Dual 24V Battery systems are to be used where installed CB's operate on 24V and no 110V systems are installed. 24/12-volt DC-DC converters used for Radio equipment power supply.

Battery chargers and batteries including rationalisation of various supply voltages to a common voltage (i.e. 12 volt, 48 volt supplies standardised at 24volts)

Tap changer controls shall be capable of Master/ Follower or circulating current operation to cope with unbalanced conditions.

Remote manual controls are installed on tap changer controls at Zone Substations and on Voltage Regulators to allow operator intervention when automatic control relays malfunction or when voltage adjustments are necessary when paralleling between to zone substations.

5.5.1.12 Communications

Construction of new or replacement asset will adhere to following standards…

Compliance with the Radio Spectrum Management Conditions and Radio Communication Regulations.

Telecom circuits 5kV isolation on all sites.
Eastland Network pilot communications circuits 5kV isolation at all sites.
LTCSS tone calling on all RT's
Equipment at each end of a link to be same make, model and age.
Power levels standardised on all repeaters at 25W. (Digital links 10W)
Detachable head RT's to be used in vehicles.

5.5.1.13 SCADA

Correct operation of the SCADA system has a direct impact on the service levels and supply restoration response times. As such the reliability requirements of the system are high.

Dual master stations, remote master connection, sub master and island operating capabilities are directly targeted at robustness of the system to faults.

The poll duration of a single SCADA port increases with the number of RTU's connected to the port. When operating remote equipment from the control room maximum poll durations of 35 seconds are targeted to ensure effective operation and feedback from the equipment being controlled. A maximum of 25 RTU's per port is necessary to achieve the targeted poll duration.

Systems connected with the SCADA system must be selected to consider use of consistent Protocols
DNP3
MODBUS
ABBEY

5.5.2 Building new assets

ENL uses external contractors to up-size or extend assets. As part of the building and commissioning process ENL's information records will be "as-built" and all testing documented.

The forecasts for new assets and asset extensions other than those identified in the development program are identified for each asset category as follows…

5.5.2.1 Distribution

The majority of distribution funding is specifically identified in the development program. Customer driven funding for distribution lines and cables is identified in the section 4.7.1.4. In most cases this funding only contributes to a portion of the total project funded by the private developer or customer. The contribution provides for the cost of increases in line or cable size beyond the minimum required for the customer which will provide for growth over the applicable planning period

5.5.2.2 LV Lines and Cables

Detailed analysis is only undertaken on the urban overhead network to identify exact capacity constraints when alterations are being made or to correct issues as they are identified. The cable network, which supplies commercial areas, is monitored more closely.

The trigger for upgrade is therefore a fuse blowing. Voltage complaints and transformer MDI readings can give an early warning. With load growth ranging between 0.5 and 11% it can be expected that in many cases conductor and cable will require capacity upgrade long before age replacement.

At present ENL is addressing capacity via additional transformer installation.
In the interim growth on these cables erodes contingency capacity which is being offset by availability of portable generation.

An annual provision to accommodate ENL's contribution for growth is made to install 1km of LV (urban/commercial) cable at $84,000.

5.5.2.3 Service Connections/Load Control

New service connections are typically associated with subdivision work or infill housing developments. Funding is generally not provided by ENL for the work directly associated with these new connections. Provision to accommodate any contribution by ENL's for new service connections is included within the provision for LV Lines and Cables above.
An allowance of $10,500 per annum is made for provision of ripple relays for new service connections.

5.5.2.4 Transformers

Allowances for ENL's contribution for additional transformers and capacity upgrades per year to cater for typical growth are as follows. Negative growth or shifting of load centers creates redundancy of transformer installations.

Funding allowances for the anticipated growth are as follows…

Large Transformers greater than or equal 100kVA, 3 at $167,525 pa.

Small Transformers less than 100kVA, 20 at $87,113 pa.

5.5.2.5 Switchgear ground mounted

Growth associated with this switchgear is triggered by industrial load or underground subdivision development. There are no constraints associated with the switchgear as the equipment is rated appropriately to the feeder capacities.

In general ENL is not involved with the funding for this development, allowance for 3 units or 9 switches per year is sufficient.

Allowance for ENL's contribution for subdivision and industrial growth of $55,842 for 2 units or 6 switches per year is provided.

5.5.2.6 LV Frames

Capacity upgrades assume reuse of existing LV frames.

Frame Installation as required with transformers.

Growth contingency associated with customer connections allows for 6 new Boxes per year at $44,673.

Installation of new Distribution boxes as ENL removes its connection fuses from shared Meter boxes on customer boundaries is covered in the renewal section of this plan

5.5.2.7 Communications

Allowance for 2 additional automated sites per year from 2021/22 onward is considered sufficient for long term development. These communications costs are included in the Scada section.

5.5.2.8 Scada

As the number of sites increases on the network the capacity of the Abbey Master station will be increased. Functionality improvements of the system are also being developed on an ongoing basis to keep the system current. Ongoing development over 10 year cycle between system replacements should assume an average annual cost of $11,168.

Development of additional sites following completion of the rural automation program is forecast from 2021/22 costs are inclusive of Scada, communications and Actuator equipment $33,505 pa.

5.5.3 Non Network Assets

The acquisition of non-network assets is managed by Eastland Group Business support services.

Assets include:

Corporate land and buildings.

Furniture and Fittings

Vehicles

Plant and Equipment

Safety equipment

Corporate IT infrastructure

Phone systems

Shared Corporate software and systems

As needs are identified, business plans and budgets are updated, selection of assets to suit the needs is undertaken and the assets are acquired.

In general asset management and planning activities for these non-network assets are managed by policies and procedures outside the scope of this AMP.

5.6 Retiring of assets

Retiring assets generally involves doing most or all of the following activities…

De-energising the asset.

Physically disconnecting it from other live assets.

Curtailing the assets revenue stream.

Removing it from the Fixed Asset Register.

Either physical removal of the asset from location or abandoning in-situ (typically for underground cables).

Disposal of the asset in an acceptable manner particularly if it contains SF_6, oil, lead or asbestos.

Key criteria for retiring an asset include…

Its physical presence is no longer required (usually because a customer has reduced or ceased demand).

It creates an unacceptable risk exposure, either because its inherent risks have increased over time or because emerging trends of safe exposure levels are declining. Assets retired for safety reasons will not be re-deployed or sold for re-use.

Where better options exist to create similar outcomes (eg. replacing lubricated bearings with high-impact nylon bushes) and there are no suitable opportunities for re-deployment.

Where an asset has been up-sized and no suitable opportunities exist for re-deployment.

6. Managing the risks to the business

ENL's business is exposed to a wide range of risks. This section examines these risk exposures, describes what ENL has done and will do about these exposures, and what ENL will do when disaster strikes.

6.1 Understanding the business risk profile

Arrangements for Eastland Infrastructure to provide all management and support services for all of it's companies, which are all owned by the Eastland Community Trust was implemented in 2003. A new management structure was developed with new appointments being made to a number of management positions at this time.

The change in company size and structure altered the business risk profile of Eastland Infrastructure and the companies it manages. A comprehensive risk management review to facilitate the ability to manage risk in accordance with the Risk management Standard AS/NZ 4360:1999 was undertaken in August 2004. The business operations of the three businesses were reviewed against a generic set of risk areas, (Governance, Personal, Financial, Business Development, Environmental, Political, Legal, Operational, Information, Technological and Business Resilience).

Having identified risks and associated existing mitigation practices, analysis was undertaken to determine likelihood (frequency or probability) of the risk occurring and the consequence (impact or magnitude of the effect) should the risk occur. By aggregating the likelihood and consequence, risk significance was assessed both with existing treatments applied and with any additional mitigations/treatments applied. This provided a measure/review of the effectiveness of current and future risk management for each business.

The review identified the following primary exposures …
A number of key staff with specialised business knowledge or skills which is not sufficiently backed up. Mitigation in the form of increased staffing levels has occurred which will be effective over time, however this exposure has yet to be reduced to acceptable levels.
An aged workforce. This exposure was evident for both personnel directly employed by the company and those engaged in contract work for the company. A bursary program to support training in the necessary skill areas has been introduced. In addition financial support of apprenticeship initiatives within the local contractors has been promoted. It is hoped that within this framework, the ability to retain graduates and trades from the

local community following training will be bring about a successful succession plan over the next 5 years. Currently the necessary personnel/shill levels within contracting companies at the local level have reached a critical low level to the extent that training apprentices in sufficient quantities is not possible.
A high degree of uncertainty in future/proposed legislative requirements and short response timeframes affecting the ability to prepare policies systems and processes to meet the requirements. Legislative changes include those relating to the Electricity industry safety standards/working practices, use of road corridors, Resource management and consents and Regulatory control and disclosure. Dedicated staff and additional consultants have been engaged to monitor and advise and assist with the development of processes to maintain alignment with the changes. A steady increase in resource levels and their associated costs is anticipated to maintain this exposure within acceptable levels.

6.2 Identifying specific risks

The risk management process as it applies to ENL's electricity network business is intended to assess exposure and prioritise mitigating actions. The process is as follows…

Risk issues are identified and recorded.

Minor risk issues are eliminated or controlled.

Potential solutions/actions are developed.

Actions are assessed against outcomes or success factors.

Actions are ranked on the basis of weighted performance against outcomes.

Results are then applied to cost benefit analysis in project viability tests.

6.2.1 Guiding principles

ENL's behavior and decision making is guided by the following principles…

Eastland Group endeavors at all times to purchase and provide secure risk managed products and services at the least cost and at the same time if possible secure long term contracts for purchases, services and sales.

Only authorised contractors and personnel may transact business in Eastland Group's name and specified limits shall be maintained for such authorisations.

ENL will only purchase or sell product or services in line with its business expertise.

ENL will only undertake transactions with approved contractors and suppliers. Such transactions shall be maintained within specified limits.

ENL's risk management policy and related procedures and systems are to be reviewed 2 yearly by an independent party.

Annual internal reviews of risk management documentation are undertaken to ensure risks have been assessed correctly and that actions to reduce risks are actually taken.

6.2.2 Risk Categories

ENL uses the following tactics to manage and respond to risk issues under the following broad categories…

Commercial risks

Competition - assessments of ENL's exposure to bypass or generation are undertaken annually as part of ENL's strategic planning process. As issues arise they are discussed at monthly board meetings.

Customer activity – regular communication is maintained will all ENL's significant consumers. In addition to growth projects ENL has policies in place to provide assistance to local businesses.

Project management & professional liability - regular training and refreshers are carried out. Insurance policies and registrations with professional bodies are kept up to date. Contracts with service providers define provisions required to control associated risks. Maintenance and inspection activities documented in this plan, in addition to condition assessment information target identification of hazards and non-compliance issues. Targets for elimination of the risks associated with the hazards and compliance issues are also documented for each asset category in section 8 of this plan.

Financial - contracts with ENL consumers define liability and performance penalties. Contracts with ENL suppliers include requirements for insurance and protection of works.

Emergency Preparedness - Procedures and contact lists for explosion, fire, disease, accident, injury or death incidents, and environmental accidents that may be associated with operation of ENL's main office facilities, network assets and incidents involving contractors working for the company.

Disaster Recovery - Policies, plans and readily accessible documentation are maintained to maximise the effectiveness of ENL's efforts to overcome disaster events. Financial arrangements and insurance policies are in place to control the associated financial impacts resulting from events of this nature. The network is not covered by catastrophe insurance. A borrowing provision is allocated in the annual funding plan for storm and large unplanned events. Events considered in the assessments include flooding, earthquake, tsunami, war, landslips, drought, volcanic eruption, severe storms and bush fire.

Legal, statutory & regulatory risks

Financial security - quality system procedures for financial authorities and identification of ENL's representatives are in place and are externally reviewed.

Confidentially- policies and quality system procedures are in place to control access to and dissemination of confidential data.

Legal compliance & statutory liability - quality system procedures and 6 monthly check lists are used to ensure all obligations are met on time and to ensure issues are identified and resolved. Issues are reviewed at 6 monthly board meetings and external parties are used for procedural reviews.

Health & safety - quality system policies, procedures and 6 monthly refresher training are in place. These procedures include hazard identification & control, contractor authorisation, incident reporting and standards for conduct. Self-auditing and independent auditing requirements are included in contractual arrangements and network authorisations.

Public Health & safety
Quality system policies, procedures, and design standards serve as the control measures to minimise residual risk to levels that are as low as reasonably practicable. Both internal and external audits of the systems to ensure compliance with requirements of the regulations are carried out.

Information security and control risks

Documentation – quality system procedures are in place for storage and duplication of critical documentation. All critical documentation is backed up via the computer systems used to generate the documents. Risk of total loss is controlled by use of multiple storage locations throughout the region.

Information systems – IT procedures are in place to provide 100% redundancy and backup for all systems used. Spares are maintained for critical equipment items. Testing of procedures and auditing of their effectiveness is undertaken on a regular basis.

Communications – alternative communications systems are maintained. Use of external service providers is duplicated by ENL's own communications network. ENL maintains the ability to relay business communications via third parties based outside of the Gisborne and Wairoa regions

Event Management Control - In the event the region is disjoint with respect to access or communications remote centers have been designated to enable decentralized planning and operational facilities to ensure for operations to continue at a localized level. Independent control will be delegated to a person based at each centre to run each area and liaise back to the control centre if communications are available. In the event that no communications are available, then the local centers have the ability to operate independently.

Physical security of resources

Physical security – Physical security provisions are maintained at all strategic sites through long-term contracts with security providers. Security systems are tested annually.

Land use – legal agreements and easements are maintained for all sites considered strategic or where land use or access is vulnerable to dispute.

Electricity supply risks

Loss of bulk supply - Transpower does not include cost penaltys within contractual arrangements for supply at the Tuai GXP. Hence there is no ability to negotiate cost penalties for loss of supply as was experienced in 2001 and 2003. The purchase of six 1MW diesel generators in 2003, when combined with the Waihi hydro scheme gives us some measure of security for up to 20% of ENL's maximum demand.

Grid Emergency- Procedures are in place so that ENL is able to meet its obligations under the Electricity Governance Rules. These procedures include an approved participant outage plan.

Civil Defence Emergency - ENL is actively involved in and supports preparedness through the involvement with the Hawkes Bay Regional Council and the Gisborne

District Council LifeLines groups. If no priorities are identified via the liaison process with Civil Defence, then the sequence of repairs are based on the following priorities…

City areas where large customer numbers are disrupted.
Critical infrastructure, such as water supplies, sewage systems and hospital / medical facilities.
Commercial business appropriate to servicing emergency needs
Rural Townships
Rural areas:
Between townships
Spurs – outlying areas

Liability for loss of supply or fluctuations - contractual arrangements and insurance policies are in place to limit ENL's exposure to the associated outcomes.

Revenue Protection- Procedures are in place to work with Energy retailers where necessary to continually monitor identify and eliminate issues.

Electricity outage risks

Breakdown and Equipment failure - Network design and material standards are used to control the quality and suitability of product used. Care is taken to align product choice with common industry options to maximise the ability to source shortfalls. Suitability of new products and product use is the responsibility of the Asset Manager and is under continual review. Asset based solutions and standards detailed specifically for each asset. Strategic spares consist of equipment generally purchased for a project ahead of time. This equipment consists of critical items with long delivery times including 50kV/11kV transformers, 50kV switchgear & line hardware, protection, SCADA and communications equipment. Equipment that can be relocated to cover failure of strategic items has also been identified which generally includes 50/11kV transformers, and down-stream 11kV switchgear and protection equipment that can be used to replace failure of primary feeder circuit breakers and protection. In many cases the strategy for failed equipment is to bypass the equipment and operate on reduced functionality or rely on backup systems. Minor breakdown of critical equipment is not uncommon and the processes, which have proven adequate to date, to maintain service levels are similar to those that would apply for catastrophic failure of the critical equipment. The Procedures for documentation of asset & equipment failure are in place to identify problem items or equipment.

Resourcing - Contracts provide for minimum re-sourcing, backup re-sourcing, and response practices. Product suppliers are monitored and audited to ensure specified minimum levels of product spares and replacements are maintained in the region. Procedures and documentation are maintained to ensure product can be sourced from outside the region in a timely manner to cater for catastrophic events. Re-locatable diesel generation is available as a substitute for normal distribution supply. ENL has maintained relationships with companies not normally involved the network and through these relationships assistance and support in past large scale events has been willingly provided.

Access to specialised equipment - Procedures and arrangements to ensure 24 hour access to specialised equipment are maintained and verified on an annual basis.

Competency and capabilities – Skills in helicopter transportation and line reconstruction techniques are maintained to ensure risks associated with road access are controlled via alternative means. This is particularly important in remote areas of the region. To manage additional resource from outside the region, ENL staff qualifications are maintained and skilled local personnel have been identified to supervise activities maintaining work procedures, safety requirements and construction standards.

Processes- Response Plans include pre-prepared switching and contingency plans for all sub-transmission and critical equipment. Testing of processes is undertaken as part of normal operations. In general severe storms occur 1 or 2 times per year causing damage levels beyond the normal resourcing capability. On these occasions the response processes to coordinate priorities and establish additional resource, are put in place to effect repairs. To date the systems have proven adequate. Procedures are in place for review of outages to identify any issues. Corrective actions are incorporated into contractual arrangements design standards and asset management plans as appropriate to control the risks.

6.2.3 Asset Management Risk Assessment

ENL considers that a risk component applies to all projects and work undertaken. All network development projects are implemented to mitigate risks to varying degrees.
The results for identified risk issues directly relating to asset management risk assessments and action plan priorities are presented in the following matrix covering specific risk issues,

For each asset management risk currently identified:
The success factors applied are as follows…
The weightings applied
The assessment scores
The resulting priorities

In general there is a strong correlation between risk priorities and current work program's. However it should be noted that risk is not the sole driver of work priorities. Risk priorities influence development plans but timings are also based on the need to co-ordinate projects.

The identified risks are addressed within the current work programs given in the Asset Management Plan. However annual review is necessary due to the rate of change in the network. This process captures new risks and adjusts priorities.

Action Plan Priorities Ranked by Risk Reduction Outcomes

Success Factor or Outcomes :

Reduced combined effect with other risks or increased combined provision
Improved Safety
Reduced SAIDI (improved service)
Reduced SAIFI (improved reliability)
Cost reduced
Return on investment required achieved or increased
Economic Impact to Community Reduced
Compliance and Environmental Responsibility
Public Acceptance
Meets Urgent Need

Ranking Criteria (against each Success Factor) : 1 to 10
0: No Impact 2: Low Impact 5: Medium Impact 7: High Impact 10: Crucial

	AMP		Criteria Weightings										Score
Priority	**Section**		**20**	**10**	**5**	**10**	**10**	**5**	**10**	**15**	**5**	**10**	**1000**
1	5.4	Red taged pole replacement high density	10	10	10	6	7	8	9	8	10	8	860
2	5.4	Red taged pole replacement rural	8	9	10	4	7	8	9	7	9	8	770
3	5.4	Red taged pole replacement remote	6	8	10	2	5	9	9	6	8	8	665
4	5.4.10	ABS replacement	7	2	10	3	1	8	9	10	10	8	660
5	4.7.1.2	33kV line extension Blacks Pad to Mahia	6	10	4	4	4	2	8	8	0	5	580
6	4.7.1.2	Waihi/Affco/Wairoa 33kV supply Rationalisation	4	10	6	7	4	4	3	8	0	4	530

8	5.3	Maintaining assets	10	7	10	0	4	4	0	0	10	3	460
9	4.7.1.4	CBD Security reinforcement due to growth	6	10	0	6	2	2	2	6	0	1	430
10	4.7.1.2	Matawai Supply security from Ngatapa	4	6	0	2	4	3	7	7	0	3	420
11	5.4.4	Meter/pillar replacement	10	7	9	0	0	0	0	0	8	3	385
12	5.4.11	Switchgear Replacement	6	5	4	0	0	0	4	4	6	3	350
13	5.5.2	Building new assets/upgrades	5	5	8	2	6	4	0	0	0	4	330
14	5.5.1.7	Circuit Breaker Renewal	3	3	5	0	2	3	4	4	3	5	315
15	5.4	Conductor renewal	3	3	8	0	2	3	4	4	3	3	310
16	5.4.14/15	Communications annd Scada Renewal	2	3	0	2	0	0	6	7	0	4	295
17	4.7.1.3	Provisional Embedded Generation	3	3	0	2	2	0	4	4	2	5	290
18	4.7.1.3	Provisional Connection of Customer Installed Generation	3	3	0	2	2	0	4	4	2	5	290
19	4.7.1.4	Improved Power Factor Correction	4	3	2	6	5	5	0	0	0	3	285
20	4.7.1.4	Reduce Network Distribution Losses	3	3	2	4	5	5	0	0	0	6	275
21	5.4.6	Zone Sub Transformer Renewal	3	3	8	0	2	3	2	2	4	3	265
22	4.7.1.1	Tuai-Gisborne Line Reconductor	2	5	10	1	0	2	0	0	1	1	175
23	4.7.1.2	Provisional Mangapapa Zone Substation	0	2	0	2	2	3	2	2	4	3	175
24	4.7.1.2	Provisional Whangara Zone Substation	0	2	0	2	2	3	2	2	4	3	175
25	4.7.1.1	Provisional Tuai-Gisborne 3rd Transmission Line	0	2	0	2	2	3	2	2	4	3	175
26	4.7.1.2	Provisional Patutahi Sub Capacity Increase	0	2	0	2	2	3	2	2	4	3	175
27	5.4.9	Distribution Transformer Renewal	2	2	6	3	0	0	0	0	2	4	170
28	4.7.1.4	Uneconomic Rural Lines	2	2	7	0	0	1	1	0	6	2	160
29	4.7.1.5	Overhead to Underground conversion	0	3	4	0	0	0	3	3	5	1	160
30	4.7.1.5	Ground fault neutralisers	0	2	4	0	0	0	3	3	4	1	145
31	4.7.1.5	Portable/Emergency Generation	2	1	0	0	0	0	2	3	0	1	125
32	4.7.1.5	Urban rural Automation	1	1	0	0	0	0	3	2	1	1	105
33	4.7.1.4	Improve Load control capability	1	1	2	4	0	0	0	0	0	1	90

6.3 Emergency Response Plans

The nature of ENL's business is such that every unplanned supply outage that occurs invokes an emergency response of some degree. In addition there are also unplanned events or incidents that can threaten the safe and continued supply of electricity which prompt an emergency response

Emergency response at a small scale includes the following types of events…
Part power to one or more premises
No power to one or more premises
Third party damage to network assets.
Property fires
These types of events occur on a daily basis. In any one day 5 to 20 events are typical.

Large scale events that require emergency response to a greater degree include…
Extreme weather e.g. Wind ,snow, lightning storms

Earthquake
Tsunami
Major flooding
These types of events are relatively rare and occur 4 or 5 times per year to varying degrees.
In these large scale events the normal emergency response strategies become swamped hence additional resources and prioritization is required for effective management of the events.

6.3.1 Minor events

The processes in place for small scale events are as follows…

6.3.1.1 Event Notification

Notification of the event is obtained…
When a member of the public calls the call centre.
When police or emergency services contact the duty control operator.
When the SCADA system automatically detects an issue and notifies the duty control operator.

6.3.1.2 First Response

The duty control operator in some cases will carry out remote operations to either isolate the assets affected by event or minimise the effects on other electricity customers.
The call centre or duty control operator directly dispatch fault contractors to the location of the event.
Where possible the first response fault contractor performs the necessary corrective actions.
Where additional personnel or equipment is required the first response fault contractor carry out actions required to ensure the assets are safe and relays all necessary information via the call centre or duty control operator to obtain additional resources.

6.3.1.3 Restoration

Where correction or restoration of supply following an event is beyond the capability of first response contractor's additional staff or contractors are dispatched and the corrective actions are carried out as quickly as possible.

6.3.2 Major events

The processes in place for large scale events are as follows…

6.3.2.1 Event Notification

Notifications of major events are obtained…
When the call centre receives multiple notifications of unrelated events.
When police or emergency services contact the duty control operator via civil defence protocols.
When the SCADA system automatically detects multiple issues and notifies the duty control operator.
When ENL personnel directly experience an event triggering a personal response. eg Earthquake, power goes off
When the automatic civil defence notification system advises the General Manager Energy, Asset and Planning Manager or Civil defence liaison directly.
When the Electricity Commission or System Operator declares an event.

6.3.2.2 Event Response

Where the number or magnitude of events exceeds normal levels the call centre or fault contractors notify the duty control operator. The duty operator makes an assessment and invokes the event actions as necessary.
When civil defence protocols are implemented the recipient of the communication in conjunction with the duty control operator invokes the event actions.
For events such as earthquakes ENL personnel and contractors respond without additional notification. In accordance with their personal emergency action priorities personnel ensure that their own needs and needs of immediate family are met. When the issues in their immediate environment have been addressed the personnel respond to the operational centers. Refer 6.3.2.4 .

6.3.2.3 Event Actions

Establish control centre.
The duty control operator is conjunction with the civil defence liaison establish the Event management centre. The necessary personnel are notified, normal activities and duties are suspended and emergency roles are activated.
Additional control room staff are activated.
The civil defence liaison attends the civil defence control centre.
A dispatch team is established to group, prioritise and organise the information from the control room staff and call centre. The dispatch team coordinates the contractor resources to the prioritised tasks. The control room staff monitor and record the activities of fault response and repair teams. The General manager Energy oversees activities of the control staff dispatch team and civil defence liaison and provides status information as necessary.

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Determine Priorities.

If no priorities are identified via the liaison process with Civil Defence, then the sequence of repair is based on the following criteria:

City areas where large customer numbers are disrupted.
Critical infrastructure, such as water supplies, sewage systems and hospital / medical facilities, communications facilities.
Commercial business appropriate to servicing emergency needs. Eg fuel, food
Rural Townships
Rural areas: Between townships
Spurs – outlying areas

Implement Repairs.
Following the allocation of resources first response teams patrol and identify damage to the asset. In addition to land based teams, helicopters are used to carry out patrols, switching, jumper cutting and supply restoration.
Damage reports and requirements for corrective action are relayed via control staff to the dispatch team.
First response teams work with the control staff to disconnect, isolate and make safe damaged assets. Where quick repairs are possible eg fuse replacement, these tasks are completed.
Once damaged assets are made safe restoration of supply to unaffected areas is carried out.
Information regarding the requirements for repair or restoration of the damaged assets is communicated by the first response teams to the control staff.
Large repair teams are dispatched with equipment for major repair work, to event locations near job sites. Due to the rugged nature of the terrain in general helicopters are used to drop personnel at the job sites and then follow up a various stages of the work to install poles, restring conductor and return personnel to the vehicles near the event locations. Scheduling of the helicopter work is coordinated by control room staff.
Specialised generator teams are used to move and install generators to remote areas where damaged assets have resulted in isolated areas on spur lines.

Allocate resources.

The dispatch team is notified of resource requirements from the field via the control staff

The team prepares recovery plans and implements the dispatch of resources as required to repair damage.
Equipment and stores providers communicate directly with the dispatch team to establish resource requirements.

The civil defence liaison provides feed back to the dispatch team and updates civil defence plans on the status of new priorities as they are determined.

The dispatch team carries out an on-going reassessment of priorities and planning and applies the available resources to the action timetable.

Arrange external resources.
The information relating to corrective action requirements reported by first response teams is assessed by the General Manager Energy and additional material, equipment and personnel requirements are determined. In general external resource form outside the region is notified of potential around 4 hours into an event. Confirmation of requirements is established with 8 hours and resources typically arrive 8 to16 hours later. Helicopters are used to collect equipment and materials from outside the region when the delivery time frames by road are excessive.

Arrange support services.
A Support services team is established to ensure the needs of emergency personnel are established.
ENL maintains a stock of food and medical supplies sufficient to cater for the short term.
Work hours and fatigue are monitored and recorded by the support team with the information being fed back to the dispatch team.
Communication between field staff and families is coordinated by the support team.
Long term needs are coordinated via the civil defence liaison where necessary.
The chief executive officer is responsible for media updates and public liaison.

6.3.2.4 Operational Centres

Primary Site

The Eastland Network Control Room is located at the 172 Carnarvon Street, Gisborne Facility.

Unavailability of the Control Room

If for any reason the Control Room is unavailable, then the backup Facility will split into the following respective areas as required:

Eastland Network – Wairoa office
Eastland Network – Kaiti Sub Station or Patutahi Sub Station

Operational Facilities

In the event the region is disjoint with respect to access or communications the following remote centres have been designated to enable decentralized planning and operational facilities to ensure for operations to continue at a localized level:

Eastland Network Wairoa
Eastland Network Carnarvon St Sub or Kaiti Sub Station
Eastland Network Tolaga Bay Sub Station
Eastland Network Tokomaru Bay Sub Station
Eastland Network Ruatoria Sub Station
Eastland Network Te Araroa Sub Station
Eastland Network Puha –Station (Te Karaka - Matawai)

Independent control will be delegated to a person based at each centre to run each area and liaise back to the control centre if communications are available.

In the event that no communications are available, then the local centres will have the ability to operate independently.

6.3.3 Contingency measures

A majority of the necessary contingency measures are incorporated into designs of the asset. These contingencies include…
Redundant or backup protection systems.
Redundant capacity inherent in conductors and transformers.
Pre-arranged connection points for portable generation
Multiple communication methods via ENL's RT network of Third party service providers.
Paper management systems ready to cover for failure of computer systems.
Manual operating mechanisms for all assets to backup failure of the SCADA system or auxiliary supply systems.
Significant battery storage at key locations.
The general approach to contingencies is…
For failed equipment with a backup inherent in the design, the backup system is used.
For failed equipment affecting supply the equipment is isolated, or removed to restore supply.
Faulty equipment is replaced with spares held at strategic locations. Spare transformers, switches circuit breakers, protection relays, tap-change equipment and battery systems are held which cover the entire range of equipment used.
Faulty equipment is bypassed to allow restoration of supply. At rural substations such as Ruatoria, Ngatapa, TeAraroa, Tokomaru, Tolaga, Pehiri, Puha, Blacks Pad and Tahaenui the entire 11kV switchboard can be bypassed and a single set of

100Amp isolation fuses used to provide a temporary supply. Portable generation is used to bypass faulty sections of line and cable enabling restoration to isolated spur assets.

6.3.4 Participant Outage Plan

ENL's participant outage plan was prepared in accordance with The Electricity Commission requirements. The plan covers methodology and processes for managing two types of event.
Class A events - These events evolve over time and occur when a shortfall of energy available for supply is expected. The electricity Commission is responsible for declaring an event. In these events ENL is required to provide a reduction in energy usage based on a comparison with typical/ normal energy usage. This is achieved by operation of the standby diesel generation, shedding of hot-water load via load control for extended periods outside of normal service levels and rolling outages in line with predetermined priorities.

Immediate (Category B) events – Events that occur with little or no warning, usually as a result of a transmission line or major generation failure. These types of event will generally result in a declaration of a Transmission Grid Emergency. In these events ENL is required to provide a reduction in demand at Grid Exit Points. Depending on the available time frame this is achieved by operation of the standby diesel generation, shedding of load via load control and interruption of load in line with predetermined priorities.
In addition to protect the Transmission System from catastrophic failure following a category B event causing instability an Automatic Under-frequency Load Shedding system is installed (AUFLS) to automatically interrupt supply based on pre-configured priorities.

6.3.5 Vulnerable Customers

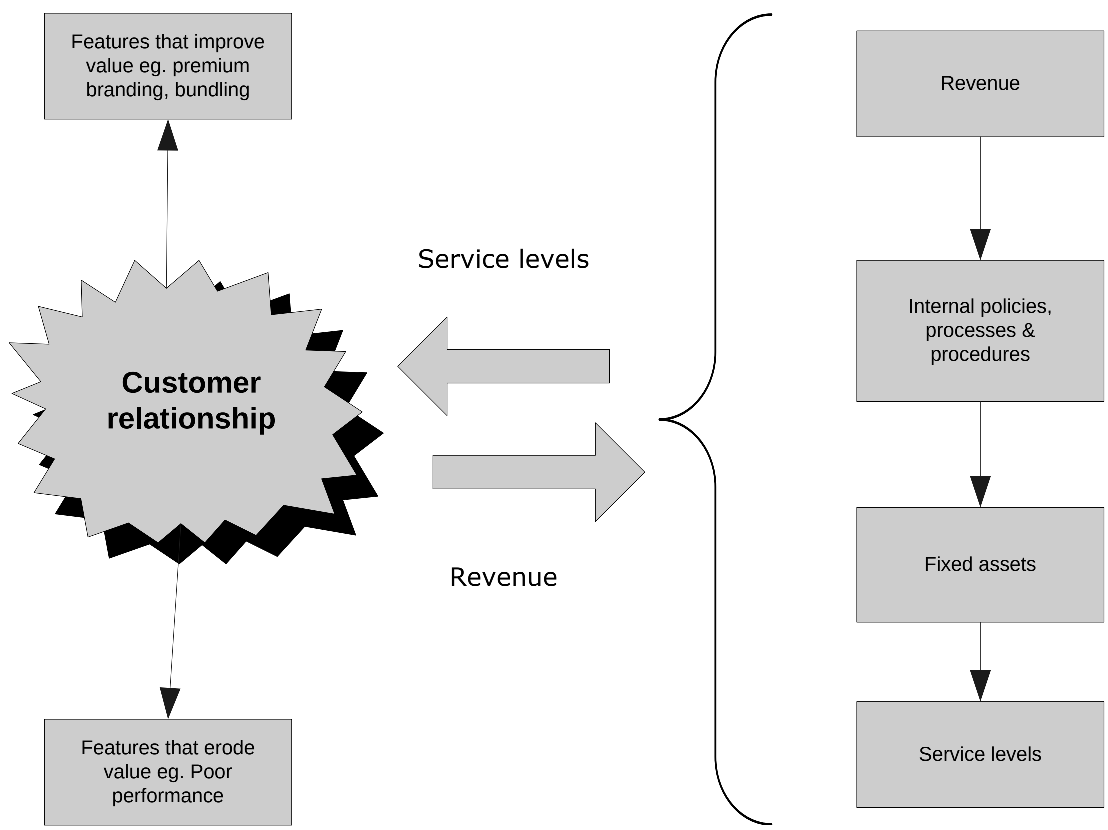
A process is in place to accommodate supply interruptions affecting customers with special medical needs.
Where ENL is notified of customers with special needs the customers are advised to prepare an individual emergency plan to ensure their needs can be met should there be an interruption to their supply. Action plans covering short term and long term outages are necessary and issues of battery backup systems or emergency transportation are identified and arranged between the customer and their healthcare provider as these individual emergency plans are developed.

7. Funding the business

7.1 ENL's business model

ENL's business model is based around the right-hand side of Figure 7.1(a) below.

Figure 7.1(a) – Customer interface model



This model shows that ENL receives revenue from its consumers (via the energy retailers who operate on the network) and then, through a wide range of internal processes, policies and plans, ENL converts that cash into fixed assets. These fixed assets in turn create the service levels such as capacity, reliability and security that consumers and other stakeholders want.

7.2 Financial Income

ENL's income comes primarily from the energy retailers who pay for conveying energy over ENL's lines. Separately identified in ENL's invoicing of charges is the pass through transmission costs associated with ENL's connections to the

Transpower Grid and Embedded Generators. The contractual agreement between ENL and the 10 energy retailers who trade over ENL's networks is the Use of System Agreement. In 2013/14 ENL commenced negotiating with energy retailers to update Use of System Agreements so that they aligned with the Model Use of System Agreement, (MUoSA) promoted by the Electricity Authority. At March 2014 energy retailers whose customers make up approximately 53% of ENL's total ICPs have changed to the UoSA. The aim is that during 2014/15 negotiations will be concluded with remaining energy retailers so that the MUoSA applies to 100% of ENL ICPs.
Energy retailers present a bundled charge which incorporates transmission, distribution and energy costs through to end user customers.
When determining the level and constituency of its charges, ENL considers the following pricing principles and influences;

Revenue Requirements

Pricing should obtain sufficient revenue for ENL to meet the following requirements;

Meet its contractual obligations for connection to the Transpower Grid.

Meet statutory contractual obligations for Distributed Generation

Meet its contractual obligations for the delivery of energy over its network to the end-consumers.

Comply with statutory requirements on public safety, environmental protection and quality of supply.

Provide for new investment.

Provide a commercially appropriate return on funds to the shareholder.

Efficiency

Pricing must be economically efficient in the investment signals it creates. This is achieved by matching the pricing structure to the cost structure as closely as practical.

Even-handedness

Pricing must be even-handed across different load groups. Specifically:

The charges to various load groups using the network should vary according to their relative use of different assets.

Where load groups have different service requirements, service at levels above the common denominator should be charged specifically to the load groups demanding higher levels of service.

Average costing will be applied where there is common good usage of assets and services within a load group.

Where new investment is required those users who obtain the benefit should be required to contribute towards the cost.

Pricing must also be even-handed in its treatment of different retailers and provide for equal access as a matter of statutory requirement.

Simplicity

Pricing must be kept as simple and as administratively efficient as practical. Specifically:

Transmission charges should be separated from distribution charges.

ENL should endeavour to ensure distribution costs are relatively stable over time.

Load Management and Embedded Generation

The pricing methodology should provide signals to encourage customer demand-side participation in load management and investment in embedded generation.

Regulation

Electricity lines companies are controlled by the requirements of Part 4 of the Commerce Act 1986 and as set out in Commerce Act (Electricity Distribution Price-Quality Path) Determination 2010. This means that ENL is assessed annually against two thresholds:

A price path threshold, which tests whether a lines companies Notional Revenue for the year is less than its Allowable Notional Revenue for that year; and
A quality threshold, which tests whether a lines companies network quality (SAIDI and SAIFI) for the year is less than its modified long run averages of quality.

The price path threshold criterion limits the amount which lines business may increase prices each year. Under the regime, prices may only be increased such that allowable maximum regulated revenue is not exceeded for each assessment period.

As with the previous price-quality regime, ENL has some concerns over the limits on revenue that are applied under this regime, especially upon a network where consumption and ICP connection growth is static or declining. This is compounded further with and aging network which requires significant levels of on-going maintenance and renewal investment.

However, unlike previous regulation, lines businesses are able to apply to the Commerce Commission for a customized price path which accounts for the specific investment requirements of that business. ENL is keeping a watching brief on its investment requirements and return on investment to determine whether application for a customised price path is required/justified.

7.3 Financial Projections

Financial projections are one of the key outputs of this AMP, representing the financial outcome of the management strategies and specific maintenance, renewal and development plans set out herein. They outline ENL's network expenditure over the planning period, separating capital and maintenance related expenditure. The Figures relating to the forecasts of capital expenditure are uplifted by an overhead allocation, (approx. 9.09%) which is allocated to all assets when capitalised, under Eastland Group policy.

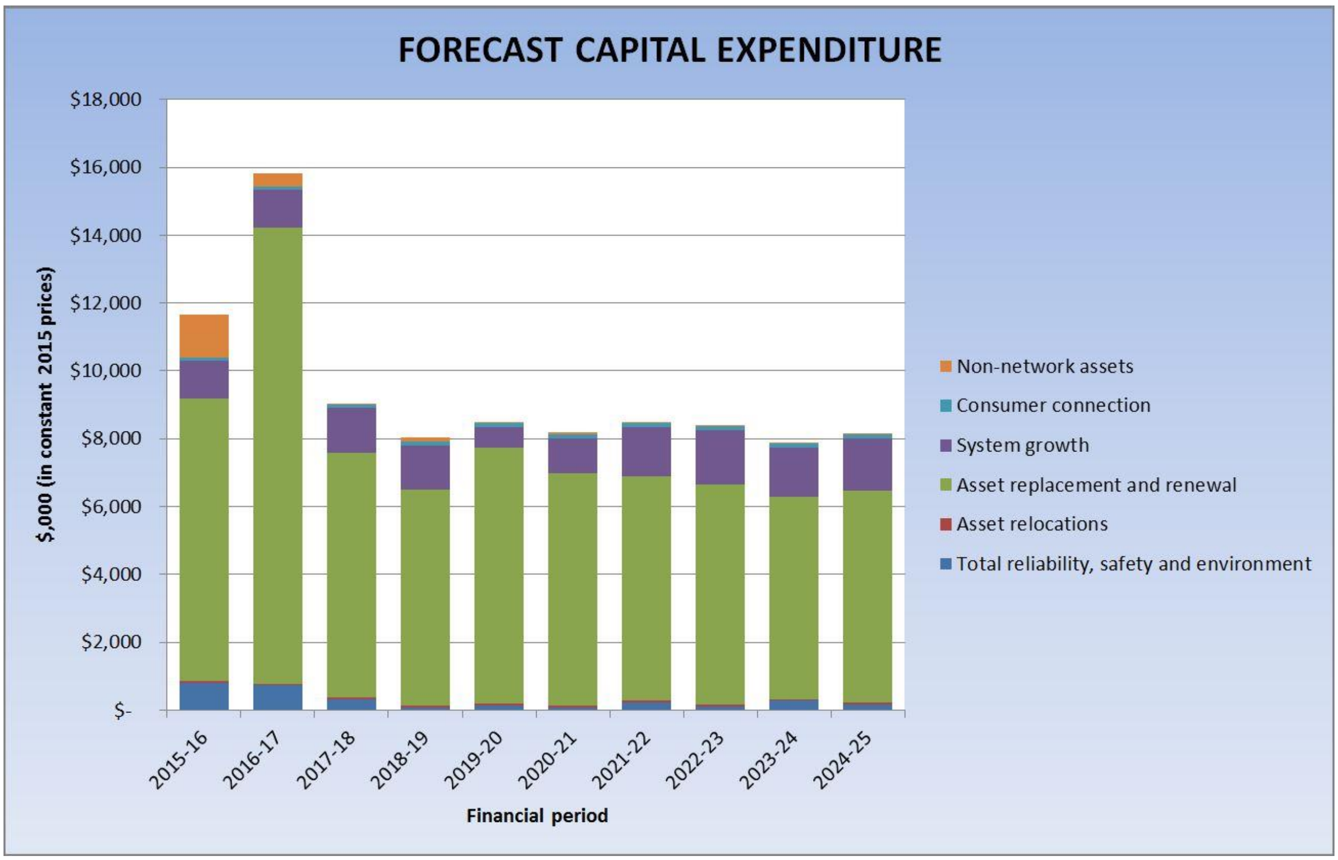
Capital expenditure is defined as expenditure that results in increased value of an asset, where the value is defined by service potential (capacity) to derive future benefits, earnings or reduced costs. If extra expenditure, say from an alteration to the original asset, results in extra value after satisfying an independent test on commercial viability, then it is capital expenditure. Overhead to underground conversion, life extension and load driven capacity upgrades fit into this category. Capital expenditure is classified in accordance with the capital expenditure categories as prescribed by the Electricity Distribution Information Disclosure Determination 2012.

