



ASSET MANAGEMENT PLAN

2016-2026

The photograph on the cover page illustrates the work and dedication of our line crew in maintaining our network.

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I Executive Summary

I.1 Introduction

The purpose of this Asset Management Plan (AMP) is to outline the various strategies employed to manage Horizon Energy Distribution Limited “Horizon Energy’s” network assets over their useful lives. As well as informing our stakeholders on our decision-making and investment decisions, the AMP outlines Horizon Energy’s Stewardship role in providing a sustainable, long-term electricity distribution network for the benefit of our communities and customers.

This AMP covers the period 1 April 2016 to 31 March 2026 with a focus on the near to medium term. As signalled in 2014, the AMP reflects Horizon Energy’s continued commitment to align with the asset management practices and framework within ISO 55000 (formerly British Standard PAS 55)¹.

This AMP is a working document and therefore represents the views and plans of Horizon Energy as at the date of the report. Through-out the year we will continue to optimise our practices and individual investment decisions, and any changes will be reflected in the following year’s AMP, as a result we give no assurances that any individual project will necessarily be implemented as described in this AMP.

I.2 Our Asset Base

Horizon Energy services over 24,500 customers in an area bounded by Whangaparaoa Bay Te Kaha to the North, Pikowai to the East, and Lake Rotoma and Ruatahuna to the South or approximately 8,400km². There are four separate distribution areas covered - Edgecumbe, Kawerau, Te Kaha, and Waiotahi supplied from Transpower’s corresponding Grid Exit Points (GXPs).

The network includes sub-transmission at 33,000 volts (33kV), distribution at 11,000 (11kV) volts and low voltage supply (400/230V) to a mixture of urban and rural customers from over 2700km of conductor. The network currently supports a peak demand of 82 MW, including 3MW of embedded generation, and approximately 539 GWh of electricity was carried by the network. The network consists of over \$108M of installed infrastructure to achieve this.

I.3 Asset Management Objectives

Horizon’s Asset Management objectives have been set in the context of the Company’s vision

“To be a recognised infrastructure services provider that generates long term value for our shareholders”¹. We strive to provide a quality service to all our customers at an affordable price, whilst maintaining our role as a Steward and keeping the public safe from harm.

The strategic goals related to the Network business include:

- Achieving our target customer service levels;
- Maintaining the value of the network assets for our owners and customers;
- Ensuring compliance with legislation;
- Continuing to improve staff and public safety;
- Minimising the impact of our activities on the environment; and
- Ensure that we maximise the returns from current regulatory regime

I.4 Key Achievements 2015-16

2015 was a year when a number of key decisions were made that impact the long term evolution of the network. Safety and reliability were key focus points for the decisions. This included not just public safety, but also worker safety and equipment operability.

¹ **Note:**

In 2014 ISO55000 was published as a set of standards, and supersedes PAS55 which will be withdrawn in January 2015.

The Company continues to proactively manage public and worker safety, as well as network risks. We are improving our safety and quality systems having implemented and been accredited in NZS 7901:2008 Safety Management Systems for Public Safety and AS/NZS 4801: Safety Management Systems. Some of the significant safety by design initiatives in 2015 includes:

- Replacing air break switches with enclosed switches. This has reduced our reliance on earthbanks at each ABS site, reducing the impact of copper theft and increasing the safety for the public on our network.
- Replacement programme for single strand copper and steel conductor. The primary purpose of this programme is to remove conductors on the network known to fatigue over time.
- Installation of neutral earthing resistors at zone substations. This has led to a reduction in the stress seen across the network assets by reducing the fault current across the network. It has also reduced the impact of earth faults on the network.
- Removing low road crossings to minimise the impact of high loads and improve safety margins on the road network.
- End of line neutral conductor earthing to ensure that there is a common earth on the MEN network.
- Installation of arc flash schemes in our substation switchrooms.
- Installing arc rated equipment such as Unipak kiosk transformers on the network in higher risk areas.

After a successful first round of reliability projects from 2010-2014, the network experienced a significant reduction in interruption duration (SAIDI) compared to 2010, with some feeders experiencing a SAIDI reduction of up to 30%. With the frequency of outages now a priority for both the network and the regulator, the network will continually review and identify further opportunities to reduce the number of outages affecting customers and along with the number of customers affected by any individual outage. The network has scoped a second round of reliability projects that will further improve the network performance. Some notable projects include:

- Changing the bus configuration in conjunction with replacing aged assets at Galatea substation to eliminate the loss of supply incurred due to faults on either incomer feeder. This will reduce the frequency of outages on that part of the network.
- Securing a 33kV supply from Aniwhenua hydro electric station to improve the quality of supply to the network at Galatea
- Undergrounding of Hinemoa St, in Whakatane and Main St. in Edgecumbe
- Installing surge arrestors on all 50kVA and above transformers
- Increasing the adoption of Fusesavers on key spur lines on the network

There was an increase in the number of vegetation outages from prior years primarily due to a significant storm event in Easter 2014. As with prior years the Network continues to actively pursue improvements in vegetation management and in 2015 and appointed a dedicated vegetation assessor within the Network team to manage the risks posed by trees and tree felling operations.

Of particular note with regard to the capital works programme for 2015 are the following:

- Commencement of the design for the new substation development at Opotiki;
- Replacement of the Plains transformer with a new 16MVA unit similar to Kope T2
- Installation of a new generation, connectivity based SCADA system that will enable us to migrate towards a self-healing network in the future
- Rollout of the Fibre optic cables on our assets at Te Urewera as part of the national Broadband Fibre to Schools project.

1.5 Major Projects 2016-19

The Asset Management Plan includes a number of significant projects² over the next three years. These are summarised in the following table (and described in detail in Appendix C):

Year Start	Project Name	Value(000)
2016	SCADA System upgrade	\$607
2016	Galatea 33kV bus upgrade	\$654
2016	Opotiki Substation Development Stage 1-11kV Site Y1	\$1318
2017	Kope 33kV indoor Conversion	\$1295
2018	2nd 33kV line into Aniwhenua	\$1008
2018	Kope T1 Replacement	\$1205
2018	Opotiki Substation Development Stage 2 -Subtransmission Y1	\$1894
2019	Station Road Replace T1	\$1359
2019	Opotiki Substation Development Stage 2 -Subtransmission Y2	\$1894

The first stage of development at Opotiki has been triggered by load requests from existing industries and is planned for implementation in 2016, with planning and design for a second stage of load increase commencing in 2017. The development will be part funded by Infrastructure Development Contributions (IDCs) from the additional increases in capacity requested. The IDC fee was introduced in 2013 to share the funding of network upgrades between new and existing customers. The additional load imposes a quality constraint on the existing network, which is discussed in section 5.14.

Kope T1 was de-tanked and re-furbished in 2015 following a bushing failure. This prompted a review of the timing of the zone substation transformer replacement program. The result is a re-scheduling of enabling projects to allow other replacement projects to proceed. The most significant of these is Kope 33kV bus indoor conversion, required to allow space for the upgrade of Kope T1, and the relocation of Kope T1 to Ohope zone substation.

1.6 Network Levels of Service

There has been significant investment in recent years to improve reliability to achieve target SAIDI and SAIFI levels. Further work and expenditure will be required to consistently meet our internal targets due in part to the random nature of faults across the network and the likelihood that the number of faults will increase as assets age/deteriorate prior to their replacement. The future focus is to respond more quickly to faults through fault analysis and automation to restore the bulk of customers. This is a shift in focus and builds on the previous strategy of segmenting feeders to limit the number of customers impacted by a fault.

From 1 April 2015 the Default Price-Quality Path (DPP) changes have resulted in the normalised regulated reporting of SAIDI and SAIFI performance no longer being comparable to prior years. The focus of this document is on understanding the underlying drivers of performance and mitigating actions/projects required. The AMP may report both values for SAIDI and SAIFI in the body of the document, unless otherwise stated the values are normalised according to the new regulatory regime.

In 2014-15 the normalised SAIDI and SAIFI performance was 172.9 and 1.98 respectively, both lower than the previous year. Both values were above the Company's internal targets of 145 SAIDI minutes and 1.80 SAIFI which are set on historic trends that normalise the extremes.

² Significant projects are defined as projects with an expected expenditure >\$500K

The internal targets set for the coming year, 2016-17, for both planned and unplanned interruptions on the Horizon Energy network are:

	Planned	Unplanned
SAIDI	20	125
SAIFI	0.14	1.6
CAIDI	140	78

The final DPP determination from the Commerce Commission released on 28 November 2014 has set Horizon Energy's Quality target at 150 minutes for SAIDI and 1.92 for SAIFI (rounded to 3 significant figures). With revised breach positions of 176 for SAIDI and 2.22 for SAIFI. There will also be either a penalty or reward for exceeding or outperforming the regulated targets. The penalty/reward incentive rates applicable to Horizon Energy are as follows: \$4,285/SAIDI minute and \$377,226/SAIFI with the total penalty/reward capped in any given year at 1% of revenue or \$220,300 within the 2015-20 regulatory period. The economic evaluation of investment in reliability projects on the network take into account the above values attributed to SAIDI and SAIFI when assessing project viability.

1.7 Key Asset Challenges

Overall, there is very little growth on the network as evidenced by the volumes delivered, however localised peak demands continue to increase driving the requirement for localised investment. The total GXP coincident peak demand and the total delivered energy have decreased over the last three years. Edgecumbe and Te Kaha GXPs' showed decreased maximum demand while Kawerau and Waitotahi had an increased maximum demand.

Some of the network challenges are:

- Kawerau town feeders are heavily loaded to 50% of the feeder rating at peak load, with substantial de-rating applied to the cables due to soil conditions, cable types (1970's XLPE and PILC) and ageing underground assets. Significant investment is planned on reinforcement and cable replacements in this region in conjunction with a planned upgrade of the 11kV bus by Transpower.
- The assets within the Opotiki region, the network and 11kV distribution system around Opotiki requires further investment, with peak load growth of 4.5% last year, and new applications for step change load increases. Preliminary plans to build a new zone substation at Opotiki are scheduled from 2016 through to 2020 and planning is proceeding on this basis.
- As a result of the failure of one of the supply transformers at Aniwhenua in 2009, the Galatea region has been predominantly supplied from Edgecumbe via the Snake Hill circuit instead of the preferred supply from Aniwhenua. This causes a lower level of reliability, higher system losses, and lower system spare capacity. The Aniwhenua transformer was returned to service in mid-2013 and supply has been agreed to be restored to Aniwhenua from April 2016.
- To plan for future load growth in the Whakatane urban area. A study was undertaken considering the benefits of increasing the size of Kope zone substation, developing new zone substations at Mill Road, or another closer to the CBD. The recommendation made was to retain Kope as a 16 MVA substation, and to plan for another 16 MVA substation closer to the CBD. Longer term, both proposed new substations (CBD and Mill Road) will likely be required, but only if justified by significant load growth. Load flow forecasts using existing organic growth rates show a likely need for the CBD substation development within the next 10 year period, and enabling works for the CBD substation are scheduled from 2025; but any step change load request in either area could trigger accelerated development of these substations. Refer to section 5.12.9 for more detail.

The investment forecasts include expenditure to address these specific issues where they are within the planning period.

Horizon Energy has also been actively assessing the impact of distribution edge technologies (such as solar and batteries) on the future of the network. Horizon Energy was an active participant in the Electricity Network Association initiated New Zealand Transform study as well as conducted its own research when investigating possible solutions to improve the security of supply at Te Kaha. The conclusion from both instances was that the impact of edge technologies on the electricity landscape was going to be minimal. The current strategy to monitor the impact of such technologies is appropriate for the foreseeable future. This includes:

1. Deploying an enhanced, more flexible and resilient communications network starting in 2015 for SCADA field devices, followed by;
2. Deploying an enhanced SCADA system in 2016 to allow the use of smart meter data to indicate outages and issues on the network as well as allow dynamic load transfer; and
3. Monitoring selected LV assets through an agreement with Metrix to provide insight into changes in consumer demand.

The above steps will allow Horizon Energy to quickly respond to the impact of edge technologies, should the regulatory incentives change consumer behaviour in the future,

1.8 Financial Summary

During 2015-16 Horizon Energy forecasts to spend around \$3.1 million on maintenance and \$7.9 million on capital works. The total expenditure uplift in 2016 reflects the capital expenditure on various stages of the Opotiki zone substation and large power transformer replacement at Plains substation. The financial budgets for 2016 onwards are shown in Figure 1.1 and described in further detail in section 8.8. A substantial proportion of the overall asset expenditure is driven by replacement and renewal requirements. Work was carried out in 2014 to validate the bottom up estimates. Two top down models have also been used to predict levels of expenditure given the age of our assets and their estimated service lives. This is described in section 8.5.

Figure 1.1 shows the projected expenditure by maintenance and capital categories for the ten year planning period. Note that it includes expenditure funded by capital contributions.

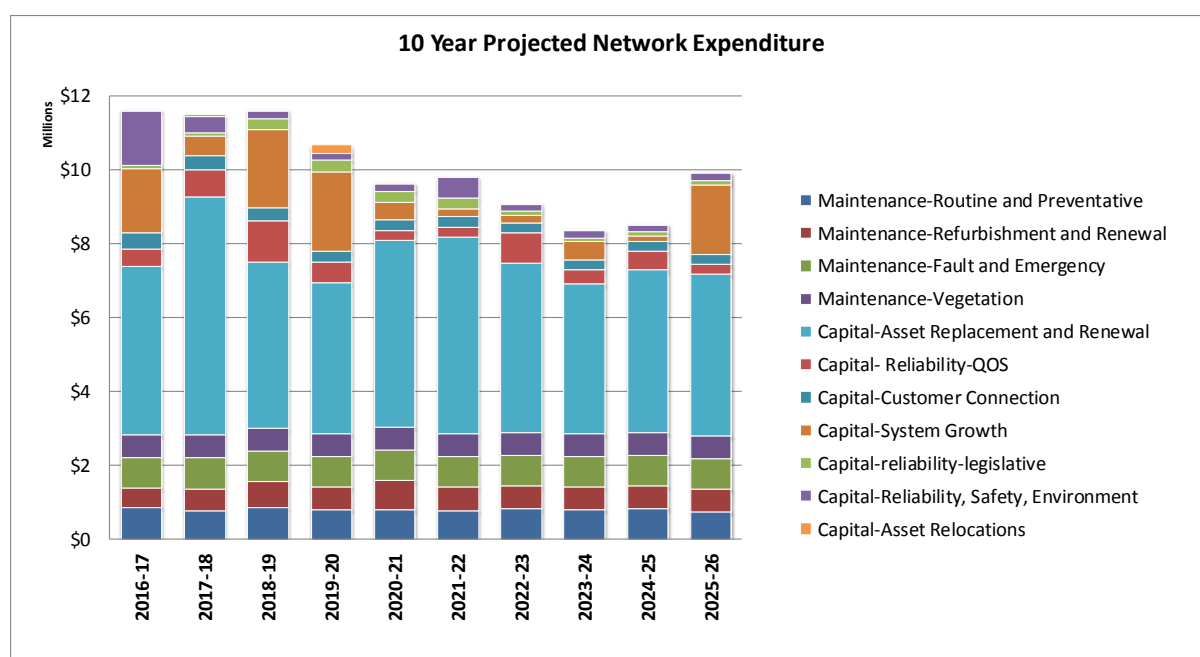


Figure 1.1 - 10 Year Projected Expenditure on Network Assets

Every year the network reviews the bottom-up model of the operational and capital expenditure based on the current state of the asset and the requirement to maintain the value of the asset base for our customers. The expenditure forecast in Figure 1.1 from 2017-2020 is \$11.7M and \$32.0M respectively for network operational and capital expenditure. This is in contrast to the network operational and capital

expenditure used by the Commerce Commission to set allowable revenue over the equivalent period which are \$10.5M and \$22.6M respectively from 2017-2020. These amounts will be subject to the incremental incentive rolling scheme to apply from 1 April 2020 in addition to the quality of supply incentive scheme currently in place. The business implications of the deviations between our own spending requirements, bottom-up forecasts and the Commerce Commission's top-down allowances will be reviewed in 2016 and commented on further in future AMPs to understand the impact of the incremental rolling incentive scheme (IRIS) on the business.