Maintenance expenditure is defined as expenditure required to operate an asset or keep it in the minimum acceptable serviceable condition needed to continue its earning until the asset has satisfied the life and earning expectations used to establish the commercial viability of the original investment decision. Commercial viability tests will assume a certain level of operating and maintenance expense. Expenditure beyond this level may threaten commercial viability. Sensitivity to this and other risks are weighted into investment decisions. Maintenance expenditure is classified in accordance with the operational expenditure categories as prescribed by the Electricity Distribution Information Disclosure Determination 2012.

7.3.1 Capital Expenditure

Total network + non-network asset capital expenditure over the planning period, as described in Sections 4.0 and 5.0, is $94.163m. The profile includes a significant 'step up' in expenditure from previous years due to the acquisition of the Eastland transmission spur assets; $21.002m of transmission asset renewal expenditure.
However the underlying distribution asset expenditure profile, (i.e. excluding the Eastland transmission spur assets) is relatively flat with an average expenditure of approximately $7.113m pa, indicating that steady state assumptions apply. This level of capital expenditure equates to approximately 3.0% of the asset replacement cost and based on the 2011 Information Disclosure statistics is below the industry average of 3.22%.

Capital expenditure forecasts for the planning period are provided by asset type and expenditure category in accordance with the Electricity Distribution Information Disclosure Determination 2012. These forecasts include capitalisation of design and planning costs averaging 9.09% per expenditure category, ($8.376m in total for the period).
The 9.07% capitalisation allowance is an increase on the average 4.7% allowance previously applied. This increase recovers additional costs associated with an increase in the volume of capital work related design and planning being undertaken by “in-house”resources and increased complexity associated with design, planning and project management associated with 110kV transmission assets.
In accordance with Electricity Distribution Information Disclosure Determination 2012 requirements the design, planning and project management allowance is netted off System Operations and Network Support operating costs.



Comments on the categories of capital expenditure are made below.

Customer Connection
Capital expenditure primarily associated with the connection of new consumers to the network or alterations to the connections of existing consumers, where the expenditure relates to connection assets and/or parts of the network for which

expenditure is recoverable in total, or in part, by a contribution from those new consumer(s).

Where assets are required to be installed to facilitate a new, upgraded or altered customer connection it is ENL policy that cost responsibility resides with the customer. Accordingly the majority of Customer Connection expenditure is funded by customers who engage directly with ENL authorised contractors to carry out the required work with the ownership of network type assets being vested to ENL upon completion.
For the planning period the total $1.117m Customer Connection expenditure is 1.1% of the total capital expenditure forecast for the period. None of this unplanned expenditure allowance is related to Eastland transmission spur assets. The allowance is based on historical actual spend associated with the provision of new or upgraded assets which with the exception of $11k pa. customer contributions to the provision of Load Control Recievers, cannot be reasonably expected to be met by the customer. Customer connection expenditure directly with contractors is not included in the forecast amounts.

System Growth
Capital expenditure primarily associated with a change in demand on the network assets, where the expenditure is not recoverable in total, or in part, through a contribution from the consumer(s) that is (are) responsible for the change in demand.

For the planning period the total $12.452m System Growth expenditure is 13% of the total capital expenditure forecast for the period. System Growth expenditure over the period is dominated by expenditure associated with capacity upgrades forecast to be required within the Gisborne CBD.
This category of expenditure includes provision for the steady state customer driven network extension and capacity upgrades that cannot be avoided. The only major projects included are those where the upgrade triggers are currently exceeded. Trigger levels for growth upgrades predicted are described in Section 5.5.
A key feature of these projections is that while the AMP attempts to predict the impact of growth on network development, probable timings, etc. these issues are excluded from financial planning until more certainty on size and location and optimum response is evident.

Asset Replacement and Renewal
Capital expenditure primarily associated with the progressive physical deterioration of the condition of network assets or their immediate surrounds or expenditure arising as result of the obsolescence of network assets.

This category of expenditure per asset type is described in Section 5.4.

For the planning period the total Asset Replacement and Renewal expenditure is $75.067m, (distribution assets $54.065m and transmission assets $21.002m) and is 79% of the total capital expenditure forecast for the period.
A significant increase in this expenditure from 2016 (over previous plans) relates to $21.002m renewal work associated with the Eastland transmission spur assets and in particular the renewal of Wairoa and Tuai 110/11kV transformers, ($8.2m) scheduled for 2016/17.
The basis of transmission asset renewal budgeting is provisional forecasting information provided by Transpower. It is expected that post gaining full operational control of the ex-transmission assets in March 2015 that ENL will aquire improved asset performance and condition information that might allow the reduction/deferral and/or smoothing of the "lumpy" asset renewal expenditure currently forecast for the transmission assets. Any proposed changes to asset renewal expenditure associated with transmission assets will be fully documented in furture versions of this AMP.

Asset Replacement driven capital expenditure for the planning period related to ENL distribution assets averages $5.46m p.a.
The predominance of this category of capital expenditure in the total expenditure for the period reflects the increasing average age of network assets, (especially poles and conductor) and that many assets are in the age replacement phase of their life cycle. Asset Replacement expenditure is predominantly funded by depreciation.

A previous issue regarding a "gap" between the failure and renewal rate of 11kV poles has been addressed by increasing the pole renewal budget to match the 10 year replacement rate.

A previously identified 8km pa "gap" between the 10 year renewal rate and targeted renewal rate for 11kV conductor has been addressed by increasing the annual renewal rate from 9km to 18km in 2016. Also performance to date indicates that the actual life of conductor is much greater than that forecast. It is not expected that any conductor renewal "gap" will unduly affect the achievement of levels of operational performance required by regulation or expected by customers.

Asset Relocation.

Capital expenditure primarily associated with the need to move assets. This normally results from local authority or Transit road widening projects. Accordingly this category of expenditure is to be used where the cost of moving assets is other than for reasons of routine maintenance, refurbishment and renewal maintenance or fault emergency maintenance.

Asset Relocation driven capital expenditure for the planning period is an annual unplanned allowance of $55.8k pa based on historical actual spend. Territorial authorities operating in ENL's network coverage area are canvassed annually for

information on immediate future and longer term requirements they might have regarding the relocation of ENL assets. Responses received have not identified any specific requirements to relocate ENL assets.
Asset Relocation capital expenditure equates to 0.58% of the total capital expenditure forecast for the period. No allowance has been made over the period for expenditure related to the relocation of transmission assets.

Reliability, Safety and Environment.
Capital expenditure primarily associated with maintaining or improving the safety of the network for customers, employees and the public; expenditure primarily associated with the improvement of reliability or service standards; and expenditure primarily associated with meeting new or enhanced environmental requirements.

Reliability, Safety and Environment driven capital expenditure for the planning period is $2.937m and equates to 3% of the total capital expenditure forecast for the period. None of this expenditure forecast relates to Eastland transmission spur assets.
This relatively low level of expenditure in this category is a result of large levels of expenditure that was undertaken between 2000 and 2004 for the purposes of addressing a backlog of safety and environmental issues and improvement of security of supply standards through the development of the sub-transmission network.
It should also be noted that a consequence of ENL's significant asset renewal program is an improvement in reliability, safety and environmental performance hence dedicated expenditure in these areas is not generally required.

Non-network Assets.
Assets related to the provision of electricity lines services but are not a network asset.

Capital expenditure on non-network assets is forecast at $2.031m over the planning period. The expenditure on non-network assets has increased significantly over previous plans with the replacement of the GIS and works management systems being included. These systems are approaching the end of their useful lives with the GIS no longer being supported, and the works management system being a bespoke development, with limited external support available. A new drawing management system is also included in the forecast, along with new software required to support the Eastland transmission spur assets.
The largest single items in the non-network asset capital spend forecast are a $1.248m contribution to a new company, (EGL), Asset Management IT System

proposed for 2015/16 and $300k budgeted in 2016/17 for a replacement GIS system.

Expenditure forecasts for other general non-network assets such as office buildings, office furniture, vehicles and PCs, have not been included in this plan. This because these assets are provide by EGL to ENL as part of an annual Shared Services Agreement with "lease" costs being included as part of Business Support expenditure.

Overhead to Underground Conversions

For the planning period total of $2.457m is forecast for overhead to underground conversions. This expenditure is included under Asset Replacement and Renewal or Reliability, Safety and Environment, Other.

Of this amount in all years 2015 – 2025, $167.5 pa is budgeted in the category of Asset Replacement and Renewal for the conversion of 400V reticulation, (1km pa) to underground.

In the years 2015/16 and 2017/18 $390.89 pa is budgeted in the category of Reliability, Safety and Environment for the conversion of 11kV reticulation to underground in streets on the fringe of the Gisborne CBD.

The following tables and graphs present the forecast expenditure as per the categorisation above, in summary by asset type and in full.

Capital Expenditure Budget 2015/16
($2015/16 constant including 0.1 on-cost)

On-Cost of 10%

$2015/16

Description	Planned / Unplanned	Info Disclosure Expenditure Category	Asset Category	Customer Type	Distribution Transpower	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	203,060 Total
Sub transmission Lines and Cables																	
Transpower Lines + Spares Transfer Cost	Planned	System Growth	Subtransmission	0	Transpower	-	-	-	-	-	-	-	-	-	-	-	-
GIS-TUI A Interphase Spacers	Planned	Asset Replacement & Renewal	Subtransmission	0	Transpower	654,143	654,143	-	-	-	-	-	-	-	-	-	1,308,287
GIS-TUI A Structure Replacement (pole/wood)	Planned	Asset Replacement & Renewal	Subtransmission	0	Transpower	141,731	-	-	163,536	-	-	-	-	-	-	-	305,267
GIS-TUI A Insulator Replacement	Planned	Asset Replacement & Renewal	Subtransmission	0	Transpower	109,024	-	-	-	-	109,024	-	-	-	-	-	218,048
GIS-TUI A Grillage Replacement	Planned	Asset Replacement & Renewal	Subtransmission	0	Transpower	226,770	226,770	226,770	226,770	226,770	226,770	226,770	226,770	-	226,770	-	2,040,927
GIS-TUI A Tower Painting	Planned	Asset Replacement & Renewal	Subtransmission	0	Transpower	-	302,359	302,359	302,359	302,359	302,359	302,359	302,359	302,359	302,359	-	2,721,230
GIS-TUI A Bridge Replacement (est 3)	Planned	Asset Replacement & Renewal	Subtransmission	0	Transpower	54,512	54,512	54,512	-	-	-	-	-	-	-	-	163,536
GIS_TUIA Grillage Refurb 12-13	Planned	Asset Replacement & Renewal	Subtransmission	0	Transpower	226,770	-	-	-	-	-	-	-	-	-	-	226,770
TUI-WRA A Tower Painting	Planned	Asset Replacement & Renewal	Subtransmission	0	Transpower	-	-	-	-	-	327,072	327,072	327,072	327,072	327,072	-	1,635,358
TUI-WRA A Base Plate, Access & Ponding Repairs	Planned	Asset Replacement & Renewal	Subtransmission	0	Transpower	54,512	-	54,512	-	-	-	-	-	-	-	-	109,024
TUI-WRA A Earth Wire Removal	Planned	Asset Replacement & Renewal	Subtransmission	0	Transpower	21,805	-	-	-	-	-	-	-	-	-	-	21,805
TUI-WRA A Replace Conductor (Span 35 - 36)	Planned	Asset Replacement & Renewal	Subtransmission	0	Transpower	65,414	-	-	-	-	-	-	-	-	-	-	65,414
TUI-WRA A Line Vibration Dampers	Planned	Asset Replacement & Renewal	Subtransmission	0	Transpower	65,414	65,414	-	-	-	-	-	-	-	-	-	130,829
TUI-WRA A Interphase Spacers	Planned	Asset Replacement & Renewal	Subtransmission	0	Transpower	-	163,536	654,143	-	-	-	-	-	-	-	-	817,679
GIS_TOB A Foundation (Grillage) Refurbishment	Planned	Asset Replacement & Renewal	Subtransmission	0	Transpower	109,024	-	81,768	-	-	-	-	-	-	-	-	190,792
GIS_TOB A Attachment Points	Planned	Asset Replacement & Renewal	Subtransmission	0	Transpower	-	109,024	-	-	-	-	-	-	-	-	-	109,024
GIS_TOB A Tower Refurbishment	Planned	Asset Replacement & Renewal	Subtransmission	0	Transpower	-	-	-	54,512	54,512	54,512	-	-	109,024	109,024	-	381,584
GIS_TOB A Bridge Replacement (est 3)	Planned	Asset Replacement & Renewal	Subtransmission	0	Transpower	-	-	-	-	-	-	-	-	-	-	-	-
(Please leave this row blank)	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Trans Assets						1,729,119	1,575,758	1,374,064	747,176	583,640	1,019,736	856,200	856,200	738,454	965,224	-	10,445,572
Replacement 80 (50kV) poles pa to 2015, then 60 poles pa	Planned	Asset Replacement & Renewal	Subtransmission	0	Distribution	335,049	335,049	335,049	335,049	335,049	335,049	335,049	335,049	335,049	335,049	-	3,350,490
Fault Replacement Line	Unplanned	Asset Replacement & Renewal	Subtransmission	0	Distribution	44,673	44,673	44,673	44,673	44,673	44,673	44,673	44,673	44,673	44,673	-	446,732
Mahia 33kV line extension and Substation (defer from 2014)	Planned	System Growth	Subtransmission	0	Distribution	502,574	502,574	-	-	-	-	-	-	-	-	-	1,005,147
Wairoa Development (GXP to North Clyde)	Planned	System Growth	Subtransmission	0	Distribution	-	-	-	-	-	335,049	335,049	335,049	335,049	-	-	1,340,196
(Please leave this row blank)	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
						882,296	882,296	379,722	379,722	379,722	714,771	714,771	714,771	714,771	379,722	-	6,142,565
11kV Lines and Cables						-	-	-	-	-	-	-	-	-	-	-	-
Conductor replacement Coast; 3km to 2016 then 6km	Planned	Asset Replacement & Renewal	Distribution and LV lines	0	Distribution	134,020	268,039	268,039	268,039	268,039	268,039	268,039	268,039	268,039	268,039	-	2,546,372
Conductor replacement Gisborne, 3km to 2016 then 6km	Planned	Asset Replacement & Renewal	Distribution and LV lines	0	Distribution	134,020	268,039	268,039	268,039	268,039	268,039	268,039	268,039	268,039	268,039	-	2,546,372
Conductor replacement Wairoa, 3km to 2016 then 6km	Planned	Asset Replacement & Renewal	Distribution and LV lines	0	Distribution	134,020	268,039	268,039	268,039	268,039	268,039	268,039	268,039	268,039	268,039	-	2,546,372
Network Line Extention/Upgrade/Fault Replacement (unplanned 1km)	Unplanned	System Growth	Distribution and LV lines	0	Distribution	100,515	100,515	100,515	100,515	100,515	100,515	100,515	100,515	100,515	100,515	-	1,005,147
Replacement 365 poles per year, GIS	Planned	Asset Replacement & Renewal	Distribution and LV lines	0	Distribution	1,351,364	1,351,364	1,351,364	1,351,364	1,351,364	1,351,364	1,351,364	1,351,364	1,351,364	1,351,364	-	13,513,643
Replacement 205 poles per year, WOA	Planned	Asset Replacement & Renewal	Distribution and LV lines	0	Distribution	737,108	737,108	737,108	737,108	737,108	737,108	737,108	737,108	737,108	737,108	-	7,371,078
Replacement 50 poles (fault & premature failure)	Unplanned	Asset Replacement & Renewal	Distribution and LV lines	0	Distribution	335,049	335,049	335,049	335,049	335,049	335,049	335,049	335,049	335,049	335,049	-	3,350,490
Network Cable Extention/Upgrade/Replacement (unplanned, 0.5km)	Unplanned	System Growth	Distribution and LV cables	0	Distribution	111,683	111,683	111,683	111,683	111,683	111,683	111,683	111,683	111,683	111,683	-	1,116,830
Cable replacement, (fault, premature failure & rationalisation, 0.5km)	Unplanned	Asset Replacement & Renewal	Distribution and LV cables	0	Distribution	111,683	111,683	111,683	111,683	111,683	111,683	111,683	111,683	111,683	111,683	-	1,116,830
Hirini St to Weigh bridge 370m	Planned	System Growth	Distribution and LV cables	0	Distribution	-	-	-	-	-	89,346	-	-	-	-	-	89,346
Cable Plunket - Ormond Rd	Planned	System Growth	Distribution and LV cables	0	Distribution	-	-	-	111,683	-	-	-	-	-	-	-	111,683
Dalton feeder Moana Rd bypass	Planned	System Growth	Distribution and LV cables	0	Distribution	-	-	-	-	-	-	-	-	-	268,039	-	268,039
Ngatapa to Otoko Hill 8km (underbuild 50kV)	Planned	System Growth	Distribution and LV lines	0	Distribution	-	-	279,208	-	-	-	-	-	-	-	-	279,208
Cable City Feeder (Pak n Save) 0.5km	Planned	System Growth	Distribution and LV cables	0	Distribution	-	-	-	-	-	-	-	156,356	-	-	-	156,356
Cable Kahutia Street feeder 1.1km	Planned	System Growth	Distribution and LV cables	0	Distribution	-	-	-	307,128	-	-	-	-	-	-	-	307,128
11kV cable Port feeder link	Planned	Reliability, Safety & Environment - Quality of Supply	Distribution and LV cables	0	Distribution	-	-	-	-	-	-	-	-	100,515	-	-	100,515
Wainui Link, Sponge Bay - Llyod George	Planned	System Growth	Distribution and LV cables	0	Distribution	-	-	150,772	-	-	-	-	-	-	-	-	150,772
Stanley Rd Link, ANZAC/Innes - Awapuni	Planned	System Growth	Distribution and LV cables	0	Distribution	-	-	-	-	-	-	-	-	-	167,525	-	167,525
CBD UG Project (Stg1 Childers, Grey Streets) - Environ	Planned	Reliability, Safety & Environment - Other	Distribution and LV cables	0	Distribution	390,891	-	-	-	-	-	-	-	-	-	-	390,891
CBD UG Project (Stg2 Roebuck, Disrallei Streets) - Environ	Planned	Reliability, Safety & Environment - Other	Distribution and LV cables	0	Distribution	-	390,891	-	-	-	-	-	-	-	-	-	390,891
Asset relocations (for Territorial authorities)	Planned	Asset Relocation	Distribution and LV cables	0	Distribution	-	-	-	-	-	-	-	-	-	-	-	-
Asset relocations (for Territorial authorities)	Unplanned	Asset Relocation	Distribution and LV cables	0	Distribution	55,842	55,842	55,842	55,842	55,842	55,842	55,842	55,842	55,842	55,842	-	558,415
(Please leave this row blank)	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
						3,596,193	3,998,251	4,037,340	4,026,172	3,607,361	3,696,707	3,607,361	3,763,717	3,707,876	4,042,925	-	38,083,903
LT Lines and Cables						-	-	-	-	-	-	-	-	-	-	-	-
Pole replacement 100 per year	Planned	Asset Replacement & Renewal	Distribution and LV lines	0	Distribution	245,703	245,703	245,703	245,703	245,703	245,703	245,703	245,703	245,703	245,703	-	2,457,026
Line Replacement with Underground 1km	Planned	Asset Replacement & Renewal	Distribution and LV lines	0	Distribution	167,525	167,525	167,525	167,525	167,525	167,525	167,525	167,525	167,525	167,525	-	1,675,245
Unplanned Network Extention/Upgrade/Replacement Line 1km	Unplanned	System Growth	Distribution and LV lines	0	Distribution	44,673	44,673	44,673	44,673	44,673	44,673	44,673	44,673	44,673	44,673	-	446,732
Allowance for Growth/Upgrade, Cables 1km	Unplanned	System Growth	Distribution and LV cables	0	Distribution	89,346	89,346	89,346	89,346	89,346	89,346	89,346	89,346	89,346	89,346	-	893,464
Cable replacement, (fault, premature failure & rationalisation, 1km)	Unplanned	Asset Replacement & Renewal	Distribution and LV cables	0	Distribution	89,346	89,346	89,346	89,346	89,346	89,346	89,346	89,346	89,346	89,346	-	893,464
(Please leave this row blank)	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
						636,593	636,593	636,593	636,593	636,593	636,593	636,593	636,593	636,593	636,593	-	6,365,931
Service Connections						-	-	-	-	-	-	-	-	-	-	-	-
New Service Fuse Boxes to Replace Meter Box Sharing 50pa - Safety	Planned	Reliability, Safety & Environment - Other	Distribution and LV cables	0	Distribution	33,505	33,505	33,505	33,505	33,505	33,505	33,505	33,505	33,505	33,505	-	335,049
Meter Bd install associated with Glv box removal 50pa. - Safety	Planned	Reliability, Safety & Environment - Other	Distribution and LV cables	0	Distribution	27,921	27,921	27,921	27,921	27,921	27,921	27,921	27,921	27,921	27,921	-	279,208
Service Pillar Replacement (40 a to 2014 then 20pa)	Planned	Asset Replacement & Renewal	Distribution and LV cables	0	Distribution	22,337	22,337	22,337	22,337	22,337	22,337	22,337	22,337	22,337	22,337	-	223,366
(Please leave this row blank)	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
						83,762	83,762	83,762	83,762	83,762	83,762	83,762	83,762	83,762	83,762	-	837,623
Load Control						-	-	-	-	-	-	-	-	-	-	-	-
Replace failed ripple relays	Planned	Asset Replacement & Renewal	Other network assets	0	Distribution	11,168	11,168	11,168	11,168	11,168	11,168	11,168	11,168	11,168	11,168	-	111,683
Provide ripple relays for new connections	Unplanned	Customer Connection	Other network assets	Residential	Distribution	11,168	11,168	11,168	11,168	11,168	11,168	11,168	11,168	11,168	11,168	-	111,683
Upgrade Wairoa pilot control system	Planned	Asset Replacement & Renewal	Other network assets	0	Distribution	-	-	-	-	-	-	-	-	-	-	-	-
Install second Injection Point Gisborne (11kV)	Planned	System Growth	Other network assets	0	Distribution	-	-	279,208	279,208	-	-	-	-	-	-	-	558,415
(Please leave this row blank)	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
						22,337	22,337	301,544	301,544	22,337	22,337	22,337	22,337	22,337	22,337	-	781,781

Sub transmission Lines and Cables								2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	
Zone Substations								-	-	-	-	-	-	-	-	-	-	-	-
Transpower Zone Subs + Spares + SCADA&Comms transfer project Transfer Cost	Planned	System Growth	Zone substations		0	Transpower		-	-	-	-	-	-	-	-	-	-	-	-
GIS 50kV DS Replacement(154 156 174 176 194 196)	Planned	Asset Replacement & Renewal	Zone substations		0	Transpower		-	-	-	-	-	-	313,989	-	-	-	-	313,989
GIS 110kV DS Replacement (217 227)	Planned	Asset Replacement & Renewal	Zone substations		0	Transpower		-	19,624	100,302	-	-	-	-	-	-	-	-	119,926
GIS 110kV DS Replacement (197 207 264 266 294 296))	Planned	Asset Replacement & Renewal	Zone substations		0	Transpower		-	-	-	-	-	-	58,873	300,906	-	-	-	359,779
GIS 110kV DS Replacement (234 237 247))	Planned	Asset Replacement & Renewal	Zone substations		0	Transpower		-	-	-	-	-	29,436	150,453	-	-	-	-	179,889
GIS 110kV Battery Bank A Replacement	Planned	Asset Replacement & Renewal	Zone substations		0	Transpower		-	-	-	-	-	-	-	27,256	-	-	-	27,256
GIS 110kV Battery Bank B Replacement & T2/T4 backfeed	Planned	Asset Replacement & Renewal	Zone substations		0	Transpower		-	217,622	-	-	-	27,256	-	-	-	-	-	244,878
GIS 110kV C1 Cap Bank Replacement	Planned	Asset Replacement & Renewal	Zone substations		0	Transpower		-	-	-	-	545,119	-	-	-	-	-	-	545,119
GIS Install Fall Arrest System	Planned	Asset Replacement & Renewal	Zone substations		0	Transpower		-	27,256	-	-	-	-	-	-	-	-	-	27,256
GIS Replace subsided walkway with garden	Planned	Asset Replacement & Renewal	Zone substations		0	Transpower		21,805	-	-	-	-	-	-	-	-	-	-	21,805
GIS Switchyard Metal Replacement	Planned	Asset Replacement & Renewal	Zone substations		0	Transpower		-	-	-	-	272,560	-	-	-	-	-	-	272,560
WRA 110kV Battery Bank 2 Replacement	Planned	Asset Replacement & Renewal	Zone substations		0	Transpower		-	27,256	-	-	-	-	-	-	-	-	-	27,256
WRA 110kV Battery Bank 1 Replacement	Planned	Asset Replacement & Renewal	Zone substations		0	Transpower		-	-	-	-	-	-	27,256	-	-	-	-	27,256
WRA 11kV Feeder Protection Replacement (CB1 & CB11)	Planned	Asset Replacement & Renewal	Zone substations		0	Transpower		-	126,468	-	-	-	-	-	-	-	-	-	126,468
WRA T1 & T2 Transformer Protection Replacement	Planned	Asset Replacement & Renewal	Zone substations		0	Transpower		-	285,643	-	-	-	-	-	-	-	-	-	285,643
WRA T1 & T2 Transformer Replacement Investigation	Planned	Asset Replacement & Renewal	Zone substations		0	Transpower		671,697	4,794,762	-	-	-	-	-	-	-	-	-	5,466,458
WRA T1 & T2 Transformer Investigation	Planned	Asset Replacement & Renewal	Zone substations		0	Transpower		110,660	-	-	-	-	-	-	-	-	-	-	110,660
WRA Fence Replacement	Planned	Asset Replacement & Renewal	Zone substations		0	Transpower		-	-	327,072	-	-	-	-	-	-	-	-	327,072
WRA 11kV CB Dismantle (2 3 4 12 13 14)	Planned	Asset Replacement & Renewal	Zone substations		0	Transpower		65,414	-	-	-	-	-	-	-	-	-	-	65,414
TUI 110/11 kV Supply Transformer Replacement	Planned	Asset Replacement & Renewal	Zone substations		0	Transpower		926,703	1,081,715	-	-	-	-	-	-	-	-	-	2,008,418
(Please leave this row blank)	0		0	0	0		0	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Trans Assets								1,796,279	6,580,345	427,374	-	817,679	56,692	550,571	328,162	-	-	-	10,557,101
New zone Sub Tatapour/Whangara 2.5MVA	Planned	System Growth	Zone substations		0	Distribution		-	-	-	-	-	-	-	-	502,574	502,574	-	1,005,147
New zone Sub Massey Road	Planned	System Growth	Zone substations		0	Distribution		-	-	-	-	-	-	502,574	502,574	-	-	-	1,005,147
Building/Switchyard Security Upgrade (2013/14 Kaiti)	Planned	Reliability, Safety & Environment - Quality of Supply	Zone substations		0	Distribution		55,842	11,168	11,168	11,168	11,168	11,168	11,168	11,168	11,168	11,168	-	156,356
Replace T1 Patutahi 5MVA	Planned	Asset Replacement & Renewal	Zone substations		0	Distribution		-	-	-	-	390,891	390,891	-	-	-	-	-	781,781
Replace T1 Tolaga 2.5MVA	Planned	Asset Replacement & Renewal	Zone substations		0	Distribution		-	-	-	-	558,415	-	-	-	-	-	-	558,415
Replace 11kV CB trucks & protection Carnarvon St	Planned	Asset Replacement & Renewal	Zone substations		0	Distribution		-	-	-	-	-	-	-	-	-	-	-	-
Switchgear Operator Suits - 1 per zone sub - safety	Planned	Reliability, Safety & Environment - Other	Zone substations		0	Distribution		-	-	-	-	-	-	-	-	-	-	-	-
Replace Puha T1 5MVA	Planned	Asset Replacement & Renewal	Zone substations		0	Distribution		-	-	228,443	228,443	-	-	-	-	-	-	-	456,885
Earthing Upgrades (step potential)	Planned	Asset Replacement & Renewal	Zone substations		0	Distribution		-	-	-	-	-	-	11,168	11,168	-	-	-	22,337
(Please leave this row blank)	0		0	0	0		0	-	-	-	-	-	-	-	-	-	-	-	-
								55,842	11,168	239,611	239,611	960,474	402,059	524,910	524,910	513,742	513,742	-	3,986,068
50kV CB's								-	-	-	-	-	-	-	-	-	-	-	-
Makaraka Line to Patutahi	Planned	Asset Replacement & Renewal	Zone substations		0	Distribution		-	-	-	89,346	-	-	-	-	-	-	-	89,346
Pehiri CB replacement	Planned	Asset Replacement & Renewal	Zone substations		0	Distribution		-	-	-	-	-	-	-	-	-	-	-	-
Ruatoria T1, Toko T1, Ruatoria T1 purchase/setup	Planned	Asset Replacement & Renewal	Zone substations		0	Distribution		-	-	-	-	-	-	-	-	-	-	-	-
Tolaga T1 install	Planned	Asset Replacement & Renewal	Zone substations		0	Distribution		-	-	-	-	-	-	-	-	-	-	-	-
Carnarvon T1	Planned	Asset Replacement & Renewal	Zone substations		0	Distribution		-	-	-	-	-	89,346	-	-	-	-	-	89,346
(Please leave this row blank)	0		0	0	0		0	-	-	-	-	-	-	-	-	-	-	-	-
								-	-	-	89,346	-	89,346	-	-	-	-	-	178,693
11kV CB's (Rural Automation)								-	-	-	-	-	-	-	-	-	-	-	-
Field Recloser Automation Plan - replacements	Planned	Asset Replacement & Renewal	Distribution switchgear		0	Distribution		-	55,842	-	55,842	-	55,842	-	55,842	-	55,842	-	279,208
11kV Field Recloser Automation Plan - additions	Planned	Reliability, Safety & Environment - Quality of Supply	Distribution switchgear		0	Distribution		55,842	-	55,842	-	55,842	-	55,842	-	55,842	-	-	279,208
(Please leave this row blank)	0		0	0	0		0	-	-	-	-	-	-	-	-	-	-	-	-
								55,842	55,842	55,842	55,842	55,842	55,842	55,842	55,842	55,842	55,842	-	558,415
Distribution Transformers								-	-	-	-	-	-	-	-	-	-	-	-
Replace Transformers <100kVA	Planned	Asset Replacement & Renewal	Distribution substations and transfor		0	Distribution		111,683	111,683	111,683	111,683	111,683	111,683	111,683	111,683	111,683	111,683	-	1,116,830
Replace Transformers >100kVA	Planned	Asset Replacement & Renewal	Distribution substations and transfor		0	Distribution		301,544	301,544	301,544	301,544	301,544	301,544	301,544	301,544	301,544	301,544	-	3,015,441
Transformers Growth <100kVA	Unplanned	System Growth	Distribution substations and transfor		0	Distribution		87,113	87,113	87,113	87,113	87,113	87,113	87,113	87,113	87,113	87,113	-	871,127
Transformers Growth >100kVA	Unplanned	System Growth	Distribution substations and transfor		0	Distribution		167,525	167,525	167,525	167,525	167,525	167,525	167,525	167,525	167,525	167,525	-	1,675,245
(Please leave this row blank)	0		0	0	0		0	-	-	-	-	-	-	-	-	-	-	-	-
								667,864	667,864	667,864	667,864	667,864	667,864	667,864	667,864	667,864	667,864	-	6,678,643
Pole Mounted Isolation Equipment								-	-	-	-	-	-	-	-	-	-	-	-
Age Replacement of 11kV ABS's	Planned	Asset Replacement & Renewal	Distribution switchgear		0	Distribution		111,683	111,683	111,683	111,683	111,683	111,683	111,683	111,683	111,683	111,683	-	1,116,830
11kV Fuse replacement 30 sets	Planned	Asset Replacement & Renewal	Distribution switchgear		0	Distribution		44,673	44,673	44,673	44,673	44,673	44,673	44,673	44,673	44,673	44,673	-	446,732
(Please leave this row blank)	0		0	0	0		0	-	-	-	-	-	-	-	-	-	-	-	-
								156,356	156,356	156,356	156,356	156,356	156,356	156,356	156,356	156,356	156,356	-	1,563,562
11kV Ground Mounted Switchgear								-	-	-	-	-	-	-	-	-	-	-	-
11kV GM SWGR New Connections	Unplanned	Customer Connection	Distribution switchgear	Industrial		Distribution		55,842	55,842	55,842	55,842	55,842	55,842	55,842	55,842	55,842	55,842	-	558,415
"A" Park Wairoa, switchgear addition/alteration	Planned	Reliability, Safety & Environment - Quality of Supply	Distribution switchgear		0	Distribution		-	83,762	-	-	-	-	-	-	-	-	-	83,762
Switchgear Replacement plan (2x plan, 2x unplan)	Planned	Asset Replacement & Renewal	Distribution switchgear		0	Distribution		251,287	251,287	251,287	251,287	251,287	251,287	251,287	251,287	251,287	251,287	-	2,512,868
(Please leave this row blank)	0		0	0	0		0	-	-	-	-	-	-	-	-	-	-	-	-
								307,128	390,891	307,128	307,128	307,128	307,128	307,128	307,128	307,128	307,128	-	3,155,045
LV Switchgear								-	-	-	-	-	-	-	-	-	-	-	-
Replace LV Link Pillars (6 boxes p.a.)	Planned	Asset Replacement & Renewal	Distribution switchgear		0	Distribution		44,673	44,673	44,673	44,673	44,673	44,673	44,673	44,673	44,673	44,673	-	446,732
LV SW/GR Allowance for New Installations	Unplanned	Customer Connection	Distribution switchgear	Residential		Distribution		44,673	44,673	44,673	44,673	44,673	44,673	44,673	44,673	44,673	44,673	-	446,732
LV SW/GR Allowance for New Installations	Unplanned	Customer Connection	Distribution switchgear	Commercial		Distribution		-	-	-	-	-	-	-	-	-	-	-	-
(Please leave this row blank)	0		0	0	0		0	-	-	-	-	-	-	-	-	-	-	-	-
								89,346	89,346	89,346	89,346	89,346	89,346	89,346	89,346	89,346	89,346	-	893,464
Control and Protection								-	-	-	-	-	-	-	-	-	-	-	-
Replace Batteries / Charges	Unplanned	Asset Replacement & Renewal	Other network assets		0	Distribution		22,337	22,337	22,337	22,337	22,337	22,337	22,337	22,337	22,337	22,337	-	223,366
Allowance for failure	Unplanned	Asset Replacement & Renewal	Other network assets		0	Distribution		11,168	11,168	11,168	11,168	11,168	11,168	11,168	11,168	11,168	11,168	-	111,683
AUFLS Relay install	Planned	Reliability, Safety & Environment - Legislative & Reg	Other network assets		0	Distribution		-	167,525	167,525	-	-	-	-	-	-	-	-	335,049
Replace 11kV protection (Kaiti & Parkinson) install	Planned	Asset Replacement & Renewal	Other network assets		0	Distribution		-	-	-	-	-	-	-	-	-	-	-	-
(Please leave this row blank)	0		0	0	0		0	-	-	-	-	-	-	-	-	-	-	-	-
								33,505	201,029	201,029	33,505	33,505	33,505	33,505	33,505	33,505	33,505	-	670,098
Communications								-	-	-	-	-	-	-	-	-	-	-	-

							2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	
Sub transmission Lines and Cables																		
Replace "backbone" Links & 13 repeaters	Planned	Asset Replacement & Renewal	Other network assets		0 Distribution		11,168	11,168	11,168	11,168	11,168	11,168	11,168	11,168	11,168	11,168	-	111,683
Replace Radio Site Generator	Planned	Asset Replacement & Renewal	Other network assets		0 Distribution		-	33,505	-	33,505	-	33,505	-	33,505	33,505	33,505	-	201,029
Unplanned Equipment Replacements (fault & premature failure)	Unplanned	Asset Replacement & Renewal	Other network assets		0 Distribution		22,337	22,337	22,337	22,337	22,337	22,337	22,337	22,337	22,337	22,337	-	223,366
Replace Vehicle RTs	Planned	Reliability, Safety & Environment - Legislative & Reg	Other network assets		0 Distribution		195,445	-	-	-	-	-	-	-	-	-	-	195,445
(Please leave this row blank)	0	0		0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
							228,950	67,010	33,505	67,010	33,505	67,010	33,505	67,010	67,010	67,010	-	731,524
SCADA							-	-	-	-	-	-	-	-	-	-	-	-
SCADA Master Station Development	Planned	Reliability, Safety & Environment - Quality of Supply	Other network assets		0 Distribution		11,168	11,168	11,168	11,168	11,168	11,168	11,168	11,168	11,168	11,168	-	111,683
Unscheduled RTU Replacement	Unplanned	Asset Replacement & Renewal	Other network assets		0 Distribution		11,168	11,168	11,168	11,168	11,168	11,168	11,168	11,168	11,168	11,168	-	111,683
SCADA Rural Automation -development	Planned	Reliability, Safety & Environment - Quality of Supply	Other network assets		0 Distribution		-	-	-	-	-	-	33,505	33,505	33,505	33,505	-	134,020
SCADA Long Term Development Additional Sites	Planned	Reliability, Safety & Environment - Quality of Supply	Other network assets		0 Distribution		-	-	-	-	-	-	55,842	-	-	55,842	-	111,683
(Please leave this row blank)	0	0		0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
							22,337	22,337	22,337	22,337	22,337	22,337	111,683	55,842	55,842	111,683	-	469,069
General							-	-	-	-	-	-	-	-	-	-	-	-
							-	-	-	-	-	-	-	-	-	-	-	-
Establish 2x Genset sites (Raupunga & Ruakituri)	Planned	Reliability, Safety & Environment - Quality of Supply	Other network assets		0 Distribution		33,505	-	-	-	-	-	-	-	-	-	-	33,505
Capital Contributions	Planned	Customer Connection	Other network assets	Commercial	Distribution		-	-	-	-	-	-	-	-	-	-	-	-
(Please leave this row blank)	0	0		0	0	0	-	-	-	-	-	-	-	-	-	-	-	-
							33,505	-	-	-	-	-	-	-	-	-	-	33,505
TOTAL NETWORK CAPEX Dist + Trans Assets							10,397,252	15,441,185	9,013,418	7,903,315	8,457,452	8,121,392	8,451,734	8,363,345	7,850,428	8,133,039	-	92,132,561
Total Network CAPEX Distribution Assets							6,871,855	7,285,082	7,211,980	7,156,139	7,056,132	7,044,964	7,044,964	7,178,983	7,111,973	7,167,815	-	71,129,887
Total Network CAPEX Transpower Assets							3,525,397	8,156,103	1,801,437	747,176	1,401,320	1,076,428	1,406,771	1,184,362	738,454	965,224	-	21,002,673
						Check	-	-	-	-	-	-	-	-	-	-	-	-
Non Network Assets (0% markup)																		
Routine																		
Test Instrument & Safety Equipment, Additional/Upgrade	Planned	Non Network Assets - Routine	Non Network Assets		0 Distribution		10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	-	101,530
Property Capital Projects	Planned	Non Network Assets - Routine	Non Network Assets		0 Distribution		-	50,765	-	101,530	-	50,765	-	-	-	-	-	203,060
General asset replacement	Planned	Non Network Assets - Routine	Non Network Assets		0 Distribution		20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	-	203,060
Atypical							-	-	-	-	-	-	-	-	-	-	-	-
Transmission safety compliance equip/training	Planned	Non Network Assets - Atypical	Non Network Assets		0 Transpower		-	-	-	-	-	-	-	-	-	-	-	-
Dynamic line rating system	Planned	Non Network Assets - Atypical	Non Network Assets		0 Transpower		-	-	-	-	-	-	-	-	-	-	-	-
AM System	Planned	Non Network Assets - Atypical	Non Network Assets		0 Distribution		1,218,360	-	-	-	-	-	-	-	-	-	-	1,218,360
Information Transfer & record system	Planned	Non Network Assets - Atypical	Non Network Assets		0 Transpower		-	-	-	-	-	-	-	-	-	-	-	-
GIS Replacement	Planned	Non Network Assets - Atypical	Non Network Assets		0 Distribution		-	304,590	-	-	-	-	-	-	-	-	-	304,590
Purchase Network Building (do not include in budget - Internal Transfer only)	Planned	Non Network Assets - Atypical	Non Network Assets		Distribution		-	-	-	-	-	-	-	-	-	-	-	-
							-	-	-	-	-	-	-	-	-	-	-	-
	Total	Non Network Assets					1,248,819	385,814	30,459	131,989	30,459	81,224	30,459	30,459	30,459	30,459	-	2,030,600
				This line balances to the summmary page	------------->		11,646,071	15,826,999	9,043,877	8,035,304	8,487,911	8,202,616	8,482,193	8,393,804	7,880,887	8,163,498	-	94,163,161
Capital Contributions							-	-	-	-	-	-	-	-	-	-	-	-
		Customer Connection					50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	-	507,650
		System Growth					-	-	-	-	-	-	-	-	-	-	-	-
		Asset Replacement & Renewal					-	-	-	-	-	-	-	-	-	-	-	-
		Reliability, Safety & Environment - Quality of Supply					-	-	-	-	-	-	-	-	-	-	-	-
		Reliability, Safety & Environment - Legislative & Reg					-	-	-	-	-	-	-	-	-	-	-	-
		Reliability, Safety & Environment - Other					-	-	-	-	-	-	-	-	-	-	-	-
		Asset Relocation					-	-	-	-	-	-	-	-	-	-	-	-
							50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	-	507,650
Total CAPEX Prior to Vested Assets							11,595,306	15,776,234	8,993,112	7,984,539	8,437,146	8,151,851	8,431,428	8,343,039	7,830,122	8,112,733	-	93,655,511
							-	-	-	-	-	-	-	-	-	-	-	-
Vested Assets Total							203,060	203,060	203,060	203,060	203,060	203,060	203,060	203,060	203,060	203,060	-	2,030,600
							203,060	203,060	203,060	203,060	203,060	203,060	203,060	203,060	203,060	203,060	-	2,030,600
GRAND TOTAL (Capex excl CapCon plus Vested assets)							11,798,366	15,979,294	9,196,172	8,187,599	8,640,206	8,354,911	8,634,488	8,546,099	8,033,182	8,315,793	-	95,686,111
					On-costs		945,205	1,403,744	819,402	718,483	768,859	738,308	768,339	760,304	713,675	739,367	-	8,375,687
					Check		-	-	-	-	-	-	-	-	-	-	-	-
		Network Asset Capex																
		Customer Connection					111,683	111,683	111,683	111,683	111,683	111,683	111,683	111,683	111,683	111,683	-	1,116,830
		System Growth					1,103,428	1,103,428	1,310,042	1,298,873	600,855	1,025,250	1,438,477	1,594,833	1,438,477	1,538,992	-	12,452,655
		Asset Replacement & Renewal					8,322,182	13,444,293	7,228,723	6,353,155	7,549,469	6,844,855	6,616,783	6,483,720	5,970,803	6,253,414	-	75,067,398
		Reliability, Safety & Environment - Quality of Supply					156,356	106,099	78,178	22,337	78,178	22,337	167,525	55,842	212,198	111,683	-	1,010,731
		Reliability, Safety & Environment - Legislative & Reg					195,445	167,525	167,525	-	-	-	-	-	-	-	-	530,494
		Reliability, Safety & Environment - Other					452,316	452,316	61,426	61,426	61,426	61,426	61,426	61,426	61,426	61,426	-	1,396,038
		Asset Relocation					55,842	55,842	55,842	55,842	55,842	55,842	55,842	55,842	55,842	55,842	-	558,415
							10,397,252	15,441,185	9,013,418	7,903,315	8,457,452	8,121,392	8,451,734	8,363,345	7,850,428	8,133,039	-	92,132,561
		Non Network Asset Capex																
		Non Network Assets - Routine					30,459	81,224	30,459	131,989	30,459	81,224	30,459	30,459	30,459	30,459	-	507,650
		Non Network Assets - Atypical					1,218,360	304,590	-	-	-	-	-	-	-	-	-	1,522,950
		Total Non Network Assets					1,248,819	385,814	30,459	131,989	30,459	81,224	30,459	30,459	30,459	30,459	-	2,030,600
		Total ENL Capex					11,646,071	15,826,999	9,043,877	8,035,304	8,487,911	8,202,616	8,482,193	8,393,804	7,880,887	8,163,498	-	94,163,161
							152,295	152,295	152,295	152,295	152,295	152,295	152,295	152,295	152,295	152,295	-	1,522,950