- The maintenance forecast varies year by year. This is caused by:
 - Routine maintenance of certain assets being time based, with different assets having between one to five yearly routine overhaul or maintenance periods.
 - The effects of the different maintenance cycles combining to give a variable amount each year. Condition based maintenance is generally time independent and based on utilisation or assessment and;
 - Significant maintenance costs associated with particular types of asset refurbishment. These values are included in the overall maintenance predictions. Refer to section 8.4.
- Increasing expenditure for years 2016-2019 is driven by the development of Opotiki substation.
- An uplift in expenditure budgeted for 2025-26 is anticipated for the start of the development of a CBD substation.

Compared to the equivalent periods presented in the 2015-2025 AMP the significant changes are:

- Labour and material cost inflation
- Additional monitoring of 33kV assets and critical end of life assets
- 5-10% savings in defect works post the implementation of the Asset Management System and enhanced prioritisation of asset work
- Optimisation of maintenance routines for assets that are under active replacement
- Kawerau 11kV Board enabling works added to the plan
- Replacement of the Station Road Board on the basis of a review of its condition and safety risk
- Increases in replacement expenditure for distribution assets and safety driven projects

It should be noted the financial forecast represents our current understanding of the work required many years in advance and with simplifying assumptions on labour and material costs. As such it is revised each year however the margin for error increases with time.

1.9 Improvement Plan

To enhance our asset management capabilities, to meet potential future demands on the Network and maintain or improve service levels we are working towards the implementation of the following improvements:

- Real-time fleet and resource optimisation with the implementation of vehicle tracking, dispatch and outage management systems;
- Enhancements to the integration of the GIS, job management and financial systems, and development of a business warehouse to improve the efficiency of regulatory reporting; and
- Assessment and selection of an Asset Management System to better manage assets over their lifecycle and position the Company for ISO55000 accreditation.

Section 9, Improvement Plan, summarises the plans in place to continually improve and refine the planning processes.

1.10 Electricity Distribution Information Disclosure Determination 2012

The Commerce Commission published the Electricity Distribution Information Disclosure Determination 2012 - (consolidated in 2015) in March 2015.

Section 2.6 of the Electricity Distribution Information Disclosure Determination 2012 - (consolidated in 2015) sets out the required disclosures relating to the AMP and forecast information. Horizon Energy has provided

the completed reports provided by the Commerce Commission as required under subclause 2.6.6(1) within Appendix A2.

2 Background and Objectives

2.1 Overview

This Asset Management Plan is based on the framework of previous plans but is undergoing a shift in emphasis to the asset management principles embodied in ISO standard ISO55000:2014.

A substantial number of the asset management practices advocated by ISO55000 are currently being employed by the Company and are included in this document. Other information is included to meet the requirements of the Commerce Commission's determinations.

This Asset Management Plan is written in accordance with section 2.6 of the Electricity Distribution Information Disclosure Determination 2012 published by the Commerce Commission in October 2012. For completeness, the information contained in each of the reports required under subclause 2.6.5(1) of the Electricity Distribution Information Disclosure Determination 2012 has been provided in Appendix A2.

The Asset Management Plan is a working document that drives the Company's capital and maintenance planning processes, providing information to all stakeholders about the forward planning objectives and the justifications for the budgets.

2.2 Plan Structure

The structure of this plan is as follows:

Section 1	Executive Summary. Provides an overview of the salient points within the document.
Section 2	Purpose of the AMP, corporate vision, stakeholders and target audiences.
Section 3	Geographical area covered and high level summaries of assets covered under the AMP.
Section 4	Service levels, targets, including performance summaries, analysis of faults and outages.
Section 5	Network planning principles and detailed description of network assets in a parent child relationship. Includes utilisation data to feeder level and identifies any constraints and projects against particular assets.
Section 6	Asset lifecycle management planning; covers asset renewals and refurbishment policies, asset lifecycle replacement and policies that are driving these programs, and asset replacement projects.
Section 7	Summarises the risk policies and programs to minimise risk to the network and Company.
Section 8	Expenditure forecasts and reconciliations. Describes development of budgets and financial forecasts.
Section 9	Improvement Plan. Details improvement initiatives to improve AMP practices and reporting.

Table 2.1 - Plan Structure

To improve usability, this AMP is structured to try to minimise data repetition. Summary data will be carried between sections but this is minimised where possible. All information pertaining to an asset or group of assets is kept in the same section where possible so that all data and information is readily accessible.

2.3 Company Background

The Horizon Energy electrical network is the result of a merger between the Bay of Plenty Electric Power Board and the Whakatane District Council Municipal Electricity Department that occurred in 1989. These two organisations first started the reticulation of the Eastern Bay of Plenty in the mid to late 1920's. During the early to mid-1990's Government initiatives resulted in this Power Board being restructured as a publicly listed integrated electrical lines/supply company (Bay of Plenty Electricity Ltd).

The action undertaken in accordance with the 1998 Electricity Industry Reform Bill, which required the separation of lines and supply businesses, resulted in the lines business selling its generation and supply business (and name), and re-branding itself as Horizon Energy Distribution. The generation and supply business so formed was Bay of Plenty Electricity Ltd, recently re-branded as Nova Energy.

Now days the network distributes electricity to over 24,700 customers from four Grid Exit Points. Its assets include 33kV sub transmission, 11kV distribution and 400V reticulation with a total depreciated replacement value as at 31 March 2014 of over \$110 million.

The Company is a publicly owned company owned by the Eastern Bay Energy Trust on behalf of the consumers connected to the Company's network.

2.4 Asset Management Policy and Corporate Vision

The Asset Management Policy drives the asset management system, and is a means of communication for Executive Management to communicate to Managers, employees and stakeholders the intentions of the Company regarding asset management. It is directly aligned to the Company's Strategic Plan and reflects the corporate Vision and Mission statements.

The following definition from ISO55000 guides Horizon Energy in the generation of this plan:

Asset management involves the balancing of costs, opportunities and risks against the desired performance of assets, to achieve the organisational objectives.

The policy statement below is core to the asset planning principles outlined in this document:

"To manage the electricity supply network assets in a safe manner that provides an appropriate, cost effective level of service for existing and future customers, and to ensure that value is created for all stakeholders within the confines of the regulated framework".

Horizon Energy's asset management process and core purpose is guided by its vision for the future. This vision forms part of the Strategic Plan which is reviewed annually by the Board.

Horizon Energy's Group **Vision** is to be a:

Nationally recognised infrastructure services provider that generates long term value for our shareholders.

The Vision is supported by the **Mission Statement**:

To be the service provider of choice in all market segments that we operate in.

The Horizon Energy Network business unit has as its component of the Mission Statement:

To provide a safe, efficient, sustainable and reliable electricity network service to the Eastern Bay of Plenty that supports growth.

The AMP is a key document that considers the past and predicted performance of the assets along with the processes that are undertaken for their replacement and maintenance. From this on-going monitoring, specific actions and targets are set out to ensure the assets meet the desired outcomes as stated in the Vision and Mission Statements.

2.5 Objectives of the Asset Management Policy

The Asset Management Policy determines the framework for the Asset Management Plan, whilst also ensuring other Company and stakeholder drivers and policies are recognised in its development and implementation.

In summary, the Asset Management Policy complies with the ISO standard ISO55000:2014 Guidelines in that it:³

- Is consistent with the strategic plan;
- Is appropriate with the nature and scale of the Company's assets and operations;
- Is consistent with other Company policies;
- Is compliant with the Company risk management policies;
- Provides the framework for best practice management of assets using an Asset Management Plan as the key driver of asset management practices and policies;
- Is designed to achieve compliance relevant legislation;
- Has due regard to health and safety, and sustainability;
- Provides for a continual improvement in asset management practices;
- Is documented, implemented and maintained;
- Is able to be communicated to all relevant stakeholders and service providers; and
- Can be reviewed so that it remains relevant and consistent with the Strategic Plan.

Expanding on the Asset Management Policy summary points, the following subsections define the requirements and guidelines for developing and managing the Asset Management Plan from the Policy.

a) Strategic Plan

The Asset Management Plan shall be written using Horizon Energy's Strategic Plan as an integral guide to decision making and policy, and will reflect the Corporate Vision and Mission Statements.

The strategic goals related to the Network business include:

- Achieving our target customer service levels;
- Maximising the value of the network assets for our owners and customers;
- Ensuring compliance with legislation;
- Continuing to improve staff and public safety; and
- Minimising the impact of our activities on the environment.

The Strategic Plan is reviewed annually by the Board.

b) Scale of the Company's Operations

The Company owns a large quantity of infrastructure assets spread over a large geographical area. Asset management planning shall consider maximising the lifecycle of assets whilst considering the operational requirements, risks, stakeholder requirements and operational costs involved in doing this. Annual budgets are derived out of the 10 year Asset Management Plan and are approved by the Board of Directors.

³ PAS55 guidelines differ from ISO55000 in that ISO standard provide a broader scope based on the most important features of PAS55. The following passages are derived directly from PAS55 guidelines and will be reviewed and updated to ISO55000 principles during the 2015-16 year.

Horizon Energy achieves economies of scale and efficiencies by adapting industry policies, using standard components, standard designs, and documented work practices and procedures wherever possible. Asset lifecycle replacement shall be determined with consideration of:

- Age;
- Condition;
- Lifetime utilisation;
- Safety for the public, staff and network;
- Maintenance history;
- Operational risk; and
- Load.

c) Consistency of Policies

Policies relevant to asset management are defined in the Quality Systems Manual and Network Standards, which defines policies and procedures around:

- Corporate policies and procedures;
- Network design standards;
- Network operation standards and procedures;
- Health and safety policy;
- Financial standard;
- Contracting standards;
- Personnel policies;
- Stores management; and
- Emergency procedures.

Where policies around network assets are not defined within these documents then the AMP will determine the maintenance and lifecycle requirements for individual assets; but in all cases the approved quality manual or network standards shall take precedence over any AMP determination if there is any conflict.

Various non-network sections of the Quality Systems Manual are managed by the designated Manager.

Standards relevant to network assets are approved by the General Manager Network.

Wherever possible, all works shall be designed and built to the relevant AS/NZS standard, or an IEC standard if an AS/NZS standard does not exist. Recommendations from professional or organisational bodies incorporated in New Zealand should be referred to and any recommendations made by them considered and approved prior to use. This includes, but is not limited to:

- Electricity Engineers Association (EEA);
- Institution of Professional Engineers New Zealand (IPENZ); and
- Electricity Networks Association (ENA).

d) Compliant with the Company Risk Management Policies

The risk management sections of the Quality Systems Manual include, but are not limited to:

- Emergency Procedures;
- Health and Safety Manual;
- Risk Management Plan;
- Environmental Policy; and
- Disaster Recovery Plans.

There shall be no deviation from the risk management policies included in these standards. Any discrepancies must be brought to the attention of Management for determination of appropriate actions.

Risk management principles which consider due risks to the Company, public, and individuals shall be an integral part of the design process in engineering new works and in assessing the condition of existing assets.

All implementation of works and work practices shall comply with relevant health and safety policies.

e) Provides the frame work for best practice management of assets using an Asset Management Plan as the key driver of asset management practices and policies

The Asset Management Plan and associated forward works plan shall drive the annual capital and maintenance plan and budget, within the dimensions specified by the Board representing shareholders and other stake holders.

The Asset Management Plan will forecast ahead for a minimum ten year rolling period.

Asset management practices shall follow the policies and practices defined in the ISO standard ISO55000:2014

Best asset management practices include the following, and these considerations have been incorporated into all asset lifecycle and maintenance deliberations:

Assets critical to sustained performance:

- How critical the assets are to system operations;
- Conducting of failure analysis (root cause analysis, failure mode analysis);
- Determining the probability of failure and listing assets by failure type;
- Analysing failure and consequences;
- Using asset decay curves; and
- Reviewing and updating system's vulnerability assessment.

Minimum lifecycle costs:

- Moving from reactive maintenance to preventative maintenance;
- Knowing the costs and benefits of rehabilitation versus replacement;
- Looking at lifecycle costs, especially for critical assets;
- Deploying resources based on asset conditions;
- Analysing the causes of asset failure to develop specific response plans; and
- Asset nominal life is as defined in the 2004 ODV Handbook unless specified different in the AMP for specific classes of assets.

Sustainable levels of service:

- Analysing current and anticipated customer demand and satisfaction with the system;
- Understanding current and anticipated regulatory requirements;
- Writing and communicating a level of service "agreement" that describes the system's performance targets; and
- Using level of service standards to track system performance over time.

Prioritisation for operational expenditure and asset replacement works shall be based on the impact to the network and number of customers or load affected if the asset should fail in service. Industry standard measurements (SAIDI, SAIFI) shall be used to determine the relative performance of assets and network enhancements. Other considerations shall include public safety, environmental and consistency with strategic plans.

f) Designed to achieve compliance with relevant legislation

The Asset Management Plan and all works shall take into account the following legislative requirements and subsequent amendments:

- Electricity Act 1992;
- Electricity Distribution Information Disclosure Determination 2012 – (consolidated in 2015)
- Electricity Distribution Services Default Price-Quality Path Determination 2015;
- Electricity Industry Act 2010;
- Electricity (Safety) Regulations 2010;
- Energy Companies Act 1992;
- Electricity Industry Reform Act 1998;
- Resource Management Act 1991;
- Building Act 2004;
- Environment Act 1986;
- Health & Safety in Employment Act 1992;
- Health and Safety in Employment Regulations 1999;
- Electricity (Hazards from Trees) Regulations 2003; and
- Commerce Act 1986.