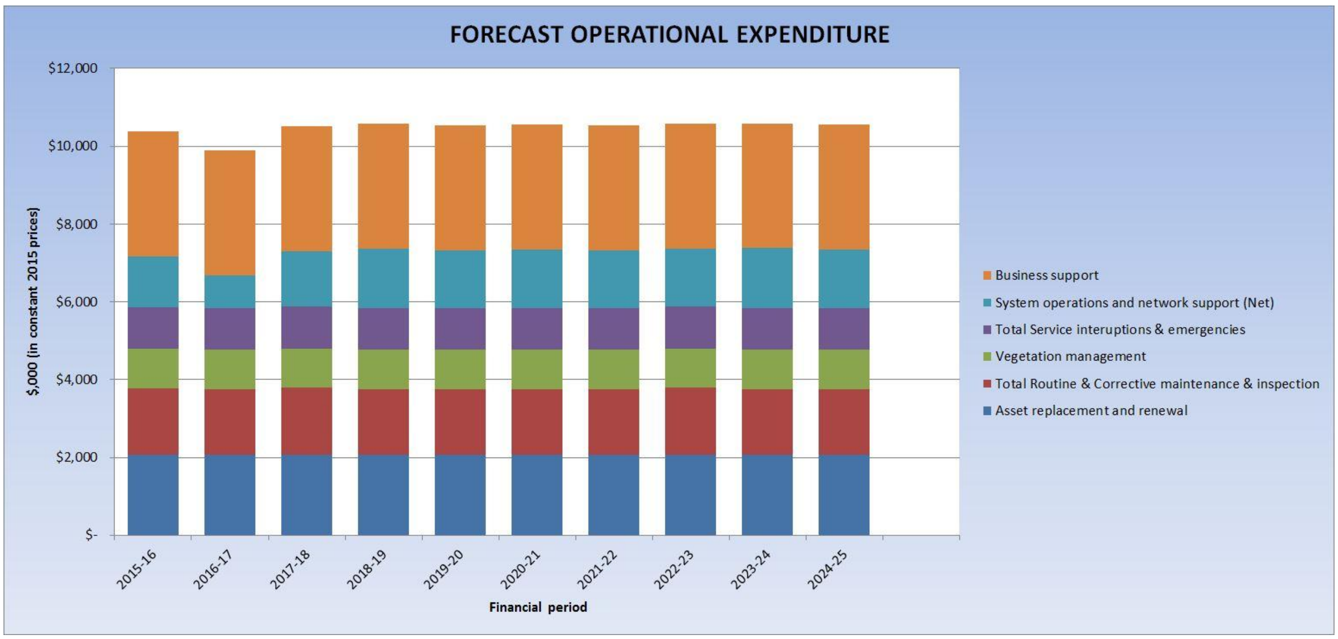
Sub transmission Lines and Cables

		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	
Summary by Category		-	-	-	-	-	-	-	-	-	-	-	
Customer Connection	Distribution	111,683	111,683	111,683	111,683	111,683	111,683	111,683	111,683	111,683	111,683	-	1,116,830
Customer Connection	Transpower	-	-	-	-	-	-	-	-	-	-	-	-
Total Customer Connection		**111,683**	**111,683**	**111,683**	**111,683**	**111,683**	**111,683**	**111,683**	**111,683**	**111,683**	**111,683**	-	**1,116,830**
System Growth	Distribution	1,103,428	1,103,428	1,310,042	1,298,873	600,855	1,025,250	1,438,477	1,594,833	1,438,477	1,538,992	-	12,452,655
System Growth	Transpower	-	-	-	-	-	-	-	-	-	-	-	-
Total System Growth		**1,103,428**	**1,103,428**	**1,310,042**	**1,298,873**	**600,855**	**1,025,250**	**1,438,477**	**1,594,833**	**1,438,477**	**1,538,992**	-	**12,452,655**
Asset Replacement & Renewal	Distribution	4,796,785	5,288,190	5,427,286	5,605,979	6,148,149	5,768,427	5,210,012	5,299,358	5,232,349	5,288,190	-	54,064,725
Asset Replacement & Renewal	Transpower	3,525,397	8,156,103	1,801,437	747,176	1,401,320	1,076,428	1,406,771	1,184,362	738,454	965,224	-	21,002,673
Total Asset Replacement & Renewal		**8,322,182**	**13,444,293**	**7,228,723**	**6,353,155**	**7,549,469**	**6,844,855**	**6,616,783**	**6,483,720**	**5,970,803**	**6,253,414**	-	**75,067,398**
Reliability, Safety & Environment - Quality of Supply	Distribution	156,356	106,099	78,178	22,337	78,178	22,337	167,525	55,842	212,198	111,683	-	1,010,731
Reliability, Safety & Environment - Quality of Supply	Transpower	-	-	-	-	-	-	-	-	-	-	-	-
Total Reliability, Safety & Environment - Quality of Supply		**156,356**	**106,099**	**78,178**	**22,337**	**78,178**	**22,337**	**167,525**	**55,842**	**212,198**	**111,683**	-	**1,010,731**
Reliability, Safety & Environment - Legislative & Reg	Distribution	195,445	167,525	167,525	-	-	-	-	-	-	-	-	530,494
Reliability, Safety & Environment - Legislative & Reg	Transpower	-	-	-	-	-	-	-	-	-	-	-	-
Total Reliability, Safety & Environment - Legislative & Reg		**195,445**	**167,525**	**167,525**	-	-	-	-	-	-	-	-	**530,494**
Reliability, Safety & Environment - Other	Distribution	452,316	452,316	61,426	61,426	61,426	61,426	61,426	61,426	61,426	61,426	-	1,396,038
Reliability, Safety & Environment - Other	Transpower	-	-	-	-	-	-	-	-	-	-	-	-
Total Reliability, Safety & Environment - Other		**452,316**	**452,316**	**61,426**	**61,426**	**61,426**	**61,426**	**61,426**	**61,426**	**61,426**	**61,426**	-	**1,396,038**
Asset Relocation	Distribution	55,842	55,842	55,842	55,842	55,842	55,842	55,842	55,842	55,842	55,842	-	558,415
Asset Relocation	Transpower	-	-	-	-	-	-	-	-	-	-	-	-
Total Asset Relocation		**55,842**	**55,842**	**55,842**	**55,842**	**55,842**	**55,842**	**55,842**	**55,842**	**55,842**	**55,842**	-	**558,415**
Network Capex	Distribution	6,871,855	7,285,082	7,211,980	7,156,139	7,056,132	7,044,964	7,044,964	7,178,983	7,111,973	7,167,815	-	71,129,887
Network Capex	Transpower	3,525,397	8,156,103	1,801,437	747,176	1,401,320	1,076,428	1,406,771	1,184,362	738,454	965,224	-	21,002,673
Total Network Capex		**10,397,252**	**15,441,185**	**9,013,418**	**7,903,315**	**8,457,452**	**8,121,392**	**8,451,734**	**8,363,345**	**7,850,428**	**8,133,039**	-	**92,132,561**
Non Network Assets - Routine	Distribution	30,459	81,224	30,459	131,989	30,459	81,224	30,459	30,459	30,459	30,459	-	507,650
Non Network Assets - Routine	Transpower	-	-	-	-	-	-	-	-	-	-	-	-
Total Non Network Assets - Routine		**30,459**	**81,224**	**30,459**	**131,989**	**30,459**	**81,224**	**30,459**	**30,459**	**30,459**	**30,459**	-	**507,650**
Non Network Assets - Atypical	Distribution	1,218,360	304,590	-	-	-	-	-	-	-	-	-	1,522,950
Non Network Assets - Atypical	Transpower	-	-	-	-	-	-	-	-	-	-	-	-
Total Non Network Assets - Atypical		**1,218,360**	**304,590**	-	-	-	-	-	-	-	-	-	**1,522,950**
Non-Network Capex	Distribution	1,248,819	385,814	30,459	131,989	30,459	81,224	30,459	30,459	30,459	30,459	-	2,030,600
Non-Network Capex	Transpower	-	-	-	-	-	-	-	-	-	-	-	-
Total Non-Network Capex		**1,248,819**	**385,814**	**30,459**	**131,989**	**30,459**	**81,224**	**30,459**	**30,459**	**30,459**	**30,459**	-	**2,030,600**
Total	Distribution	8,120,674	7,670,896	7,242,439	7,288,128	7,086,591	7,126,188	7,075,423	7,209,442	7,142,432	7,198,274	-	73,160,487
Total	Transpower	3,525,397	8,156,103	1,801,437	747,176	1,401,320	1,076,428	1,406,771	1,184,362	738,454	965,224	-	21,002,673
TOTAL		**11,646,071**	**15,826,999**	**9,043,877**	**8,035,304**	**8,487,911**	**8,202,616**	**8,482,193**	**8,393,804**	**7,880,887**	**8,163,498**	-	**94,163,161**

7.3.2 Operational Expenditure

Total operational expenditure over the planning period, as described in Section 5.3, is $104.721m. This level of expenditure has increased over the previous plan as a result of the maintenance requirements associated with the Eastland transmission spur assets, and an increase in System Operations and Network Support.

Operational expenditure forecasts for the planning period are provided by asset type and expenditure category in accordance with the Electricity Distribution Information Disclosure Determination 2012.



General comments on the categories of expenditure are made below.

Maintenance Expenditure

The total maintenance for the 10 year AMP period is forecast at $58.508m, ($47.28m distribution assets and $11.228m ex-transmission assets).

For current distribution assets maintenance plans have been prepared by asset type and expenditure category. These plans detail the regular on-going work that is necessary to keep assets operating, including the basis for condition monitoring, equipment standards, planned maintenance and provisions for unplanned actions in response to faults or incidents. It has been identified that ENL's current distribution assets are in the age replacement phase of their life cycle. The management tactic is to therefore replace rather than to continue with a heavy maintenance strategy. The expected improvement in average asset

condition will lift performance and allows low maintenance expenditure to be sustained.
Average annual distribution asset maintenance expenditure for the planning period has increased by $1.606m on prior years. This is a result of Audit advising that ACOD payments made from ENL to EGeL, (Waihi & Gensets) need to be included in the Asset replacement and renewal maintenance category as opposed to inclusion in non-network operational expenditure categories.

For ex-transmission assets, Transpower maintenance forecasts totaling $11.228m have been applied from 2015/16. These forecasts are based on information supplied by Transpower and have been supplemented with additional information commissioned from 3rd party advisors during the due diligence process. As ENL gains operational experience of the ex-transmission assets it is expected that maintenance requirements and associated expenditures will be refined.

Maintenance expenditure forecasts in the AMP are provided by asset type and expenditure type as per EDIDD 2012 categories. The expenditure categories are;

Service Interruptions and Emergencies
For the planning period the total $10.781m, ($10.527m distribution assets and $253k ex-transmission assets), Fault and Emergency expenditure is 18% of the total maintenance expenditure forecast for the period. As described in section 5.3.1 included in this expenditure category is a standing allowance of $303k pa relating to a fault management/response service. This expenditure category has not been materially impacted by the acquisition of the Eastland transmission spur assets due to the very high reliability of those assets.

Vegetation management
For the planning period the total $10.041m, ($9.13m distribution assets and $903k ex-transmission assets), Vegetation Management expenditure is 17% of the total maintenance expenditure forecast for the period. The acquisition of the Eastland transmission spur assets results in an annual increase of $90k pa. in vegetation management expenditure. The 110kV lines routes have generally been well maintained by Transpower, and vegetation management spend represents an ongoing ‘maintenance’ programme to address network performance issues.

Routine and Corrective Maintenance and Inspection
This expenditure that is driven by pre-planned and programmed work schedules and includes routine inspection and testing activities.

For the planning period the total $17.107m, ($8.558m distribution assets and $8.549m ex-transmission assets), Routine and corrective expenditure is 30% of the total operational expenditure forecast for the period. The increase in expenditure from 2016 reflects the comprehensive inspection and maintenance regime applied to the Eastland transmission spur assets. A comprehensive inspection and maintenance approach is warranted for these assets given the potential high consequence of the failure. The forecasts reflect the level of expenditure forecast by Transpower, and the programmes and costs will be reviewed as ENL gains operational experience of these assets.

Asset Replacement and Renewal (expensed)
For the planning period the total $20.58m, ($19.057m distribution assets and $1.523m ex-transmission assets), Refurbishment and Renewal expenditure is 34% of the total maintenance expenditure forecast for the period.

As explained above, incorporated in Asset Replacement and Renewal maintenance expenditure associated with distribution assets, is $1.606m of annual ACOD expenditure, ($16.062m total for the period). The forecast ACOD payment is made to network connected distributed generation in recognition of avoiding investment, (in additional distribution assets and the upgrading of transmission assets), so as to meet required network service and performance standards.

This level of actual maintenance expenditure on the renewal of assets over the period is relatively low for both distribution and ex-transmission assets, and is the result of the large capital asset replacement and renewal program.

Non-network Operational Expenditure
In accordance with the Electricity Distribution Information Disclosure Determination 2012, information and forecasts relationg to two classifications of non-network operational expenditure are as follows;

Business Support
Business Support expenditure includes expenditure associated with corporate activities such as HR, IT, finance, regulatory compliance, property management, pricing, billing and revenue collection.

Business Support expenditure includes the provision to ENL of general non-network assets such as office buildings, office furniture, vehicles and PCs, from Eastland Group Limited.

The following Methodogoly is used to allocate Business support costs from Eastland Group Limited to Eastland Network Limited.

– Any overhead costs directly attributable to an individual business unit are budgeted by the individual business and expensed to the individual business. Examples of which include but are not exclusive to:

- Stationary delivered to the Port would be coded to Port Stationary
- The mobile phone bill of a Linesman would be coded to Eastech Telecommunications

- A team lunch to celebrate success at the Network would be coded to Network Entertainment
- Security
- Rent
- Cleaning
- Expenses relating to Vehicles would be coded to the relevant business unit
- Computer Expenses – Licences for business unit specific software
- Legal/Consulting Costs specific to a business unit
- Payroll costs

\- Any costs that are incurred at a Group/Corporate level are expensed into shared services and form part of a management fee. Examples of which include but are not exclusive to:

- Any costs directly attributable to Shared Services/Corporate
- All Group staff functions
- Tax & Treasury advice
- Legal/Consulting
- Computer Expenses (PC's/Laptops, licences for Group-wide software, Servers)
- HR & Recruitment costs for the Group
- Superannuation costs
- Sponsorship

Management Fee Allocation

The management fee as allocated to business units using the following methodology.

- By using the latest available forecast balance sheet position, to determine the % of assets held per business unit.
- By using the latest available payroll information to determine the % of headcount per business unit.
- By using the latest available information from IT to determine the % of headcount with computers per business unit.

The following table shows the management fee percentage allocations determined by Eastland Group Limited for the 2015/16 financial year

Business Development	10%
Gisborne Airport	2%
Eastech	2%
Network	44%
Port Operations	34%
Cookstores	1%

Commercial Property	3%
Generation	4%

For the planning period the total $32.37m Business Support expenditure is 31% of the total operational expenditure forecast for the period.

Business Support costs have been forecast 'steady state' for this plan. These business support costs include charges in relation to the 'backbone' IT platform and financial system (which are supplied by Eastland Group to ENL). Eastland Group have recently commenced work on investigating the replacement of their legacy financial system to obtain efficiencies in the services provided.

System Operations and Network Support

System Operations and Network Support expenditure includes expenditure where the primary driver is the management of the network.

For the planning period the total $22.448m System Operations and Network Support expenditure is 22% of the total operational expenditure forecast for the period. Total System Operations and Network Support expenditure is reduced by capitalised design, planning and project management costs totalling $8.376m, giving a net forecast expenditure for the period of $14.112m.

Increases in System Operations and Network Support expenditure on pervious years has been driven in part by an increase in engineering and associated support staff as a result of the increase in regulatory compliance and additional transmission assets. ENL is embarking on a strategy to increase its resourcing to improve its asset management practices (in conjunction with the replacement of its core asset management systems). It is expected that this investment will improve future AMMAT scores.

The following tables and graphs present the forecast expenditure as per the categorisation above, in summary by asset type and in full.

Maintenance Expenditure Budget 2015/16
Maintenancel Expenditure Projections 2015/16 - 2025/26; ($2015/16 constant)

									1	2	3	4	5	6	7	8	9	10	11	12	
Description	Planned / Unplanned	Info Disclosure Expenditure Category	Asset Category	Distribution Custon Transpower	Quantity	Rate	Planned Cost	Unplanned Cost	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	Total
									10,375,562	9,896,717	10,516,595	10,581,978	10,531,602	10,562,152	10,532,121	10,575,692	10,586,786	10,561,094	0	0	104,720,298
Sub-transmission Lines																					
GIS-TOK A 110kV - Condition Asssment	Planned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			-	-	-	-	-	-	-	-	-	-	-	-	-		-
GIS-TOK A 110kV - Patrols	Planned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			152,315	-	15,232	15,232	15,232	15,232	15,232	15,232	15,232	15,232	15,232	15,232	-		152,315
GIS-TOK A 110kV - Access Road Maint	Unplanned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			-	507,650	50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	-		507,650
GIS-TOK A 110kV - Conductors	Unplanned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			-	-	-	-	-	-	-	-	-	-	-	-	-		-
GIS-TOK A 110kV - Foundations	Unplanned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			-	49,171	4,917	4,917	4,917	4,917	4,917	4,917	4,917	4,917	4,917	4,917	-		49,171
GIS-TOK A 110kV - Insulators	Unplanned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			-	-	-	-	-	-	-	-	-	-	-	-	-		-
GIS-TOK A 110kV - Structures	Unplanned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			-	70,157	7,016	7,016	7,016	7,016	7,016	7,016	7,016	7,016	7,016	7,016	-		70,157
GIS-TOK A 110kV - Vegetation Control	Unplanned	Vegetation management	Subtransmission	Transpower			-	332,704	33,270	33,270	33,270	33,270	33,270	33,270	33,270	33,270	33,270	33,270	-		332,704
GIS-TOK A 110kV- Grillage Maint	Planned	Asset replacement and renewal	Subtransmission	Transpower			177,678	-	60,918	40,612	76,148	-	-	-	-	-	-	-	-		177,678
GIS-TOK A 110kV - Tower Maint	Planned	Asset replacement and renewal	Subtransmission	Transpower			101,530	-	-	101,530	-	-	-	-	-	-	-	-	-		101,530
GIS-TUI A 110kV - Condition Assessment	Planned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			1,043,891	-	104,389	104,389	104,389	104,389	104,389	104,389	104,389	104,389	104,389	104,389	-		1,043,891
GIS-TUI A 110kV - Patrols	Planned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			195,587	-	19,559	19,559	19,559	19,559	19,559	19,559	19,559	19,559	19,559	19,559	-		195,587
GIS-TUI A 110kV - Access Road Maint	Unplanned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			-	1,015,300	101,530	101,530	101,530	101,530	101,530	101,530	101,530	101,530	101,530	101,530	-		1,015,300
GIS-TUI A 110kV - Conductors	Unplanned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			-	-	-	-	-	-	-	-	-	-	-	-	-		-
GIS-TUI A 110kV - Foundations	Unplanned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			-	-	-	-	-	-	-	-	-	-	-	-	-		-
GIS-TUI A 110kV - Insulators	Unplanned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			-	142,508	14,251	14,251	14,251	14,251	14,251	14,251	14,251	14,251	14,251	14,251	-		142,508
GIS-TUI A 110kV - Structures	Unplanned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			-	123,532	12,353	12,353	12,353	12,353	12,353	12,353	12,353	12,353	12,353	12,353	-		123,532
GIS-TUI A 110kV - Vegetation Control	Unplanned	Vegetation management	Subtransmission	Transpower			-	455,585	45,559	45,559	45,559	45,559	45,559	45,559	45,559	45,559	45,559	45,559	-		455,585
TUI-WRA A 110kV - Condition Asssment	Planned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			-	-	-	-	-	-	-	-	-	-	-	-	-		-
TUI-WRA A 110kV - Patrols	Planned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			308,631	-	30,863	30,863	30,863	30,863	30,863	30,863	30,863	30,863	30,863	30,863	-		308,631
TUI-WRA A 110kV - Access Road Maint	Unplanned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			-	507,650	50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	-		507,650
TUI-WRA A 110kV - Conductors	Unplanned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			-	185,830	18,583	18,583	18,583	18,583	18,583	18,583	18,583	18,583	18,583	18,583	-		185,830
TUI-WRA A 110kV - Foundations	Unplanned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			-	-	-	-	-	-	-	-	-	-	-	-	-		-
TUI-WRA A 110kV - Insulators	Unplanned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			-	226,300	22,630	22,630	22,630	22,630	22,630	22,630	22,630	22,630	22,630	22,630	-		226,300
TUI-WRA A 110kV - Structures	Unplanned	Routine & Corrective Maint & Inspection	Subtransmission	Transpower			-	-	-	-	-	-	-	-	-	-	-	-	-		-
TUI-WRA A 110kV - Vegetation Control	Unplanned	Vegetation management	Subtransmission	Transpower			-	114,678	11,468	11,468	11,468	11,468	11,468	11,468	11,468	11,468	11,468	11,468	-		114,678
TUI-WRA A 110kV - Earthwire Refurbishment	Planned	Asset replacement and renewal	Subtransmission	Transpower			21,321	-	21,321	-	-	-	-	-	-	-	-	-	-		21,321
TUI-WRA A 110kV - Base Plate Refurbishment	Planned	Asset replacement and renewal	Subtransmission	Transpower			101,530	-	50,765	-	50,765	-	-	-	-	-	-	-	-		101,530
All ex TP Lines - provision for major maint post 2018	Planned	Asset replacement and renewal	Subtransmission	Transpower			941,691	-	-	-	-	134,527	134,527	134,527	134,527	134,527	134,527	134,527	-		941,691
				Transpower			-	-	-	-	-	-	-	-	-	-	-	-	-		
Sub Total Transmission Lines							3,044,174	3,731,065	676,153	685,291	670,061	677,676	677,676	677,676	677,676	677,676	677,676	677,676	-	-	6,775,239
50kV Patrols (Ground & Helicopter)	Planned	Routine & Corrective Maint & Inspection	Subtransmission	Distribution	2,000	12	243,672	-	24,367	24,367	24,367	24,367	24,367	24,367	24,367	24,367	24,367	24,367	-		243,672
50kV Inspections (Climbing)	Planned	Routine & Corrective Maint & Inspection	Subtransmission	Distribution	135	150	203,060	-	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	-		203,060
50kV Testing - Ultrasound scan (Poles)	Planned	Routine & Corrective Maint & Inspection	Subtransmission	Distribution	200	50	101,530	-	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	-		101,530
50kV Defect / Fault repairs	Unplanned	Service interruptions and emergencies	Subtransmission	Distribution	2	6,250	-	126,913	12,691	12,691	12,691	12,691	12,691	12,691	12,691	12,691	12,691	12,691	-		126,913
50kV Fault response (incl Helicopter)	Unplanned	Service interruptions and emergencies	Subtransmission	Distribution	5	4,000	-	203,060	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	-		203,060
50kV Radio Interference correction	Unplanned	Service interruptions and emergencies	Subtransmission	Distribution	3	2,000	-	60,918	6,092	6,092	6,092	6,092	6,092	6,092	6,092	6,092	6,092	6,092	-		60,918
50kV Pole component replacement/maint	Planned	Asset replacement and renewal	Subtransmission	Distribution	60	1,000	507,650	-	50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	-		507,650
50kV Faults Management	Planned	Service interruptions and emergencies	Subtransmission	Distribution			203,060	-	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	-		203,060
				Distribution			-	-	-	-	-	-	-	-	-	-	-	-	-		-
						Subtrans Lines	1,258,972	390,891	164,986	164,986	164,986	164,986	164,986	164,986	164,986	164,986	164,986	164,986	-	-	1,649,863
11kV Lines Cables																					
11kV Patrols & general maintenance	Planned	Routine & Corrective Maint & Inspection	Distribution and LV lines	Distribution	40 feeders	5,000	2,030,600	-	203,060	203,060	203,060	203,060	203,060	203,060	203,060	203,060	203,060	203,060	-		2,030,600
11kV Testing -Ultrasound scan (Poles)	Planned	Routine & Corrective Maint & Inspection	Distribution and LV lines	Distribution	1,600	50	812,240	-	81,224	81,224	81,224	81,224	81,224	81,224	81,224	81,224	81,224	81,224	-		812,240
11kV Tree Control program Wairoa	Planned	Vegetation management	Distribution and LV lines	Distribution	300 sites	500	1,522,950	-	152,295	152,295	152,295	152,295	152,295	152,295	152,295	152,295	152,295	152,295	-		1,522,950
11kV Tree control program Gisborne	Planned	Vegetation management	Distribution and LV lines	Distribution	900 sites	500	4,568,850	-	456,885	456,885	456,885	456,885	456,885	456,885	456,885	456,885	456,885	456,885	-		4,568,850
11kV Forestry Tree Control Program	Planned	Vegetation management	Distribution and LV lines	Distribution	10 sites	20,000	2,030,600	-	203,060	203,060	203,060	203,060	203,060	203,060	203,060	203,060	203,060	203,060	-		2,030,600
11kV Storm Contengency	Unplanned	Service interruptions and emergencies	Distribution and LV lines	Distribution			-	1,015,300	101,530	101,530	101,530	101,530	101,530	101,530	101,530	101,530	101,530	101,530	-		1,015,300
11kV Trees forced cutting	Unplanned	Vegetation management	Distribution and LV lines	Distribution	125	320	-	1,015,300	101,530	101,530	101,530	101,530	101,530	101,530	101,530	101,530	101,530	101,530	-		1,015,300
11kV Defect / Fault repairs	Unplanned	Service interruptions and emergencies	Distribution and LV lines	Distribution			-	2,639,780	263,978	263,978	263,978	263,978	263,978	263,978	263,978	263,978	263,978	263,978	-		2,639,780
11kV Fault response	Unplanned	Service interruptions and emergencies	Distribution and LV lines	Distribution	145	1,000	-	1,472,185	147,219	147,219	147,219	147,219	147,219	147,219	147,219	147,219	147,219	147,219	-		1,472,185
11kVControl and Switching costs	Unplanned	Routine & Corrective Maint & Inspection	Distribution and LV lines	Distribution			-	203,060	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	-		203,060
11kV ABS & Redundant Equip Removal/Disposal	Planned	Routine & Corrective Maint & Inspection	Distribution and LV lines	Distribution	100	500	406,120	-	40,612	40,612	40,612	40,612	40,612	40,612	40,612	40,612	40,612	40,612	-		406,120
11kV Faults Management/MEP/SB Linemechanic	Planned	Service interruptions and emergencies	Distribution and LV lines	Distribution			2,412,353	-	241,235	241,235	241,235	241,235	241,235	241,235	241,235	241,235	241,235	241,235	-		2,412,353
				Distribution			-	-	-	-	-	-	-	-	-	-	-	-	-		-
						11kV Lines Cables	13,783,713	6,345,625	2,012,934	2,012,934	2,012,934	2,012,934	2,012,934	2,012,934	2,012,934	2,012,934	2,012,934	2,012,934	-	-	20,129,338
400V Lines Cables																					
400VLine Patrols & minor maintenance	Planned	Routine & Corrective Maint & Inspection	Distribution and LV lines	Distribution	50km	200	101,530	-	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	-		101,530
400V Testing -Ultrasound scan (Poles)	Planned	Routine & Corrective Maint & Inspection	Distribution and LV lines	Distribution	500	30	152,295	-	15,230	15,230	15,230	15,230	15,230	15,230	15,230	15,230	15,230	15,230	-		152,295
400V Defect / Fault repairs	Unplanned	Service interruptions and emergencies	Distribution and LV lines	Distribution			-	507,650	50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	-		507,650
400V Fault response	Unplanned	Service interruptions and emergencies	Distribution and LV lines	Distribution	100	250	-	253,825	25,383	25,383	25,383	25,383	25,383	25,383	25,383	25,383	25,383	25,383	-		253,825
400V General Maint Cables	Planned	Routine & Corrective Maint & Inspection	Distribution and LV cables	Distribution			101,530	-	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	-		101,530
400V Faults Management	Planned	Service interruptions and emergencies	Distribution and LV lines	Distribution			192,907	-	19,291	19,291	19,291	19,291	19,291	19,291	19,291	19,291	19,291	19,291	-		192,907
				Distribution			-	-	-	-	-	-	-	-	-	-	-	-	-		-
						400V Lines Cables	548,282	761,475	130,974	130,974	130,974	130,974	130,974	130,974	130,974	130,974	130,974	130,974	-	-	1,309,737
Service Connections																					
Service Patrols/inspection & minor maint	Planned	Routine & Corrective Maint & Inspection	Distribution and LV cables	Distribution	500	10	50,765	-	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	-		50,765
Voltage Checks/Complaints	Unplanned	Routine & Corrective Maint & Inspection	Distribution and LV lines	Distribution	100	200	-	203,060	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	-		203,060
				Distribution			-	-													-
						Service Connections	50,765	203,060	25,383	25,383	25,383	25,383	25,383	25,383	25,383	25,383	25,383	25,383	-	-	253,825
Load Control																					
Load Control Injection plant testing & routine maint	Planned	Routine & Corrective Maint & Inspection	Other network assets	Distribution	2	4,000	81,224	-	8,122	8,122	8,122	8,122	8,122	8,122	8,122	8,122	8,122	8,122	-		81,224
Load Control Defect / Fault repairs	Unplanned	Service interruptions and emergencies	Other network assets	Distribution			-	50,765	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	-		50,765
Load Control Fault response	Unplanned	Service interruptions and emergencies	Other network assets	Distribution	36	250	-	50,765	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	-		50,765
Load Control Faults Management	Planned	Service interruptions and emergencies	Other network assets	Distribution			40,612	-	4,061	4,061	4,061	4,061	4,061	4,061	4,061	4,061	4,061	4,061	-		40,612
				Distribution			-	-													-
						Load Control	121,836	101,530	22,337	22,337	22,337	22,337	22,337	22,337	22,337	22,337	22,337	22,337	-	-	223,366
Zone Substations																					

Description	Planned / Unplanned	Info Disclosure		Distribution	Quantity	Rate	Planned	Unplanned	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	Total
GIS - Fault Restoration	Unplanned	Service interruptions and emergencies	Zone substations	Transpower			-	94,986	10,554	10,554	10,554	10,554	10,554	10,554	10,554	10,554	10,554	10,554	-		94,986
GIS - Inspections	Planned	Routine & Corrective Maint & Inspection	Zone substations	Transpower			1,009,323	-	112,147	112,147	112,147	112,147	112,147	112,147	112,147	112,147	112,147	112,147	-		1,009,323
GIS - Repairs	Planned	Routine & Corrective Maint & Inspection	Zone substations	Transpower			691,532	-	76,837	76,837	76,837	76,837	76,837	76,837	76,837	76,837	76,837	76,837	-		691,532
GIS - Service Charge	Planned	Routine & Corrective Maint & Inspection	Zone substations	Transpower			39,329	-	4,370	4,370	4,370	4,370	4,370	4,370	4,370	4,370	4,370	4,370	-		39,329
GIS -10 yr Earth Test	Planned	Routine & Corrective Maint & Inspection	Zone substations	Transpower			-	-	9,645	-	-	-	-	-	-	-	-	-	-		-
TOK - Fault Restoration	Unplanned	Service interruptions and emergencies	Zone substations	Transpower			-	11,587	1,287	1,287	1,287	1,287	1,287	1,287	1,287	1,287	1,287	1,287	-		11,587
TOK - Inspections	Planned	Routine & Corrective Maint & Inspection	Zone substations	Transpower			202,126	-	22,458	22,458	22,458	22,458	22,458	22,458	22,458	22,458	22,458	22,458	-		202,126
TOK - Repairs	Planned	Routine & Corrective Maint & Inspection	Zone substations	Transpower			94,182	-	10,465	10,465	10,465	10,465	10,465	10,465	10,465	10,465	10,465	10,465	-		94,182
TOK - Service Charge	Planned	Routine & Corrective Maint & Inspection	Zone substations	Transpower			28,985	-	3,221	3,221	3,221	3,221	3,221	3,221	3,221	3,221	3,221	3,221	-		28,985
TUI - Fault Restoration	Unplanned	Service interruptions and emergencies	Zone substations	Transpower			-	2,019	224	224	224	224	224	224	224	224	224	224	-		2,019
TUI - Inspections	Planned	Routine & Corrective Maint & Inspection	Zone substations	Transpower			101,264	-	11,252	11,252	11,252	11,252	11,252	11,252	11,252	11,252	11,252	11,252	-		101,264
TUI - Repairs	Planned	Routine & Corrective Maint & Inspection	Zone substations	Transpower			419,000	-	46,556	46,556	46,556	46,556	46,556	46,556	46,556	46,556	46,556	46,556	-		419,000
TUI - 10 yr Earth Test	Planned	Routine & Corrective Maint & Inspection	Zone substations	Transpower			-	-	5,077	-	-	-	-	-	-	-	-	-	-		-
WRA - Fault Restoration	Unplanned	Service interruptions and emergencies	Zone substations	Transpower			-	119,594	13,288	13,288	13,288	13,288	13,288	13,288	13,288	13,288	13,288	13,288	-		119,594
WRA - Inspections	Planned	Routine & Corrective Maint & Inspection	Zone substations	Transpower			533,249	-	59,250	59,250	59,250	59,250	59,250	59,250	59,250	59,250	59,250	59,250	-		533,249
WRA - Repairs	Planned	Routine & Corrective Maint & Inspection	Zone substations	Transpower			460,686	-	51,187	51,187	51,187	51,187	51,187	51,187	51,187	51,187	51,187	51,187	-		460,686
WRA - Service Charge	Planned	Routine & Corrective Maint & Inspection	Zone substations	Transpower			20,331	-	2,259	2,259	2,259	2,259	2,259	2,259	2,259	2,259	2,259	2,259	-		20,331
GIS - Landscaping	Planned	Asset replacement and renewal	Zone substations	Transpower			-	-	19,291	-	-	-	-	-	-	-	-	-	-		-
WRA- 10 yr Earth Test	Planned	Routine & Corrective Maint & Inspection	Zone substations	Transpower			-	-	5,584	-	-	-	-	-	-	-	-	-	-		-
WRA - 11kV CBs Dismantle	Planned	Asset replacement and renewal	Zone substations	Transpower			-	-	-	-	-	-	-	-	-	-	-	-	-		-
All ex TP Substns - provision for major maint	Planned	Asset replacement and renewal	Zone substations	Transpower			159,910	-	-	10,153	25,383	17,768	17,768	17,768	17,768	17,768	17,768	17,768	-		159,910
				Transpower			-	-													-
Sub Total Transmission Zone Substations							3,759,917	228,187	464,952	435,508	450,737	443,123	443,123	443,123	443,123	443,123	443,123	443,123	-	-	3,988,103
Sub Total Trans Lines + Subs Maint							6,804,091	3,959,252	1,141,105	1,120,799	1,120,799	1,120,799	1,120,799	1,120,799	1,120,799	1,120,799	1,120,799	1,120,799	-	-	10,763,343
Zone Sub 4 Monthly Inspections & minor maint	Planned	Routine & Corrective Maint & Inspection	Zone substations	Distribution	3	8,333	253,825	-	25,383	25,383	25,383	25,383	25,383	25,383	25,383	25,383	25,383	25,383	-		253,825
Zone Sub Grounds Maintenance	Planned	Routine & Corrective Maint & Inspection	Zone substations	Distribution	240	185	446,732	-	44,673	44,673	44,673	44,673	44,673	44,673	44,673	44,673	44,673	44,673	-		446,732
Zone Sub Occupational Health and safety Inspect	Planned	Routine & Corrective Maint & Inspection	Zone substations	Distribution	20	250	50,765	-	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	-		50,765
Zone Sub Thermovision/Ultrasound Inspections (10 sit	Planned	Asset replacement and renewal	Zone substations	Distribution	10	2,000	203,060	-	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	-		203,060
Zone Sub Transformer paint	Planned	Asset replacement and renewal	Zone substations	Distribution	1	20,000	203,060	-	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	-		203,060
Zone SubAverage Routine Maintenance/major maint	Planned	Routine & Corrective Maint & Inspection	Zone substations	Distribution			659,945	-	65,995	65,995	65,995	65,995	65,995	65,995	65,995	65,995	65,995	65,995	-		659,945
Zone Sub DGA furrow tests 2yr	Planned	Routine & Corrective Maint & Inspection	Zone substations	Distribution	10	1,140	115,744	-	11,574	11,574	11,574	11,574	11,574	11,574	11,574	11,574	11,574	11,574	-		115,744
Zone Sub Average tap changer overhauls 2 units p.a.	Planned	Asset replacement and renewal	Zone substations	Distribution	1	15,000	152,295	-	15,230	15,230	15,230	15,230	15,230	15,230	15,230	15,230	15,230	15,230	-		152,295
Zone Sub Average oil processing 2 p.a.	Planned	Asset replacement and renewal	Zone substations	Distribution	2	6,000	121,836	-	12,184	12,184	12,184	12,184	12,184	12,184	12,184	12,184	12,184	12,184	-		121,836
Zone Sub 5yr "Step Touch" earth test (5 yr)	Planned	Routine & Corrective Maint & Inspection	Zone substations	Distribution			71,071	-	-	-	35,536	-	-	-	-	35,536	-	-	-		71,071
Zone Sub Protection Testing/CB Service/5 yr	Planned	Routine & Corrective Maint & Inspection	Zone substations	Distribution	3 subs	6,666	253,825	-	25,383	25,383	25,383	25,383	25,383	25,383	25,383	25,383	25,383	25,383	-		253,825
Zone Sub Defect / Fault repairs	Unplanned	Service interruptions and emergencies	Zone substations	Distribution			-	253,825	25,383	25,383	25,383	25,383	25,383	25,383	25,383	25,383	25,383	25,383	-		253,825
Zone Sub Fault response	Unplanned	Service interruptions and emergencies	Zone substations	Distribution			-	40,612	4,061	4,061	4,061	4,061	4,061	4,061	4,061	4,061	4,061	4,061	-		40,612
Zone Sub Faults Management	Planned	Service interruptions and emergencies	Zone substations	Distribution			60,918	-	6,092	6,092	6,092	6,092	6,092	6,092	6,092	6,092	6,092	6,092	-		60,918
				Distribution			-	-													-
						Zone Substations	2,593,076	294,437	281,644	281,644	317,180	281,644	281,644	281,644	281,644	317,180	281,644	281,644	-	-	2,887,513
Pole Mounted Isolation Equipment																					
Rural CB Annual Inspections	Planned	Routine & Corrective Maint & Inspection	Distribution switchgear	Distribution	90	150	137,066	-	13,707	13,707	13,707	13,707	13,707	13,707	13,707	13,707	13,707	13,707	-		137,066
Rural CB Average Routine Maintenance	Planned	Routine & Corrective Maint & Inspection	Distribution switchgear	Distribution	45	400	182,754	-	18,275	18,275	18,275	18,275	18,275	18,275	18,275	18,275	18,275	18,275	-		182,754
Rural CB Defect /Fault repairs	Unplanned	Service interruptions and emergencies	Distribution switchgear	Distribution	5	4,000	-	203,060	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	20,306	-		203,060
Rural CB Faults Management	Planned	Service interruptions and emergencies	Distribution switchgear	Distribution			15,230	-	1,523	1,523	1,523	1,523	1,523	1,523	1,523	1,523	1,523	1,523	-		15,230
				Distribution			-	-													-
						Pole Mounted Isolation Equipment	335,049	203,060	53,811	53,811	53,811	53,811	53,811	53,811	53,811	53,811	53,811	53,811	-	-	538,109
Distribution Transformers																					
TX Refurbishment <100kVA	Planned	Asset replacement and renewal	Distribution substations and transform	Distribution	10	500	50,765	-	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	-		50,765
TX Refurbishment >100kVA	Planned	Asset replacement and renewal	Distribution substations and transform	Distribution	2	4,000	81,224	-	8,122	8,122	8,122	8,122	8,122	8,122	8,122	8,122	8,122	8,122	-		81,224
GM TX Inspection (incl minor maint & MDI's)	Planned	Routine & Corrective Maint & Inspection	Distribution substations and transform	Distribution	528	50	253,825	-	25,383	25,383	25,383	25,383	25,383	25,383	25,383	25,383	25,383	25,383	-		253,825
TX Oil Analysis/Handling /filtering /TX disposal	Planned	Asset replacement and renewal	Distribution substations and transform	Distribution			101,530	-	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	-		101,530
TX Earth testing	Planned	Routine & Corrective Maint & Inspection	Distribution substations and transform	Distribution	800	75	609,180	-	60,918	60,918	60,918	60,918	60,918	60,918	60,918	60,918	60,918	60,918	-		609,180
TX Earthing system repairs	Planned	Asset replacement and renewal	Distribution substations and transform	Distribution	100	450	456,885	-	45,689	45,689	45,689	45,689	45,689	45,689	45,689	45,689	45,689	45,689	-		456,885
TX Defect /Fault repairs	Unplanned	Service interruptions and emergencies	Distribution substations and transform	Distribution			-	152,295	15,230	15,230	15,230	15,230	15,230	15,230	15,230	15,230	15,230	15,230	-		152,295
TX Faults Management	Planned	Service interruptions and emergencies	Distribution substations and transform	Distribution			61,020	-	6,102	6,102	6,102	6,102	6,102	6,102	6,102	6,102	6,102	6,102	-		61,020
				Distribution			-	-													-
						Transformers	1,614,429	152,295	176,672	176,672	176,672	176,672	176,672	176,672	176,672	176,672	176,672	176,672	-	-	1,766,724
11kV Switchgear Ground Mounted																					
11kV SWGR Inspection & Servicing/minor maint	Planned	Routine & Corrective Maint & Inspection	Distribution switchgear	Distribution	194	50	101,530	-	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	-		101,530
11kV SWGR Average Switch maintenance 5yrs	Planned	Asset replacement and renewal	Distribution switchgear	Distribution	15	1,000	152,295	-	15,230	15,230	15,230	15,230	15,230	15,230	15,230	15,230	15,230	15,230	-		152,295
11kV SWGR Defect /Fault repairs	Unplanned	Service interruptions and emergencies	Distribution switchgear	Distribution			-	101,530	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	-		101,530
11kV SWGR General maint consumer/kiosk substns	Planned	Routine & Corrective Maint & Inspection	Distribution switchgear	Distribution			101,530	-	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	-		101,530
11kV SWGR Faults Management	Planned	Service interruptions and emergencies	Distribution switchgear	Distribution			43,069	-	4,307	4,307	4,307	4,307	4,307	4,307	4,307	4,307	4,307	4,307	-		43,069
				Distribution			-	-													-
						11kV Switchgear Ground Mounted	398,424	101,530	49,995	49,995	49,995	49,995	49,995	49,995	49,995	49,995	49,995	49,995	-	-	499,954
LV Switchgear & Pillars																					
400V SWGR Inspection & Servicing/minor maint	Planned	Routine & Corrective Maint & Inspection	Distribution switchgear	Distribution	500	30	152,295	-	15,230	15,230	15,230	15,230	15,230	15,230	15,230	15,230	15,230	15,230	-		152,295
400V SWGR Defect /Fault repairs	Unplanned	Service interruptions and emergencies	Distribution switchgear	Distribution	100	100	-	101,530	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	-		101,530
Galv Box inspections & maint	Planned	Routine & Corrective Maint & Inspection	Distribution switchgear	Distribution	150	33	50,765	-	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	-		50,765
400V OH Service Fuse Base & Carrier replacement	Unplanned	Asset replacement and renewal	Distribution switchgear	Distribution	250	200	-	507,650	50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	50,765	-		507,650
				Distribution			-	-													-
						LV Switchgear	203,060	609,180	81,224	81,224	81,224	81,224	81,224	81,224	81,224	81,224	81,224	81,224	-	-	812,240
Communications																					
Comms Maintenance/Calibration	Planned	Asset replacement and renewal	Other network assets	Distribution			355,355	-	35,536	35,536	35,536	35,536	35,536	35,536	35,536	35,536	35,536	35,536	-		355,355
Comms Track Inspection & Maintenance	Planned	Routine & Corrective Maint & Inspection	Other network assets	Distribution			40,612	-	4,061	4,061	4,061	4,061	4,061	4,061	4,061	4,061	4,061	4,061	-		40,612
Comms Hut Inspection & Maintenance	Planned	Routine & Corrective Maint & Inspection	Other network assets	Distribution			40,612	-	4,061	4,061	4,061	4,061	4,061	4,061	4,061	4,061	4,061	4,061	-		40,612
Comms Radio Licences	Planned	Routine & Corrective Maint & Inspection	Other network assets	Distribution			131,989	-	13,199	13,199	13,199	13,199	13,199	13,199	13,199	13,199	13,199	13,199	-		131,989
Comms Defect/Fault repairs	Unplanned	Service interruptions and emergencies	Other network assets	Distribution			-	162,448	16,245	16,245	16,245	16,245	16,245	16,245	16,245	16,245	16,245	16,245	-		162,448
				Distribution			-	-													-
						Communications	568,568	162,448	73,102	73,102	73,102	73,102	73,102	73,102	73,102	73,102	73,102	73,102	-	-	731,016
SCADA																					