Local legislation and by-law issues by the following territorial authorities:

- Bay of Plenty Regional Council;
- Whakatane District Council;
- Kawerau District Council; and
- Opotiki District Council.

The requirements of these bodies are included in:

- Policy Statements;
- Land Management Plans; and
- Coastal Environmental Plans and District Plans.

Other organisations that have requirements that must be adhered to are:

- New Zealand Transport Agency (NZTA) as stated in its State Highway Plan;
- Transpower; and
- Telecommunication companies.

g) Has due regard to health and safety, and sustainability

- The AMP shall not be in conflict with any Company health and safety policy;
- The AMP document provides a long term management plan; although the document itself does not have direct responsibility for the implementation of health and safety practices, the implementation of asset management planning, as works derived from the AMP, does;
- Health and safety shall be an integral part of all implementation works planning and shall be incorporated in all aspects of the works. The health and safety policy will be managed by a designated person;
- Budgets derived from the AMP 10 year plan are for works. Departmental budgets must additionally allow for health and safety practices, including training, staff retention and recruitment, safety equipment, inspections, safe work practices, public safety, certification, etc.;
- Company health and safety policies describe the responsibilities and the requirements of staff and contractors to work in a safe and healthy environment; and
- Environmental considerations and public impact are to be considered in all works. These shall be:
 - Visual interference;
 - Physical interference;
 - Disturbance to domestic services and other utility assets;
 - Reinstatement of work sites;
 - Minimising operating noise including machinery;
 - Emission of unnecessary fumes and pollutants;

- Minimising contamination risk by oil, fuel or other contaminants;
- Engineering assessments reflect the life cycle impact of the various alternatives;
- Optimise the useful life of its assets;
- Minimising the likelihood of property damage;
- Noise;
- Public safety; and
- End of life policies.

h) Provides for a continual improvement in asset management practices

The guiding principles for asset management improvements are:

- The AMP is a living document and will be continuously updated;
- Works will be added to the long term 10 year works plan throughout the year;
- All works prices will be at current costs and refreshed annually;
- There will be a person responsible for maintaining and managing the asset plan documentation and data up-dates;
- Network standards will be reviewed and amended on an as-required basis ensuring new technologies, practices and equipment will have network standards established to ensure consistency of design and work practices;
- The asset management practices and plan are to be assessed regularly for asset management maturity to ISO 55000 and to the criteria defined by the Electricity Distribution Information Disclosure Determination 2012. Areas showing a low maturity are to be prioritised for improvement;
- Regular (generally not more than three yearly) assessments of network and stakeholder requirements; and
- The Asset Management practices which drive improvements include:
 - Setting of forward service levels and retrospective measurement against these;
 - Comparison of actual expenditure against budgets at high level and at project level;
 - Regular reporting to Management and Board on variance to budgets and non-compliance issues;
 - The review of complaints by public, and;
 - The review of satisfaction level of stakeholders.

To facilitate consistency of reporting between the AMP and regulatory reporting, the following principles will apply:

- Interconnection of asset management and financial management systems shall be streamlined to provide traceable and repeatable reporting between years;
- Reports shall be developed using a change control process to facilitate any required changes directly linked to regulatory reporting;
- Sufficient data categories shall be built into any reporting system to enable regulatory reporting to be carried out with minimum manual data manipulation;
- Where reporting assumptions are made these must be clearly stated; and
- The Asset Management Plan data and regulatory reporting data will be the same, if not; the reasons for discrepancies are to be noted.

i) Is able to be communicated to all relevant stakeholders and service providers

The AMP will be published annually on the Company internet and intranet and will be provided in printed form to:

- Any person who requests a copy.

j) Can be reviewed so that it remains relevant and consistent with the Strategic Plan

Reviews of the AMP and 10 year works plan shall occur on a regular basis:

- Works reviews are on a continuous basis;
- Annual load and asset data updates August;
- Policies and works reviews by Network during the year;
- Draft works plan issued to contracting and finance for review and budgeting by November;
- Issue draft budgets to Management and Contractor– January;
- Issue to Board – February;
- Approval by Board – March; and
- Publish I April each year.

2.6 Corporate Strategic Plan

In conjunction with the Board, the Chief Executive is responsible for the preparation of the Company's Strategic Plan and review activities. The Strategic Plan shall:

- Be reviewed and adopted by the Board annually;
- Have a five-year focus;
- Include a staff resource plan covering staff numbers and skills; and
- Include objectives for achievement of the plan with responsibilities and achievement dates.

The Strategic Plan looks at many areas of the existing and potential business activities. The strategic goals related to the Network business include:

- Achieve prescribed customer service levels;
- Maximise the value of the network assets for the owners;
- Ensure legislative compliance;
- Continue to improve staff and public safety; and
- Ensure compliant and improving environmental practices.

To achieve those goals the Company strives to achieve industry best practice through the following:

- Optimising system reliability and the quality of supply as required by consumers;
- Providing an effective 24 hour service;
- Optimising the network configuration to ensure the system fully utilises its available capacity and operates in the most efficient manner;
- Managing the system load profile;
- Meet changing customer requirements;
- Providing a service in an equitable manner;
- Ensuring the system is installed and maintained in a manner that removes or mitigates any safety hazard to the general public and its staff;
- Ensure all contractors undertaking works on the network are skilled and competent in the activity they are to perform; and
- Select technology and designs considering the life cycle economic and environmental costs.

The following definitions affect the need, priority and scope of asset management practices summarised as:

(a) Shareholder Wealth

Shareholder wealth is enhanced when corporate objectives are met and stakeholders' targets are achieved. This requires an AMP that is continually up-dated to meet new and improved targets.

(b) Customer Service

At present Horizon Energy's direct customers are the retailers that sell electricity to consumers connected to the Horizon Energy network, and major customers that have Connection Agreements with the Company.

Through this relationship with the retailers, Horizon Energy has a prime responsibility to the electricity end-user, as indirect customers, for the performance and reliability of the network.

(c) Network Expansion

Horizon Energy has a goal of meeting the on-going and future needs of network users at the most efficient economic cost.

AMP planning provides clear justification for forward work programs and provides the ability to level out funding demands and account for changes in asset service potential.

The network must have the capability to meet the demands of existing consumers, and the ability to be augmented as required to meet the needs of increased demand and new consumers

(d) Safety

Horizon Energy's objective is to achieve high standards of health and safety through the prevention of accidents and the promotion of health and welfare.

Horizon Energy states in its safety policy that it will:

- **S**upport and nurture a culture that promotes employee wellness and raises health and safety awareness;
- **A**dopt and maintain management systems designed to support continuous performance improvement;
- **F**urnish necessary information, training and support and provide a healthy and safe working environment;
- **E**nsure commitment from employees and all levels of management; and
- **R**equire our business partners to meet the same health and safety standards.

In conjunction with the above, Horizon Energy maintains a safety management system to safeguard members of the public and property by providing:

- Preparation, implementation and review of policies, procedures and guidelines relevant to the safe design and management of the network assets; and
- Control of the safety and integrity of those assets and the minimisation of the potential for, and consequences of failure.

The Company's occupational health and safety policies and procedures are comprehensive and are documented in Horizon Energy's Quality system.

In recognition of the commitment and importance of this objective, the Company has a Health and Safety Manager, who along with line managers, ensures that the Company, its staff and its contractors comply with health and safety requirements and industry best practice at all times.

Horizon Energy achieved certification under AS/NZS 4801 Occupational Health and Safety Management and NZS 7901 Safety Management System for Public Safety certification in 2012 and maintains certification.

(e) Economic Efficiency (Pricing)

End use customers and electricity retailers have an interest in ensuring that Horizon Energy conveys electricity at the price-quality level expected by consumers. The AMP supports economic efficiency by:

- Providing a basis for monitoring asset performance and utilisation, taking into account pricing;
- Enabling asset managers to anticipate, plan, and prioritise asset maintenance and renewal expenditure;
- Plan funding of asset maintenance and renewal;
- Quantifying any environmental effects;
- Extending the life of an asset by optimising maintenance programs and demand management;
- Ensuring that customer consultation is undertaken and their expectations are considered in all planning undertaken; and
- Relating the investment on reliability to the type and number of customers being supplied.

(f) Environmental

Horizon Energy encourages its staff, customers and suppliers to interact with the environment in a responsible manner for the sustainable benefit of the community. Environmental requirements for works are set out in Horizon Energy's standards.

Horizon Energy is working towards Environmental certification under NZS14000.

Horizon Energy strives to implement its policies and procedures such that the Company adheres to the principles contained within the Resource Management Act 1991. Notifiable works are carried out after receiving consent from the relevant District and/or Regional Council.

- All work undertaken by Horizon Energy includes consideration for environmental effects Visual interference;
- Disturbance to domestic services and other utility assets;
- Reinstatement of work sites;
- Minimising operating noise including machinery;
- Emission of unnecessary fumes and pollutants;
- Minimising contamination risk by oil, fuel or other contaminants;
- Engineering assessments reflect the life cycle impact of the various alternatives;
- Optimise the useful life of its assets; and
- Minimising the likelihood of property damage.

2.7 Period Covered

This plan provides a long-term indication of AMP requirements and specific work programs over the 10 year planning period from 1 April 2016 to 31 March 2026.

This plan is based on recorded levels of service, current available information and the experience and knowledge of Horizon Energy staff and key contractors/consultants. The plan does not commit the Company to any specific project or work mentioned in the plan and Horizon Energy may change the plan at any time to reflect changing needs or new information.

2.8 AMP Plan Approval

This plan was approved by the Horizon Energy Board of Directors on 11 March 2016.

2.9 Stakeholders

2.9.1 Stakeholder Interest Identification

Key stakeholders methods used to identify their interests are presented over four pages in Table 2.2 - Stakeholder Interest Identification

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2.9.2 Accommodation of Interests

Stakeholder's interests are considered within Horizon Energy's asset management practices. The desire to provide a reliable electricity supply is common to all stakeholders but must be undertaken in a manner that ensures a price/quality trade off that matches the stakeholder's expectation.

2.9.3 Conflict Resolution

The framework that Horizon Energy uses in resolving conflict considers the following factors:

- Safe and reliable electricity supply;

- Legal compliance;
- Cost effectiveness;
- Fairness and equitable solution to all parties; and
- Regulatory requirement.

Specific issues of conflict are expected to be resolved directly between the Company and the other party by a complaints investigation process and negotiation. Should there not be a satisfactory resolution neither party may refer the dispute to the Electricity and Gas Complaints Commission.

Stakeholders

Stakeholder	Method of Identifying Stakeholder Interests	Key Interests	Accommodation into AMP Process
Customers (end user and retailers)	<ul style="list-style-type: none"> Customer satisfaction surveys Use of System Agreements with retailers 	<p>Electricity end-users require the product purchased to be delivered consistently and to meet the level of price versus quality that they desire. In particular they have concerns with regard to the level of charges made by Horizon Energy, the network performance and response to network development requirements.</p> <p>Network Users are mainly electricity retail companies who have a Network Use of System Agreement with Horizon Energy for the transportation of electrical energy that they are selling to end-use customers.</p>	<ul style="list-style-type: none"> Adequacy - security and capacity, refer to Section 4, Level of Service (LOS) Reliability – frequency and duration of supply interruptions, refer to Section 4, LOS Growth – requests for additions or alterations to the network, refer to Section 6, Asset Utilisation Supply quality – refer to Section 4, LOS
Customers (Major direct connect agreements)	<ul style="list-style-type: none"> Direct customer meetings and feedback 	<p>Major consumers in the network area have individual agreements for the provision of their connection to the nearest GXP. These companies have a specific interest that the network performance and quality of supply will deliver electricity in accordance with their Distribution Services or Connection Agreements to ensure they are able to meet their operation requirements.</p>	<ul style="list-style-type: none"> Quality of supply and capacity, Sections 4 and 5 Lifecycle management planning for direct connect assets, refer to Section 6 Load growth management, refer to Section 5
Regulator (Commerce Commission)	<ul style="list-style-type: none"> Submissions Relationship meetings Industry forums 	<ul style="list-style-type: none"> Statutory obligations Economic efficiency Conformity/Compliance Delivery of Plan 	<ul style="list-style-type: none"> Asset investment – refer to Section 6, Lifecycle Management Plan Operating cost – refer to Section 8, Financial Summary Network Performance and quality of supply, refer to Section 4, LOS Structure of the AMP document

Stakeholder	Method of Identifying Stakeholder Interests	Key Interests	Accommodation into AMP Process
Industry regulators (Commerce Commission, Ministry of Business Innovation and Employment, Electricity Authority, Ministry for the Environment, Department of Labour)	<ul style="list-style-type: none"> • Submissions • Relationship meetings • Industry forums 	<ul style="list-style-type: none"> • Statutory obligations • Economic efficiency • Environmentally and safe service • Safety of staff and the public • Staff welfare 	<ul style="list-style-type: none"> • As above • Environmental management – refer to Section 7, Risk Management • Safety – refer to Section 7, Risk Management
District and Regional Councils	<ul style="list-style-type: none"> • Coordination meetings • Planning awareness • Submissions • Relationship meetings • Membership of strategy groups 	Four District Councils are stakeholders in the Company and have an interest in the Company's performance and in particular assets that are installed in the public domain and in the conversion of overhead lines to underground cables. These are the Whakatane, Opotiki, Kawerau and Rotorua District Councils.	<ul style="list-style-type: none"> • Asset investment – undergrounding of overhead lines, refer to Section 6, Lifecycle Management Plan • Emergency response – refer to Section 7, Risk Management • Environmental management – refer to Section 7, Risk Management
Shareholders and lenders	<ul style="list-style-type: none"> • Relationship meetings • Shareholder briefing (AGM) • Annual Report 	Horizon is wholly owned by The Eastern Bay Energy Trust. A key shareholder interest is the maximisation of Company value and the return of an appropriate dividend through the efficient and effective operation of the Company. The banks have an interest in the security of any debt incurred.	<ul style="list-style-type: none"> • Return on investment – refer to Section 8, Financial Summary • Good service for customers - refer to Section 4, Levels of Service • Prudent investment practices

Stakeholder	Method of Identifying Stakeholder Interests	Key Interests	Accommodation into AMP Process
Other stakeholders (Transpower and Embedded generators)	<ul style="list-style-type: none"> Regular communications at planning and operational levels 	<p>Transpower have an interest in the maintenance and growth of their business, the impact on the quality of supply to other customers and their relationship as portrayed to the end user of energy. Both companies have significant mutual interest in each other's future development plans.</p> <p>They are also interested in the revenue they receive from Horizon Energy.</p> <p>Embedded generators have an interest in the on-going performance of the transmission corridor through which they get their energy to the market.</p>	<ul style="list-style-type: none"> Maintenance management – refer to Section 6, Lifecycle Management Plan Growth planning, Asset Utilisation, and Development Planning – refer to Section 5 Network Planning Long term financial forecasts – refer to Section 8, Financial Summary
Contractors	<ul style="list-style-type: none"> Contract Procurement framework 	<p>Horizon Energy engages contractors for much of its fieldwork and also some of its administrative requirements. Contractors have a stakeholder involvement in the Company as a source of income (and a measure of their efficiency reflected by Horizon Energy's performance). Contractors also have an interest in work continuity, a safe work environment and a good contractual relationship.</p>	<ul style="list-style-type: none"> Workflow – refer to Section 6, Lifecycle Management Plan Safety – Risk Management including auditing, refer to Section 7, Risk Management
Board of Directors	<ul style="list-style-type: none"> Monthly Board meetings Regular meetings with senior management 	<p>The Board of Directors have a specific interest in the Company's performance related to its statutory obligations and their responsibilities as the governing body of the Company on behalf of the shareholders.</p> <p>Not the least of these is the Company's planned investment profile.</p>	<ul style="list-style-type: none"> Financial performance – refer to Section 8, Financial Expenditure Summary – refer Section 8 Risk Management and good governance – refer to Section 7, Risk Management Corporate KPI's - refer to Section 4, LOS

Stakeholder	Method of Identifying Stakeholder Interests	Key Interests	Accommodation into AMP Process
Staff	<ul style="list-style-type: none"> Performance appraisals Internal communications Allocation of responsibilities 	<p>Staff implements the Company's AMP and policies to maximise utilisation and the best performance of the Company assets. They are interested in the successful achievement of network performance targets and in meeting the requirements of network users. Staff also have an interest in the safety, profitability, longevity and reputation of the Company.</p> <p>Accountability for financial performance is clearly defined and allocated to those senior managers best able to manage the outcome. Delegated authorities for expenditure are similarly well defined and provide for appropriate levels of expenditure beyond which detailed business cases are required prior to any financial commitment being entered into.</p>	<ul style="list-style-type: none"> Health and Safety - refer to Section 7, Risk Management Professional work environment - refer to Section 7, Risk Management Good business culture - refer to Section 7, Risk Management
Landowners and the General Public	<ul style="list-style-type: none"> Meetings with Landowners prior to the installation or planned maintenance of assets Vegetation Control Programmes Asset inspection programmes Feedback through local Authorities Public safety messages using various media 	<ul style="list-style-type: none"> The integrity of their property rights The mitigation or removal of hazards Safety of the assets Environmental degradation 	<ul style="list-style-type: none"> Maintenance management – refer to Section 6, Lifecycle Management Plan Growth planning, Asset Utilisation, and Development Planning – refer to Section 5 Network Planning Safety – Risk Management including auditing, refer to Section 7, Risk Management

Table 2.2 - Stakeholder Interest Identification

2.10 Asset Management Responsibilities

2.10.1 Governance and Board Reporting

Horizon Energy is a Trust owned company governed by a Board of Directors and managed by an Executive Management Team. The following sets out the Governance and Management reporting relationships.

2.10.2 Accountabilities and Responsibilities

Horizon Energy's hierarchal Management model for defining asset management responsibilities and relationships is presented in Figure 2.1. In 2015 Horizon Energy became 100% Trust owned and was subsequently delisted from the NZ Stock Exchange (NZX).

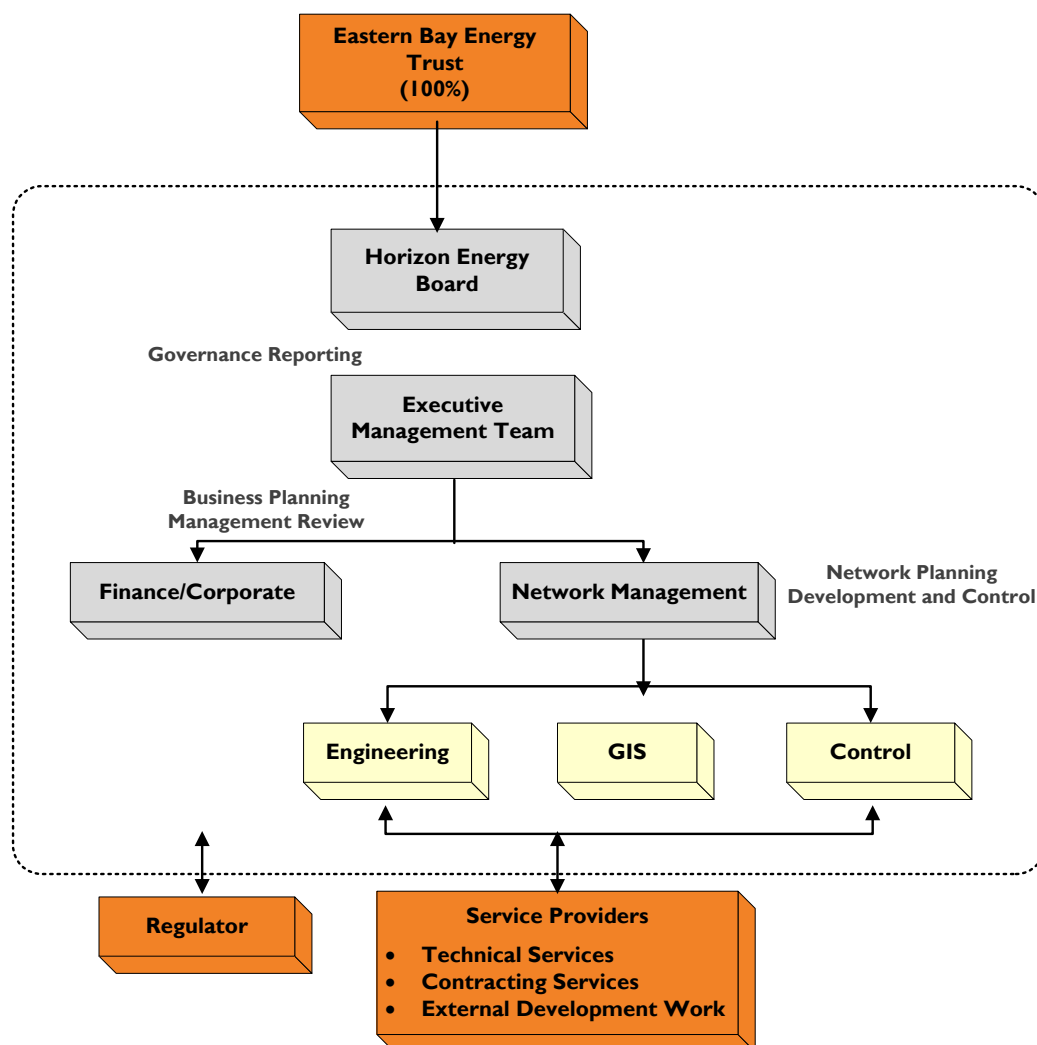


Figure 2.1 - Asset Management Responsibilities at Horizon Energy

A summary of the parties identified above and their relationship towards managing the assets follows:

Horizon Energy Board

The Board is responsible for the overall corporate governance of Horizon Energy and are responsible to all shareholders for their actions.

The governance role of the Board includes the setting and monitoring the delivery of the Company's strategic direction. The Directors meet at least ten times a year and more often if required to undertake specific consideration or to attend committee meetings.

The Board reviews and approves the following asset management processes and plans:

- Strategic Plan;
- Health and safety KPI's
- The Asset Management Plan document;
- Annual operating and capital expenditure forecasts;
- Delegated operating and financial authorities for the Executive Management Team;
- Major projects;
- Risk Management Plan;
- Interim and Annual Reports; and
- Disclosure documents.

The Board approves any purchase expenditure >\$250,000.

Executive Management Team

The Executive Management Team has the responsibility for the day to day management of Horizon Energy, delivering the asset management plan and all operational systems.

The regular reporting to the Board includes the following:

- Any new risks identified;
- Annual Strategic Plan objectives;
- Annual Budgets (directly linked to AMP);
- Actual financial performance against budget;
- Business unit operational key issues reports;
- Monthly reports presenting the monthly KPI's including SAIDI and SAIFI;
- Major project approval as required;
- Major project progress and report against annual budgets;
- Compliance and safety reports; and
- Financial and corporate reporting

This Team is led by the Chief Executive Officer and consists of:

Chief Executive Officer

- Responsible for all non-governance management of the Company, its assets and the service that is supplied to its customers and other stakeholders; health and safety; and
- Responsible for delivering the AMP and for achieving the operational objectives.

Chief Financial Officer/Company Secretary

- Provides financial accounting and business information in support of all Company operations;
- Ensures that adequate financial resources are available; and
- Also co-ordinates the risk management review process.

General Manager Electrical Services

- Manages the subsidiary Company Horizon Services Limited (HSL) that provides the majority of the field services.

Group People and Performance Manager

- Responsible for ensuring the safety and wellbeing of staff in conjunction with line managers and also the provision and monitoring of training, standards and certifications;
- Compliance of Standards, EGCC, Risk Mitigation; and
- Safety audits and safety policies.

General Manager Commercial

- Oversees the regulatory function within the Company, responsible for all regulatory compliance requirements;
- Leads the Commercial team that delivers the revenue assurance and pricing function for the Company; and
- Also the Executive in charge of the ICT function, providing corporate infrastructure and systems for the Company.

General Manager Network

Responsible for all network operations including:

- Service delivery;
- Operations;
- Planning;
- GIS and asset information systems;
- Resourcing and planning; and
- Capital plan.

Network Team

This group is led by the General Manager Network and consists of the following specific roles:

Asset Manager

- Responsible for the long term planning;
- Responsible for standard setting; and
- Responsible for condition assessment and data analysis.

Operations Manager

- Responsible for management of the operations control centre;
- Responsible for the safe and efficient day to day operations of the Network;
- Management and co-ordination of planned outages;
- Liaison with energy suppliers and customers; and
- Control of switching required to manage the network.

Service Delivery Manager

- Implementation of the capital and operational maintenance plans;
- Customer driven works; and
- Application of the network standards and designs.

Control Room Operators

- Manage the processes installed to monitor and control network operating systems;
- Provide operational network related services and the customer connection data; and
- Provide a network support base 24 hours a day, 7 days a week.

Engineering Staff

- Planning and supervising maintenance activities;
- Identifying and managing threats to supply integrity;
- Providing engineering and project management services for network works; and
- Processing of new connections for supply.

Planning and Design Engineer

- Primary responsibility for producing and maintaining the asset management plan;
- Manages long term (10 year) plan;
- Assessment of the performance of the network system; and
- Development of projects that will enhance performance, address issues of poor supply, quality or cater for growth.

Draughting/GIS Manager

- Management of the asset records, drawings, and geographical information services in support of network operational, planning and financial objectives. Manages asset inspections.

2.10.3 Field Operations

Field service operations provide the support to manage and maintain the network, and to provide response to faults and emergencies, assess asset condition, and undertake the network maintenance and capital works.

Preferred Provider	Service	Service Provided
Horizon Energy	Asset Inspection	Horizon has employed dedicated asset inspectors to ensure seamless information flow from asset inspection into asset recording systems.
Horizon Energy, Horizon Services Limited	Project Management and Estimating	Provision of project management, supervision, quantity surveying and estimating skills.
	Vegetation Control	Skilled Arborists providing vegetation management and tree trimming services. These services are managed by a dedicated Horizon Vegetation Assessor.
Horizon Services Limited	Technical Services	Technician level support for substation protection and maintenance Radio communications support Cable jointing, cable locations

Preferred Provider	Service	Service Provided
	Line Construction and Maintenance	Line maintenance Line construction, network and private Faults response
	Live Line Services	Specialist crew that are able to perform 11kV and 33kV line work whilst the line is still energised
	Logistics	Dedicated specialist network warehouse service including spares management and procurement services.
	Fault Response	Fault response for all network faults.
ESP Technologies Limited	Electrical Services	Electricians for network and non-network (private) support Street lighting servicing Data cabling

To be able to deliver on the plan detailed in this AMP there are a number of different strategies and plans either in place or under development intending to streamline and improve the planning and delivery of works.

Horizon Energy provides the following field operations:

- Operation control;
- Engineering services;
- Design and project management;
- Network management; and
- Asset condition assessment

HSL provide the following field operations:

- Fault response;
- Routine maintenance operations;
- Defect remedial works;
- Implementation of the capital works plan;
- Customer liaison for works and connections;
- Disconnections;
- Management of spare parts and consumables;
- Live line services; and
- Project works

The existing field operations model is based around utilising HSL as a first call service provider. Where neither HSL nor Horizon Energy have the skill sets or specialised equipment required, or undertaking the works would overload the capability of either to successfully deliver the service required, external specialised contractors and consultants are engaged to complete work. Services that are outsourced to a number of different suppliers are:

- Specialised services for SCADA and communications systems;
- Detailed or specialised design engineering, protection systems, earthing design, detailed engineering and draughting services;
- Thermal vision, partial discharge, and tan–delta cable testing;
- Specialised substation maintenance and construction work;
- Protection design, programming and testing;
- Specialised audits and compliance monitoring;
- Non-destructive testing of assets;
- Oil testing;
- Roadside safety and traffic management;
- Specialised construction works; and
- Civil works.

Service delivery improvements being implemented or considered are:

- Greater use of unit rate form of contracts;
- Competitive fixed price tender process for certain works;
- Single bid fixed price works;
- Design and build contracts;
- More use of sub-contract models to better define responsibilities; and
- Formalising supplier / contractor relationships with the implementation of service level agreements.

2.11 Asset Management Documentation, Controls and Review Processes

The data used to manage the network is derived from many sources as summarised in Table 2.3. The source data is supplied by contractors and staff in either hard copy or electronic formats and is verified by the individual engineer responsible for the works prior to passing to the GIS Team for further validation and data entry. Due to the various input sources, multiple non-integrated data storage systems, and the historical practice of capturing electronic data input from field updated forms, this data has varying levels of accuracy. The data sources currently used, and the levels of confidence in the data that they contain, is summarised below in Table 2.3, Asset Data Sources:

Item Description	Record Type	Record Location/Software	Data Confidence	System Management	Planned Improvements
Overhead Lines	Plans/GIS	Oracle DB /GIS	High	GIS team	On going asset inspection
Zone Substation Wiring	Plans	Drawing Office	Medium	GIS Team	Drawing verification project
Streetlight Connections	Database/GIS	Oracle DB /GIS	Medium	GIS Team	Link to Councils' Data
11kV Switchgear	Database/GIS	Oracle DB /GIS	High	GIS Team	Link Maintenance Records
11/0.4 kV Transformers	Database/GIS	Oracle DB /GIS	High	GIS Team	Link Maintenance Records
Overhead Distribution Equipment and Poles	Database/GIS	Oracle DB /GIS	High	GIS Team	Link Maintenance Records
Distribution Substations	Database/GIS	Oracle DB /GIS	High	GIS Team	Link Maintenance Records
Zone Substation Transformers	Card System/ Database	Engineering Office and Contractor Records plus some on SQL Server	High	GIS Team	Link Maintenance Records
Zone Substation Protection Relays	Card System/ Database	Engineering Office and Contractor Records plus some on SQL Server	Medium/High	Planning Engineer	Centralised records management system
Zone Substation Switchgear and Field Circuit Breakers	Card System/ Database	Engineering Office and Contractor Records plus some on SQL Server	High	GIS Team	Centralised records management system
Zone Substation Maintenance Records	Log Book and Card System	Individual Zone Substations and Maintenance Contractor	Medium	Contractor	Integration into asset management system
Underground Cables Sizes and Cable Type	Plans /GIS	Oracle DB /GIS	Medium	GIS Team	Sizes and type verified as required for projects or works
11kV Underground Cables Location	GIS	Oracle DB /GIS	Medium/High	GIS Team	Locations verified prior to any work undertaken. There is no plan to improve this asset detail for existing installed assets.