Description	Planned /	Info Disclosure		Distribution	Quantity	Rate	Planned	Unplanned	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	Total
SCADA Support fees	Planned	Routine & Corrective Maint & Inspection	Other network assets	Distribution			101,530	-	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	-		101,530
SCADA Software Licences	Planned	Routine & Corrective Maint & Inspection	Other network assets	Distribution			50,765	-	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	5,077	-		50,765
SCADA maintenance allowance	Planned	Asset replacement and renewal	Other network assets	Distribution			101,530	-	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	-		101,530
SCADA Configuration and file alterations	Planned	Routine & Corrective Maint & Inspection	Other network assets	Distribution			60,918	-	6,092	6,092	6,092	6,092	6,092	6,092	6,092	6,092	6,092	6,092	-		60,918
SCADA Defect/Fault repairs	Unplanned	Service interruptions and emergencies	Other network assets	Distribution			-	101,530	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	10,153	-		101,530
				Distribution			-	-													-
						SCADA	314,743	101,530	41,627	41,627	41,627	41,627	41,627	41,627	41,627	41,627	41,627	41,627	-	-	416,273
ACOD - EGL	Planned	Asset replacement and renewal	Other network assets	Distribution			16,062,046	-	1,606,205	1,606,205	1,606,205	1,606,205	1,606,205	1,606,205	1,606,205	1,606,205	1,606,205	1,606,205	-		
						ACOD	16,062,046	-	1,606,205	1,606,205	1,606,205	1,606,205	1,606,205	1,606,205	1,606,205	1,606,205	1,606,205	1,606,205	-	-	-
FAULTS MANAGEMENT																					
(Total from above)	Planned	Service interruptions and emergencies		Distribution			3,029,168	-	302,917	302,917	302,917	302,917	302,917	302,917	302,917	302,917	302,917	302,917	-	-	3,029,168
				Distribution			-	-													-
						Faults MGT	3,029,168	-	302,917	302,917	302,917	302,917	302,917	302,917	302,917	302,917	302,917	302,917	-	-	3,029,168
Total Maintenance (Ntk) Expenditure Projections				Distribution			37,852,943	9,427,061	4,720,893	4,720,893	4,756,429	4,720,893	4,720,893	4,720,893	4,720,893	4,756,429	4,720,893	4,720,893	-	-	47,280,003
Total Maintenance (Trans) Expenditure Projections				Transpower			6,804,091	3,959,252	1,141,105	1,120,799	1,120,799	1,120,799	1,120,799	1,120,799	1,120,799	1,120,799	1,120,799	1,120,799	-	-	11,228,294
Total Maintenance (Trans + Ntk) Expenditure Projections							44,657,033	13,386,312	5,861,998	5,841,692	5,877,228	5,841,692	5,841,692	5,841,692	5,841,692	5,877,228	5,841,692	5,841,692	-	-	58,508,297
Total Business Support Ntk + Trans									3,209,913	3,209,913	3,209,913	3,209,913	3,209,913	3,209,913	3,209,913	3,209,913	3,209,913	3,209,913	-		32,099,126
Total System Operations Network Support Ntk + Trans									2,248,856	2,248,856	2,248,856	2,248,856	2,248,856	2,248,856	2,248,856	2,248,856	2,248,856	2,248,856	-		22,488,562
Less On-Costs									(945,205)	(1,403,744)	(819,402)	(718,483)	(768,859)	(738,308)	(768,339)	(760,304)	(713,675)	(739,367)	-		(8,375,687)
Net SONS									1,303,651	845,112	1,429,455	1,530,373	1,479,997	1,510,548	1,480,517	1,488,552	1,535,181	1,509,489	-	-	14,112,875
Net Business Support (BS) & System Operations and Network Support (SONS)									4,513,564	4,055,025	4,639,367	4,740,286	4,689,910	4,720,460	4,690,429	4,698,465	4,745,094	4,719,402	-	-	46,212,000
Total Opex									10,375,562	9,896,717	10,516,595	10,581,978	10,531,602	10,562,152	10,532,121	10,575,692	10,586,786	10,561,094	-	-	104,720,298

Maintenance Summary		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Service interruptions and emergencies	Distribution	1,052,716	1,052,716	1,052,716	1,052,716	1,052,716	1,052,716	1,052,716	1,052,716	1,052,716	1,052,716	-	-	10,527,158
Service interruptions and emergencies	Transpower	25,354	25,354	25,354	25,354	25,354	25,354	25,354	25,354	25,354	25,354	-	-	253,541
Total Service interruptions & emergencies		1,078,070	1,078,070	1,078,070	1,078,070	1,078,070	1,078,070	1,078,070	1,078,070	1,078,070	1,078,070	-	-	10,780,699
Routine & Corrective Maint & Inspection	Distribution	848,689	848,689	884,225	848,689	848,689	848,689	848,689	884,225	848,689	848,689	-	-	8,557,964
Routine & Corrective Maint & Inspection	Transpower	873,159	852,853	852,853	852,853	852,853	852,853	852,853	852,853	852,853	852,853	-	-	8,548,836
Total Routine & Corrective maint & Inspection		1,721,848	1,701,542	1,737,078	1,701,542	1,701,542	1,701,542	1,701,542	1,737,078	1,701,542	1,701,542	-	-	17,106,800
Asset replacement and renewal	Distribution	1,905,718	1,905,718	1,905,718	1,905,718	1,905,718	1,905,718	1,905,718	1,905,718	1,905,718	1,905,718	-	-	19,057,181
Asset replacement and renewal	Transpower	152,295	152,295	152,295	152,295	152,295	152,295	152,295	152,295	152,295	152,295	-	-	1,522,950
Total Asset replacement and renewal		2,058,013	2,058,013	2,058,013	2,058,013	2,058,013	2,058,013	2,058,013	2,058,013	2,058,013	2,058,013	-	-	20,580,131
Vegetation management	Distribution	913,770	913,770	913,770	913,770	913,770	913,770	913,770	913,770	913,770	913,770	-	-	9,137,700
Vegetation management	Transpower	90,297	90,297	90,297	90,297	90,297	90,297	90,297	90,297	90,297	90,297	-	-	902,967
Total Vegetation Management		1,004,067	1,004,067	1,004,067	1,004,067	1,004,067	1,004,067	1,004,067	1,004,067	1,004,067	1,004,067	-	-	10,040,667
TOTAL MAINTENANCE		5,861,998	5,841,692	5,877,228	5,841,692	5,841,692	5,841,692	5,841,692	5,877,228	5,841,692	5,841,692	-	-	58,508,297

7.4 How is the asset value changing

Ideally ENL's asset value should remain fairly constant given the average position in terms of security and performance and general satisfaction, across the consumer base with the security/performance verses price trade off currently provided. Any decline of service potential associated with the aging asset should be off-set by an equal restoring of service potential. Factors that will influence the asset value are shown in Table 7.4(a) below…

Table 7.4(a) – Factors influencing asset value

Factors that increase asset value	Factors that decrease asset value
Addition of new assets to the network as a result of improvements to Security and Performance levels or new asset in response to growth.	Removal of assets from the network generally associated with moving industrial and commercial load centers.
Renewal of existing assets. Note the definition of renewal as being restoration of original functionality – no increase in service potential beyond original functionality.	On-going depreciation of assets.
Increase of standard component values implicit in the ODV methodology.	Reduction of standard component values implicit in the ODV methodology.

At a practical level ENL's asset valuation will vary even in the absence of component revaluations. This is principally because the accounting treatment of depreciation models the decline in service potential as a straight line (when in most cases it is more closely reflected by an inverted bath-tub curve) whilst the restoration of service potential is very "lumpy". However the aggregation of many depreciating assets and many restoration projects tends to smooth short-term variations in asset value.

The asset value ratio across the urban and rural assets is changing. The urban asset value is increasing as the rural asset value is decreasing. This shift is in line with the greater levels of security and higher performance levels provided in the urban centers. The shift is also influenced by economic justification. With controls on the differential between more economic urban and less uneconomic rural tariffs, the matching of expenditure, affecting asset condition and age, to income, ultimately results in a corresponding shift of asset value.

7.5 Depreciation and Renewal of the assets

ENL has identified a small gap between required renewal rates for some assets to maintain asset age, primarily limited by available funding and economic returns.
The nature of the existing asset is such that it will physically deteriorate over its life until it reaches a stage where renewal is required to maintain service. In addition the life expectancies of the components making up the asset are varied which affects the accuracy of renewal forecasts. The renewal costs for these asset components need to be provided for over their respective lives.
Depreciation provides the mechanism to fund this renewal.
The ability for renewal to be funded by depreciation is affected by-
The correct value being assigned to the assets
The correct age expectancy being assigned to the assets
Stability of the costs for the new equivalent asset over time.
Selection of the correct asset components to be removed.

The asset value for ENL has been based on the ODV methodology. This methodology values the existing asset assuming no asset exists initially, 'Green fields approach' and lowest standard cost of the minimum required asset over a 10 year planning cycle.
This method of valuation differs from the actual renewal situation in the following areas…
Renewal costs include costs to remove the existing asset and maintain service while the new asset is installed.
The planning period adopted for new assets is generally greater than 10 years to align more closely with asset life hence avoiding frequent upgrade on an in-service asset that is difficult to access.
At the component level it is often appropriate to change assets not at end of life in conjunction with the asset targeted for renewal.

Any short fall between depreciation funding and renewal cost must be provided from some other source.
The justifiable growth component of renewal expenditure can be sourced from growth funding made available from growth revenue or borrowing.
Higher charges or reduction in the Return on Asset provided to the shareholder can also provide the additional funding.
Finally retiring of the asset at the time of failure, with the resulting reduction or total loss of service is a consideration.
Given set requirements for shareholder expectations ,set requirements from regulators for revenue, defined limits and justifications on borrowing levels and the need to allocate funding to growth and performance improvement, ENL has identified a gap developing between forecast required renewal rates and the target rates that can be financially achieved. This will be particularly significant as ENL approaches the "bow wave" of asset renewals that can be seen in the age profiles for asset components.

The renewal section of this plan identifies the forecast and targeted renewal rates ENL has adopted. For 11kV conductor, a gap as described above is currently developing. For the general case while the set limits remain in place the average age of the asset is increasing and the performance may decline. The observable effects of the declining performance are being offset in the medium term by technology innovations that can be implemented at lower cost than the renewal alternative. Also ENL has identified medium term options to minimise this issue for remote or uneconomic lines which focus on improving systems to target the components requiring renewal more precisely and allowing failures while ensuring backup systems are adequate to maintain performance.

ENL’s conclusion is that at some point it must be given an opportunity to increase prices which will enable a balance to be achieved between the level of network investment required and return on asset requirements. Otherwise there is increased risk of performance failure in terms of regulation, customer expectation and sustainability of the business.

8. Performance & improvement

8.1 Performance against financial plans

ENL's financial year operates from 1 April to 31 March. The results for performance against budget for the previous 12 month asset management period for both capital and maintenance expenditure are shown in the tables below.

Capital Expenditure Comparison Summary by Asset Group	2013/14 Budget $	2013/14 Actual $	2013/14 Difference $
50 kV Lines	$890,000	$394,325	$495,675
11kV Lines and Cables	$2,550,000	$2,426,956	$123,044
LT Lines and Cables	$550,000	$360,287	$189,713
Service Connections	$95,000	$67,141	$27,859
Load Control	$20,000	$7,320	$12,680
Zone Substations	$90,000	$60,989	$29,011
50kV CB's	$40,000	$37,261	$2,739
11kV CB's	$310,000	$282,533	$27,467
Distribution Transformers	$573,000	$654,558	-$81,558
Pole Mounted Isolation Equipment	$140,000	$133,641	$6,359
11kV Ground Mounted Switchgear	$115,000	$125,619	-$10,619
LV Switchgear	$80,000	$14,175	$65,825
Control and Protection	$85,000	$77,941	$7,059
Communications	$20,000	$16,501	$3,499
SCADA	$110,000	$93,523	$16,477
Other	$30,000	$-	$30,000
TOTAL	**$5,698,000**	**$4,752,771**	**$945,229**

Capital Expenditure Comparison Summary by Category	2013/14 Budget $	2013/14 Actual $	2013/14 Difference $
Performance/Development	$165,000	$91,191	$73,809
Growth/Security	$978,000	$523,444	$454,556
Asset Replacement and Renewal	$4,415,000	$4,075,972	$339,028
Customer Connection	$90,000	$56,734	$33,266
Asset Relocations	$50,000	$5,430	$44,570
TOTAL	**$5,698,000**	**$4,752,771**	**$945,229**

Capital Expenditure Comparison Summary by Type	2013/14 Budget $	2013/14 Actual $	2013/14 Difference $
Planned	$4,600,000	$3,692,529	$907,471

Unplanned	$1,098,000	$1,060,242	$37,758
TOTAL	**$5,698,000**	**$4,752,771**	**$945,229**

Maintenance Expenditure Comparison Summary by Asset Group	2013/14 Budget $	2013/14 Actual $	2013/14 Difference $
50 kV Lines	$162,500	$178,451	-$15,951
11kV Lines and Cables	$1,882,600	$1,901,552	-$18,952
LT Lines and Cables	$129,000	$99,313	$29,687
Service Connections	$75,000	$29,160	$45,840
Load Control	$22,000	$8,954	$13,046
Zone Substations	$252,400	$234,874	$17,526
CB's	$78,000	$39,276	$38,724
Distribution Transformers	$174,010	$68,453	$105,557
11kV Ground Mounted Switchgear	$49,242	$10,617	$38,625
LV Switchgear	$72,000	$12,623	$59,377
Communications	$72,000	$84,332	-$12,332
SCADA	$41,000	$5,794	$35,206
TOTAL	**$3,009,752**	**$2,673,399**	**$336,353**

Maintenance Expenditure Comparison Summary by Asset Group	2013/14 Budget $	2013/14 Actual $	2013/14 Difference $
Routine and Preventative	$1,635,900	$1,434,595	$201,305
Refurbishment and Renewal	$337,000	$199,740	$137,260
Fault and Emergency	$1,036,852	$1,039,064	-$2,212
TOTAL	**$3,009,752**	**$2,673,399**	**$336,353**

Maintenance Expenditure Comparison Summary by Category	2013/14 Budget $	2013/14 Actual $	2013/14 Difference $
Unplanned	$803,500	$788,064	$15,436
Planned	$2,206,252	$1,885,336	$320,916
TOTAL	**$3,009,752**	**$2,673,399**	**$336,353**

A total variation of $1.281m under spend exists between the 2013/14vcombined capital ($945k) and maintenance ($336k) expenditure budgets and the actual expenditure achieved.

Capital Expenditure
A total variance of $945k occurred between the 2013/14 budget and actual capital expenditure. Reasons for this variance are provided below in relation to the categories of capital expenditure.

The $339k variance in Condition and Compliance, Asset replacement and renewal expenditure is the resultant of the following;

The short fall of available contractor resources. Both locally and nationally based contractors are depleted of skilled resources due to the legacy over past years of scaled back training of electrical workers and the financial attraction of overseas employment. Poor responses to tenders issued for renewal projects resulted in scheduled 50kV pole and 11kV conductor replacements being deferred.
Unrealistic cost. Due to a combination of a number of external factors tender for work have indicated costs in the order of 4 times ODV standard costs reflecting supply and demand leverage due to resource shortages rather than true costs to undertake the work.
Planning influence of regulated service levels. To ensure compliance with regulated outage measures, large shutdowns typically associated with conductor replacement projects have not proceeded as planned.

ENL continues to encourage local contractors to employ more staff however in common with other many Gisborne based industries they have difficulty in attracting interest from suitably qualified and experienced applicants. The Eastland Group has established Eastech as a contracting business to support ENL and maintain minimum response resource levels in the region. Whilst these actions do not completely address the resource shortage in the medium term ENL continues to canvas national electrical contracting companies about carrying out work on a project basis in the Gisborne area.

The $454k variance in Growth and Security expenditure is the resultant of the following;

Mahia 33kV project is delayed pending consents and the negotiation of easements
Regional development is low hence forecast growth has not been met.

The $73k variation in Development and Performance expenditure is the resultant of the following;

Deferal of Kaiti Substation and A Park Substation Projects due to reallocation of Design Resources to Regulatory Projects and the transmission asset acquisition project.

Maintenance Expenditure

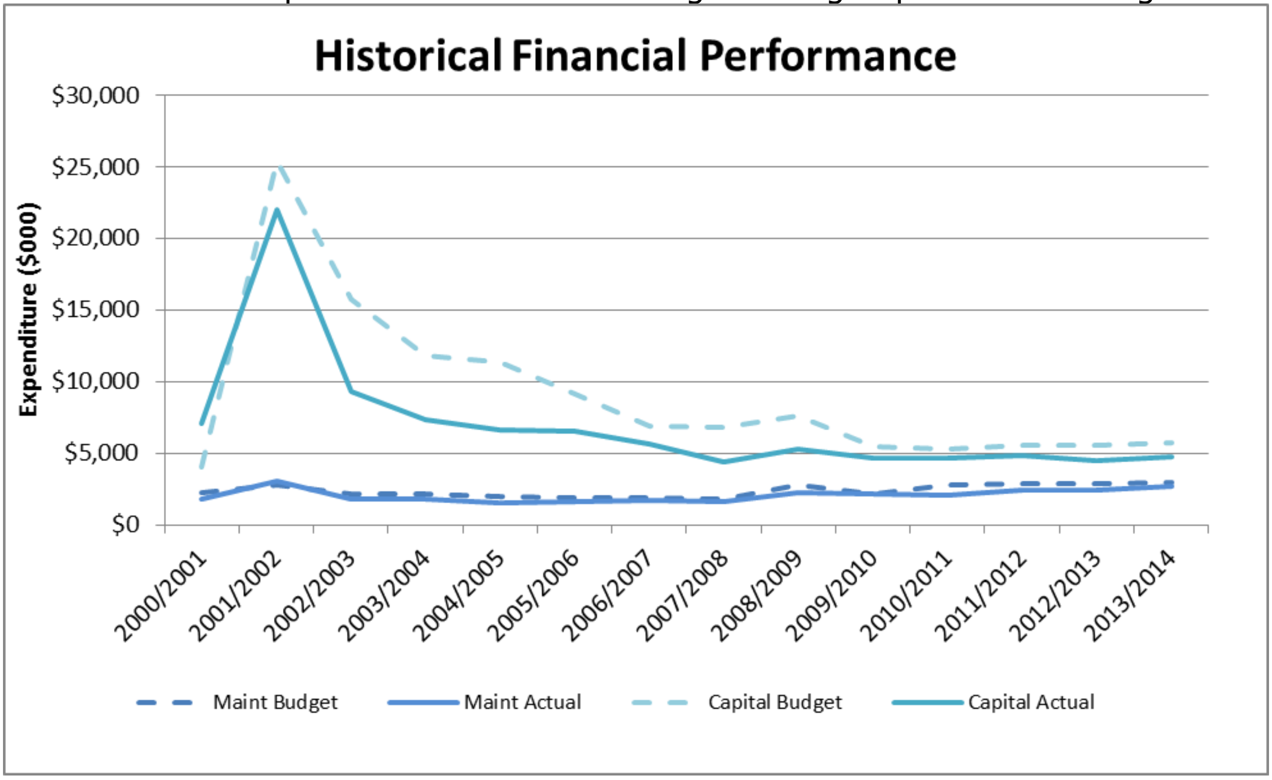
A total variance of $336k occurred between the 2013/14 budget and actual maintenance expenditure. Reasons for this variance are as follows;

Unplanned maintenance, $15k underspend spend reflected a year in terms of environmental and physical operational conditions which caused damage lower than the typical expectation.

Planned maintenance, a $320k variation against a budget of $2.20m. The underspend occurred primarily due to

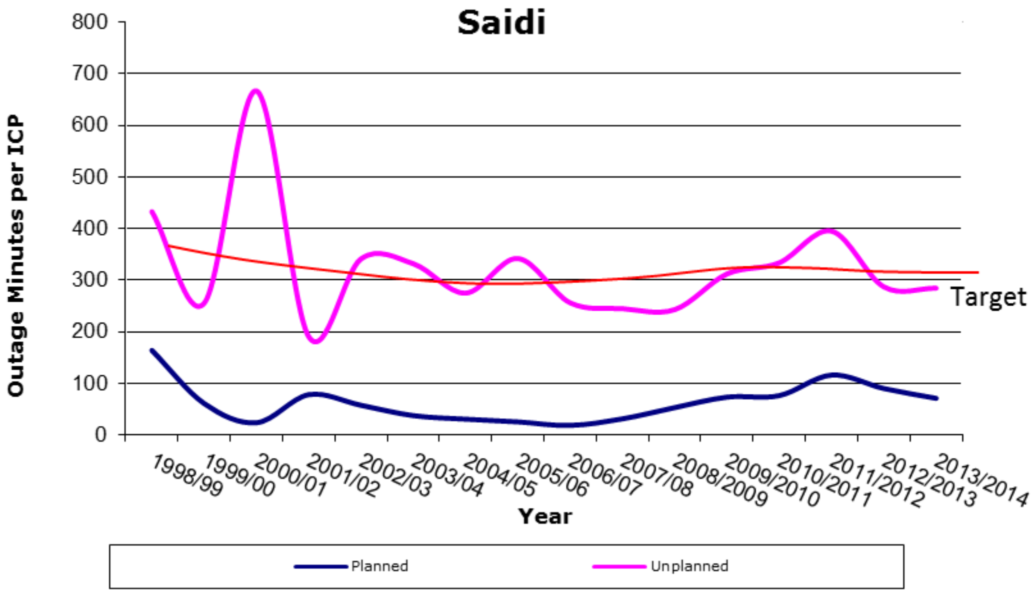
a) the lack of skilled contractor resources to carry out some of the higher end activities such as load control plant injection testing and 50kV, 11kV, zone substation thermo vision/ultrasound testing and communications work. Planning influence of regulated service levels.
b) The need to ensure compliance with regulated outage measures, shutdowns to enable maintenance work have not proceeded as planned.

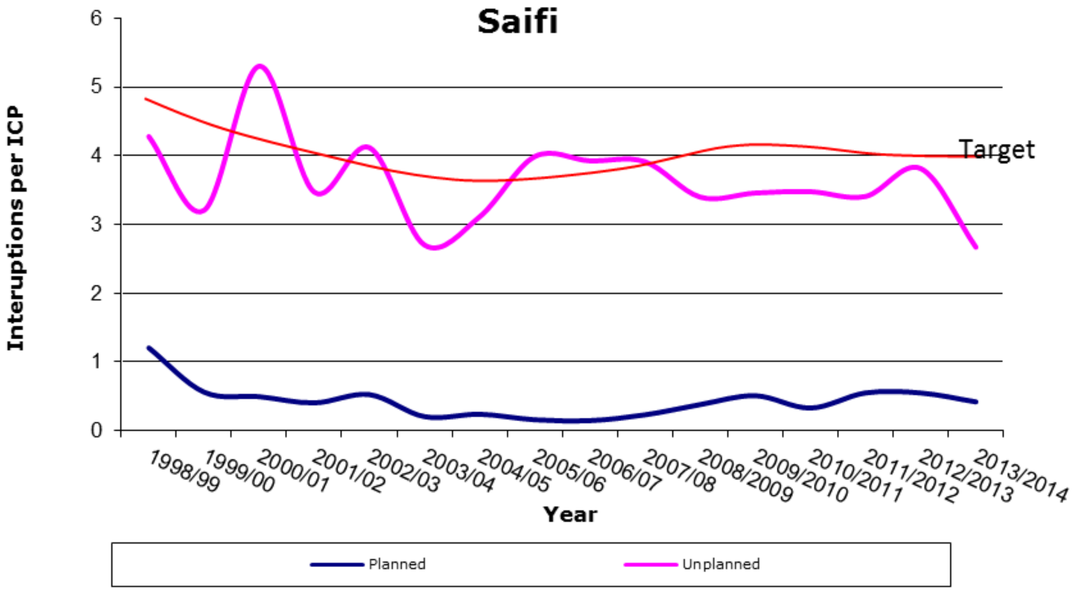
Historical performance
The overall past performance to budget is indicated in the following chart. Following the 2001/02 catch up capital expenditure shows a trend declining to over time 2007/08.
From 2007/08 the trend indicates a steady state pattern.
Shortfalls of actual verses budgeted expenditure reflects the gradual increase in asset age forecast over time and potentially indicates the need for future catch up work when the factors governing expenditure change.



8.2 Meeting performance targets

8.2.1 Primary Service Levels





The primary indicator of reliability performance is the SAIDI index. The annual regulatory Limits applicable to the current 2010 -2015 regulatory period are 302.3 SAIDI and 4.25 SAIFI. These limits are calculated in accordance with the Electricity Information Disclosure Rules. Besides inherent system security, a wide range of factors impact on observed reliability.

Protection and rural automation is an area where technology delivers large reductions in the impact of outages. ENL has progressively improved the network with this technology between 2000 and 2006.

Optimisation of isolation points between 2000 and 2001 has also contributed to improved performance.

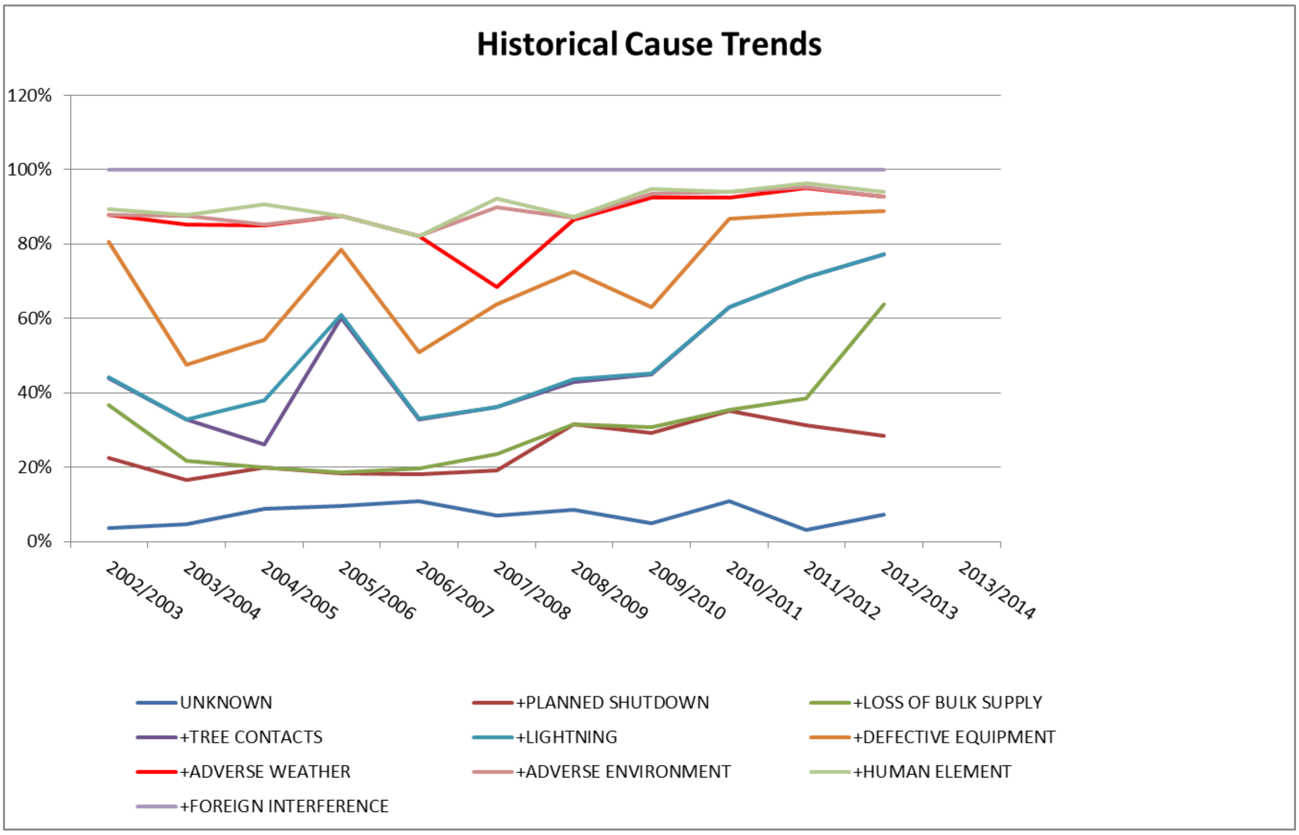
Installation of remote diesel generators between 2002 and 2003 has reduced the impact of planned outages. On average over the past 8 years use of generators has avoided 300 SAIDI minutes p.a. The extent of this reduction cannot be seen in the statistics as pole replacement work spur 50kV lines, and substation maintenance work is now carried out without any impact on outage statistics.

Use of Live line technologies has avoided an average of 10 SAIDI minutes p.a. between 2001 and 2008. As a result of skill shortages in 2007 and 2008 and an increase in line renewal work over rugged terrain, the use of Live Line technologies is currently suspended.

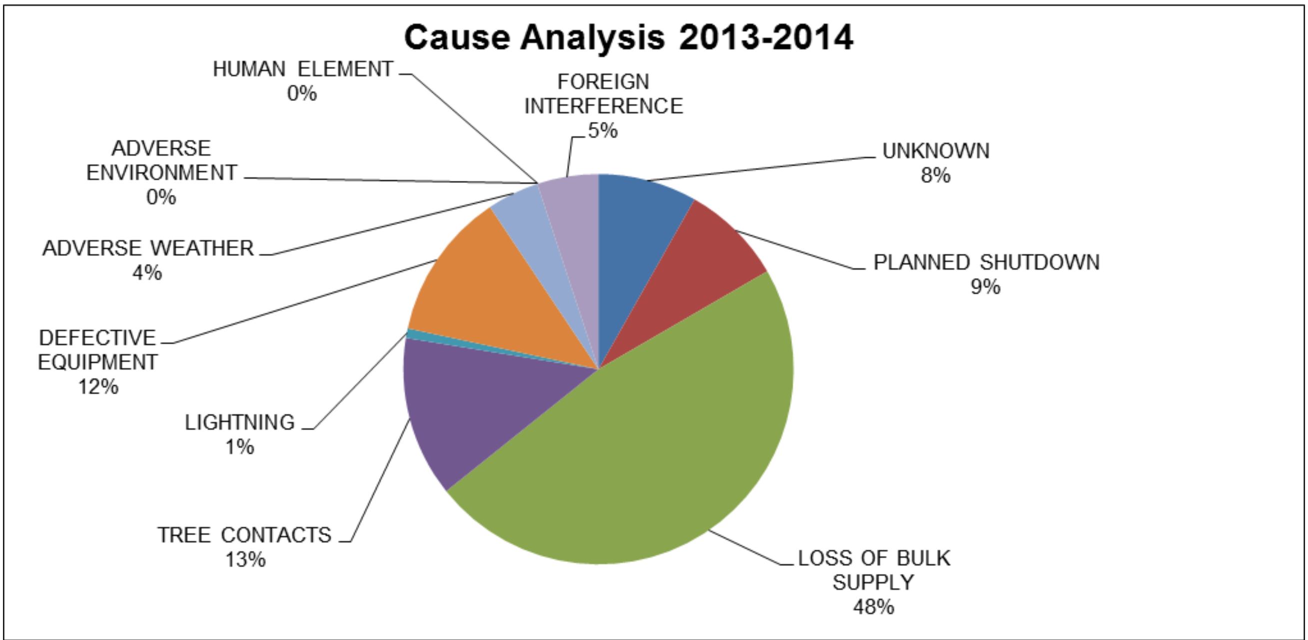
While the targeted SAIDI is set at the regulated limit a shift to renewal projects on lines not suited to generator support will increase planned SAIDI figures. This increase will be partially mitigated through the installation of temporary isolation points, (ie. the cutting of jumpers at shackle points), which results in reduced outage areas affecting less customers.
.
Significant storm events and environmental factors such as slips after long periods of, generally considered as normal, rainfall have the most significant impact on ENL's ability to achieve its targets. This is evident in the 2000/2001 result where a single 24 hour event contributed to 415.64 SAIDI minutes i.e. 64% of the year's unplanned outages.
Other examples of significant events are as follows…
2003/2004, 130.36 Minutes, July storm
2005/2006, 83.83 Minutes, October storm
2006/2007, 99.07 Minutes, June storm
2007/2008, 53.00 Minutes, December Earthquake
2010/2011, 38.80 Minutes, September storm
2011/2012, 41.00 Minutes, March storm.
2012/2013, 40.00 Minutes, October Storm
Subtraction of these events shows ENL can obtain the target levels through activities it can control.

8.2.2 Outage Cause analysis

The historical cause analysis as a percentage of the total customer's affected multiplied by-minutes of interruption time is shown below.
The trend is dominated by variation in adverse weather, tree contacts and defective equipment.



Cause analysis as a percentage of the total customers affected multiplied by-minutes of interruption time during the last year provides the following spread:



Loss of Bulk Supply at 48% reflected rare events within the Transpower Grid over the period an increase from 35 % in the previous year. Planned shutdowns average 17% p.a. over the past 10 years, and have changed from 7% of outage duration during 2006/07 to 24-28% from 2009 to 2013. In 2013-2014 the figure of 8% reflects reduction in capital and maintenance program activities requiring outages.

Actions have been taken to reduce the level of unknown causes averaging 7% over past years, since it frustrates an effective management response. Initiatives have included improved field fault reporting, automation projects, and follow-up patrols to short lived faults.

The adverse weather component averages 18% p.a. and is in effect indicative of poor past design, ageing asset condition or changing weather trends. Under design is not normally an issue with the exception of extreme wind snow loading events every 2 or 3 years. Designing to these conditions is not considered economic and ENL chooses to manage this risk.

Foreign interference while previously increasing, initially at 9% the figure climbed to 18% in 2007/08 and has now reduced to 4% giving an average of 10% p.a. This figure is driven by vehicles/pole collisions. Rural automation technology has minimised the impact of these faults however the number of incidents is increasing. The road authorities introduced new standards for location of structures alongside roads in 2006. All replacement structures need to conform to set minimum distances from the road edge or be protected by barriers. The costs to upgrade the existing works as part of the renewal will ultimately be borne by ENL’s customers rather than the road users, under the new rules.
Bird strikes also contribute to this category. A long-term objective is to clean down structure design and increase separations to reduce bird strikes and animal interference.

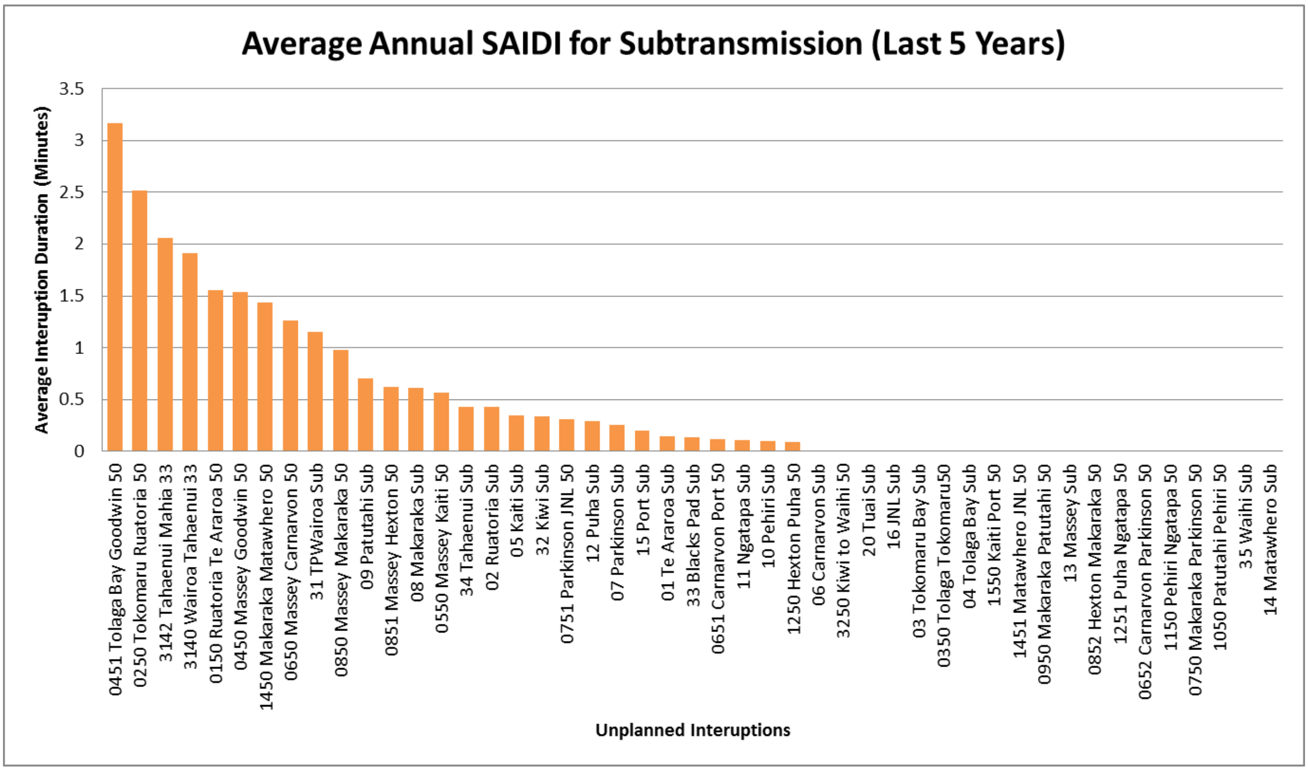
Defective equipment averages 22%. Faults in this category tend to have long repair times/high customer minutes. Causes are generally condition related resulting from assets remaining in service after their optimum replacement date hence the result is reflecting the decision to allow the asset in rural areas to increase in age. There is also an increasing trend for newer equipment to fail prior to expectations largely due to reduced quality and workmanship at manufacture. Standardisation on proven product, rigid specification and quality control procedures has been introduced to address this issue.
Defective equipment events (particularly pole failures) have reduced significantly since completion of the major Compliance Management Project undertaken in 2001–2002. This captured many age-related condition issues and brought performance more into line with normal expectations.
Improvement of the ABS asset condition is being managed via long term replacement programs.
Conductor failure is expected to predominate. This is discussed in lifecycle replacement plans.