Item Description	Record Type	Record Location/Software	Data Confidence	System Management	Planned Improvements
400V Underground Cables Location	GIS	Drawing Office and GIS terminals	Medium	GIS Team	Marked up as located Individually located for excavation requests. No data accuracy improvement planned.
Transpower and Embedded Generation Demand Data	SQL server	Accounts / SQL Server	High	GM Commercial	
SCADA Equipment	Database	SQL Server	High	Operations Manager	
SCADA Historian	Database	SQL Server	High	Operations Manager	
Applications for Supply	Database and paper record	SQL Server and manual filing system	High	Operations Manager	
Works Order and Purchase Order Database	Database	SQL Server	High	IT Team	Microsoft Dynamics Navision
Works Analysis against Regulatory Reporting Categories	Database from works NAV	Analysed by spread sheets and SQL reporting	High	GM Commercial	Data rules applied at source entry reduces category choices. Linked to asset in new ISR system.
Fault Logs	Database	SQL Server	High	Operations Manager	Audited process and system
Defects	Database	SQL Server	Medium	SD Manager	To be integrated in to centralised storage system
Customer Connections (ICP)	Database	SQL Server	High	SD Manager	ICP database and registry differ slightly, to be reconciled as part of ISR project
Works Plan	Spreadsheet	Server	High	Planning Engineer	Rolling updates, estimating databases

Table 2.3 - Asset Data Sources

The criteria of high, medium and low are used in assessing the level of confidence for the data as follows:

- High - the data is regarded as accurate and can be relied on with little or no verification, has a verification tag attached in GIS, has been marked as-built, or is collected electronically with little human intervention;
- Medium - historical records, GIS data with no verification tag, data that is manually collected with limited verification process or limited additional information. Data that should be verified prior to use; and
- Low - historical data that has been transferred manually between capture and storage systems with little verification. Manually recorded data that cannot be readily verified. Existing data that requires a level of research or verification before it can be reliably used.

2.11.1 Independent Review of Asset Management Practices

As part of Horizon Energy's desire to monitor and improve the asset management practices, external consultant AECOM was engaged during 2013 to undertake a review to determine Horizon Energy's readiness for assessment and potential accreditation to PAS55 standard for asset management practices.

Since the completion of this assessment, the International Standards Organisation has released a new standard, ISO55000, which is based on PAS55, and PAS55 has been withdrawn. The following sections refer to the Company's assessed compliance to PAS55 as at 2013, and the findings, assessments, and recommendations have not been updated with reference to ISO55000 at this stage.

General Findings

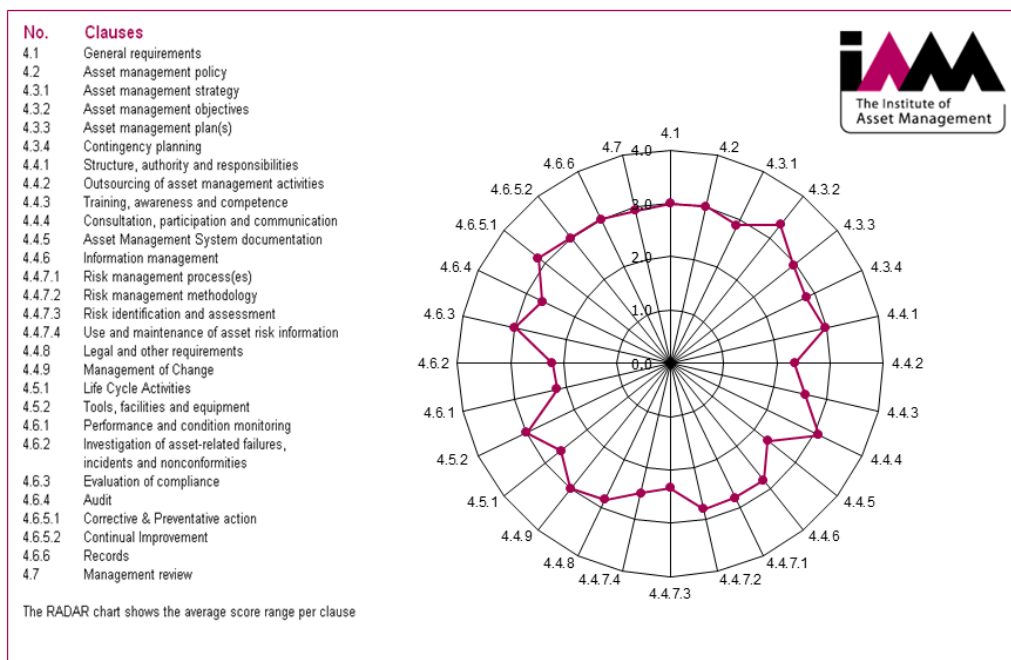
The purpose of the review was to undertake a gap analysis of the current Horizon Energy Asset Management System to identify any necessary actions which will need to be undertaken to ensure alignment with and to achieve formal accreditation in accordance with PAS55.

To obtain PAS55 accreditation the requirement was to achieve a maturity level of above 2.5 in all 28 categories of the assessment. Horizon Energy set a goal of achieving above a level 3.0 in all 28 categories of the assessment.

The assessment results for the maturity level for asset management are shown in the diagram below and have been scored in a range from 2.2 to 3.3 out of 4. Of these scores 11 out of 28 (39.3%) achieve the level of 3 or above, with a list of evidence provided and associated scores summarised in the regulatory disclosures AMMAT self-assessment section in the appendices.

ISO55000 cannot currently be certified as there are no approved competency assessors able to certify ISO55000 for formal certification and these are unlikely to be available before 2016. ⁴

⁴ <http://www.assetivity.com.au/article/asset-management/5-things-you-need-to-know-about-iso-55000-certification.html>



To obtain a level 3 and above for all 28 categories the following projects that were recommended by the assessment consultant and remain outstanding are:

- 1) Implement a Computerised Maintenance Management System (CMMS) to store the maintenance history, which includes a gap analysis of alignment with the Horizon Energy asset management requirements.

Timeframe: 18 months following selection of AMS vendor in 2015-16.

- 2) Implement an electronic data acquisition system (mobile field dispatch) and integrate with the CMMS. Include a gap analysis of alignment with the Horizon Energy asset management requirements.

Timeframe: Started

- 3) Implement as mandatory, the requirement for Hazard and Operability identification (HAZOP) as a part of the approval process for the design of new infrastructure.

Timeframe: To be completed 2015-16

Note that not all projects may be implemented fully in the suggested time frames, nor may they be required to be implemented in full to achieve accreditation, as to achieve PAS55 accreditation the average score is required to be 3 or better.

2.12 Asset Management Planning Processes

2.12.1 Relationship To Other Planning Documents

The Asset Management Plan (AMP) is a key part of the planning process linking with other plans including strategic plans, business plans, legislation and operational / maintenance policies. Interaction of the key process is shown in Figure 2.2.

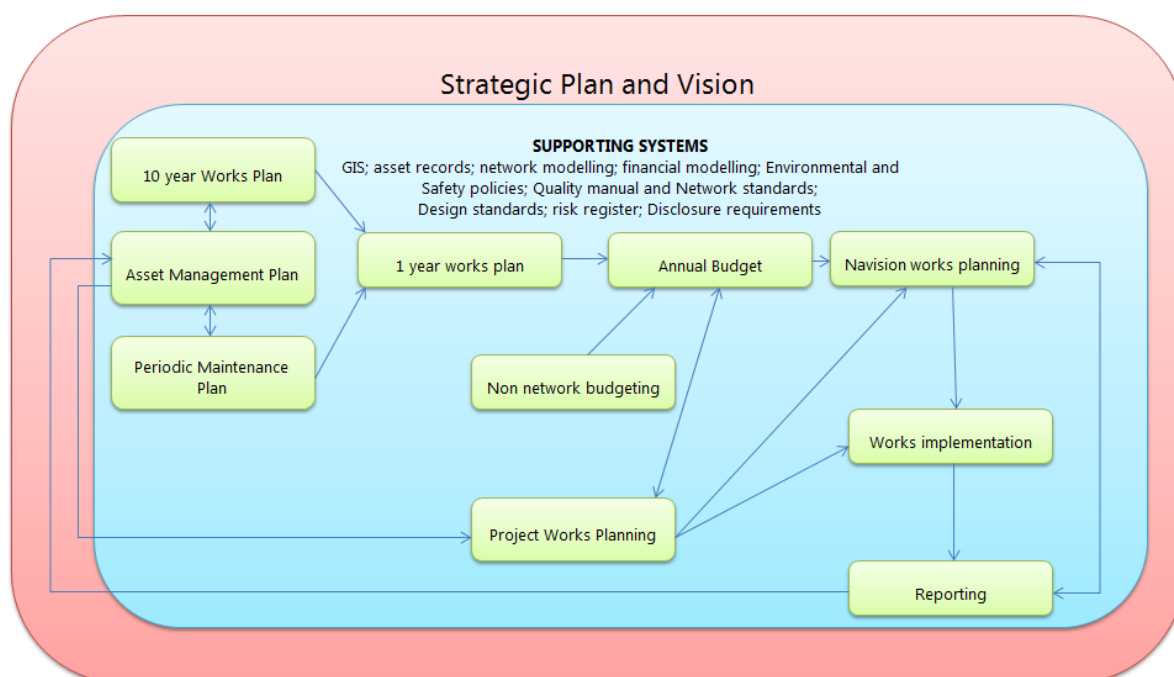


Figure 2.2 - Asset Management Planning Documentation Flow Process

The AMP is a key input into the corporate planning process. The interaction of the AMP with the other key plans and processes are summarised as follows:

Strategic Plan

- Three year focus and sets the key goals and objectives for the business; and
- Provides a corporate overview and guidance under which projects, staff levels, budgets and resources are made available.

Budgets

- Budgets are prepared based on the capital and operational expenditure projections in the AMP;
- The budget and AMP are an interactive process that balances the forecast earnings, risk, and capacity of the business against the future requirements of the network;
- The production of the two documents is an interactive process managed by the Executive and the Board. The budgets are updated annually.

Asset Planning Process

- Planning for growth renewals, third party development, maintenance and operations;
- Has a long term >10 year focus;
- Feeds into the strategic, capital and maintenance plans; and
- This process designs the projects summarised in the AMP.

Capital Plans

- Projects described by the AMP are collated into annual capital plans; and
- These projects are for network extensions, replacement of assets, additional assets to meet customer services or to improve service levels and quality of supply.

Maintenance Process

- Comprised of a mixture of preventative maintenance and reactive maintenance;
- Previous fault performance is a major driver of preventative maintenance schedules; and

- Managed such that the network system performance meets the service levels detailed in the AMP.

Operations Process

- Provides real time operation of the network;
- Manages reduction of losses and capacity utilisation;
- Outage and performance information is gathered for planning and reporting purposes; and
- This process endeavours to ensure that the target levels of performance as detailed in the AMP are met.

2.12.2 AMP Delivery

The structure of the planning and approval process around this AMP ensures a high level of confidence that the plan can be delivered as intended. By following the work and approval flow process described in section 2.5 ensures that there is buy in from Senior Management, Board, functional managers, and users at an early stage.

The process of driving the annual works plan and annual budgets from the AMP 10 year plan provides a direct linkage from the 10 year plan through to the annual budget setting processes, and then to the implementation phase. The document flow relationships shown in the above Figure 2.2 shows how the 10 year plan drives the annual budgets, and timing of the various stages of information distribution and approvals is covered in section 2.5, with the approval process starting six months before the start of the financial year, and preliminary works programs being reviewed prior to finalising budgets. This process has been used in this format since 2010 and is now an accepted and integral part of the annual plan and budgeting process.

During the review process in developing the plan, considerations such as the ability of contractors to deliver, the needs of the network, lead times, high level and detailed budgets, stakeholders requirements, and the cash flow requirements of the business are all taken into account. These decision points are detailed throughout this document.

3 Assets Covered

3.1 Network Area

The geographical area supplied by Horizon Energy is shown in Figure 3.1. The Horizon Energy sub-transmission network is summarised as:

- Four Transpower grid exit point (GXP) substations;
- Bay of Plenty Energy owned Aniwhenua power station;
- Six 11kV zone substations;
- Three Transpower GXP substations provide supply directly to 11kV distribution; and
- Forty-two 11kV feeders.

Figure 3.1 shows the layout of Horizon Energy's sub-transmission Network along with the Transpower 110kV and 50kV lines that supply the eastern parts of the area. The total service area covered is approximately 8,400km² and over 24,700 customers in the area bounded north of Whangaparaoa Bay Te Kaha, Pikowai, and Lake Rotoma to Ruatahuna.

There are four separate GXP supplied distribution areas - Edgecumbe, Kawerau, Te Kaha, and Waioatahi, and an Edgecumbe GXP embedded generation direct connection at Aniwhenua power station, in the Galatea region.



Figure 3.1 - Horizon Energy Network Area Sub-transmission

* Transpower owned and operated.

Areas supplied by each GXP**Transpower Edgecumbe, GXP**

- Edgecumbe GXP is supplied by three 220kV circuits (one from Kawerau, two from Tarukenga near Rotorua) and two 110kV lines (one from Kawerau and one from Owkata in Tauranga);
- Edgecumbe GXP supplies:
 - the Whakatane district region including Whakatane urban, Edgecumbe urban, and surrounding regions;
 - Waiotahi GXP at 110kV, which then supplies Te Kaha GXP at 50kV, with each of these circuits being single radial feeds; and
 - Galatea region when not supplied from Aniwhenua.

Transpower Kawerau GXP

- Directly connected at 110kV to the hydro generating stations at Matahina and Aniwhenua, to the national grid at 220kV, and to the geothermal powered Mighty River Power Kawerau generator;
- This generation capability is sufficient to make the Eastern Bay of Plenty almost self-sufficient for electrical energy. Although Aniwhenua is listed above as a GXP, it is physically connected to Horizon Energy assets and is treated commercially as being embedded within the Edgecumbe GXP supply area. Matahina is likewise considered embedded within the Edgecumbe GXP.

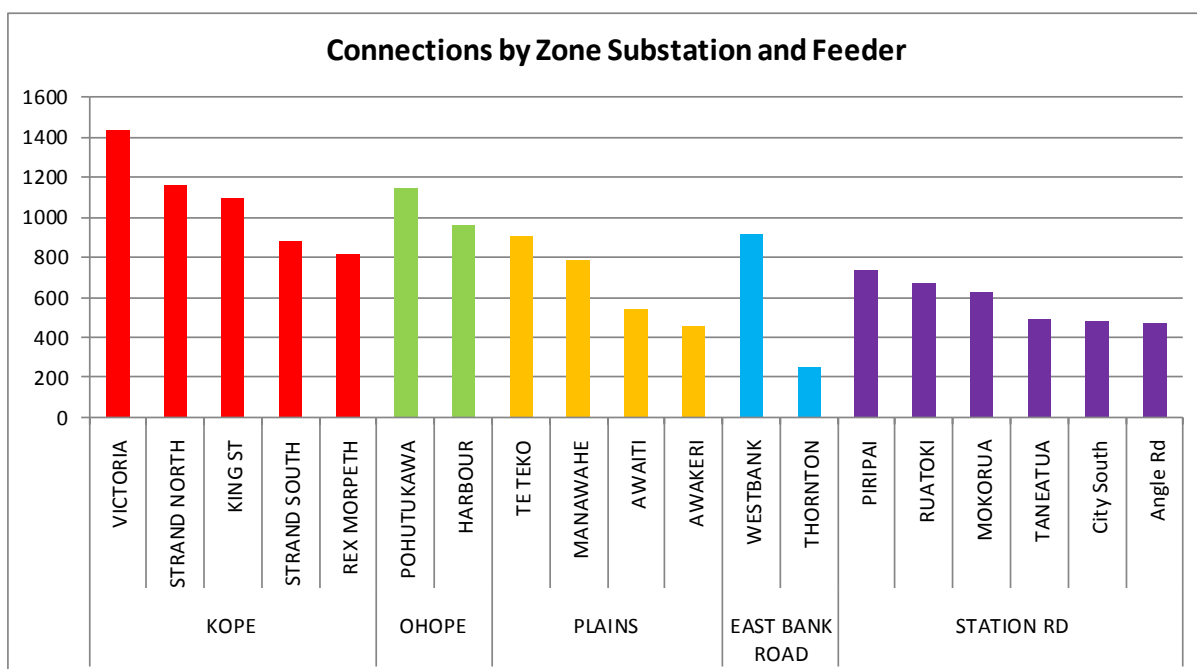
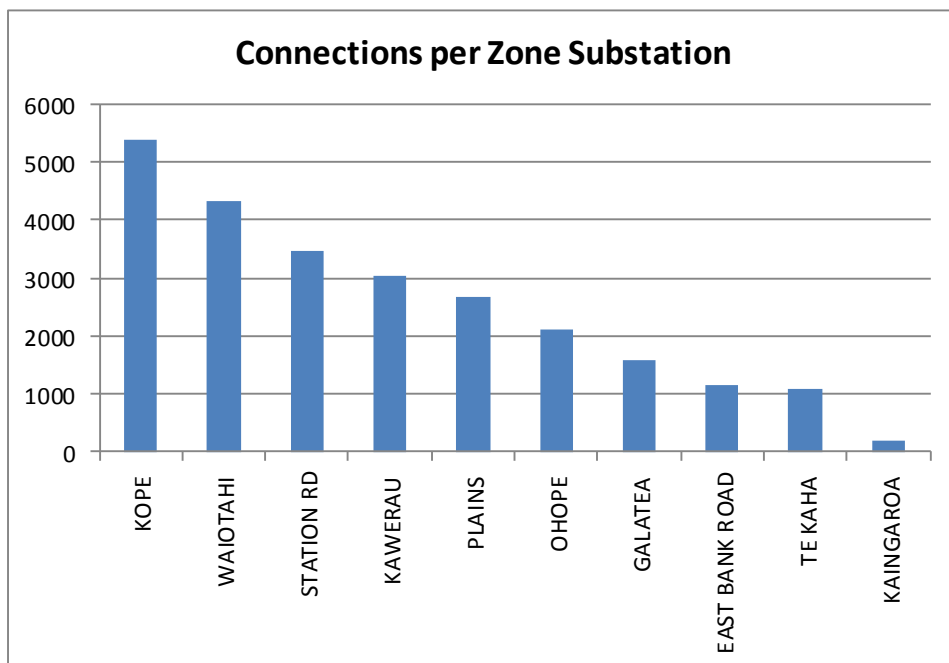
Transpower Waiotahi and Transpower Te Kaha

- Supplied from single circuit feeders and as such have N security at 110kV to Waiotahi and 50kV to Te Kaha.

Waiotahi, Te Kaha, and Kawerau have Transpower owned 11kV assets that distribute directly into the Horizon Energy network, rather than through a Horizon Energy zone substation. Refer to Table 5.22 for summaries of each GXP.

3.2 Zone Substations Summary

A chart of zone substation and feeders as at 31 March 2015, identifying the zone substations, feeders and number of customer connection points shown in Table 3.1



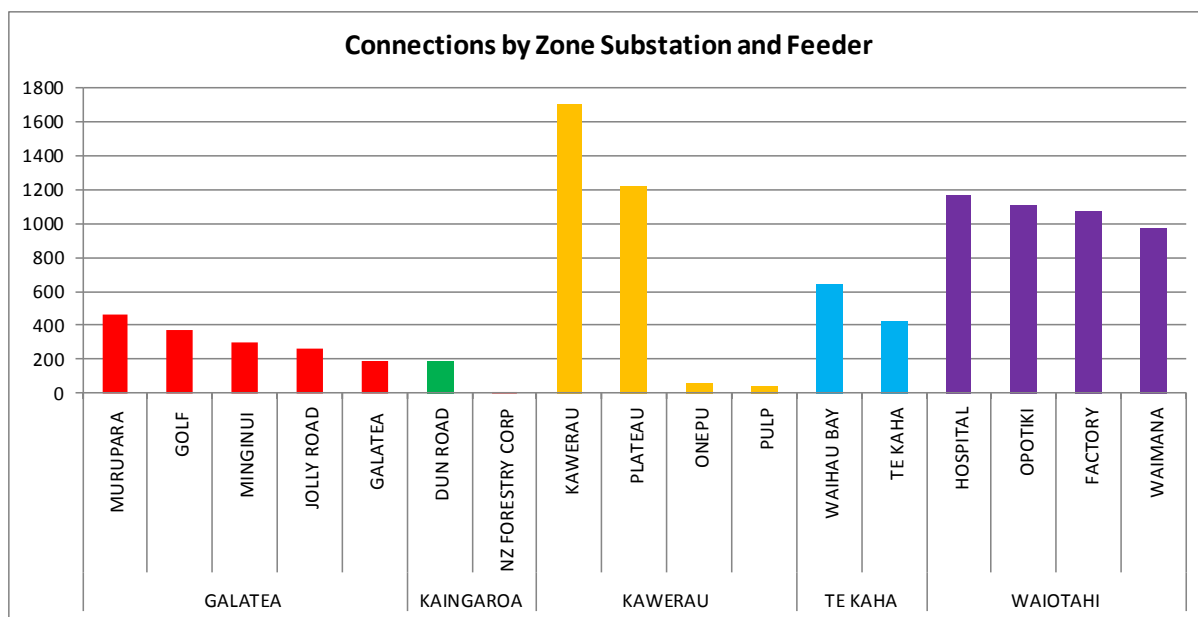


Table 3.1 - Horizon Energy Zone Substation Summary

3.3 Zone Substation Load Characteristics

Table 3.2 summarises the peak load data for each zone substation for the year 1 April 2014 to 31 March 2015

Zone Substation	Peak Demand (MVA)	Av 100 peak periods (MVA)	Peak Period
Eastbank	6.4	5.72	Winter
Galatea	4.6	4.28	Summer
Kaingaroa	2.6	2.4	Winter
Kawerau (GXP)	17.8	16.28	All year
Kope	14.4	13	Winter
Ohope	4.4	3.8	Winter
Plains	5.9	5.4	Summer
Station Road	10.0	7.7	Winter
Te Kaha (GXP)	1.6	1.6	Summer
Waiotahi (GXP)	9.4	8.8	Winter

Table 3.2 - Zone Substation Load Summary as at 31 March 2015

Note: Edgecumbe GXP load included Galatea region load during 2009-14 due to Galatea load being supplied by Edgecumbe after the failure of BOPE's Aniwhenua TI in 2009. See Section 0 for more detail.

3.4 Major Customers

Major customers are defined as customers with a demand load that exceeds 1MW. These customers are summarised in Table 3.3 below:

Customer	Business	Connection	Load	Comments
Whakatane Mill Ltd	Packaging board manufacture	Edgecumbe GXP	25 MVA	Two dedicated 33kV feeders
Fonterra	Milk Products	Plains and East Bank zone substation	8 MVA	Connection to both East Bank and Plains substation. Embedded generation reduces peak demand with normal operation being energy export from the site. Horizon Energy owns all dedicated distribution assets on the factory site
Asaleo Care	Tissue Products	Kawerau, Pulp feeder	9.5MVA	Dedicated single feeder with 100% backup from second feeder
Sequal Lumber	Sawn Timber Production	Kawerau, Paper feeder	2 MVA	Horizon Energy owns dedicated distribution assets on the mill site
Norske Skog	Oxidation Ponds	Kawerau, Onepu feeder	2.5 MVA	Supply to effluent treatment site with Horizon Energy assets on site
Nova Energy	Generation	Kawerau, Onepu feeder	5 MVA	TG2 geothermal generation plant. Nova TG1 generator disconnected 2014
Southern Generation	Generation	Aniwhenua power stations	N/A	Notionally embedded generation within Edgecumbe GXP supply area. Direct connect to Transpower and Galatea region offtake
Trustpower	Generation	Matahina	N/A	Notionally embedded generation within Edgecumbe GXP supply area. Direct connect to Transpower

Customer	Business	Connection	Load	Comments
Carter Holt Harvey	Timber Mill	Kawerau, Onepu feeder	3.5 MVA	Normally on one 11kV cable
Timberlands	Wood Products	Kaingaroa	2 MVA	Low security supply
Carter Holt Harvey Wood Products	Wood Products	Kawerau	5MVA	Sawn timber production

Table 3.3 - Major Customer Summary

3.5 Embedded Generation

Embedded generation is generation that is connected to the distribution network, as opposed to being connected to Transpower. There are a number of generation sites embedded within the Horizon Energy network that are connected either directly to the distribution network or to customers' load. These are summarised below:

Generator	Owner	Connection	Capacity
Co-generation	Fonterra	Connected to site loads and to Plains substation	2x5 MW = 10MW
Geothermal, TG2	Nova Energy	Onepu Feeder, Kawerau	5 MW
Hydro	Nova Energy	Aniwhenua Barrage compensation flow generator connected to the Galatea feeder, Galatea	100 kW
Steam Turbine	Whakatane Mill	On site - currently not operational	2x2.5 MVA
Mini Hydro		Braemar Road, Awaiti feeder, Plains	400kW

The policy for new generator connections is available from the Horizon Energy website.
<http://www.horizonenergy.net.nz/customers/distributed-private-generation>.

While Horizon Energy is not actively engaged in the development of distributed generation projects in its own right, Horizon Energy does support the development of distributed generation within its service area by:

- Facilitating network connections for independent power providers to exploit local energy sources;
- Discussing on-site co-generation or demand management schemes with large industrial customers as an option for managing load peak demand; and
- Assessing each application individually to ascertain it can be safely connected to the network.

There has been a slow growth in the number of small, mainly solar, distributed generation units.

Non-Embedded Generation

Generation located within the network region that is not embedded within the Horizon Energy distribution network:

- 70MW Matahina Hydro Station, connected to Transpower Kawerau;
- 24MW Aniwhenua Hydro Station has both a network connection at 33kV and a Transpower connection at 110kV;
- 105MW Mighty River Power, Kawerau, has a Transpower Kawerau direct connection at 110kV;
- 23MW Norkse Skog Tasman geothermal binary power plant; and
- 10 MW KA24 geothermal generator at Kawerau is embedded into the Norske Skog Mill site.

3.6 Other Horizon Energy Generation Assets

Two truck-mounted 300kVA mobile generator units are available to help manage planned and unplanned outages. A small trailer mounted mobile 300kVA substation has been configured for use with the generator units when a connection is required directly onto the 11kV network system.

One 1MVA transportable generator set and transformer procured in 2013 is used to support outages, as well as voltage support and peak load lopping. The unit is planned to be located within the Waiotahi network but can be transported elsewhere if required.

3.7 Assets that are not covered by this AMP

A core principal of ISO55000 is that physical assets required to support a business to achieve its objectives need to be managed as part of an asset management plan, but the standard can be applied to non-physical assets as well. As a lines business, previous asset management plans have focused on distribution assets only. Horizon Energy is working towards including all assets required to sustain the business objectives into the asset management practices, although the AMP business focus is still on managing the lines business. Assets owned by Horizon Energy that are not directly or indirectly required to support the lines business not currently covered in this Asset Management Plan include:

- Land and buildings, other than substation land and buildings;
- Subsidiary companies and their assets;
- Corporate assets; IT, vehicles, office equipment; and
- Staff

3.8 Summary of Assets

3.8.1 Asset Summary List

Assets and asset ages, as reported in the information disclosure schedules, is included in Appendix A2.

3.8.2 Distribution Assets

The distribution system assets and their management policies are summarised in detail in Sections 5 and 6.

4 Service Levels

4.1 Introduction

The levels of service (LOS) defined in this Section are used to:

- Inform stakeholders, in particular customers, of the proposed type and level of service to be offered;
- Identify strategies to deliver required service levels;
- Measure the effectiveness of actions undertaken in accordance with this and past AMP's; and
- Demonstrate compliance with regulatory requirements.

Definition of Customers

Horizon Energy Distribution commercial customers are energy retailers and direct supply customers.

When the term 'customer' is used throughout this document it is intended to refer to the end user of the energy, the consumer, and the service that is supplied is for the benefit of the end user 'customer', particularly in the assessment of price/quality trade off.

The drivers behind service level expectations are generally based on:

- **Network capability:**
The type of network (overhead, underground), the environment the overhead line is exposed to (e.g. vegetation, coastal, geothermal), its locality (e.g. rural, remote) and its ability to be configured to provide alternate supply routes are all primary drivers for the number of faults, or outage durations, that a customer can expect to experience.
- **Customer Expectations:**
Information gained directly or from current and potential electricity customers and retailers, on expected quality and price of services offered.
- **Regulatory Requirements:**
Environmental standards, Regulations and Acts that impact on the way assets are managed (i.e. resource consents, electricity regulations, and health and safety legislation). These requirements set the mandatory minimum level of service that must be provided.
- **Strategic and Corporate Goals:**
Provide guidelines for the scope of current and future services offered, the manner of service delivery and define specific levels of service which the organisation wishes to achieve over and above the legislative requirement.