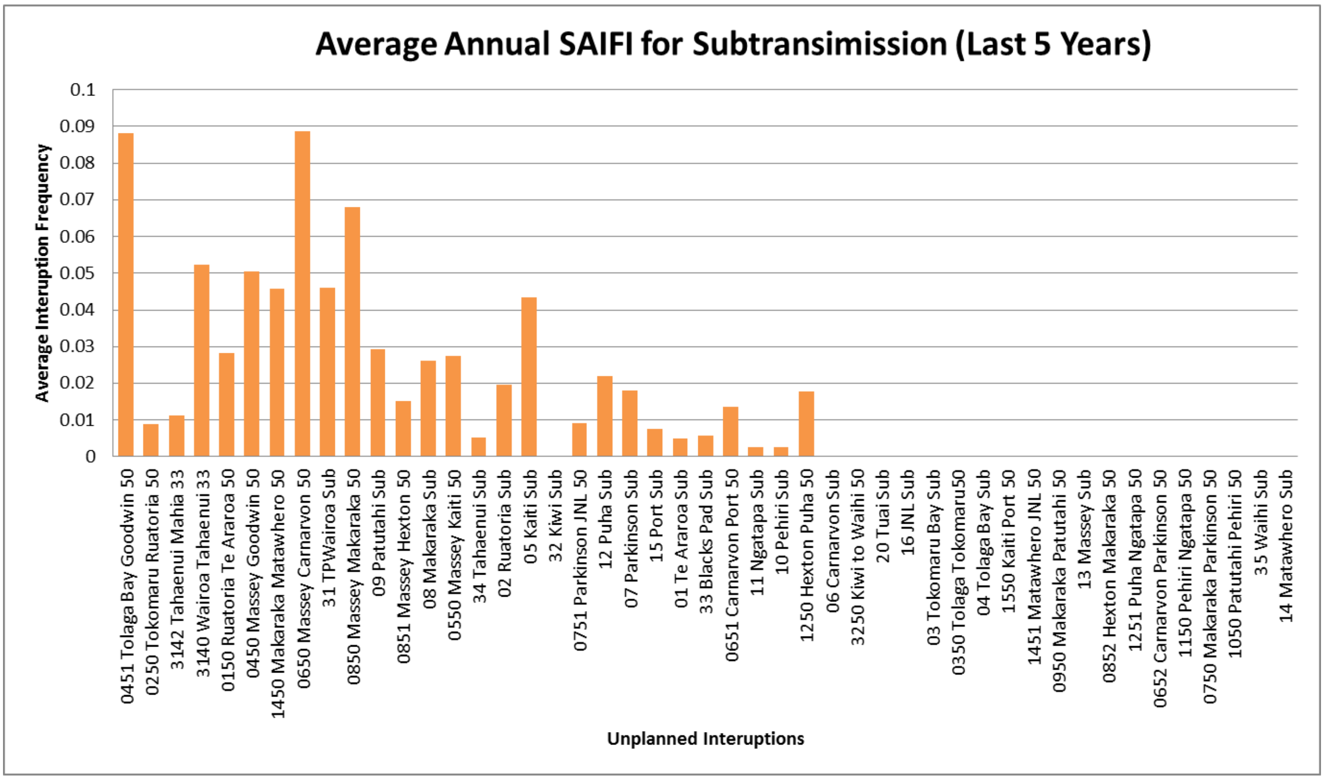
Tree contacts average of 18% p.a. The result is influenced by the type and nature of large storms. The figure includes minor tree contacts flying tree debris and falling trees typically outside of the cut zone. The tree regulations and rules governing access to private property have influenced the poor result. As the rules have been implemented the notification processes involved have provided a window in which the trees have encroached safe cut zones. Having grown within the safe cut zone, outages, which are also constrained to ensure regulatory targets are not breached, are now required to remove the trees. The approved resource trained to cut the trees safely is also limited. Over time ENL's expects to reduce the tree problems as much as practicable, within the requirements of the regulations, which are generally confined to inaccessible rural and remote areas, on privately owned sections of line or forestry blocks. Although the tree regulations provide for cost recovery from tree owners ENL's experience is that faults are likely to occur well before owners can act once the trees have reached the notice zone. Expenditure forecasts for tree control have been increased to compensate.

The Human element figure averaging 1% reflects the quality of safety standards and work practices in place to minimise contractor error.

8.2.3 Subtransmission Performance

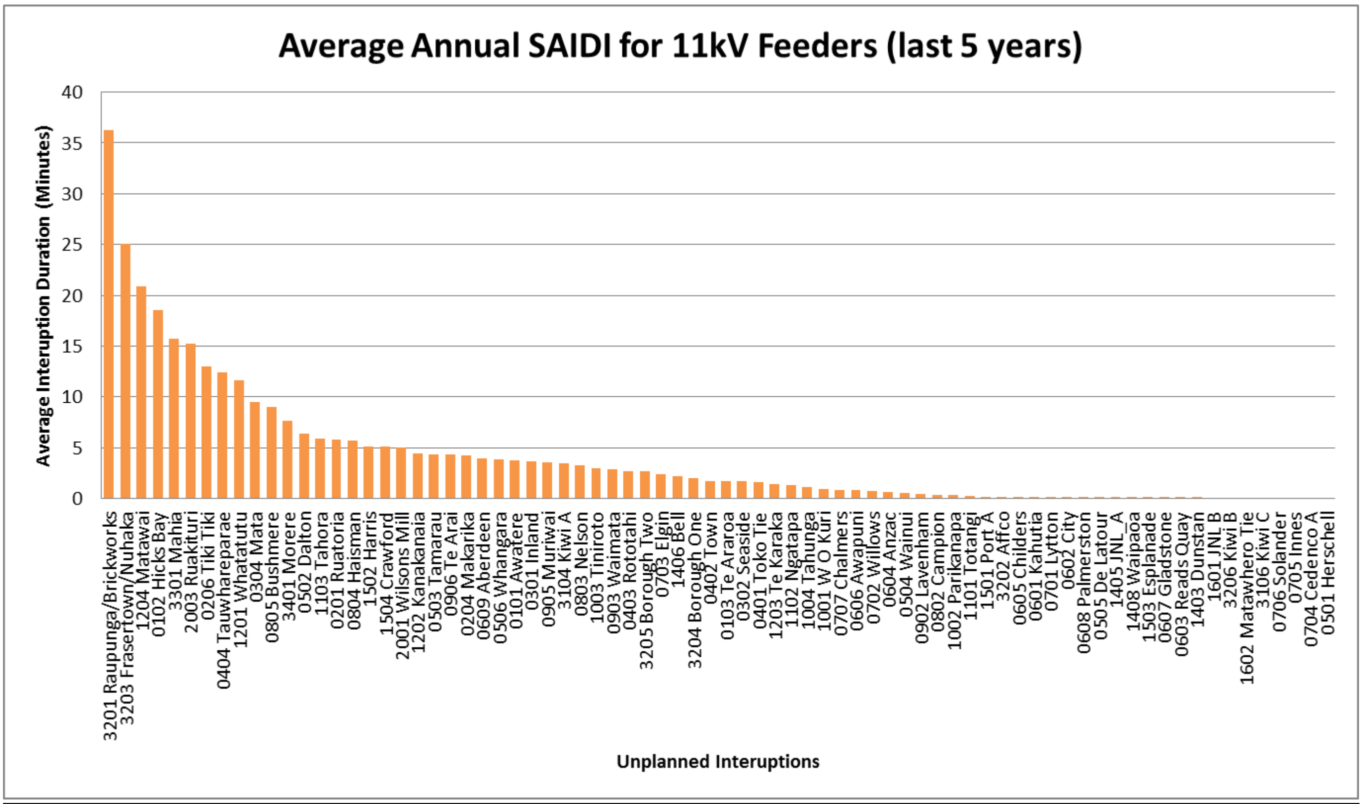
The performance of Subtransmission feeders is summarised in the following charts showing an average annual performance over the past 7 years. The Gisborne Substation to Goodwin 50kV line appears as the worst performing section of line. As the line is a spur line use of distributed generation is the only method of support. The development work on the 50kV rings described in previous plans has been completed following these events hence performance of urban feeders is improving. The Tolaga Bay Goodwin 50kV line has also had significant pole renewal between 2007 and 2008; hence the line is expected to show improved performance in future.

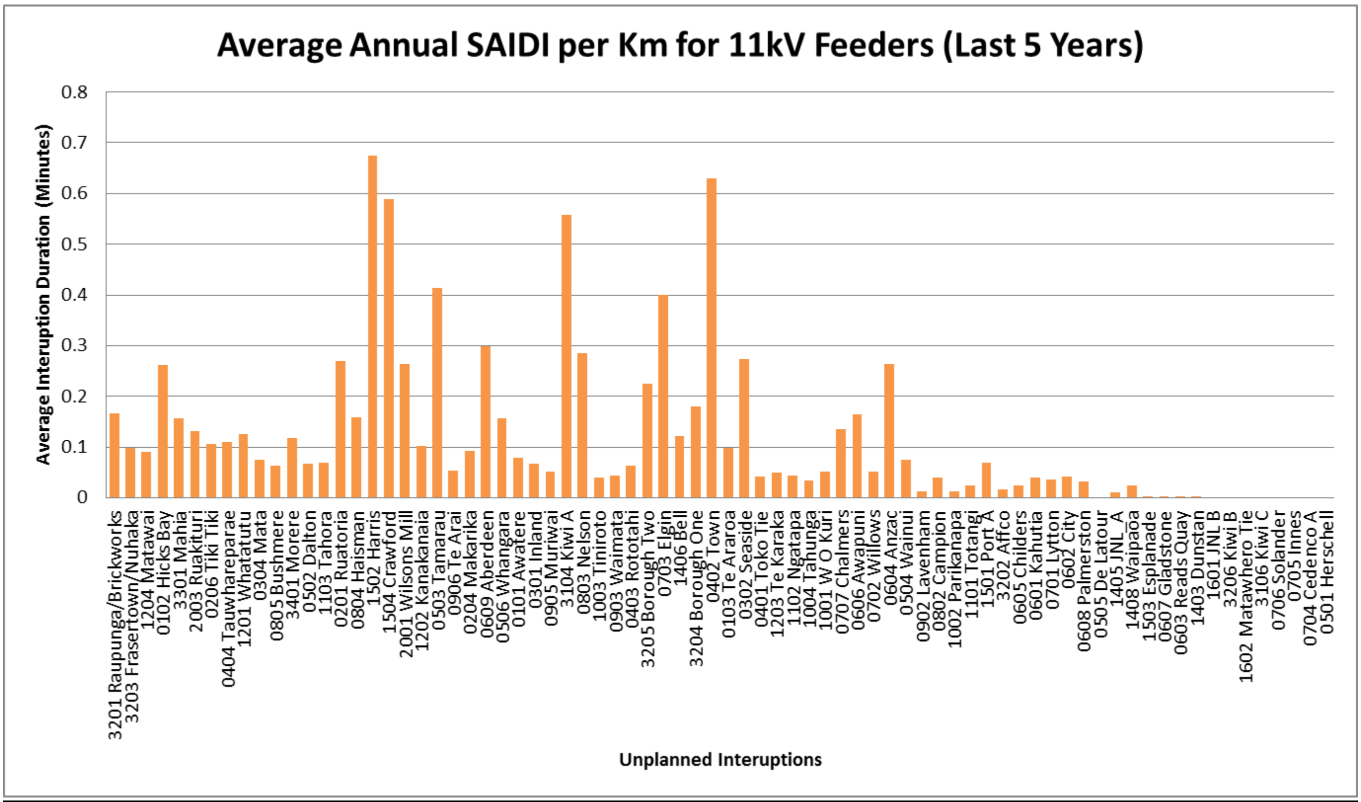

Average Annual SAIDI for Subtransmission (Last 5 Years)
Average Interuption Duration (Minutes)
3.5
3
2.5
2
1.5
1
0.5
0
0451 Tolaga Bay Goodwin 50
0250 Tokomaru Ruatoria 50
3142 Tahaenui Mahia 33
3140 Wairoa Tahaenui 33
0150 Ruatoria Te Araroa 50
0450 Massey Goodwin 50
1450 Makaraka Matawhero 50
0650 Massey Carnarvon 50
31 TPWairoa Sub
0850 Massey Makaraka 50
09 Patutahi Sub
0851 Massey Hexton 50
08 Makaraka Sub
0550 Massey Kaiti 50
34 Tahaenui Sub
02 Ruatoria Sub
05 Kaiti Sub
32 Kiwi Sub
0751 Parkinson JNL 50
12 Puha Sub
07 Parkinson Sub
15 Port Sub
01 Te Araroa Sub
33 Blacks Pad Sub
0651 Carnarvon Port 50
11 Ngatapa Sub
10 Pehiri Sub
1250 Hexton Puha 50
06 Carnarvon Sub
3250 Kiwi to Waihi 50
20 Tuai Sub
16 JNL Sub
03 Tokomaru Bay Sub
0350 Tolaga Tokomaru50
04 Tolaga Bay Sub
1550 Kaiti Port 50
1451 Matawhero JNL 50
0950 Makaraka Patutahi 50
13 Massey Sub
0852 Hexton Makaraka 50
1251 Puha Ngatapa 50
0652 Carnarvon Parkinson 50
1150 Pehiri Ngatapa 50
0750 Makaraka Parkinson 50
1050 Patutahi Pehiri 50
35 Waihi Sub
14 Matawhero Sub
Unplanned Interuptions

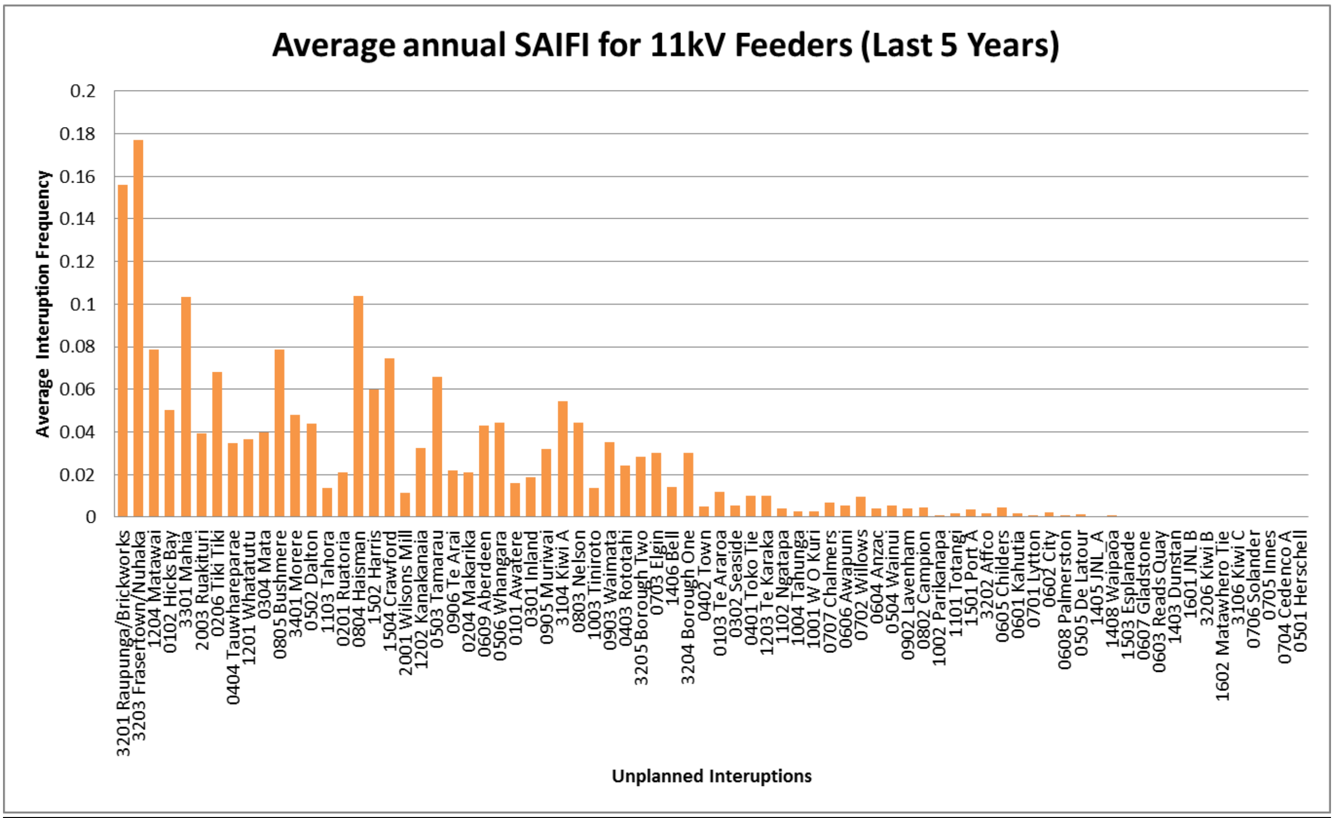

Average Annual SAIFI for Subtransimission (Last 5 Years)
Average Interuption Frequency
0.1
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0
0451 Tolaga Bay Goodwin 50
0250 Tokomaru Ruatoria 50
3142 Tahaenui Mahia 33
3140 Wairoa Tahaenui 33
0150 Ruatoria Te Araroa 50
0450 Massey Goodwin 50
1450 Makaraka Matawhero 50
0650 Massey Carnarvon 50
31 TPWairoa Sub
0850 Massey Makaraka 50
09 Patutahi Sub
0851 Massey Hexton 50
08 Makaraka Sub
0550 Massey Kaiti 50
34 Tahaenui Sub
02 Ruatoria Sub
05 Kaiti Sub
32 Kiwi Sub
0751 Parkinson JNL 50
12 Puha Sub
07 Parkinson Sub
15 Port Sub
01 Te Araroa Sub
33 Blacks Pad Sub
0651 Carnarvon Port 50
11 Ngatapa Sub
10 Pehiri Sub
1250 Hexton Puha 50
06 Carnarvon Sub
3250 Kiwi to Waihi 50
20 Tuai Sub
16 JNL Sub
03 Tokomaru Bay Sub
0350 Tolaga Tokomaru50
04 Tolaga Bay Sub
1550 Kaiti Port 50
1451 Matawhero JNL 50
0950 Makaraka Patutahi 50
13 Massey Sub
0852 Hexton Makaraka 50
1251 Puha Ngatapa 50
0652 Carnarvon Parkinson 50
1150 Pehiri Ngatapa 50
0750 Makaraka Parkinson 50
1050 Patutahi Pehiri 50
35 Waihi Sub
14 Matawhero Sub
Unplanned Interuptions

8.2.4 Distribution Performance

The performance of distribution feeders is summarised in the following charts showing an average annual performance over the past 5 years. Based on location, terrain and feeder length comparisons the results indicate a performance in line with expectations. Improvements associated with Matawai and The Wairoa feeders (3201, 3203 and Mahia) have been addressed by projects identified in the development section of this plan.




Average Annual SAIDI per Km for 11kV Feeders (Last 5 Years)
Average Interuption Duration (Minutes)
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
3201 Raupunga/Brickworks
3203 Frasertown/Nuhaka
1204 Matawai
0102 Hicks Bay
3301 Mahia
2003 Ruakituri
0206 Tiki Tiki
0404 Tauwhareparae
1201 Whatatutu
0304 Mata
0805 Bushmere
3401 Morere
0502 Dalton
1103 Tahora
0201 Ruatoria
0804 Haisman
1502 Harris
1504 Crawford
2001 Wilsons Mill
1202 Kanakanaia
0503 Tamarau
0906 Te Arai
0204 Makarika
0609 Aberdeen
0506 Whangara
0101 Awatere
0301 Inland
0905 Muriwai
3104 Kiwi A
0803 Nelson
1003 Tiniroto
0903 Waimata
0403 Rototahi
3205 Borough Two
0703 Elgin
1406 Bell
3204 Borough One
0402 Town
0103 Te Araroa
0302 Seaside
0401 Toko Tie
1203 Te Karaka
1102 Ngatapa
1004 Tahunga
1001 W O Kuri
0707 Chalmers
0606 Awapuni
0702 Willows
0604 Anzac
0504 Wainui
0902 Lavenham
0802 Campion
1002 Parikanapa
1101 Totangi
1501 Port A
3202 Affco
0605 Childers
0601 Kahutia
0701 Lytton
0602 City
0608 Palmerston
0505 De Latour
1405 JNL_A
1408 Waipaoa
1503 Esplanade
0607 Gladstone
0603 Reads Quay
1403 Dunstan
1601 JNL B
3206 Kiwi B
1602 Matawhero Tie
3106 Kiwi C
0706 Solander
0705 Innes
0704 Cedenco A
0501 Herschell
Unplanned Interuptions

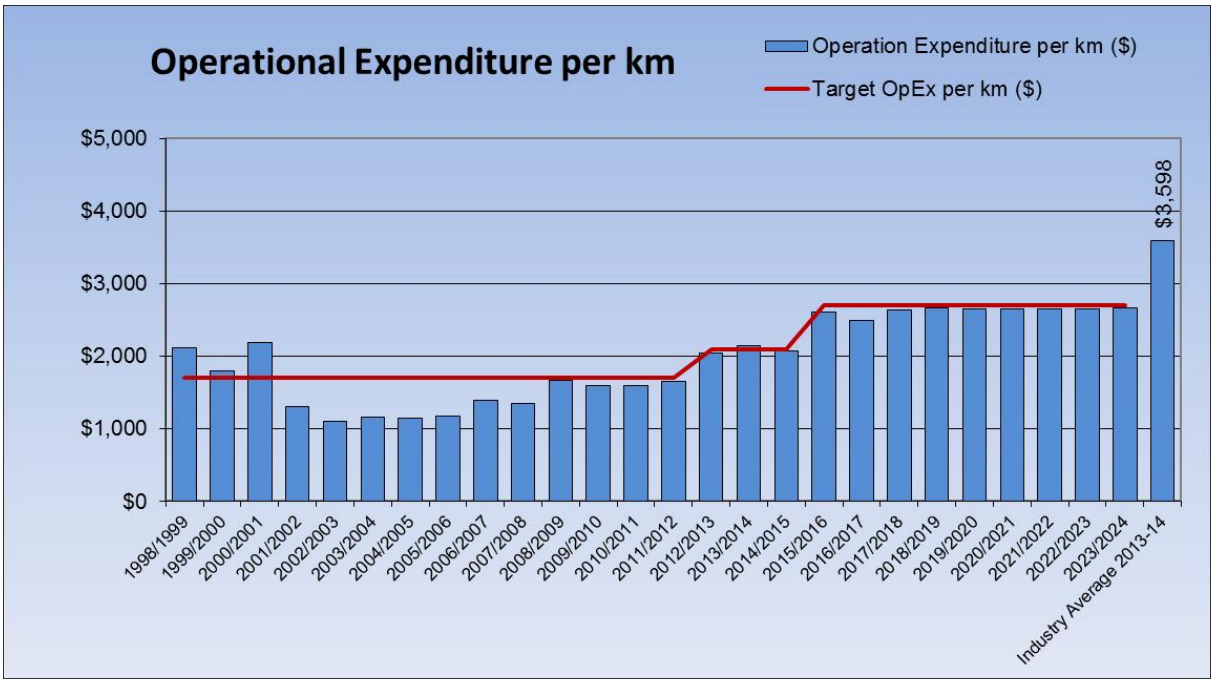

Average annual SAIFI for 11kV Feeders (Last 5 Years)
Average Interuption Frequency
0.2
0.18
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
3201 Raupunga/Brickworks
3203 Frasertown/Nuhaka
1204 Matawai
0102 Hicks Bay
3301 Mahia
2003 Ruakituri
0206 Tiki Tiki
0404 Tauwhareparae
1201 Whatatutu
0304 Mata
0805 Bushmere
3401 Morere
0502 Dalton
1103 Tahora
0201 Ruatoria
0804 Haisman
1502 Harris
1504 Crawford
2001 Wilsons Mill
1202 Kanakanaia
0503 Tamarau
0906 Te Arai
0204 Makarika
0609 Aberdeen
0506 Whangara
0101 Awatere
0301 Inland
0905 Muriwai
3104 Kiwi A
0803 Nelson
1003 Tiniroto
0903 Waimata
0403 Rototahi
3205 Borough Two
0703 Elgin
1406 Bell
3204 Borough One
0402 Town
0103 Te Araroa
0302 Seaside
0401 Toko Tie
1203 Te Karaka
1102 Ngatapa
1004 Tahunga
1001 W O Kuri
0707 Chalmers
0606 Awapuni
0702 Willows
0604 Anzac
0504 Wainui
0902 Lavenham
0802 Campion
1002 Parikanapa
1101 Totangi
1501 Port A
3202 Affco
0605 Childers
0601 Kahutia
0701 Lytton
0602 City
0608 Palmerston
0505 De Latour
1405 JNL_A
1408 Waipaoa
1503 Esplanade
0607 Gladstone
0603 Reads Quay
1403 Dunstan
1601 JNL B
3206 Kiwi B
1602 Matawhero Tie
3106 Kiwi C
0706 Solander
0705 Innes
0704 Cedenco A
0501 Herschell
Unplanned Interuptions

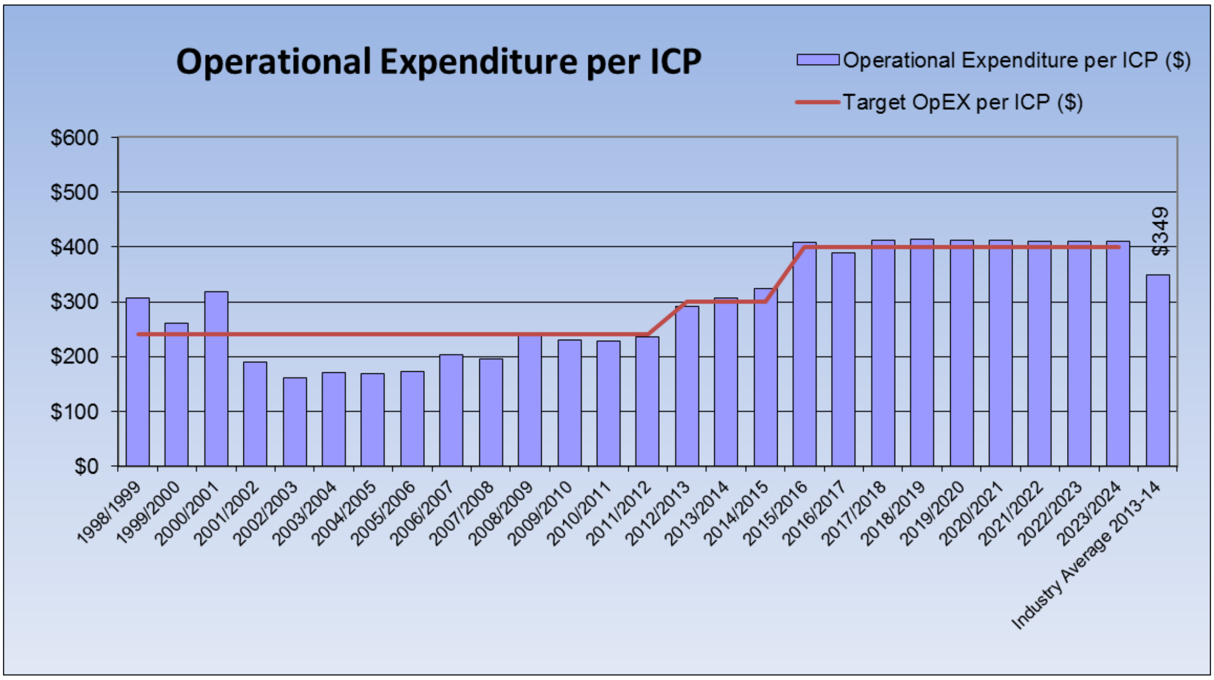
8.3 Meeting Delivery Efficiency targets

Cost performance measures that are disclosed each year include:

Operational Expenditure / km
Operational Expenditure / connection

The historical trends for ENL's efficiency targets compared with the industry position are as follows…





Changes to targets occur as a result of the analysis of the business results and changes to the business strategic plan. Operational expenditure directly corresponds to strategic changes in the structure of Eastland Group support services, increasing insurance costs, increasing rates, increasing regulatory compliance costs and the acquisition of additional assets such as Eastland transmission spur assets.

8.4 Asset Management Systems Review

ENL's quality management system incorporates procedures and processes for review and improvement of all areas of the asset management system. The management systems, processes and plans evolve on an on-going basis.

Targets, Budgets, Project programs, Issues and Forecasts presented in this AMP are typically updated on an annual basis in line with the strategic and business planning process outlined in section 1.2.3 as new or changed Strategies, Requirements, Issues, Developments, Information and Data is obtained.

Legislative compliance reviews are carried out internally on a 6 monthly basis and reported to the Board of Directors.
Executive and Board level assessments of the ENL Asset Management Plans indicate that the nature and level of content in the plan required under regulation exceeds the levels necessary for ENL to efficiently carry out its asset management activities.

Weekly asset management team meetings incorporate review and assessments of the ENL asset management system covering;

- Health and safety
- Public safety
- Systems development
- Design standards
- Quality control
- Resource planning

The balance of risk, efficiency, performance is optimised through this mechanism of team discussion.

An overall assessment of the AMP document, undertaken by the engineering management team indicates that while the description and layout of information may have room for improvement, the additional resource and expenditure to achieve a fully compliant plan is not justified as there would be an insignificant impact on the physical outcomes relating to the assets.

An internal review of ENL's asset management systems is undertaken on an annual basis against NZS7001:2008 which covers, Life cycle Risk, Design, Maintenance and Performance of the Network assets in terms of

Public safety management. Non-compliances and corrective actions are incorporated into the improvement initiatives and action plans as necessary.

An internal review consistent with the level of a gap analysis exercise is carried out on ENL's asset management system. This review is conducted on an annual basis. An AMMAT (Asset Management Maturity) assessment is completed in the form of a Questionnaire that has been prepared by the Commerce Commission to conform to extracts/components of the international PAS55 specification for asset management. To ensure the AMMAT is an effective assessment of the maturity of ENL's asset management capability and processes. The most recent completed questionnaire is attached as an Appendix to this AMP.

An external review of the asset management plan and the AMMAT report is undertaken by an independent Engineer. The review confirms alignment of the content of the AMP with the Electricity Information Disclosure Requirements for EDB Asset Management Plans. Non-compliances and corrective actions are incorporated into the AMP, improvement initiatives and action plans as necessary.

An external Telarc audit is undertaken to audit the aspects of Asset Management associated with Public Safety Management as required by the Electricity Safety Regulations. As there is a significant overlap between the legislative requirements relating to public safety management of the asset and the mandatory disclosure requirements for asset management determined by the Commerce Commission this audit identifies any gaps that exist in terms of ENL's overall asset management maturity level. Non-compliances and corrective actions are incorporated into improvement initiatives and action plans. On successful completion of each audit a registration certificate is issued by the auditor and forwarded to the Electricity Commission.

Reviews of the AMP are undertaken by consultants appointed by the Commerce Commission. Results of the review are published by the Commerce Commission. ENL carries out an assessment of the specific non compliances and incorporates any additional content or clarifications to subsequent versions of the plan.

8.5 Areas for Improvement

In general historical expenditure in any given period has been below the financial targets set. While deferral of costs is valid when forecast triggers do not occur at the time initially predicted, there is an on-going need to minimise the reaction time frame once the expenditure requirement has occurred. The ability to predict the timing for necessary renewal and growth expenditure can also be improved.

The customer oriented service levels currently established, rely on representation from government, significant customers and key groups. Refer section 3.1. The survey results to date have identified customers have issues but they are not asking for correction of these issues if the measures are linked to increased costs. Identification of methods to eliminate the issues without increasing costs disproportionately is necessary in order to improve the satisfaction of end users.

The installation profile of the overall asset and historical practices has provided a 'bow wave' effect where at some point the steady state approach for asset renewal adopted by ENL to manage expenditure in line with predictable revenues may not keep up with the asset deterioration. To ensure the correct assets are targeted for renewal at the right time the process for condition assessments and selection need to be optimised and regularly improved.

The uncertainty associated with correct and informed decision making for network development, linked to changing regulatory control, safety and environmental protection requirements requires a high level of understanding of industry direction going forward. Past systems used in a stable environment with a lower rate of change are no longer adequate and increased involvement in the industry policy making arena is becoming increasing necessary.

8.6 Improvement Implementation

ENL has identified the following contributors affecting the ability to improve in these areas…
Re-sourcing and maintaining the necessary skills and skill balance for internal staffing, external consulting and local contracting resources
Provision of sufficient and suitable resource to ensure accurate and timely information capture, used as inputs to the prediction and forecasting processes used for management of the assets.
Correct use of appropriate and efficient technologies including tools and equipment to optimise asset construction, condition assessment and maintenance costs.
The level of involvement within the local community and at the policy making level.

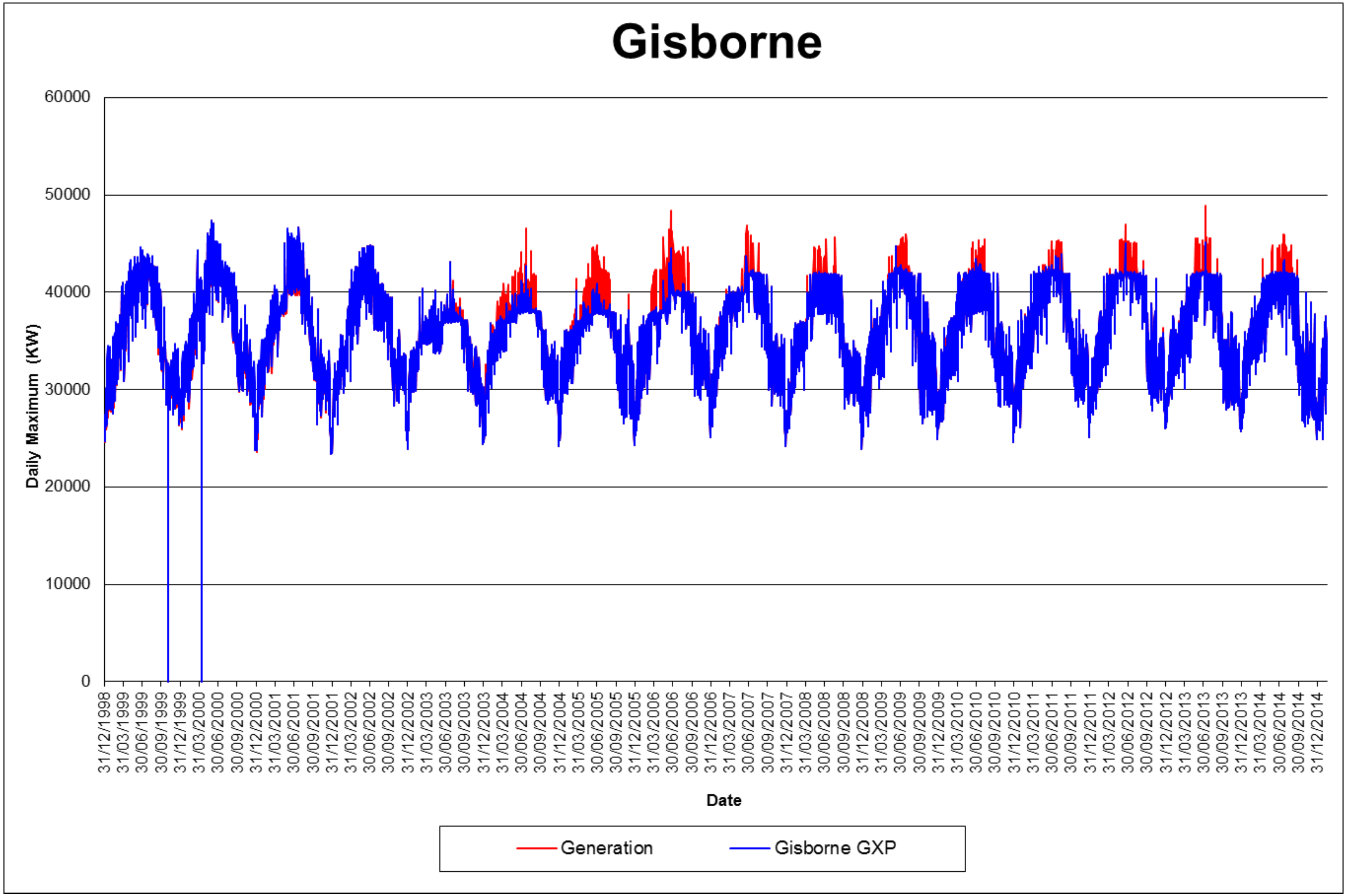
With a shortfall in available resources which is more significant in the local region ENL has identified a need to contribute to training and development of new resource from entry level to ensure improvement in the long term. ENL has a technology focus and is active in identification and development of equipment and systems designed to offset the short term re-sourcing short fall.

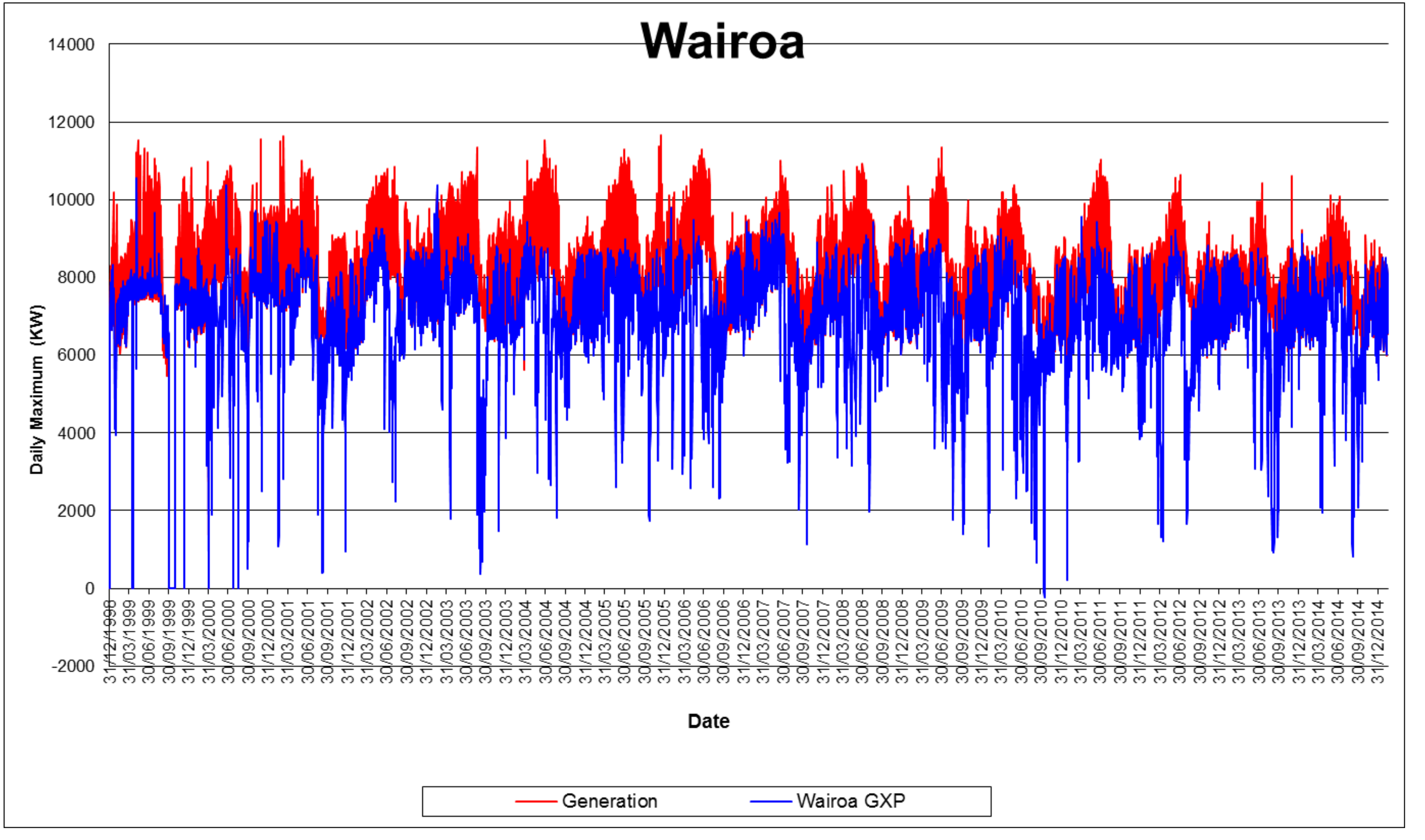
Membership, strategic partnership and alliances are being developed in the short to medium term to improve ENL's understanding and input into the direction of the industry.

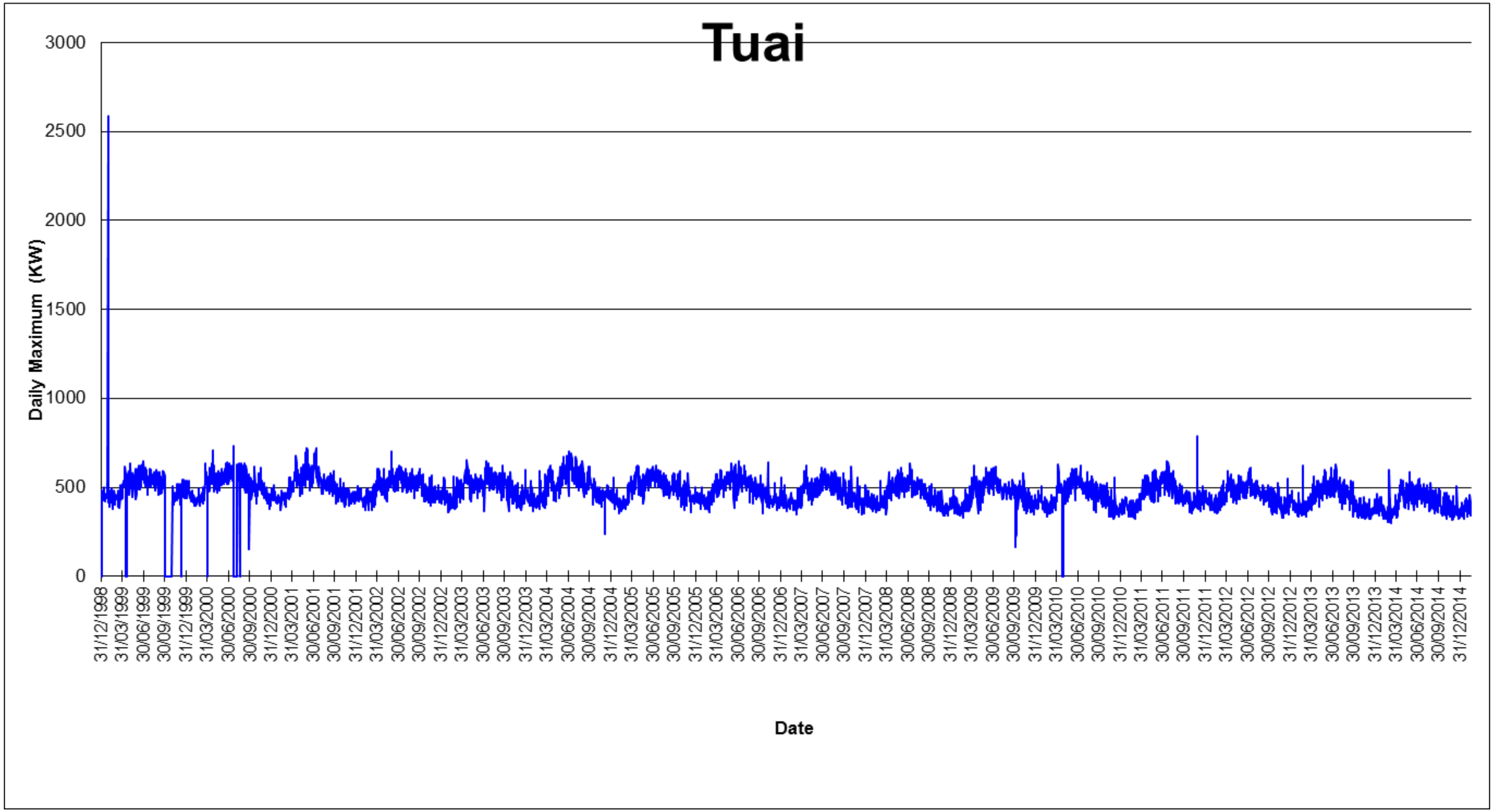
No improvement recommendations following review of the ANNMAT report in Appendix A8 were made.

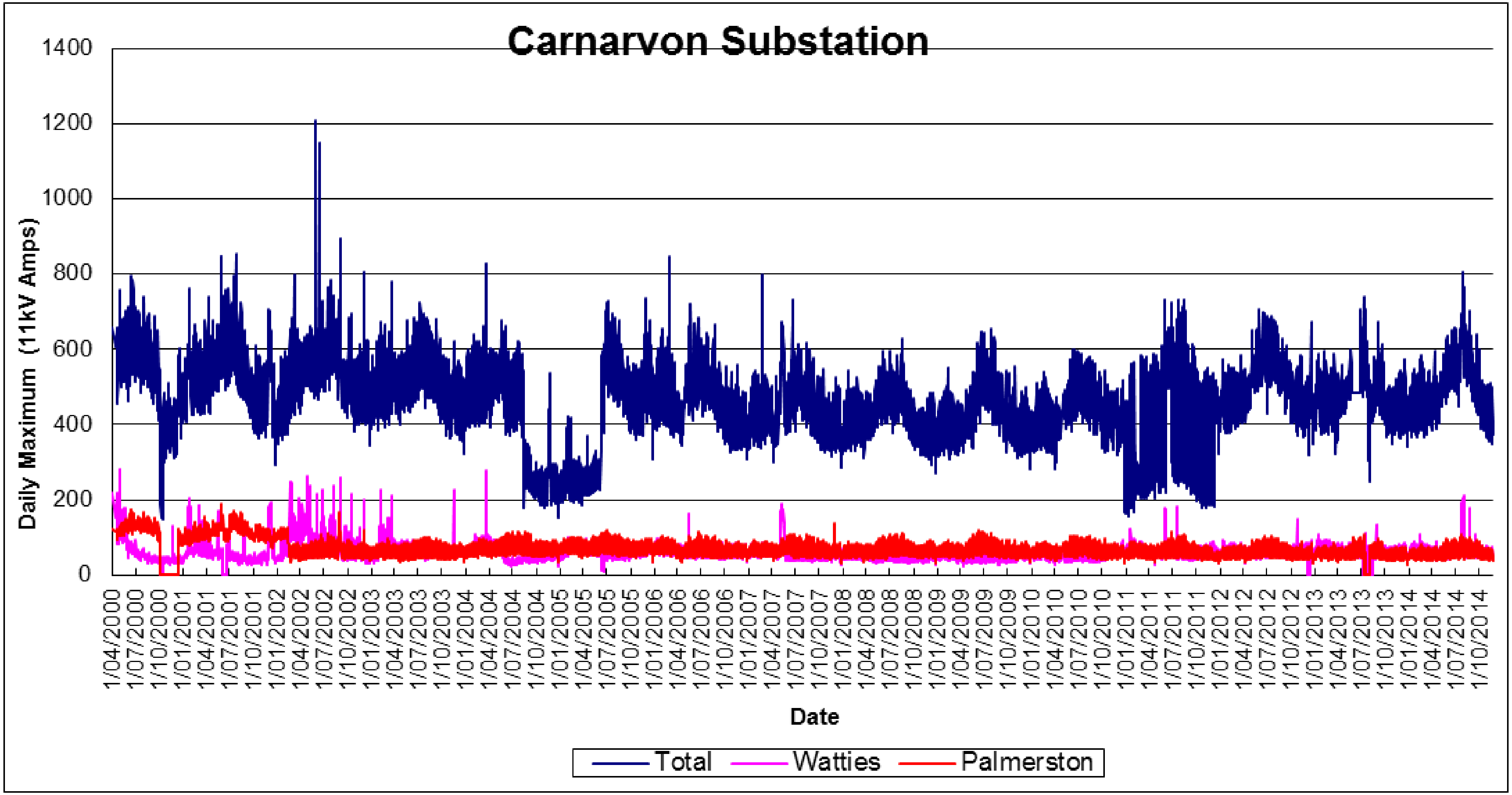
A1. Feeder loadings

Feeder loadings since 1 December 1998 are shown below. Note some zone substations require more than one chart.


Gisborne
Daily Maximum (KW)
60000
50000
40000
30000
20000
10000
0
Date
Generation
Gisborne GXP


Wairoa
14000
12000
10000
8000
6000
4000
2000
0
-2000
Daily Maximum (KW)
Date
Generation
Wairoa GXP


Tuai
Daily Maximum (KW)
3000
2500
2000
1500
1000
500
0
Date


Carnarvon Substation
Daily Maximum (11kV Amps)
1400
1200
1000
800
600
400
200
0
1/04/2000
1/07/2000
1/10/2000
1/01/2001
1/04/2001
1/07/2001
1/10/2001
1/01/2002
1/04/2002
1/07/2002
1/10/2002
1/01/2003
1/04/2003
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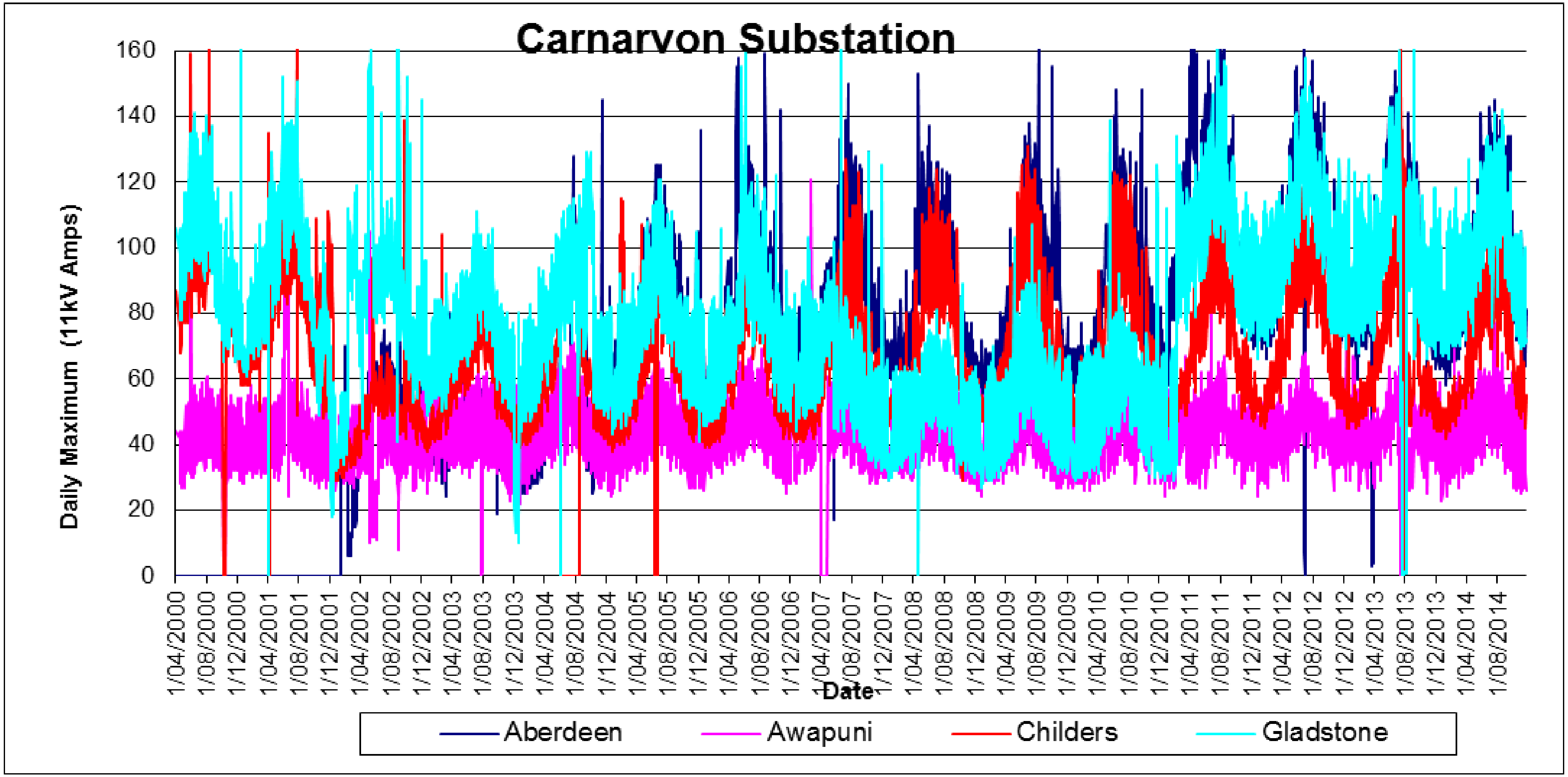
1/01/2011
1/04/2011
1/07/2011
1/10/2011
1/01/2012
1/04/2012
1/07/2012
1/10/2012
1/01/2013
1/04/2013
1/07/2013
1/10/2013
1/01/2014
1/04/2014
1/07/2014
1/10/2014
Date
Total
Watties
Palmerston


Carnarvon Substation
Daily Maximum (11kV Amps)
160
140
120
100
80
60
40
20
0
Date
1/04/2000
1/08/2000
1/12/2000
1/04/2001
1/08/2001
1/12/2001
1/04/2002
1/08/2002
1/12/2002
1/04/2003
1/08/2003
1/12/2003
1/04/2004
1/08/2004
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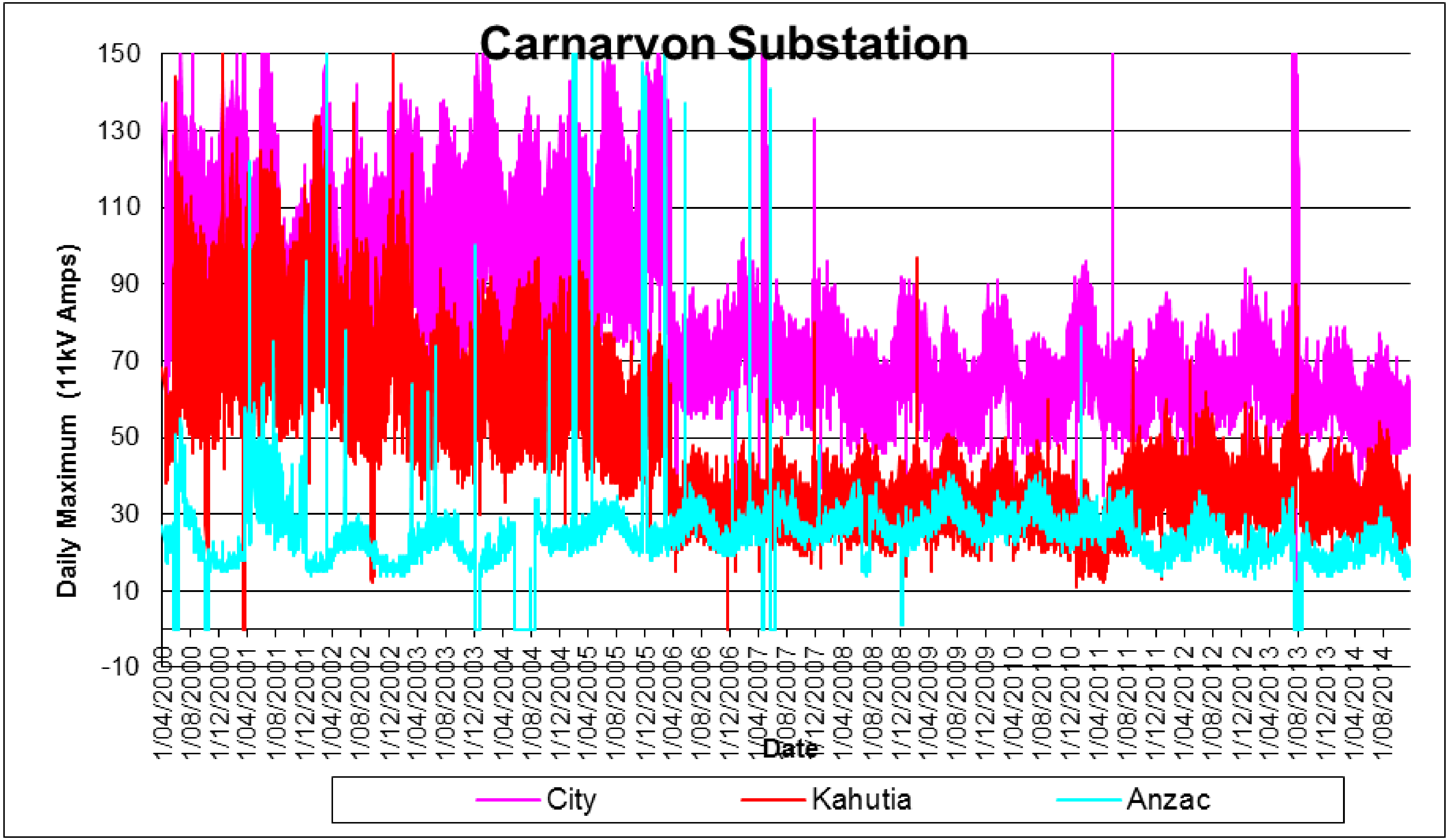
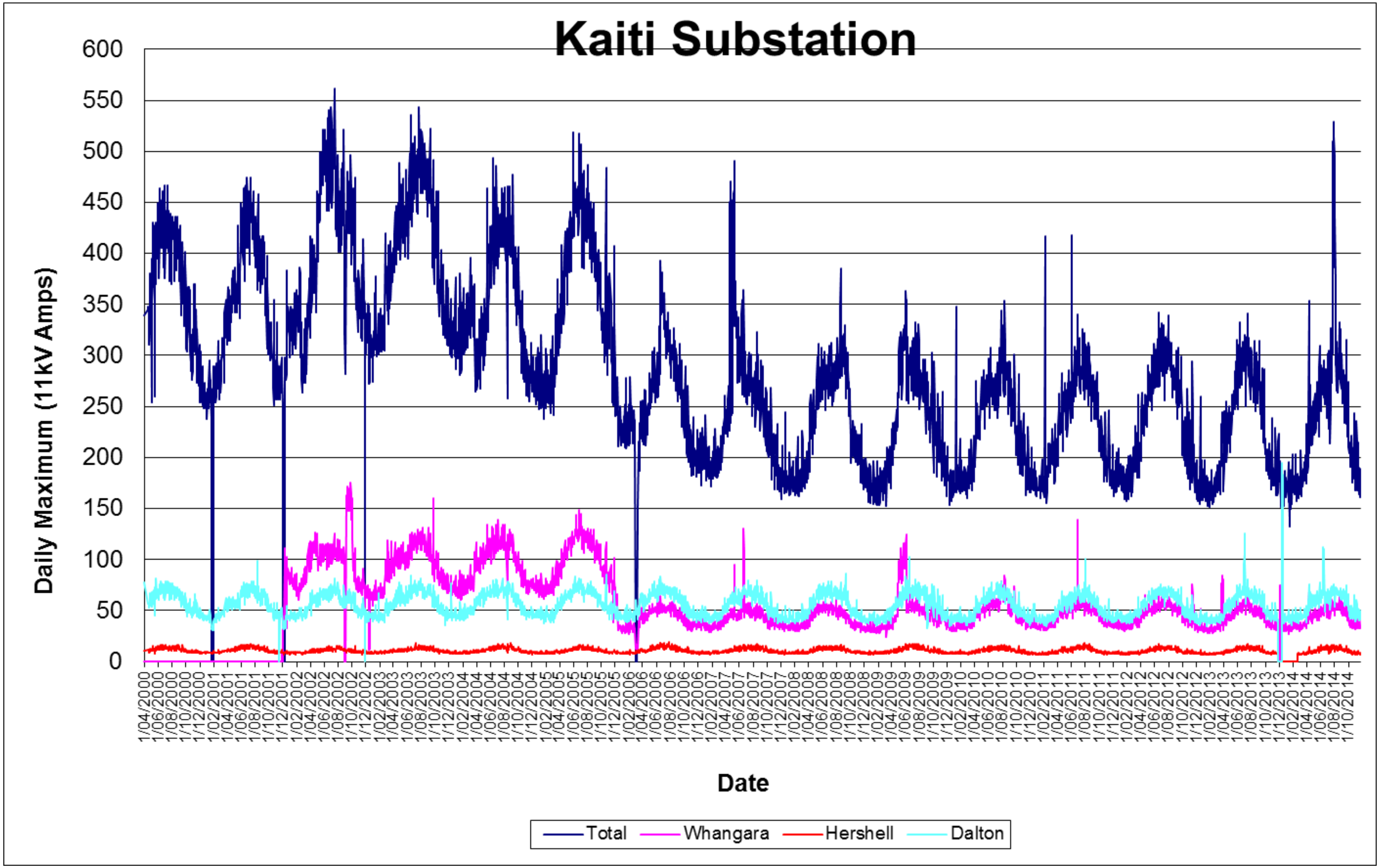
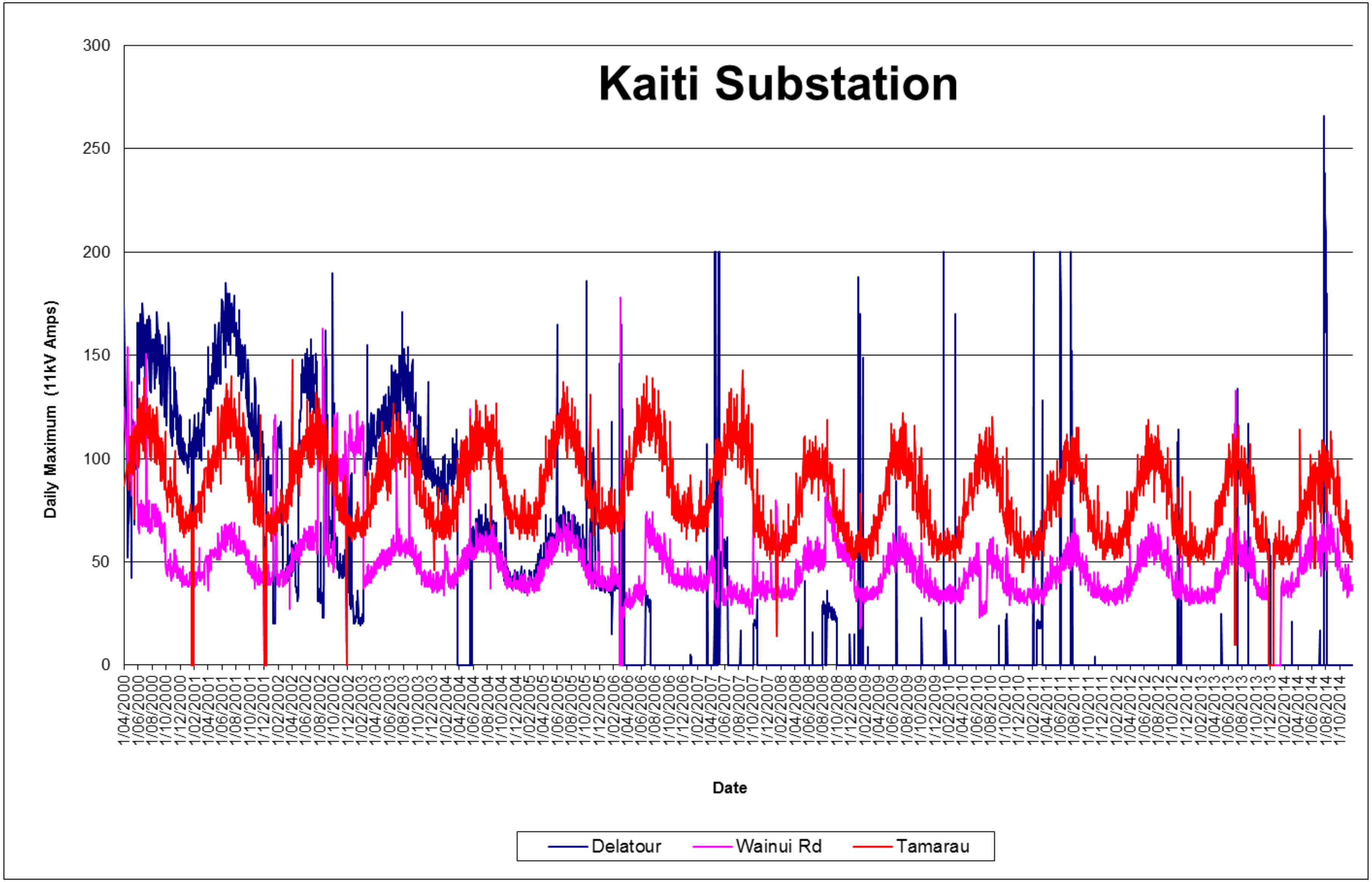
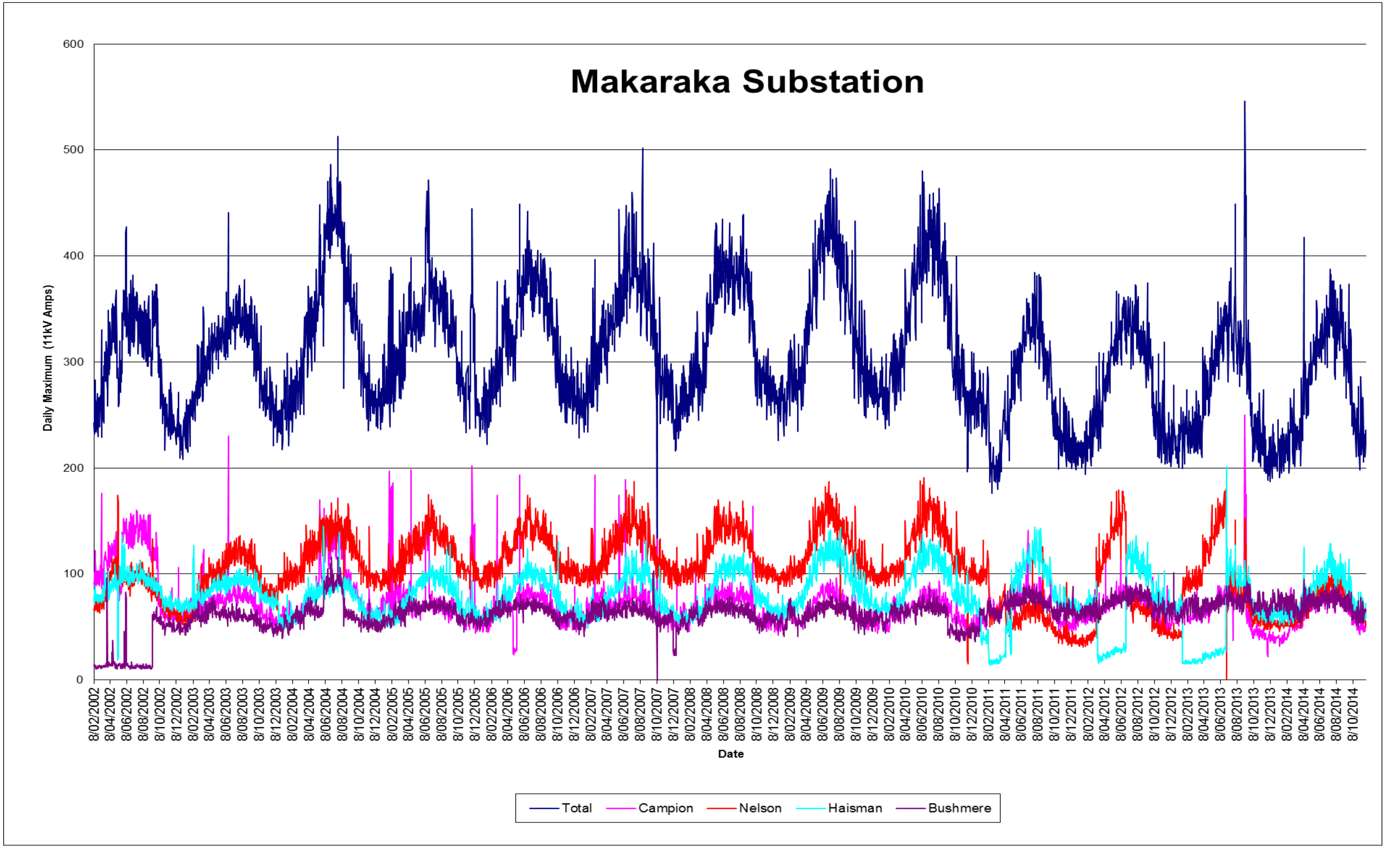
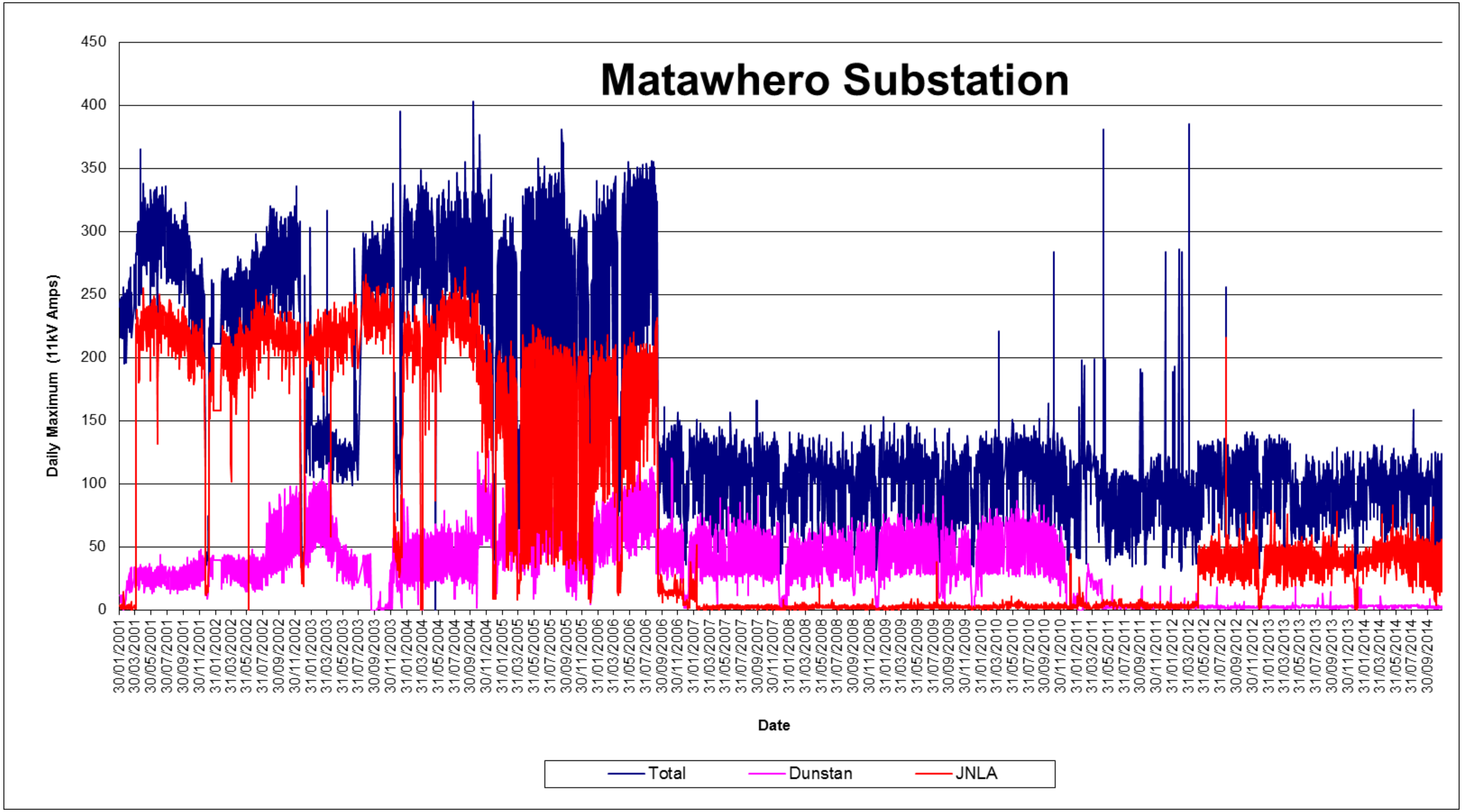
1/12/2009
1/04/2010
1/08/2010
1/12/2010
1/04/2011
1/08/2011
1/12/2011
1/04/2012
1/08/2012
1/12/2012
1/04/2013
1/08/2013
1/12/2013
1/04/2014
1/08/2014
Aberdeen
Awapuni
Childers
Gladstone

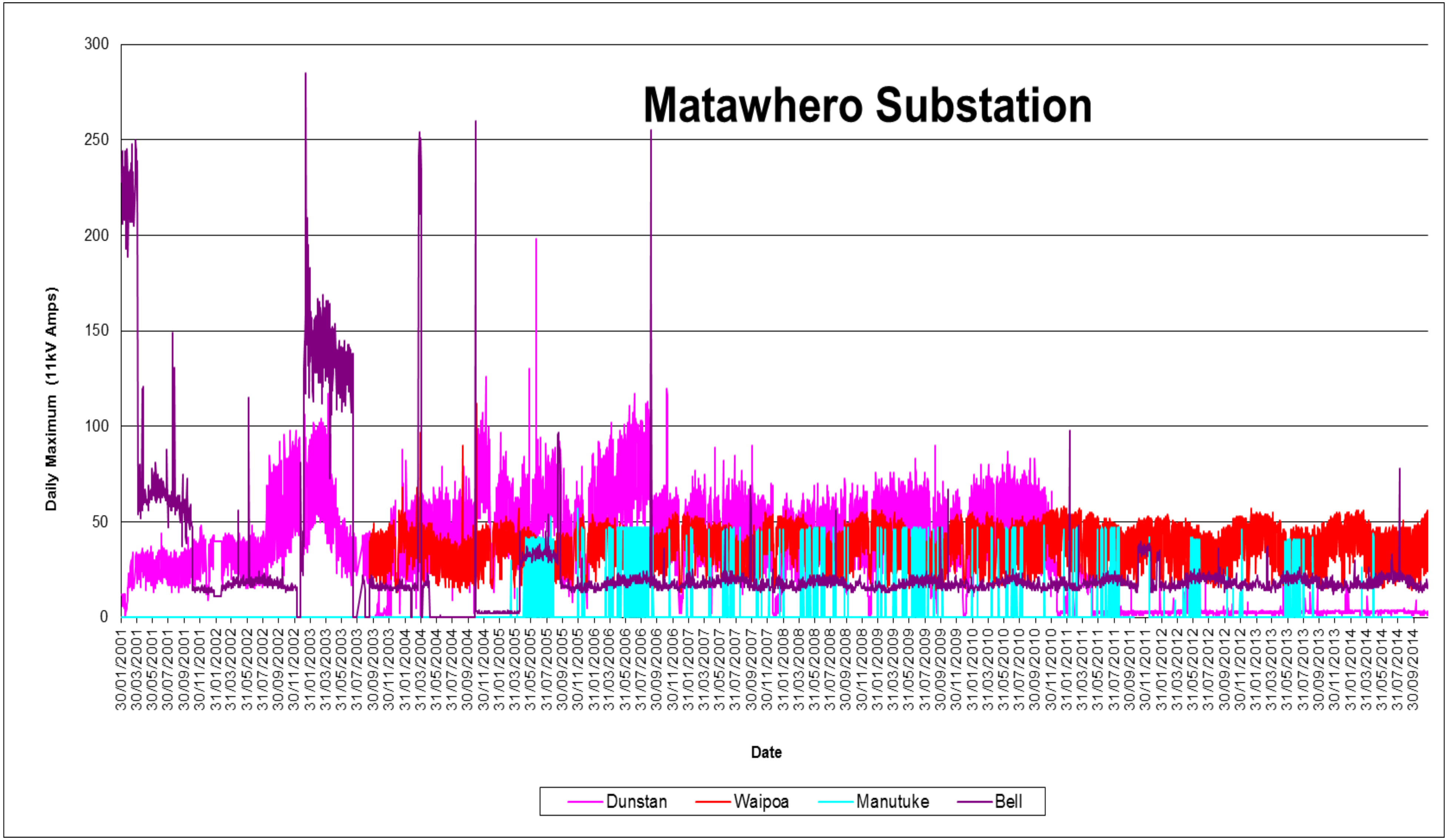

Carnarvon Substation
Daily Maximum (11kV Amps)
150
130
110
90
70
50
30
10
-10
Date
City
Kahutia
Anzac

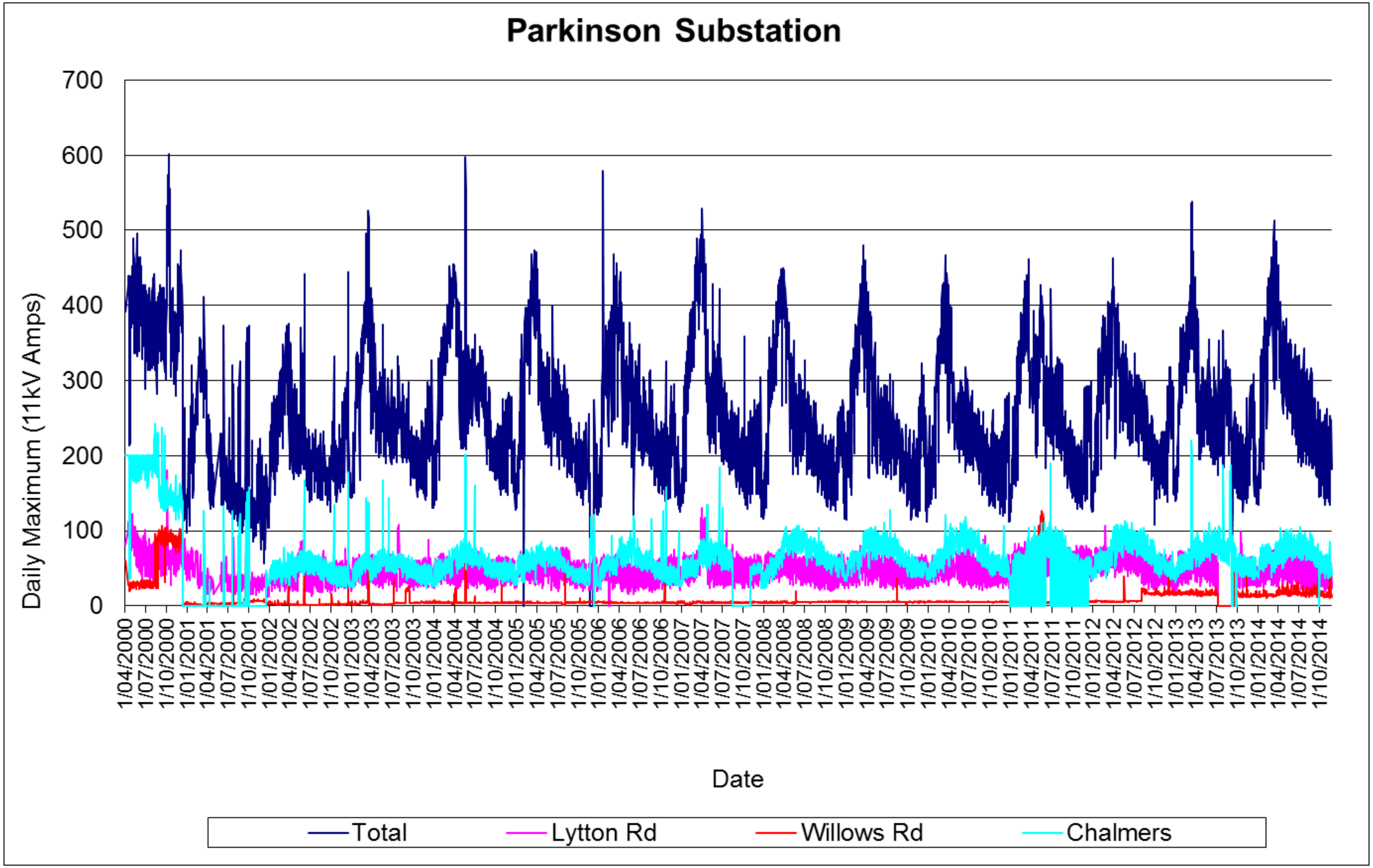

Kaiti Substation
Daily Maximum (11kV Amps)
Date
Total
Whangara
Hershell
Dalton

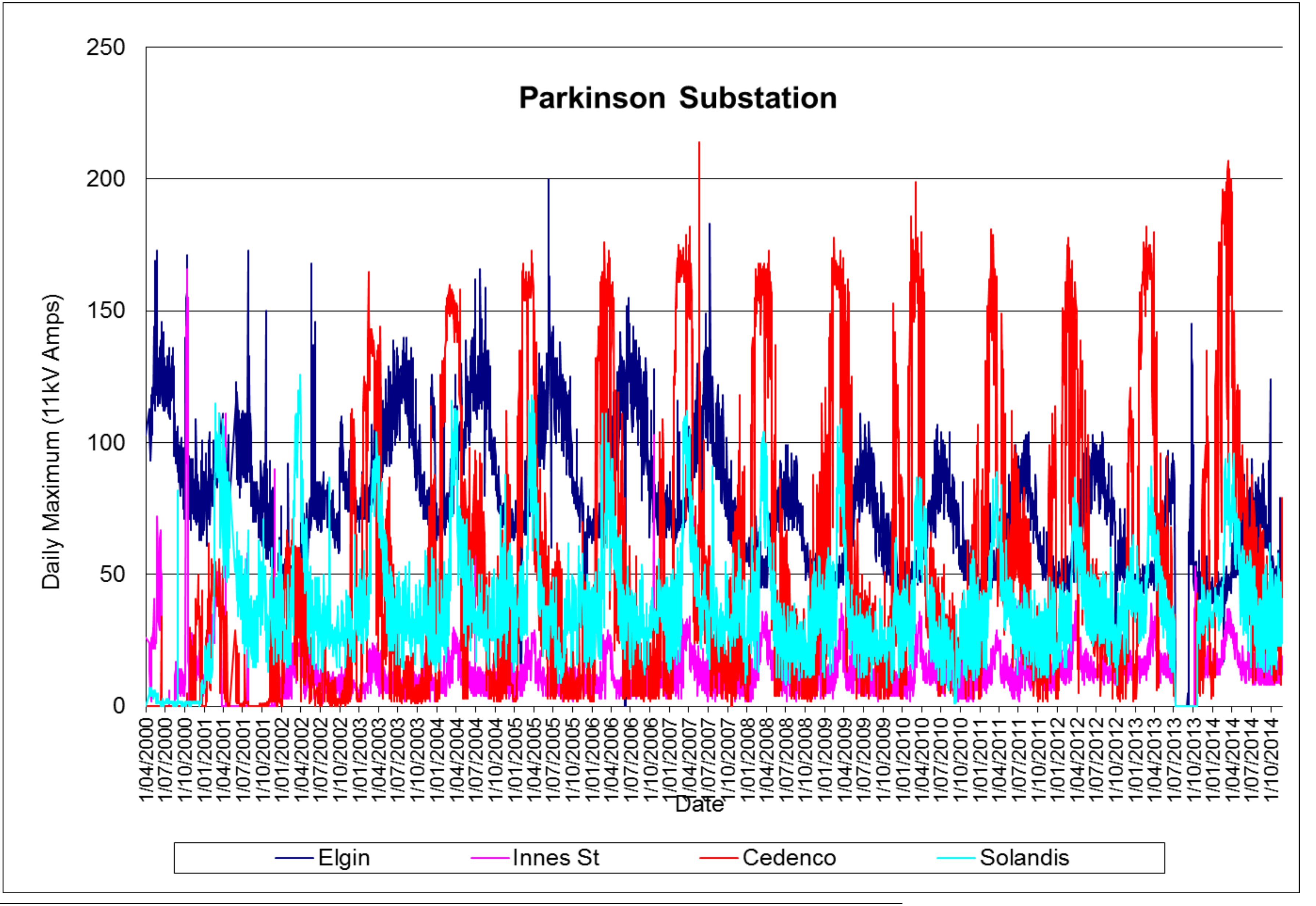

Kaiti Substation
Daily Maximum (11kV Amps)
300
250
200
150
100
50
0
Date
Delatour
Wainui Rd
Tamarau