Target levels of service fall into two categories:

1. Technical (asset/product) related measures, which define the outputs the stakeholder receives in terms of:

- | | |
|--------------------------|-------------------------------|
| • Safety | • Capacity |
| • Quality | • Environmental impacts |
| • Quantity | • Cost / Affordability |
| • Availability | • Maintainability |
| • Legislative compliance | • Reliability and performance |

2. Functional (process related) measures, which can be measured by customer satisfaction surveys, and define how the customer perceives the service in terms of:

- | | |
|------------------|--|
| • Tangibles | • Empathy (understanding, attention) |
| • Responsiveness | • Assurance (knowledge, trust, confidence) |
| • Courtesy | |

4.2 Customers Research and Expectations

A customer research survey completed in 2014 highlighted findings relating to customers perceptions of Horizon's performance and customer's expectations. Below is the summary of the findings. Further detail can be obtained by referring to the 2014-2024 AMP on Horizon Energy website.

Findings from the survey are below:

1. **Name of Fault Organisation and Lines Company:**

Changes in retailer operations resulted in a reduction of the recall of "name of Lines Company" and "name of fault organisation", with significant increases in "Don't Know" responses.

2. **Horizon Energy Ownership Awareness:**

There was a decrease in customer awareness of who owned Horizon Energy. Eight out of 10 commercial customers and three out of four residential customers stated they did not know who owned Horizon Energy.

3. **Overall Satisfaction:**

Across all areas and segments satisfaction levels were maintained 3.89 on the 1=low and 5=high satisfaction scale.

4. **Deliverable service ratings:**

There were minor decreases in performance rating for Horizon "service", "availability in the event of faults", "frequency of outages", "notifying of planned shut downs" and "duration of outages"; there was an increase in "quality – keeping flickering lights to a minimum".

"Continuity of supply" remains the most important deliverable with three out of four customers highlighting it, with "price" second and "response to outages" third.

5. **Better or worse perceptions:**

Across all areas most respondents stated that their power supply had remained the same.

6. **Low Voltage issues:**

35% of all respondents indicated they had experienced "flickering lights", 24% stated they experienced "lights that go up and down in brightness" and 64% stated they experienced "short power interruptions lasting less than a minute".

7. **Outages:**

Recalled outages differed across the survey years within many areas. Edgecumbe, Kawerau and Waiotahi recalled LESS outages in 2014. Across many areas and segments, satisfaction with the frequency of outages continued to decrease or hold levels. Although there is some similarity in the duration of outages experienced by area, patterns varied widely and most noticeably in Aniwhenua. Most areas and segments satisfaction with outage duration increased with the exception of Aniwhenua, Kawerau, Te Kaha and rural customers. Tolerance for outages lasting 1-3 hours has declined with both commercial and residential customers. More customers are indicating shorter response time as being acceptable. The greater the security of supply, the lower the acceptance of longer restoration times.

8. **Price/Quality:**

Fewer customers indicated they wanted an improvement in the quality of their power supply with the exception of Aniwhenua where there was an increase in those wanting an improvement. Across all areas 90% of all customers stated any increase would be too much to pay for improved power quality. 80% of all customers stated they would DEFINITELY NOT be willing to accept poorer quality for a reduction in price.

Almost 90% of all customers indicated that any increase in their power bill would be too much to pay for improved restoration times.

9. **Awareness of safety messages:**

In 2014 just over half of all respondents indicated they were aware of communications or messages on behalf of Horizon Energy in relation to safety and that current levels of safety messages were about right. and approximately 40% stated more could be done.

10. Preferred communication methods:

Letters or flyers to home address or business and local radio or newspapers were the most effective ways for Horizon to communicate information.

11. Awareness of “before you dig” cable location service:

There was a significant drop in awareness of messages relating to the dangers of digging and underground cables. Horizon did not undertake any “beforeudig” local marketing.

12. Responsibility for keeping trees from power lines:

Two out of three respondents were aware that it was their responsibility for ensuring trees on their property do not get close to power lines; changes over previous years were most noticeable in Edgumbe, Kawerau and Waitohi.

13. Interest in received mobile phone text update during outages:

Interest in receiving information sent to customers’ mobile phone during power cuts increased over previous years in all areas except Kawerau.

14. Awareness of lines-to-property ownership:

There has been an increase in “lines from the street to property” ownership awareness across all areas. Horizon Energy as the primary point of contact in the event of an issue with “lines from the street to property” has continued to grow.

15. Awareness of Horizon Energy involvement in community activity:

One third of customers indicated they were aware of any community event or activity that Horizon Energy has been involved in. Most respondents aware of community events that Horizon Energy has been involved in stated they had a neutral to somewhat positive impression of Horizon Energy based on these communications about the Company.

16. Awareness of “other” Horizon Services:

Eight out of ten respondents stated they did not know of any other services Horizon offers. Tree trimming and electrical services were the two most predominantly recalled services. Only 30% of respondents indicating they were aware of “other” services offered by Horizon indicated they had used any of these services.

4.3 Current Levels of Service

4.3.1 Prudent Investment

Accountability for financial performance is clearly defined and allocated to those Senior Managers best able to manage the outcome. Delegated authorities for expenditure are similarly well defined and provide for appropriate levels of expenditure beyond which detailed business cases are required prior to any financial commitment.

A high standard of reporting is provided to the Board of Directors monthly and to other stakeholders in the form of the Company’s Annual and Interim Reports.

The financial performance of the Company impacts directly on the return to shareholders. This must be managed in consideration to legislation that monitors (restricts) the level of return on assets employed to levels considered appropriate for a distribution lines business by the regulator.

Continued effort is being made to optimise the financial burdens and benefits to shareholders and customers within the constraints of the regulated environment. This is reflected in both the tariff options available and the rates applied to those options.

4.3.2 *Physical Performance*

Actual network performance is compared, typically on a monthly basis, with developed targets for each performance measure.

The performance against target for each reporting category is reviewed and carefully analysed. This is done yearly for most targets as part of the DPP Compliance review. Others, like SAIDI and SAIFI reporting are undertaken monthly for staff, Management and the Company Directors. Trends are evaluated and action taken as appropriate.

Where a trend develops that indicates a need for concern, the following steps are undertaken:

1. Any mitigating factors are analysed and in some instances a “one off” event may well have distorted the results. Some events (such as a major flood event causing extensive damage to distribution circuits) are reported, and then an adjustment made as it is accepted that the infrastructure is not designed to withstand such an extreme event.
2. Next, analysis is undertaken to identify the root cause of the problem and actions put in place to reverse the trend.
3. Lastly the target is re-evaluated to ensure that it is realistic and that the original target considered all factors in the setting of that particular level.

All factors that affect the results are examined, including:

- Maintenance Policies;
- Capital Expenditure Policies;
- Internal and External Contractor Work Practices;
- Material Supply and Specification Review; and
- Design and Construction Standards.

Changes are then made as appropriate.

Analysis reviews are essential to ensure performance and practices are maintained at an optimal level. End of year results are important indicators of how the system performed against target.

4.3.3 *Reliability*

Historic network performance for both planned and unplanned shutdowns are shown in the following graphs. The key indicators used are those adopted by the industry (and regulations) as standard for network companies and include:

- System Average Interruption Duration Index (SAIDI) (minutes / customer);
- System Average Interruption Frequency Index (SAIFI) (interruptions / customer); and
- Customer Average Interruption Duration Index (CAIDI) (minutes / interruption).

The data shown applies only to interruptions caused by failures or planned outages on the Horizon Energy network and does not include outages due to Transpower or generation sources. The latter is, however, captured and analysed as it is important in the assessment of impact on customers who do not differentiate between what part of the upstream supply network caused the outage.

The graphs shown below are for the Horizon Energy network performance as a whole from 2008 to 2015.

Significant events during 2014/15 were

- Insulator failure on Ohope Harbour feeder affecting 994 customers.
- Faulty 11kV cable in Kawerau Plateau feeder.
- Planned works at Waitotahi and Te Kaha by Transpower.
- 33kV trip of Snake Hill feeder supplying Galatea.

The number of faults against different fault categories for the previous five years is summarised below. Vegetation had been showing an increasing trend compared to earlier in the period and this has been addressed since 2011 with additional budgeted expenditure in vegetation control.

Additional fault cause categories have been added, wildlife and adverse environment, to provide a better understanding of root cause failures to try to better understand the 'unknown causes' and 'defective equipment' fault type categories.

SAIDI, SAIFI, and CAIDI performance over the previous five years are shown on the figures below:

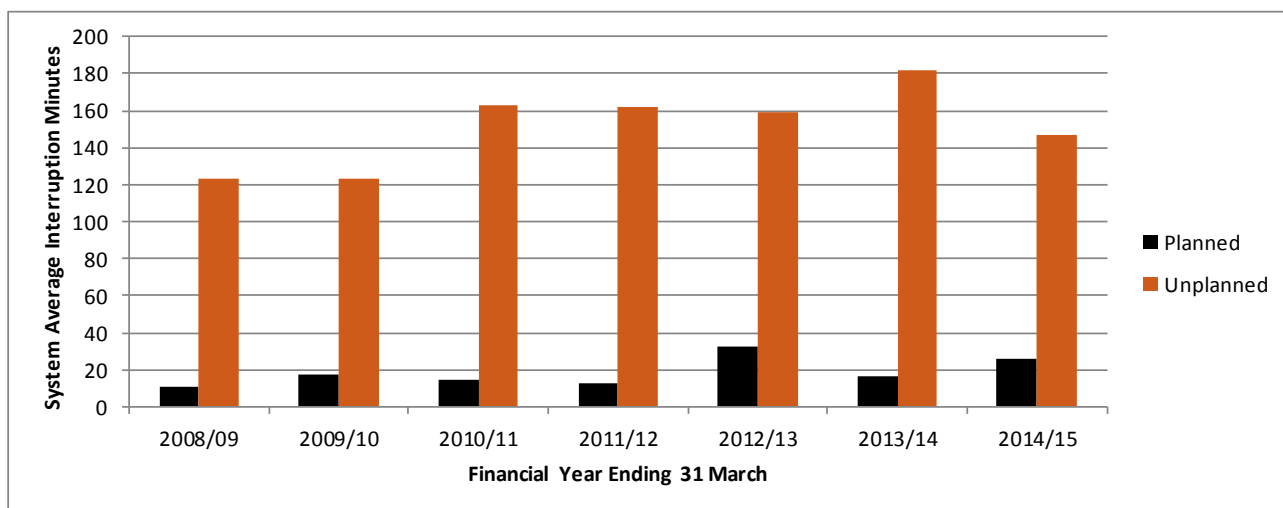


Figure 4.1- SAIDI Performance 2009 to 2015

SAIDI is a measure of how long the average customer will be without power during a year. SAIDI is expected to improve as the effects of the reliability initiatives come on stream.

A project to trial self-healing networks has been proposed for the Plains region and is intended to assist in improving the SAIDI and CAIDI results. Initial feasibility engineering for this project is planned for 2014-15.

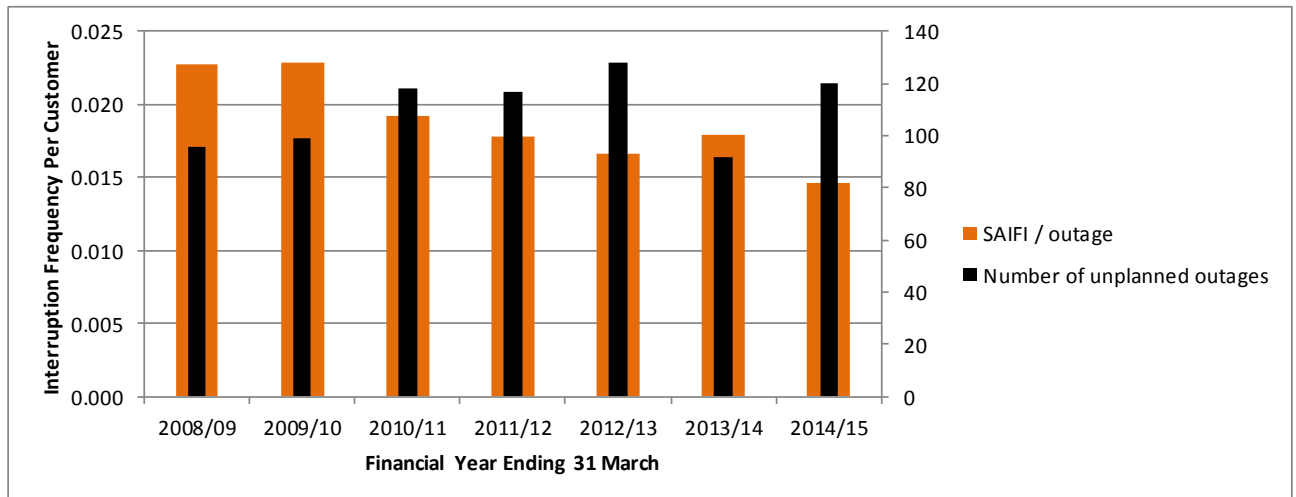


Figure 4.2- SAIFI Performance 2009 to 2015

SAIFI is a measure of the number of times an average customer will suffer an interruption to their supply during a year.

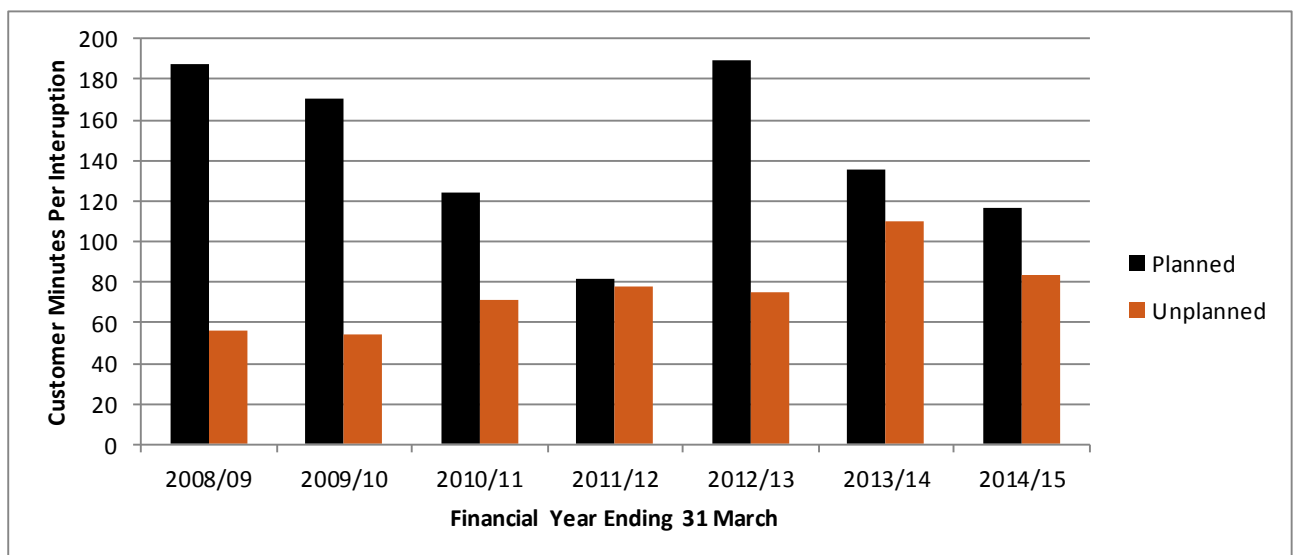


Figure 4.3 - CAIDI Performance 2009 to 2015

CAIDI is a measure of how long an interruption to supply will last on average.