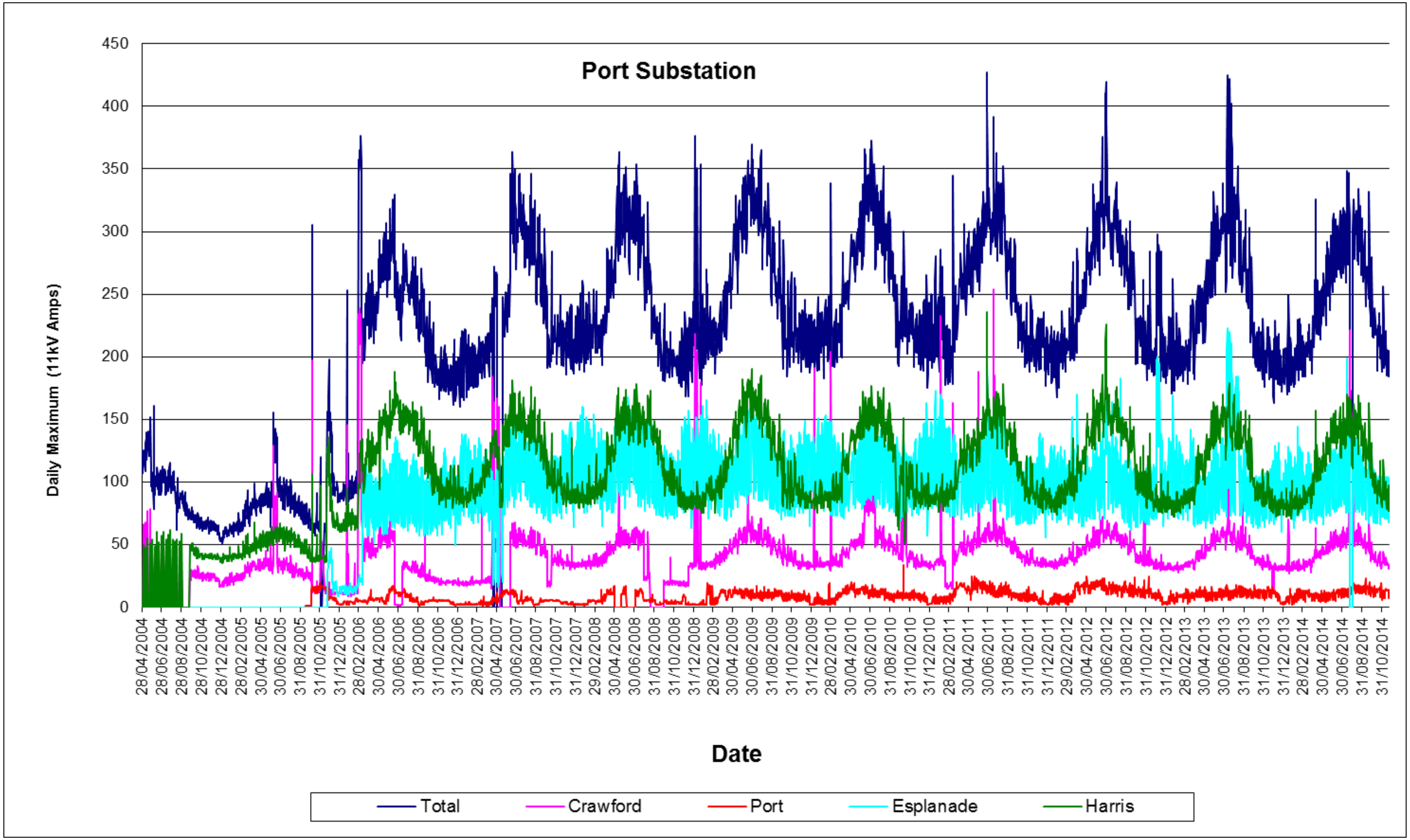

Makaraka Substation
Daily Maximum (11kV Amps)
600
500
400
300
200
100
0
Date
Total
Campion
Nelson
Haisman
Bushmere


Matawhero Substation
Daily Maximum (11kV Amps)
Date
Total
Dunstan
JNLA

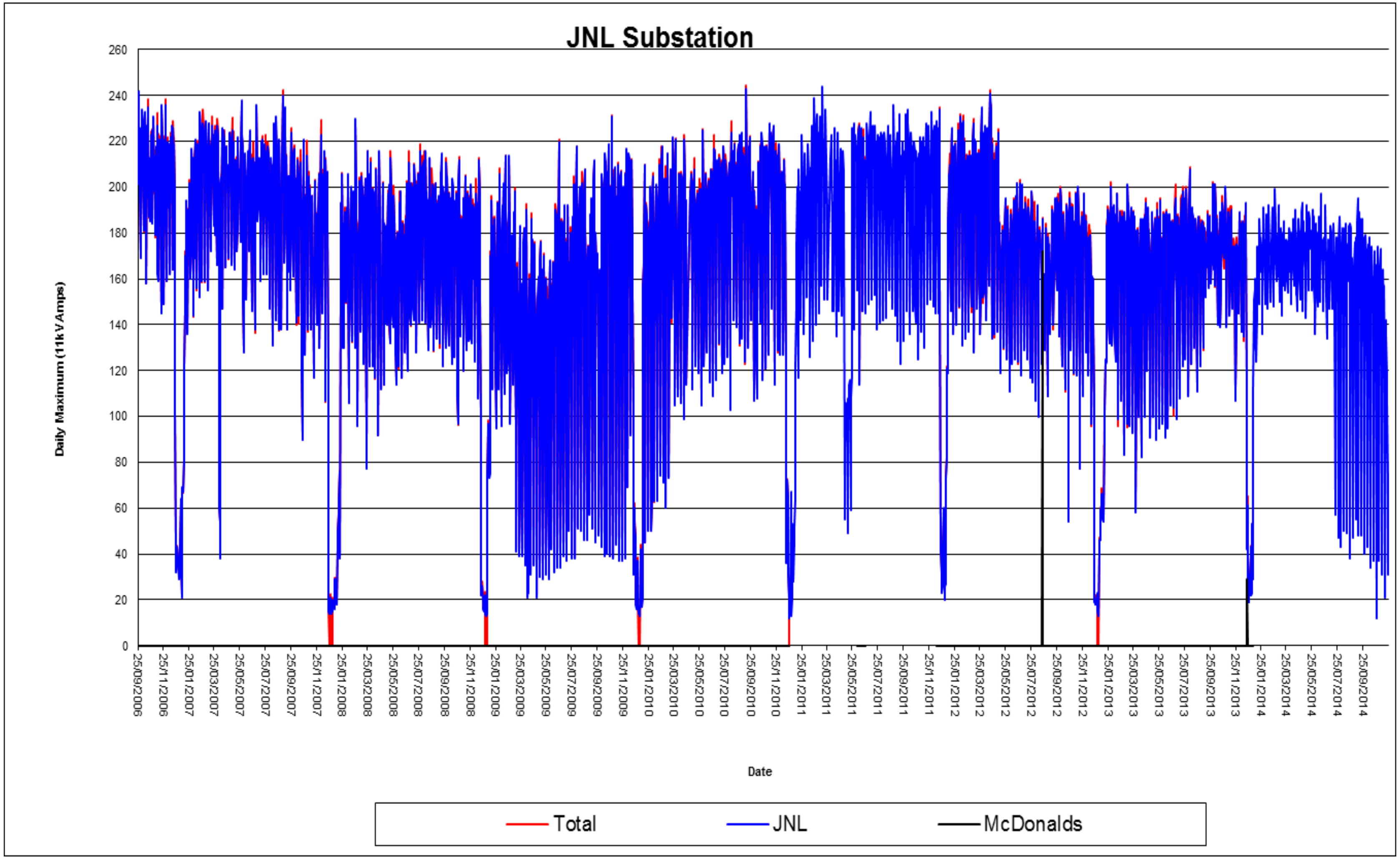

Matawhero Substation
Daily Maximum (11kV Amps)
300
250
200
150
100
50
0
Date
Dunstan
Waipoa
Manutuke
Bell


Parkinson Substation
Daily Maximum (11kV Amps)
Date
Total
Lytton Rd
Willows Rd
Chalmers


Parkinson Substation
Daily Maximum (11kV Amps)
250
200
150
100
50
0
Date
Elgin
Innes St
Cedenco
Solandis

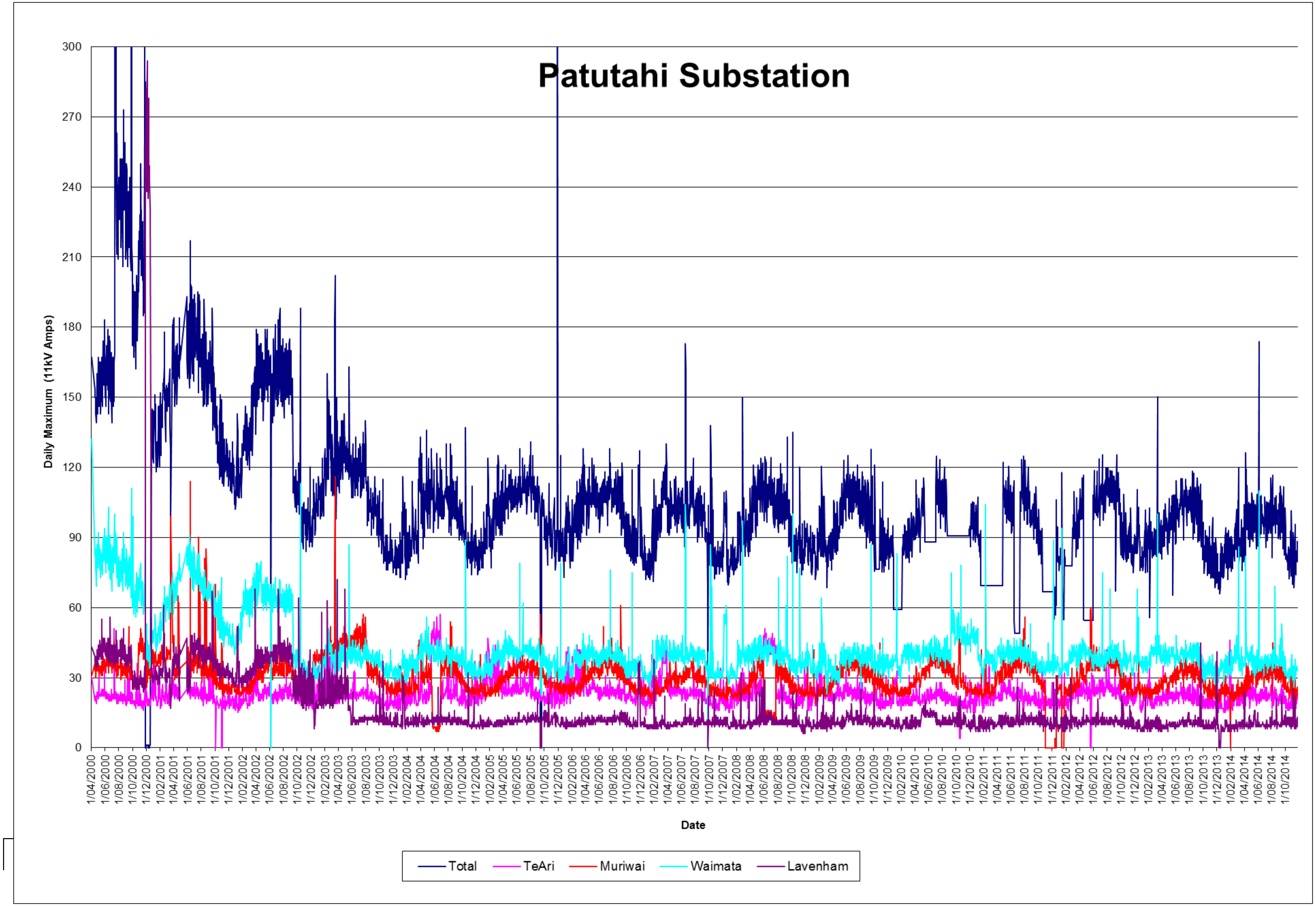


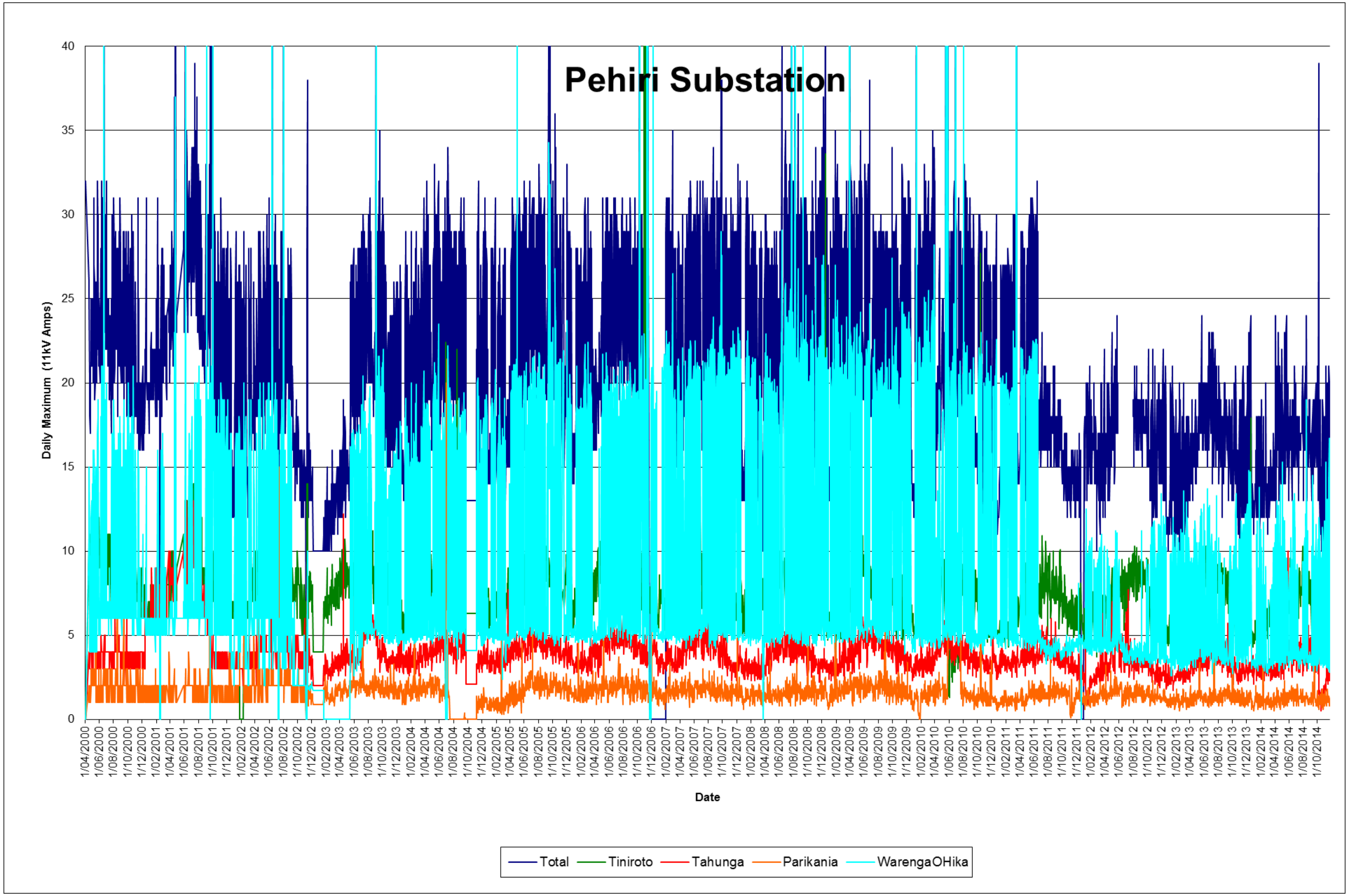
Port Substation
Daily Maximum (11kV Amps)
450
400
350
300
250
200
150
100
50
0
Date
Total
Crawford
Port
Esplanade
Harris

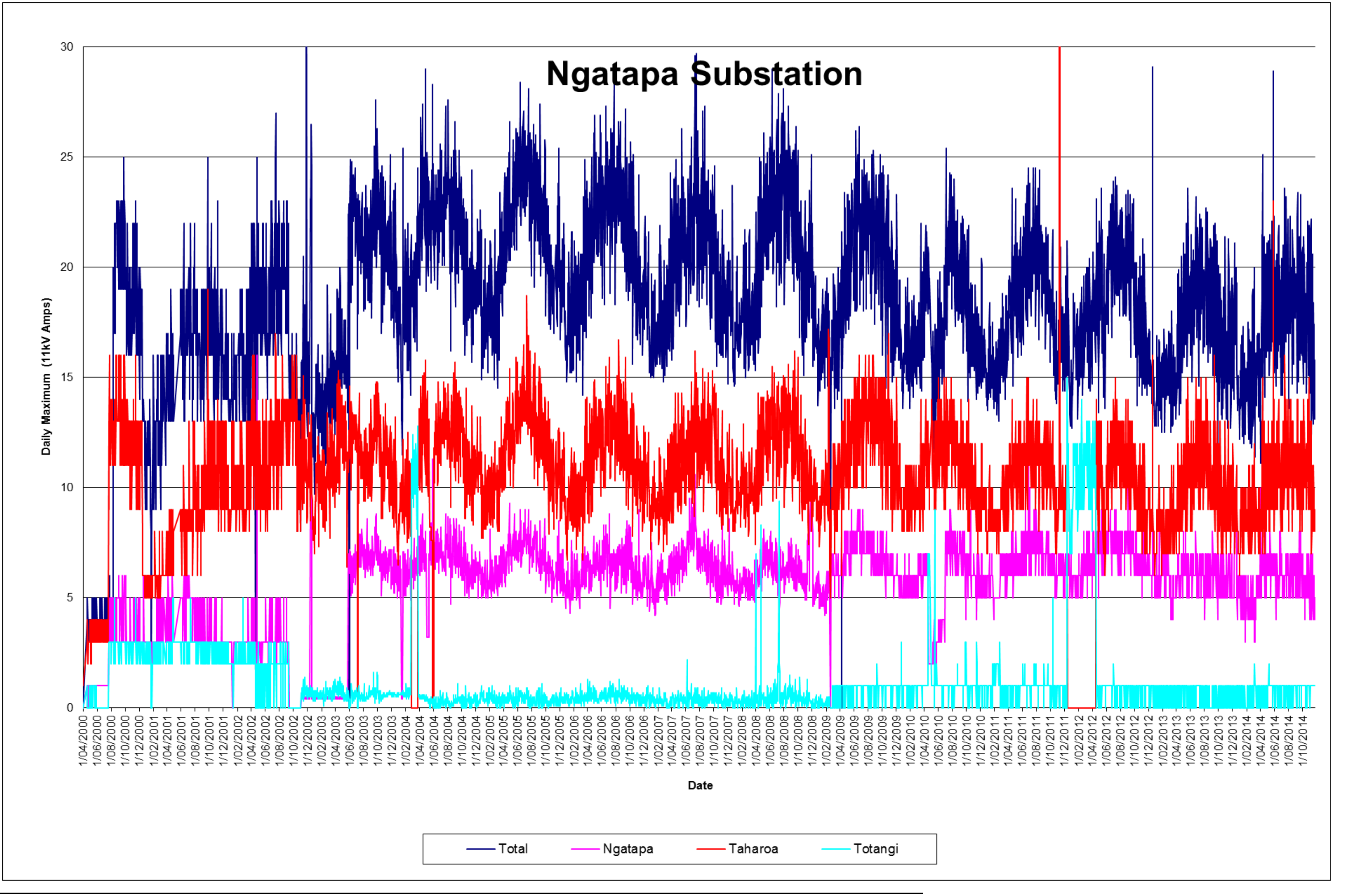


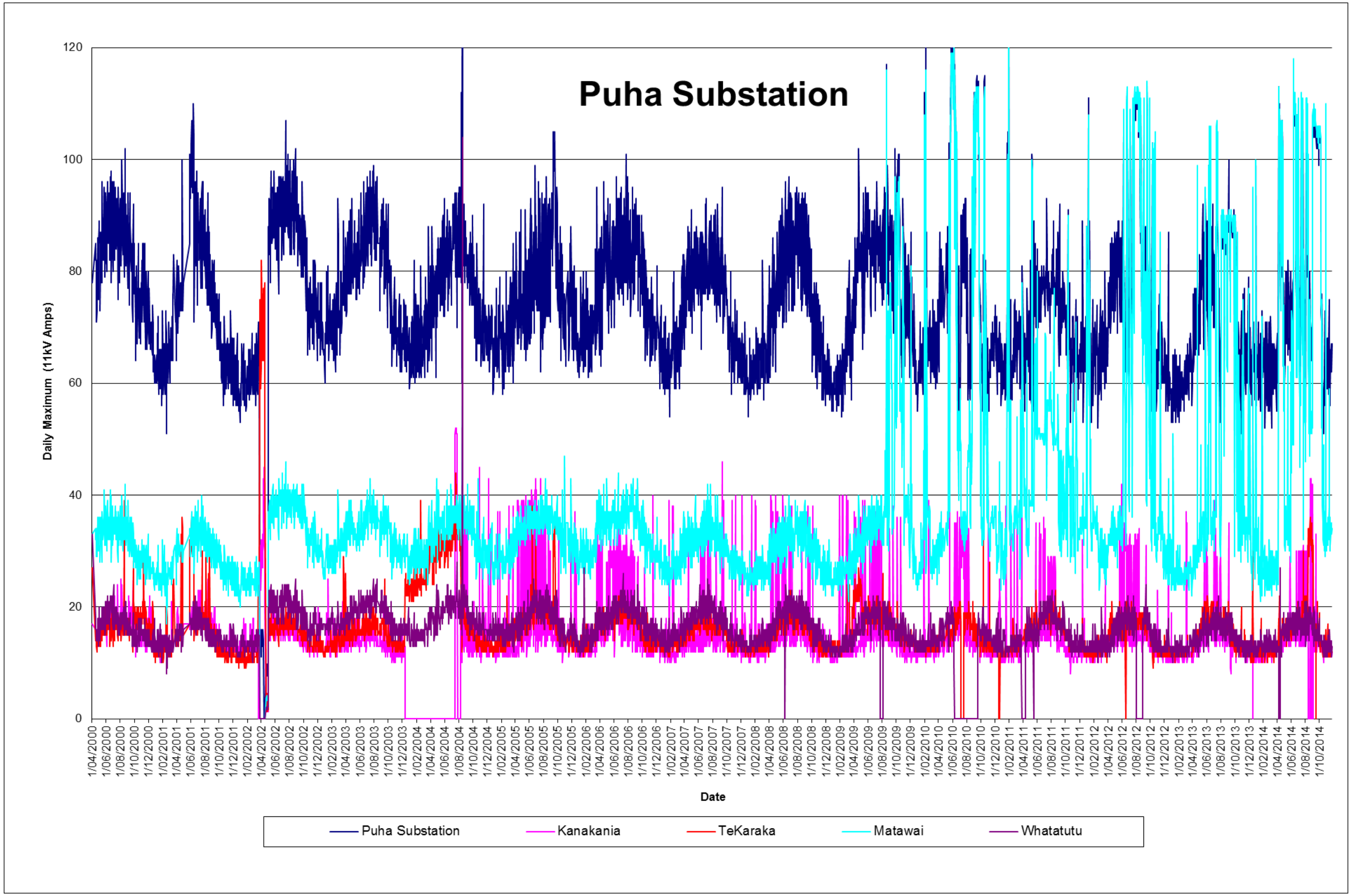
JNL Substation
Daily Maximum (11kV Amps)
Date
Total
JNL
McDonalds

Feeder Loadings

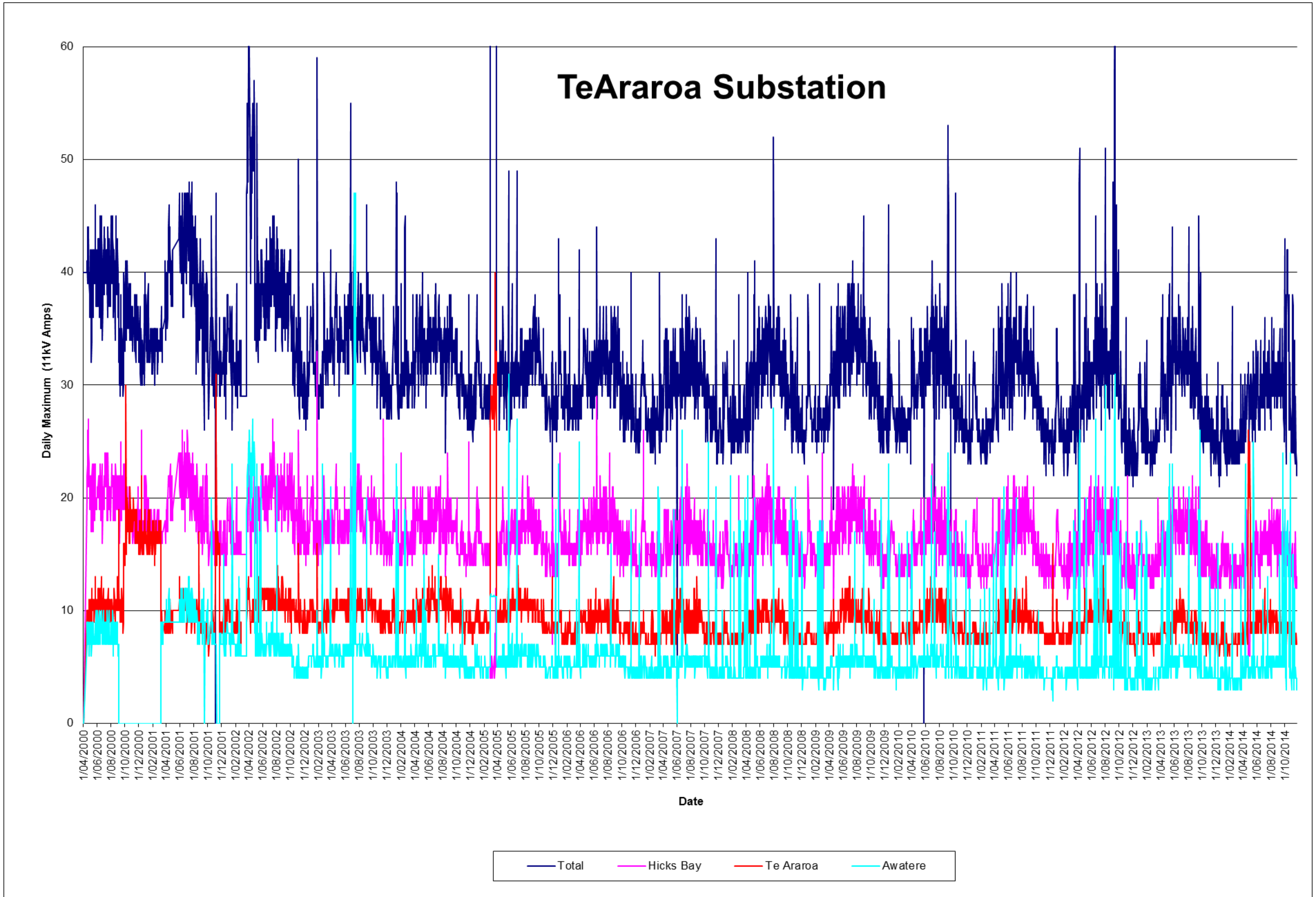


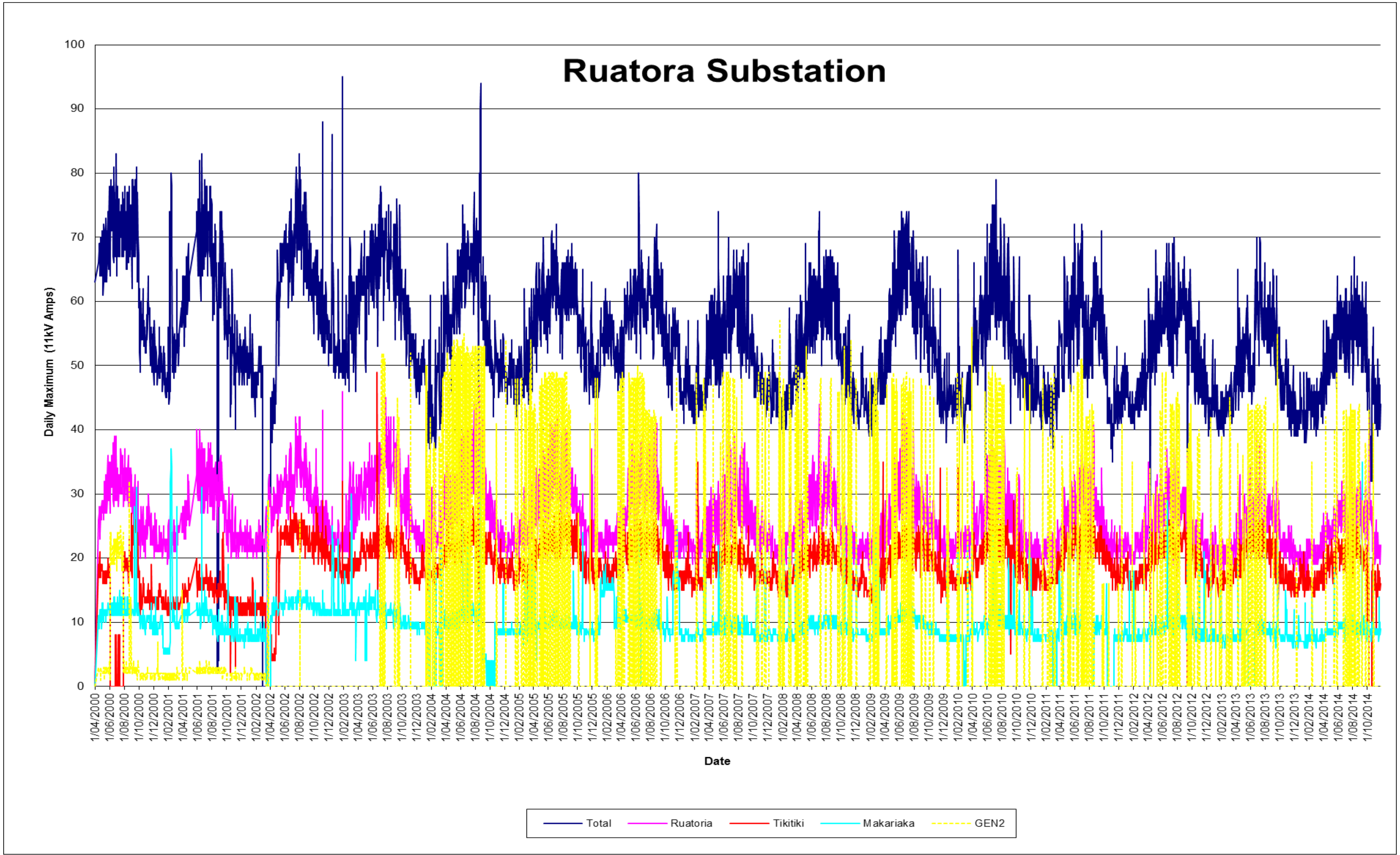

Pehiri Substation
Daily Maximum (11kV Amps)
40
35
30
25
20
15
10
5
0
Date
Total
Tiniroto
Tahunga
Parikania
WarengaOHika

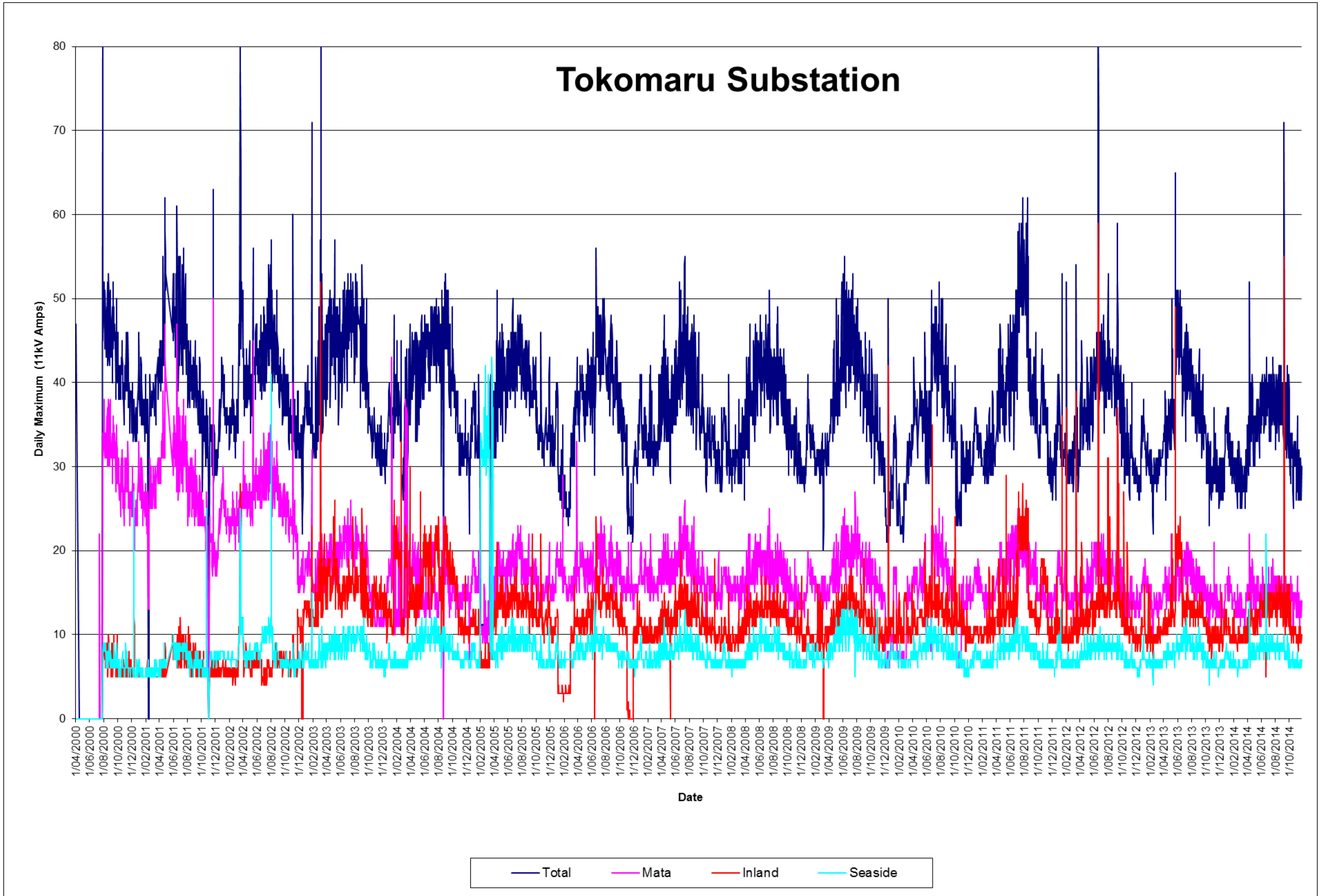

Ngatapa Substation
Daily Maximum (11kV Amps)
30
25
20
15
10
5
0
Date
Total
Ngatapa
Taharoa
Totangi

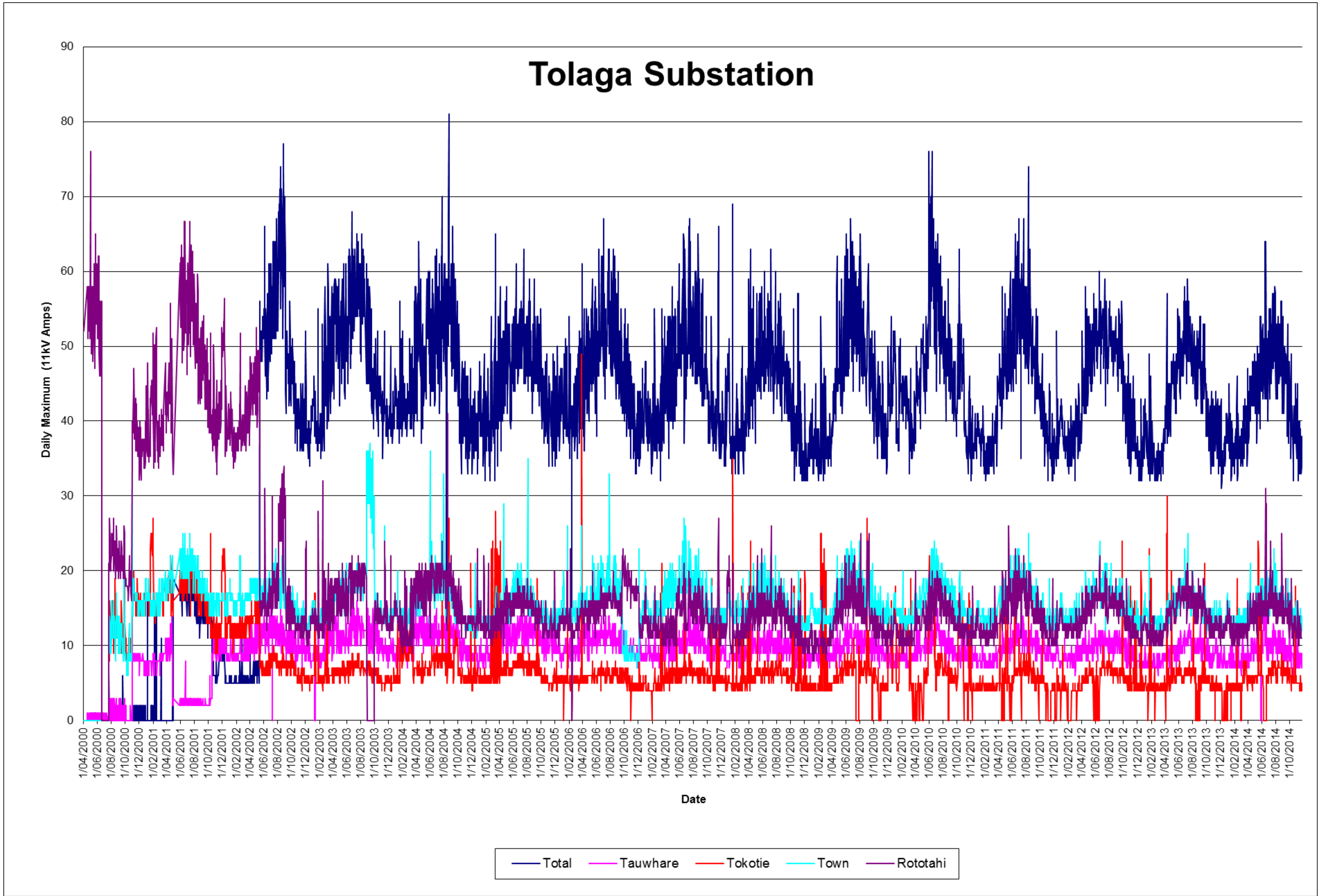


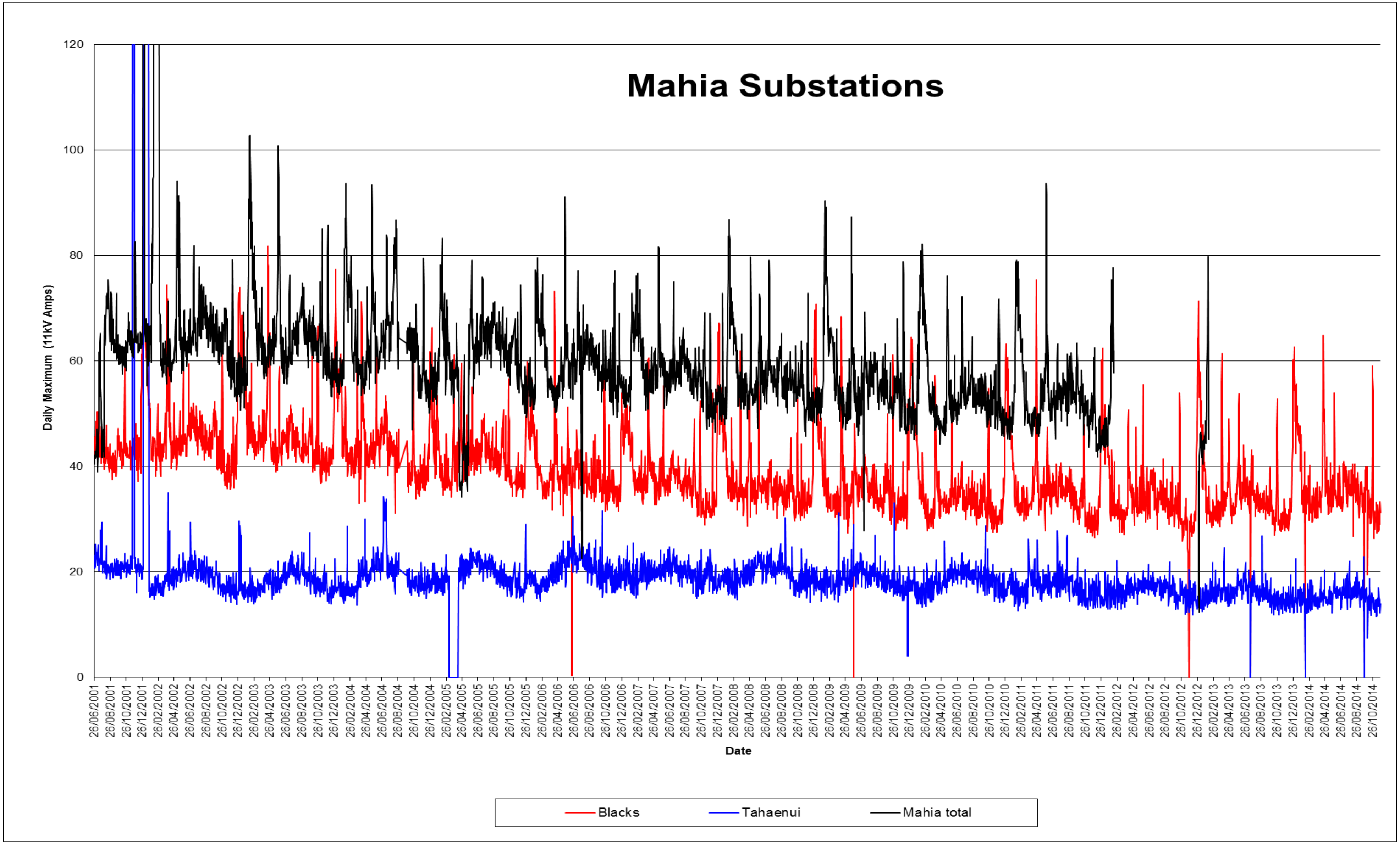
Puha Substation
Daily Maximum (11kV Amps)
120
100
80
60
40
20
0
Date
Puha Substation
Kanakania
TeKaraka
Matawai
Whatatutu

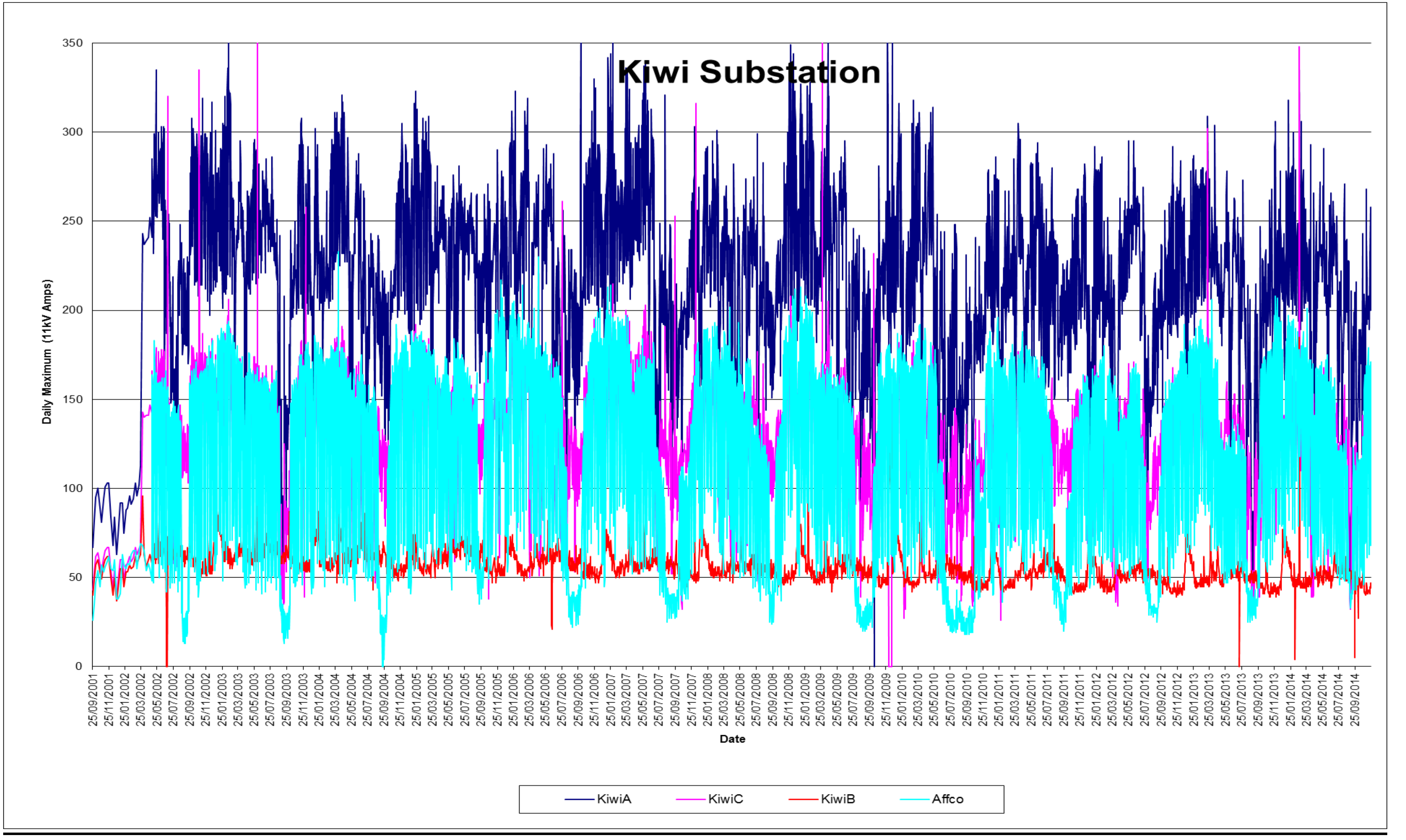

TeAraroa Substation
Daily Maximum (11kV Amps)
Date
Total
Hicks Bay
Te Araroa
Awatere

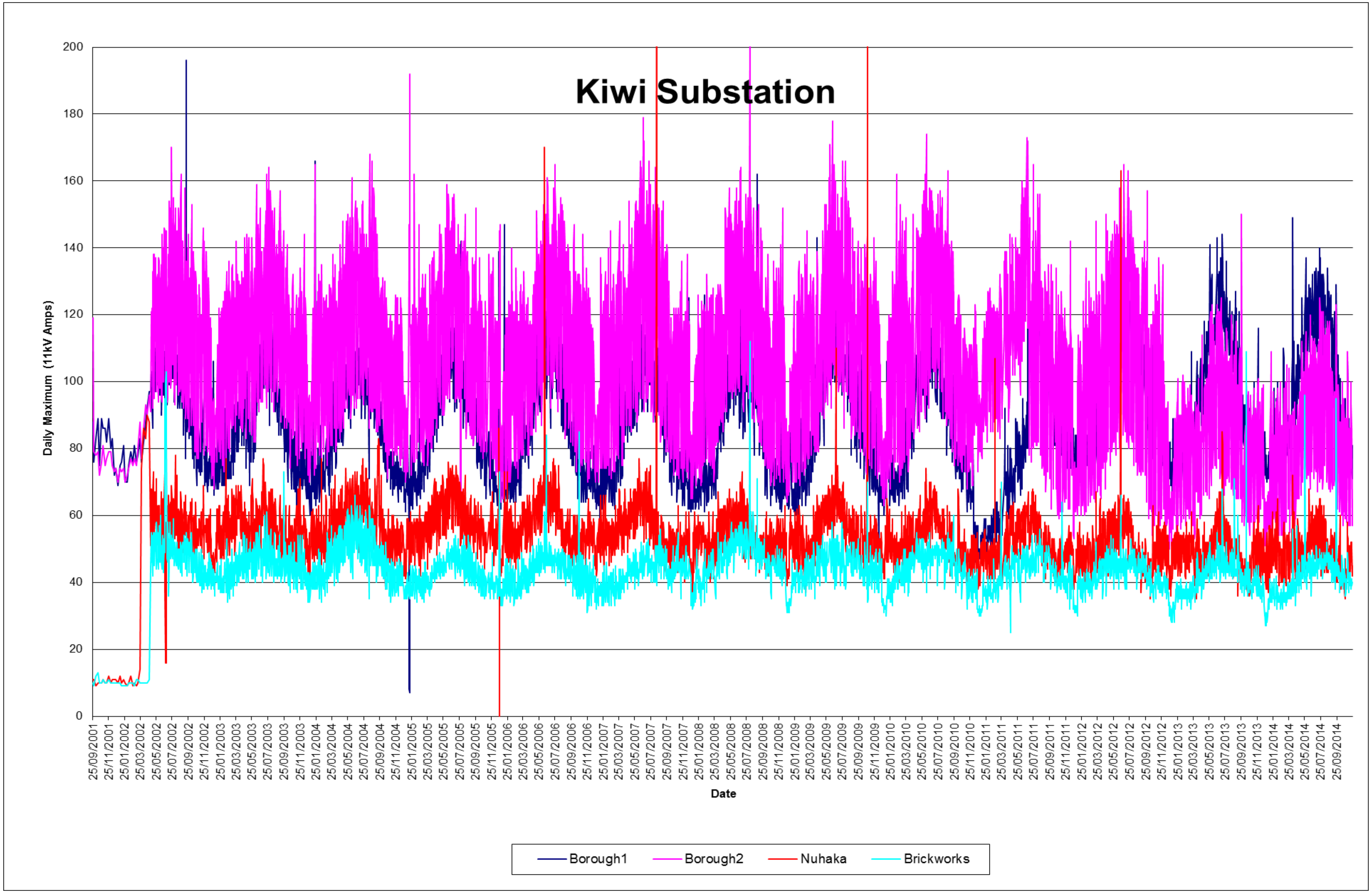

Ruatora Substation
Daily Maximum (11kV Amps)
Date
Total
Ruatoria
Tikitiki
Makariaka
GEN2


Tokomaru Substation
Daily Maximum (11kV Amps)
80
70
60
50
40
30
20
10
0
Date
Total
Mata
Inland
Seaside


Tolaga Substation
Daily Maximum (11kV Amps)
90
80
70
60
50
40
30
20
10
0
Date
Total
Tauwhare
Tokotie
Town
Rototahi


Mahia Substations
Daily Maximum (11kV Amps)
120
100
80
60
40
20
0
Date
Blacks
Tahaenui
Mahia total


Kiwi Substation
Daily Maximum (11kV Amps)
Date
KiwiA
KiwiC
KiwiB
Affco


Kiwi Substation
Daily Maximum (11kV Amps)
0
20
40
60
80
100
120
140
160
180
200
25/09/2001
25/11/2001
25/01/2002
25/03/2002
25/05/2002
25/07/2002
25/09/2002
25/11/2002
25/01/2003
25/03/2003
25/05/2003
25/07/2003
25/09/2003
25/11/2003
25/01/2004
25/03/2004
25/05/2004
25/07/2004
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25/05/2012
25/07/2012
25/09/2012
25/11/2012
25/01/2013
25/03/2013
25/05/2013
25/07/2013
25/09/2013
25/11/2013
25/01/2014
25/03/2014
25/05/2014
25/07/2014
25/09/2014
Date
Borough1
Borough2
Nuhaka
Brickworks

A2. Schedule 11a Report on Forecast Capital Expenditure

Company Name: Eastland Network Limited
AMP Planning Period: 1 April 2015 – 31 March 2025

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8		for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
9		**11a(i): Expenditure on Assets Forecast**	$000 (in nominal dollars)										
10		Consumer connection	160	162	165	168	171	175	179	182	186	189	193
11		System growth	14,365	1,103	1,120	1,354	1,371	648	1,127	1,613	1,824	1,678	1,831
12		Asset replacement and renewal	5,187	8,322	13,647	7,468	6,702	8,135	7,523	7,418	7,414	6,964	7,440
13		Asset relocations	55	56	57	58	59	60	61	63	64	65	66
14		Reliability, safety and environment:											
15		Quality of supply	99	156	108	81	24	84	25	188	64	248	133
16		Legislative and regulatory	193	196	170	173	-	-	-	-	-	-	-
17		Other reliability, safety and environment	72	453	460	64	65	67	68	69	71	72	74
18		**Total reliability, safety and environment**	364	805	738	318	89	151	93	257	135	320	207
19		**Expenditure on network assets**	20,131	10,449	15,727	9,365	8,392	9,169	8,983	9,533	9,622	9,217	9,737
20		Non-network assets	468	5,818	392	31	139	33	89	34	35	36	36
21		**Expenditure on assets**	20,599	16,267	16,118	9,397	8,531	9,202	9,072	9,567	9,657	9,252	9,773
22													
23	*plus*	Cost of financing	-	-	-	-	-	-	-	-	-	-	-
24	*less*	Value of capital contributions	50	51	52	52	54	55	56	57	58	59	60
25	*plus*	Value of vested assets	200	203	206	210	214	219	223	228	232	237	242
26													
27		**Capital expenditure forecast**	20,749	16,419	16,273	9,554	8,691	9,366	9,239	9,738	9,831	9,430	9,955
28													
29		Value of commissioned assets	18,504	17,718	16,317	11,570	8,950	9,163	9,277	9,588	9,803	9,550	9,797

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 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
32			$000 (in constant prices)										
33		Consumer connection	160	160	160	160	160	160	160	160	160	160	160
34		System growth	14,365	1,087	1,087	1,291	1,280	592	1,010	1,417	1,571	1,417	1,516
35		Asset replacement and renewal	5,187	8,197	13,242	7,120	6,257	7,436	6,742	6,517	6,386	5,881	6,159
36		Asset relocations	55	55	55	55	55	55	55	55	55	55	55
37		Reliability, safety and environment:											
38		Quality of supply	99	154	105	77	22	77	22	165	55	209	110
39		Legislative and regulatory	193	193	165	165	-	-	-	-	-	-	-
40		Other reliability, safety and environment	72	446	446	61	61	61	61	61	61	61	61
41		**Total reliability, safety and environment**	364	793	716	303	83	138	83	226	116	270	171
42		**Expenditure on network assets**	20,131	10,292	15,260	8,929	7,835	8,381	8,050	8,375	8,288	7,783	8,061
43		Non-network assets	468	5,730	380	30	130	30	80	30	30	30	30
44		**Expenditure on assets**	20,599	16,022	15,640	8,959	7,965	8,411	8,130	8,405	8,318	7,813	8,091
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	165	550	550	165	165	165	165	165	165	165	165
49		Research and development											

Company Name	Eastland Network Limited
AMP Planning Period	1 April 2015 – 31 March 2025

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
58		for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
59	**Difference between nominal and constant price forecasts**		$000										
60	Consumer connection		-	2	5	8	11	15	19	22	26	29	33
61	System growth		-	17	33	63	91	56	117	196	253	261	315
62	Asset replacement and renewal		-	125	405	348	444	699	781	901	1,028	1,083	1,280
63	Asset relocations		-	1	2	3	4	5	6	8	9	10	11
64	Reliability, safety and environment:												
65	Quality of supply		-	2	3	4	2	7	3	23	9	39	23
66	Legislative and regulatory		-	3	5	8	-	-	-	-	-	-	-
67	Other reliability, safety and environment		-	7	14	3	4	6	7	8	10	11	13
68	**Total reliability, safety and environment**		-	12	22	15	6	13	10	31	19	50	36
69	**Expenditure on network assets**		-	157	467	436	556	788	933	1,158	1,334	1,434	1,676
70	Non-network assets		-	88	12	1	9	3	9	4	5	6	6
71	**Expenditure on assets**		-	245	479	438	565	791	942	1,162	1,339	1,439	1,682
72													

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
73			31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
74	**11a(ii): Consumer Connection**	for year ended						
75	*Consumer types defined by EDB**		$000 (in constant prices)					
76	Residential		55	55	55	55	55	55
77	Commercial		50	50	50	50	50	50
78	Industrial		55	55	55	55	55	55
79	[EDB consumer type]							
80	[EDB consumer type]							
81	**include additional rows if needed*							
82	**Consumer connection expenditure**		160	160	160	160	160	160
83	*less* Capital contributions funding consumer connection		50	50	50	50	50	50
84	**Consumer connection less capital contributions**		110	110	110	110	110	110
85	**11a(iii): System Growth**							
86	Subtransmission		5591	495	495	0	0	0
87	Zone substations		8182	0	0	0	0	0
88	Distribution and LV lines		143	143	143	418	143	143
89	Distribution and LV cables		198	198	198	347	611	198
90	Distribution substations and transformers		251	250.8	251	251	251	251
91	Distribution switchgear		0	0	0	0	0	0
92	Other network assets		0	0	0	275	275	0
93	**System growth expenditure**		14,365	1,087	1,087	1,291	1,280	592
94	*less* Capital contributions funding system growth		0	0	0	0	0	0
95	**System growth less capital contributions**		14,365	1,087	1,087	1,291	1,280	592

Company Name: Eastland Network Limited
AMP Planning Period: 1 April 2015 – 31 March 2025

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
104		for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
105	**11a(iv): Asset Replacement and Renewal**		$000 (in constant prices)					
106		Subtransmission	484	2,077	1,926	1,727	1,110	949
107		Zone substations	176	1,769	6,481	646	313	1,740
108		Distribution and LV lines	3,190	3,190	3,586	3,586	3,586	3,586
109		Distribution and LV cables	220	220	220	220	220	220
110		Distribution substations and transformers	407	407	407	407	407	407
111		Distribution switchgear	501	446	501	446	501	446
112		Other network assets	209	88	121	88	121	88
113		**Asset replacement and renewal expenditure**	5,187	8,197	13,242	7,120	6,257	7,436
114	*less*	Capital contributions funding asset replacement and renewal	0	0	0	0	0	0
115		**Asset replacement and renewal less capital contributions**	5,187	8,197	13,242	7,120	6,257	7,436
116	**11a(v):Asset Relocations**							
117		*Project or programme**						
118		Asset Relocation Unplanned/Unknown	55	55	55	55	55	55
119		[Description of material project or programme]	0	0	0	0	0	0
120		[Description of material project or programme]	0	0	0	0	0	0
121		[Description of material project or programme]	0	0	0	0	0	0
122		[Description of material project or programme]	0	0	0	0	0	0
123		**include additional rows if needed*						
124		All other asset relocations projects or programmes						
125		**Asset relocations expenditure**	55	55	55	55	55	55
126	*less*	Capital contributions funding asset relocations	0	0	0	0	0	0
127		**Asset relocations less capital contributions**	55	55	55	55	55	55
128								
129	**11a(vi):Quality of Supply**							
130		*Project or programme**						
131		11kV cable Port feeder link	0	0	0	0	0	0
132		Building/Switchyard Security Upgrade (2013/14 Kaiti)	55	55	11	11	11	11
133		11kV Field Recloser Automation Plan - additions	0	55	0	55	0	55
134		"A" Park Wairoa, switchgear addition/alteration	0	0	83	0	0	0
		SCADA Master Station Development	11	11	11	11	11	11
		SCADA Rural Automation -development	0	0	0	0	0	0
		SCADA Long Term Development Additional Sites	0	0	0	0	0	0
135		Establish 2x Genset sites (Raupunga & Ruakituri)	33	33	0	0	0	0
136		**include additional rows if needed*						
137		All other quality of supply projects or programmes						
138		**Quality of supply expenditure**	99	154	105	77	22	77
139	*less*	Capital contributions funding quality of supply	0	0	0	0	0	0
140		**Quality of supply less capital contributions**	99	154	105	77	22	77
141								

Company Name: Eastland Network Limited
AMP Planning Period: 1 April 2015 – 31 March 2025

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
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sch ref								
142	**11a(vii): Legislative and Regulatory**							
143	*Project or programme**							
144	AUFLS Relay install		0	0	165	165	0	0
145	Replace Vehicle RTs		193	193	0	0	0	0
146	[Description of material project or programme]							
147	[Description of material project or programme]							
148	[Description of material project or programme]							
149	**include additional rows if needed*							
150	All other legislative and regulatory projects or programmes							
151	**Legislative and regulatory expenditure**		193	193	165	165	-	-
152	Capital contributions funding legislative and regulatory	*less*	0	0	0	0	0	0
153	**Legislative and regulatory less capital contributions**		193	193	165	165	-	-

Company Name: Eastland Network Limited
AMP Planning Period: 1 April 2015 – 31 March 2025

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
161							
162		31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
163	**11a(viii): Other Reliability, Safety and Environment** — for year ended						
164	*Project or programme**	**$000 (in constant prices)**					
165	CBD UG Project (Stg1 Childers, Grey Streets) - Environ	0	385	0	0	0	0
166	CBD UG Project (Stg2 Roebuck, Disraliei Streets) - Environ	0	0	385	0	0	0
167	New Service Fuse Boxes to Replace Meter Box Sharing 50pa - Safety	33	33	33	33	33	33
168	Meter Bd install associated with Glv box removal 50pa. - Safety	28	28	28	28	28	28
169	Switchgear Operator Suits - 1 per zone sub - safety	11	0	0	0	0	0
170	**include additional rows if needed*						
171	All other reliability, safety and environment projects or programmes						
172	**Other reliability, safety and environment expenditure**	72	446	446	61	61	61
173	*less* Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
174	**Other reliability, safety and environment less capital contributions**	72	446	446	61	61	61
175							
176							
177							
178	**11a(ix): Non-Network Assets**						
179	**Routine expenditure**						
180	*Project or programme**						
181	Test Instrument & Safety Equipment, Additional/Upgrade	10	10	10	10	10	10
182	Property Capital Projects	0	0	50	0	100	0
183	General asset replacement	0	20	20	20	20	20
184	[Description of material project or programme]						
185	[Description of material project or programme]						
186	**include additional rows if needed*						
187	All other routine expenditure projects or programmes						
188	**Routine expenditure**	10	30	80	30	130	30
189	**Atypical expenditure**						
190	*Project or programme**						
191	Transmission safety compliance equip/training	150	0	0	0	0	0
192	Dynamic line rating system	103	0	0	0	0	0
193	AM System	0	1200	0	0	0	0
194	Information Transfer & record system	205	0	0	0	0	0
	GIS Replacement	0	0	300	0	0	0
195	Purchase Network Building	0	4500	0	0	0	0
196	**include additional rows if needed*						
197	All other atypical projects or programmes						
198	**Atypical expenditure**	458	5,700	300	-	-	-
199							
200	**Non-network assets expenditure**	468	5,730	380	30	130	30

A3. Schedule 11b Report on Forecast Operational Expenditure

	Company Name	Eastland Network Limited
	AMP Planning Period	1 April 2015 – 31 March 2025

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8	for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,037	1,078	1,094	1,114	1,137	1,162	1,185	1,209	1,233	1,257	1,283
11	Vegetation management	900	1,004	1,019	1,037	1,059	1,082	1,104	1,126	1,148	1,171	1,195
12	Routine and corrective maintenance and inspection	836	1,722	1,727	1,795	1,795	1,833	1,870	1,908	1,986	1,985	2,024
13	Asset replacement and renewal	815	2,058	2,089	2,126	2,171	2,218	2,262	2,307	2,353	2,400	2,448
14	**Network Opex**	3,588	5,862	5,930	6,072	6,162	6,295	6,421	6,549	6,721	6,814	6,950
15	System operations and network support	1,305	1,304	858	1,477	1,614	1,595	1,660	1,660	1,702	1,791	1,796
16	Business support	3,323	3,210	3,258	3,316	3,386	3,459	3,528	3,599	3,671	3,744	3,819
17	**Non-network opex**	4,628	4,514	4,116	4,793	5,000	5,054	5,188	5,258	5,373	5,535	5,615
18	**Operational expenditure**	8,216	10,376	10,046	10,864	11,162	11,348	11,609	11,807	12,093	12,348	12,564

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
20	for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,037	1,062	1,062	1,062	1,062	1,062	1,062	1,062	1,062	1,062	1,062
23	Vegetation management	900	989	989	989	989	989	989	989	989	989	989
24	Routine and corrective maintenance and inspection	836	1,696	1,676	1,711	1,676	1,676	1,676	1,676	1,711	1,676	1,676
25	Asset replacement and renewal	815	2,027	2,027	2,027	2,027	2,027	2,027	2,027	2,027	2,027	2,027
26	**Network Opex**	3,588	5,774	5,754	5,789	5,754	5,754	5,754	5,754	5,789	5,754	5,754
27	System operations and network support	1,305	1,284	832	1,408	1,507	1,458	1,488	1,458	1,466	1,512	1,487
28	Business support	3,323	3,162	3,162	3,162	3,162	3,162	3,162	3,162	3,162	3,162	3,162
29	**Non-network opex**	4,628	4,446	3,994	4,569	4,669	4,619	4,649	4,620	4,628	4,674	4,648
30	**Operational expenditure**	8,216	10,219	9,748	10,358	10,423	10,373	10,403	10,373	10,416	10,427	10,402
31	**Subcomponents of operational expenditure (where known)**											
32–33	Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
34	Direct billing*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Research and Development	-	-	-	-	-	-	-	-	-	-	-
	Insurance	150	100	100	100	100	100	100	100	100	100	100

37 * *Direct billing expenditure by suppliers that direct bill the majority of their consumers*

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
40	for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	16	32	52	75	100	123	147	171	196	221
43	Vegetation management	-	15	30	48	70	93	115	137	159	182	206
44	Routine and corrective maintenance and inspection	-	26	51	84	119	158	194	232	275	309	348
45	Asset replacement and renewal	-	31	62	99	144	191	235	280	326	373	421
46	**Network Opex**	-	88	176	283	408	541	667	795	932	1,060	1,196
47	System operations and network support	-	20	25	69	107	137	172	202	236	279	309
48	Business support	-	48	97	155	224	297	366	437	509	582	657
49	**Non-network opex**	-	68	122	223	331	434	539	639	745	861	966
50	**Operational expenditure**	-	156	298	506	740	975	1,206	1,434	1,677	1,921	2,163

A4. Schedule 12a Report on Asset Condition

Company Name	Eastland Network Limited
AMP Planning Period	1 April 2015 – 31 March 2025

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref											
7					Asset condition at start of planning period (percentage of units by grade)						
8											
9	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
10	All	Overhead Line	Concrete poles / steel structure	No.	1.17%	3.50%	15.76%	79.58%	-	1	5.83%
11	All	Overhead Line	Wood poles	No.	2.75%	8.24%	61.07%	27.94%	-	1	13.73%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	4	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	0.06%	0.18%	77.07%	22.69%	-	1	0.30%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	80.00%	20.00%	-	1	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	100.00%	-	1	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	-	4	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	4	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	-	4	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	4	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	4	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	4	-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	4	-
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	4	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	10.00%	90.00%	-	1	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	25.00%	75.00%	-	-	1	20.00%
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	-	100.00%	-	1	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	4	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	-	-	-	4	-
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	4	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	4	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	3.13%	-	28.13%	68.75%	-	1	3.00%
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	12.12%	-	29.29%	58.59%	-	1	12.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	100.00%	-	1	-

Company Name **Eastland Network Limited**

AMP Planning Period **1 April 2015 – 31 March 2025**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref					Asset condition at start of planning period (percentage of units by grade)						
43											
44	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
45	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	5.56%	55.56%	38.89%	-	1	5.56%
46	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0.12%	0.37%	83.11%	16.39%	-	1	0.62%
47	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	4	-
48	HV	Distribution Line	SWER conductor	km	-	-	100.00%	-	-	1	-
49	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	50.00%	50.00%	-	1	-
50	HV	Distribution Cable	Distribution UG PILC	km	-	-	32.46%	67.54%	-	1	-
51	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	-	4	-
52	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	2.56%	7.69%	15.38%	74.36%	-	1	12.82%
53	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	44.44%	55.56%	-	1	-
54	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1.51%	4.53%	58.51%	35.45%	-	1	7.55%
55	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	1.80%	5.41%	9.01%	83.78%	-	1	9.01%
56	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	1.20%	3.60%	6.00%	89.20%	-	1	6.00%
57	HV	Distribution Transformer	Pole Mounted Transformer	No.	1.64%	4.91%	53.55%	39.91%	-	1	8.18%
58	HV	Distribution Transformer	Ground Mounted Transformer	No.	1.40%	4.20%	31.17%	63.22%	-	1	7.01%
59	HV	Distribution Transformer	Voltage regulators	No.	-	-	80.00%	20.00%	-	1	-
60	HV	Distribution Substations	Ground Mounted Substation Housing	No.	1.40%	4.20%	31.17%	63.22%	-	1	7.01%
61	LV	LV Line	LV OH Conductor	km	-	-	77.88%	22.12%	-	1	-
62	LV	LV Cable	LV UG Cable	km	0.38%	1.15%	53.08%	45.38%	-	1	1.92%
63	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	-	52.43%	47.57%	-	1	-
64	LV	Connections	OH/UG consumer service connections	No.	1.96%	5.87%	60.49%	31.68%	-	1	9.79%
65	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	30.00%	20.00%	20.00%	30.00%	-	1	-
66	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	6.00%	18.00%	26.00%	50.00%	-	1	30.00%
67	All	Capacitor Banks	Capacitors including controls	No.	-	-	100.00%	-	-	1	-
68	All	Load Control	Centralised plant	Lot	-	-	100.00%	-	-	1	-
69	All	Load Control	Relays	No.	6.00%	18.00%	26.00%	50.00%	-	1	5.00%
70	All	Civils	Cable Tunnels	km	-	-	-	-	-	4	-

A5. Schedule 12b Report on Forecast Capacity

Company Name	Eastland Network Limited
AMP Planning Period	1 April 2015 – 31 March 2025

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	Existing Zone Substations	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	TeAraroa	1	-	N-1 Switched	1	-	-	-	Transformer	Constraint supported by Generation AMP 4.2.2.4
10	Ruatoria	1	-	N-1 Switched	1	-	-	-	Transformer	Constraint supported by Generation AMP 4.2.2.4
11	Tokomaru	1	-	N-1 Switched	2	-	-	-	Transformer	Constraint Suported by adjacent Substations AMP 4.2.2.4
12	Tolaga	1	-	N-1 Switched	1	-	-	-	Transformer	Constraint supported by Generation AMP 4.2.2.4
13	Kaiti	7	-	N-1 Switched	8	-	-	-	Transformer	Constraint Suported by adjacent Substations AMP 4.2.2.4
14	Port	8	-	N-1 Switched	8	-	-	-	Transformer	Constraint Suported by adjacent Substations AMP 4.2.2.4
	Gisborne	45	60	N-1	-	75%	60	75%	No constraint within +5 years	
15	Carnarvon	14	13	N-1	8	113%	13	90%	No constraint within +5 years	Current Peak caused when load transferred to site during contengency
16	Parkinson	10	13	N-1	8	78%	13	37%	No constraint within +5 years	Constraint Suported by adjacent Substations AMP 4.2.2.4
17	Makaraka	11	-	N-1 Switched	8	-	-	-	Transformer	Constraint Suported by adjacent Substations AMP 4.2.2.4
18	Patutahi	2	-	N-1 Switched	5	-	-	-	Transformer	Constraint Suported by adjacent Substations AMP 4.2.2.4
19	Pehiri	0	-	N-1 Switched	2	-	-	-	Transformer	Constraint Suported by adjacent Substations AMP 4.2.2.4
20	Ngatapa	0	-	N-1 Switched	2	-	-	-	Transformer	Constraint Suported by adjacent Substations AMP 4.2.2.4
21	Puha	2	-	N-1 Switched	3	-	-	-	Transformer	Constraint supported by Generation AMP 4.2.2.4
22	JNL	4	-	N-1 Switched	8	-	-	-	Transformer	Constraint Suported by adjacent Substations AMP 4.2.2.4
23	Matawhero	3	5	N-1	8	52%	5	70%	No constraint within +5 years	Current Peak caused when load transferred to site during contengency
24	Tuai	1	-	N	-	-	-	-	Transformer	Portable Generation Used for extended repair times AMP 4.2.2.4
	Kiwi	5	7	N	-	74%			Transformer	Generation Infeed
25	Wairoa	10	10	N-1	-	102%	10	102%	No constraint within +5 years	Constraint Suported by Generation AMP 4.2.2.4
26	Blacks pad	1	-	N-1 Switched	1	-	-	-	Transformer	Constraint supported by Generation AMP 4.2.2.4
27	Tahaenui	0	-	N-1 Switched	1	-	-	-	Transformer	Constraint Suported by adjacent Substations AMP 4.2.2.4
28	Waihi	5	7	N	-	74%	-	-	Transformer	Generation Infeed

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

30 **12b(ii): Transformer Capacity**

sch ref		(MVA)
32	Distribution transformer capacity (EDB owned)	216
33	Distribution transformer capacity (Non-EDB owned)	36
34	**Total distribution transformer capacity**	251
35		
36	**Zone substation transformer capacity**	323

A6. Schedule 12c Report on Forecast Network Demand

Company Name	Eastland Network Limited
AMP Planning Period	1 April 2015 – 31 March 2025

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
7	**12c(i): Consumer Connections**						
8	*Number of ICPs connected in year by consumer type*				Number of connections		
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
11	*Consumer types defined by EDB**						
12	Domestic	19,312	19,331	19,356	19,394	19,432	19,470
13	Non Domestic	6,033	6,039	6,047	6,059	6,071	6,082
14	Non Domestic Large	45	45	45	45	45	45
15	Non Domestic Industrial	4	4	4	4	4	4
16	[EDB consumer type]						
17	**Connections total**	25,394	25,419	25,452	25,502	25,552	25,602
18	**include additional rows if needed*						
19	**Distributed generation**						
20	Number of connections	45	66	81	91	99	107
21	Installed connection capacity of distributed generation (MVA)	14	14	14	14	14	14
22	**12c(ii) System Demand**						
23		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)** for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
25	GXP demand	53	55	57	59	61	62
26	*plus* Distributed generation output at HV and above	5	5	5	6	6	6
27	**Maximum coincident system demand**	58	60	62	65	67	68
28	*less* Net transfers to (from) other EDBs at HV and above						
29	**Demand on system for supply to consumers' connection points**	58	60	62	65	67	68
30	**Electricity volumes carried (GWh)**	0.192192769	0.192843744	0.198675841	0.20766619	0.213415672	0.215953121
31	Electricity supplied from GXPs	287	296	297	298	299	300
32	*less* Electricity exports to GXPs	-	-	-	-	-	
33	*plus* Electricity supplied from distributed generation	15	15	15	15	15	15
34	*less* Net electricity supplied to (from) other EDBs	-	-	-	-	-	
35	**Electricity entering system for supply to ICPs**	302	311	312	313	314	315
36	*less* Total energy delivered to ICPs	281	282	282	283	284	285
37	**Losses**	21	30	30	30	30	30
38							
39	**Load factor**	59%	59%	57%	55%	53%	53%
40	**Loss ratio**	7.0%	9.5%	9.5%	9.5%	9.5%	9.5%

A7. Schedule 12d Report on Forecast Interuptions and Duration

Company Name: Eastland Network Limited
AMP Planning Period: 1 April 2015 – 31 March 2025
Network / Sub-network Name: Total

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
9	for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
10	SAIDI						
11	Class B (planned interruptions on the network)	46.0	40.0	40.0	40.0	40.0	40.0
12	Class C (unplanned interruptions on the network)	256.0	232.0	232.0	232.0	232.0	232.0
13	SAIFI						
14	Class B (planned interruptions on the network)	0.40	0.54	0.54	0.54	0.54	0.54
15	Class C (unplanned interruptions on the network)	3.80	3.00	3.00	3.00	3.00	3.00

Company Name: Eastland Network Limited
AMP Planning Period: 1 April 2015 – 31 March 2025
Network / Sub-network Name: Gisborne

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

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
9	for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
10	SAIDI						
11	Class B (planned interruptions on the network)	30.0	22.0	22.0	22.0	22.0	22.0
12	Class C (unplanned interruptions on the network)	237.0	170.0	170.0	170.0	170.0	170.0
13	SAIFI						
14	Class B (planned interruptions on the network)	0.30	0.41	0.41	0.41	0.41	0.41
15	Class C (unplanned interruptions on the network)	3.80	2.90	2.90	2.90	2.90	2.90

Company Name: Eastland Network Limited
AMP Planning Period: 1 April 2015 – 31 March 2025
Network / Sub-network Name: Wairoa

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

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
9	for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
10	SAIDI						
11	Class B (planned interruptions on the network)	60.0	28.0	28.0	28.0	28.0	28.0
12	Class C (unplanned interruptions on the network)	400.0	302.0	302.0	302.0	302.0	302.0
13	SAIFI						
14	Class B (planned interruptions on the network)	0.50	0.50	0.50	0.50	0.50	0.50
15	Class C (unplanned interruptions on the network)	4.60	4.60	4.60	4.60	4.60	4.60

A8. Schedule 13 Report on Asset Management Maturity

Company Name	Eastland Network Limited
AMP Planning Period	1 April 2015 – 31 March 2025
Asset Management Standard Applied	PAS 55

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	AMP Section 8 Performance and Improvement, SMS 5.3	Asset Manager review.	Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	Industry Participation EEA, IPENZ. Forum and Confrence attendance. Supplier relationships. Quality System procedures for Continuous Improvement, Review and Performance monitoring. SMS 5.3	Asset Manager review.	In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	AMP Section 5 Lifecycle management, ENL4 Section 3 - 7 and 8 describe activity elements for life cycle,SMS 5.3	Asset Manager review.	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?	3	Maintenance, Condition assessment and performance records incorporated into plans. Annual AMP produced - Director sign off - External Review	Asset Manager review.	The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

Company Name: Eastland Network Limited
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Asset Management Standard Applied: PAS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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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?	3	Publicly Disclosed via web site, Sent to regulator annually, Submitted to board annually, Copy on front counter main office, Plans comunicated via standards, work programs and asset management activities, SMS 5.8	Asset Manager review.	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?	3	Publicly Disclosed via web site, Sent to regulator annually, Submitted to board annually, Copy on front counter main office, Plans comunicated via standards, work programs and asset management activities,SMS 2.4 and 5.4	Asset Manager review.	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)	3	The quality system documents policies, processes, procedures and design standards to achieve the outcomes identified in the annual AMP, Asset and Financial performance indicators demonstrate compliance with efficiency targets over time	Asset Manager review.	It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	AMP Section 6 Managing risk,QM8 Emergency Prepardness, ENL2 Network control operational procedures, ENL10 Network safety management system, Civil Defence and Lifelines participation, External audit as part of safety management system Regulations. SMS 4.5	Asset Manager review.	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	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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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)?	3	AMP section 1.5, Roles and Responsibilities are incorporated into position descriptions and performance incentive plans. SMS 2.4 and 5.4	Asset Manager review.	In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	Annual Strategic and Business Planning considers Resourcing, Incident and event reviews provide a mechanism for identifying gaps. The AMP identifies shortfalls in resourcing. SMS 5.4	Asset Manager review.	Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	AMP section 1.5, Roles and Responsibilities are incorporated into position descriptions and performance incentive plans. Board reporting of key asset management indicators is undertaken. SMS 5.4	Asset Manager review.	Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
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?	3	Activities associated with asset information, planning, design undertaken inhouse, ENL4 Section 7 Outsourced contracting, consulting and review managed via contract documentation including scope and specification. Audit and review processes in place.	Asset Manager review.	Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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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	QM2 Section2 Training Programme. ENL1 Setcion 4 Compentency/Authorisation Database. Scholarship programme in place , Apprentice programe in place, Close relationship with ESITO and regional contractors to ensure training opertunities are identified. Performance Review Programme in place. Induction procedures in place, SMS 5.2 and 5.7	Asset Manager review.	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?	3	ENL1 Section 4 Individual Compentency assessment process with skills and training matrix. Job descriptions, Performance review process, Contractor Management and Auditing Process.SMS 5.7	Asset Manager review.	Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	3	ENL1 Section 4 Individual Comp	Asset Manager review.	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	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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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?	3	Annual Reporting processes, Monthly Reporting Processes, Weekly Meeting process, Monthly Contractor Meeting Process. Processes for Datacapture and provision of asset information in place. Design and Maintenance Standards communicated via contracts., SMS 5.9	Asset Manager review.	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?	3	AMP 1.6 Describes the processes and systems in place. Quality system documentation describes procedures for data capture and reporting. SMS 5.2	Asset Manager review.	Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
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?	3	Regulatory requirements for Performance, Asset management, Public safety Management, Health and Safety and Design Paramaters mandate the requirements. Internal and External Reviews or Adults identify data processes and review suitability/accuracy. Continiuous improvement processes enable improvement over time. Strategic goals balance the information costs with derived benifits.	Asset Manager review.	Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3	ENL7 Information Procedures, ENL 14 ENL maintenance Procedures, ENL8 Standard Forms, ENL's safety management system covers review of data and controls from design standards to defect reporting and corrective action consistent with Asset management requirements.	Asset Manager review.	The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	3	Procedures documented in Quality System. Internal Reviews and where appropriate, Internal/External Audits documented. SMS 4.6	Asset Manager review.	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?	3	Asset Risk assesment audited under regulation for public safety management system. SMS 4.0	Asset Manager review.	Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	AMP 6.0 Business Risk sumarised and Action plan prioritised by risk reduction outcomes.ENL10 Network safety Management system procedures. QM8 Emergency management documentation related to risk controls. ENL4 section 11 Emergency procedures. ENL4 section 13 Risk management assessments	Asset Manager review.	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?	3	Legal Compliance procedures audited under regulation for public safety management system. SMS 4.6g	Asset Manager review.	In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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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
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?	3	AMP Section 5 Lifecycle management, ENL4 Section 3 - 7 and 8 describe activity elements for life cycle. ENL9 contains design standards, Audited underregulation for safety management system.	Asset Manager review.	Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	3	AMP Section 5 Lifecycle management, ENL4 Section 3 - 7 and 8 describe activity elements for life cycle. AMP section 3 Performance Monitoring, Audited under regulation for public safety management system. SMS 6.0	Asset Manager review.	Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3	AMP Section 3 Performance, AMP Section 4 Development Plans. ENL7 Information Procedures. Amp Section 7 Financial Forcasts, AMP Section 8 Performance and Improvement SMS 2.11 and 6.0	Asset Manager review.	Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	3	Incident Reporting, Real time monitoring, Investigation Procedures. Monthly Board Reporting. Audited under regulation for public safety management , SMS 5.10	Asset Manager review.	Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

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Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
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?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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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
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3	Procedures documented in Quality System. Internal Reviews and where appropriate, Internal/External Audits documented.	Asset Manager review.	This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	Procedures documented in Quality System. Internal Reviews and where appropriate, Internal/External Audits documented.SMS 5.10	Asset Manager review.	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	AMP Section 8 Performance and Improvement, SMS 5.3	Asset Manager review.	Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
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?	3	Industry Participation EEA, IPENZ. Forum and Confrence attendance. Supplier relationships. Quality System procedures for Continuous Improvement, Review and Performance monitoring. SMS 5.3	Asset Manager review.	One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

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Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
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?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

A9. Director certification

CERTIFICATE FOR YEAR-BEGINNING DISCLOSURES

Asset Management Plan

Clause 2.9.1 of Section 2.9

We, Nelson John Patrick Cull and William John Clarke being directors of Eastland Network Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) The following attached information of Eastland Network Limited prepared for the purposes of clause 2.6.1 and sub clauses 2.6.3(4) and 2.6.5(3) of the Electricity Distribution Information 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.

Dated this 31st March 2015

Director

Director