The spike in 'Planned outages' in 2012/13 was an increase in outage durations due to the two 300KVA generators being out of service for a major refit.

Reliability Projects

A focus on reliability driven projects since 2009 is now drawing to a close, with completion of the worst performing feeders now complete. These projects involved:

- The installation of additional circuit breakers and sectionalising circuit interrupters;
- Drop out sectionalisers and fuse saving circuit breakers;
- More fuse links; and
- Automated tie point switches.

The reliability improvement projects are showing an average reduction of 30% in SAIDI minutes for the feeders that have been completed, despite a 4% increase in the number of faults over the same period. The next phase in the drive for reliability is to implement intelligent switching of the network and auto restoration, or smart networks.

Interruptions by Type

Figure 4.4 and Figure 4.5 below show the interruptions by cause type. These charts highlight the following issues:

- The high percentage of “Defective Equipment” is indicative of the half life age of the network, and is addressed by asset renewal and replacements. A large percentage is overhead conductor and insulator failures, followed by DDO failures. There is a specific plan to replace stainless steel DDO units but no practical plan yet for proactive insulator replacements separate to line rebuild projects due to the high cost to proactively replace and difficulty in predicting or condition assessing imminent failure;
- “Third Party interference” was vehicle accidents, or trees which are outside of the vegetation managed zones which have been felled by other parties;
- Vegetation contacts have reduced as tree maintenance was increased in 2012; and
- “Unknown” events have no identified cause, including auto-reclose events

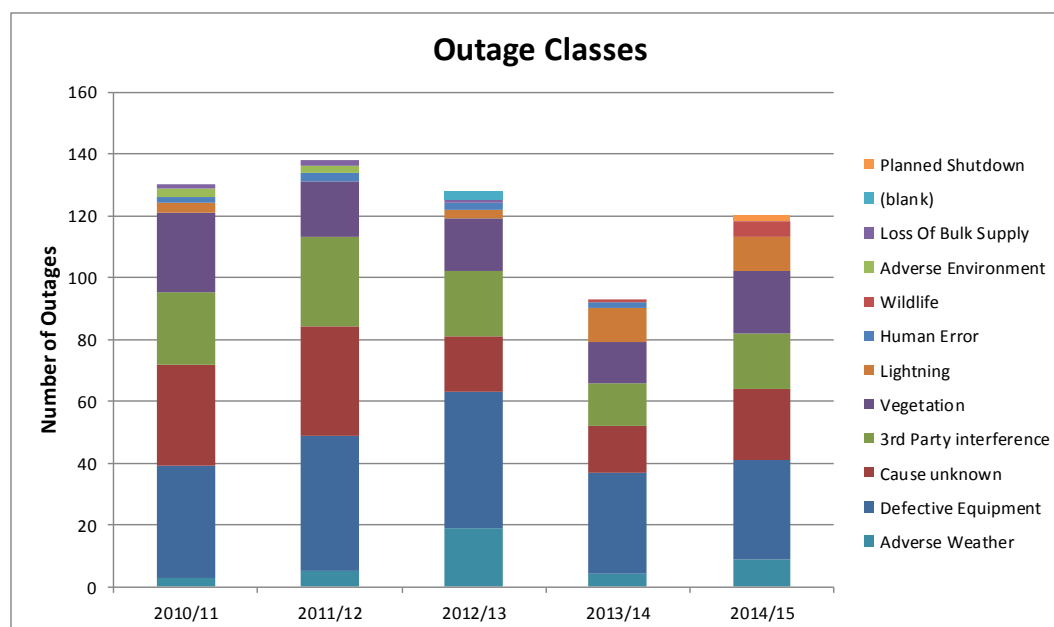


Figure 4.4 - Cause of Unplanned Interruptions Last Five Years

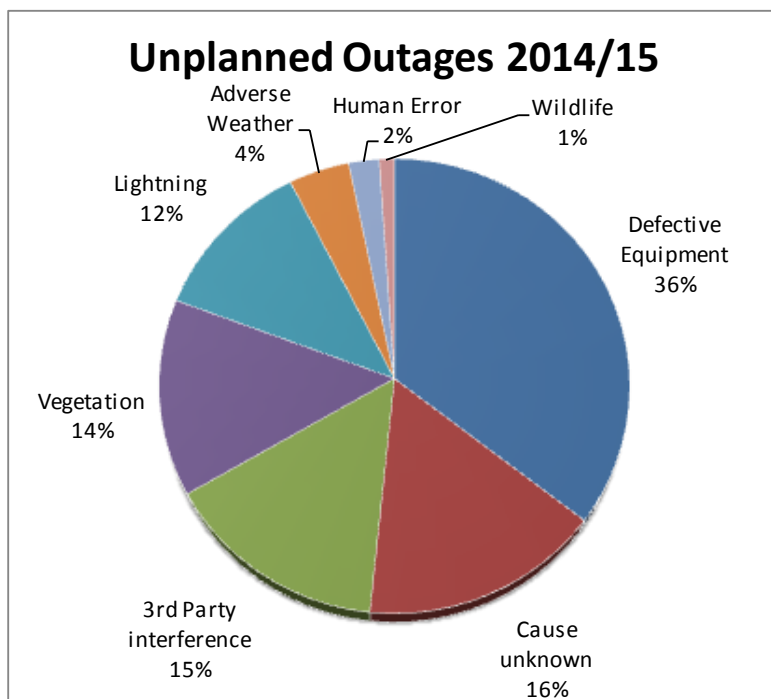


Figure 4.5 - Unplanned Outages Performance by Cause

Strategies in place to ensure that on-going improvements are made include:

- Ongoing vegetation management and asset inspections;
- On-going replacement of low capacity conductor sections;
- Discontinued use of small diameter squirrel conductor except on private or dedicated spur lines;
- Increased partial discharge testing on ground mounted switchgear;
- Continued installation of automation equipment;
- Increased use of spur line fusing;
- Trialling of electronic devices that are designed to protect fuses from operating on momentary faults; and
- Trialling of self-healing networks in the Plains area.

Vegetation

There was a large increase in tree contact faults in 2010-11, as shown in Figure 4.6. In recognition of this increasing trend, Horizon Energy implemented an increase in vegetation expenditure for vegetation management for the 2012-13 year, which is now showing some benefits. A number of the faults still tend to be trees outside of the legal vegetation management zone. As a further means of managing vegetation, a new role has been established within Horizon Energy to actively manage the vegetation control program, contractors, and public liaison.

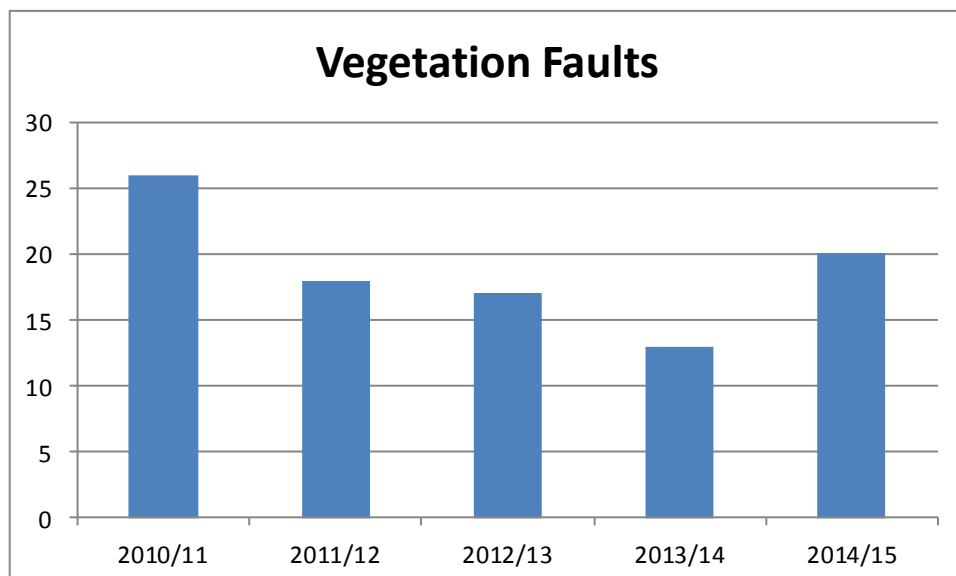


Figure 4.6 - Faults due to Vegetation

The vegetation faults are generally spread fairly evenly across the rural feeders with Manawahae and Waimana having slightly more faults than any of the other feeders. The increase in 2014/15 is due in part to out-of-zone trees causing faults.

4.3.4 Feeder Performance

Figure 4.7 indicates the faults per 100km relative performance between overhead feeders for the 2014-15 financial year and unplanned interruptions per feeder. Waimana and Manawahae feeders continue to be poor performers.

As expected, short feeders show a high number of faults per 100km so the focus on fault mitigation works is on feeders with a high number of unplanned interruptions

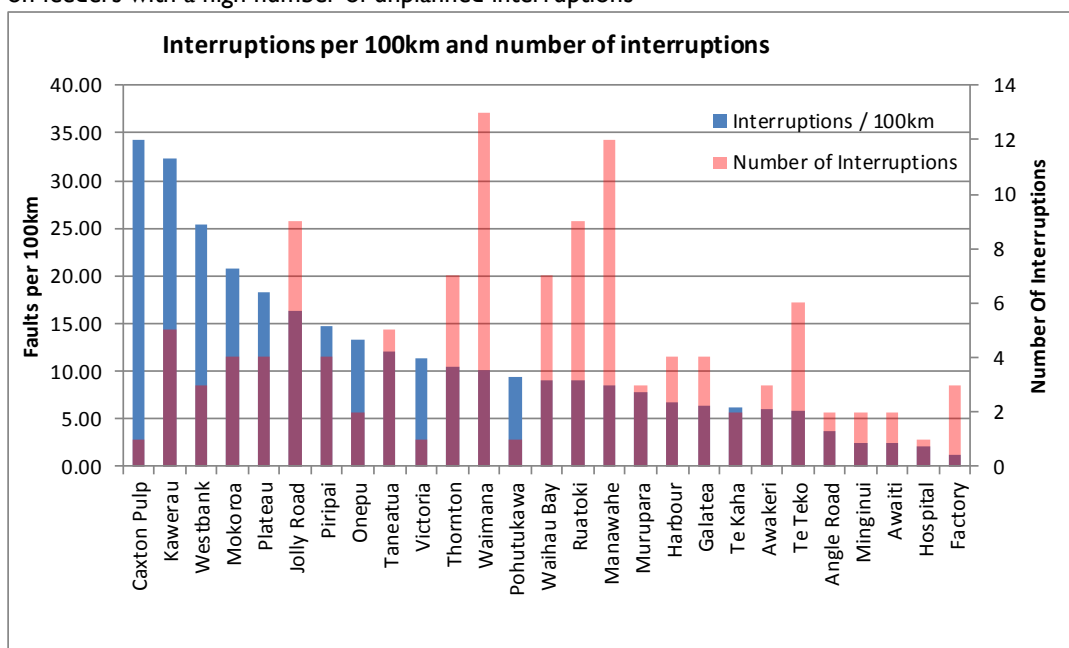


Figure 4.7a - Feeder Faults per 100km

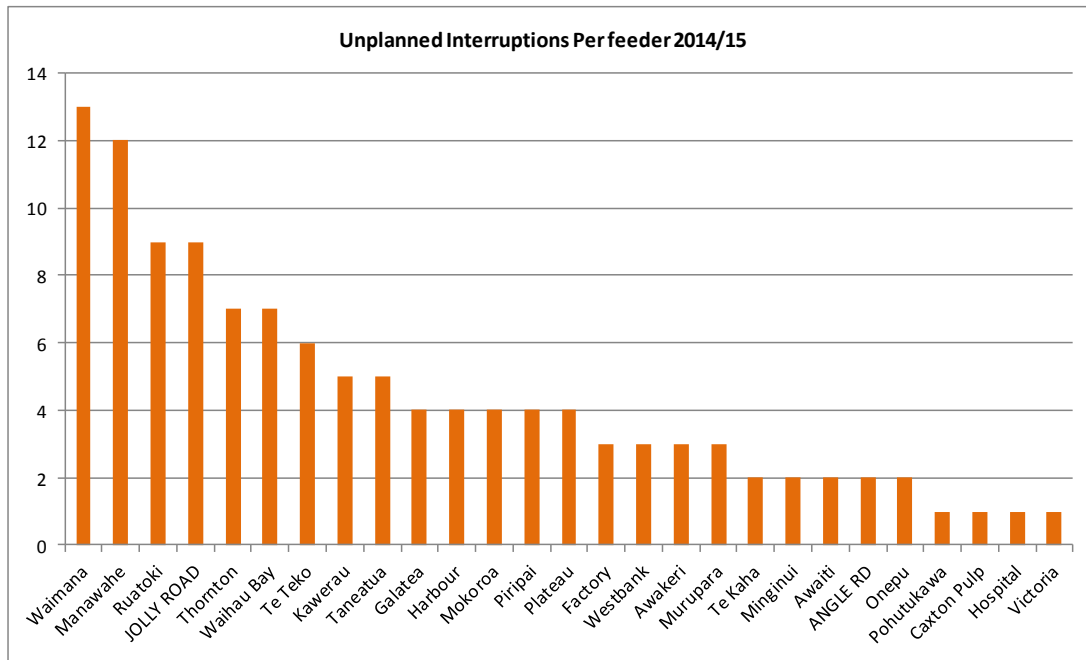


Figure 4.8b – Unplanned Interruptions per feeder

4.3.5 Quality of Supply

With the Electricity Distribution Services Default Price-Quality Path Determination 2015 for lines businesses there is an incentive scheme that links quality of customer supply to revenue.

The scheme links revenue to quality performance, with a financial incentive (within limits) for improving quality. Examples of how this affects Horizon Energy are shown below in Figure 4.9 with a comparison to the last 10 years historical performance values that have been normalised such that it can be compared to the 2015-2020 period.

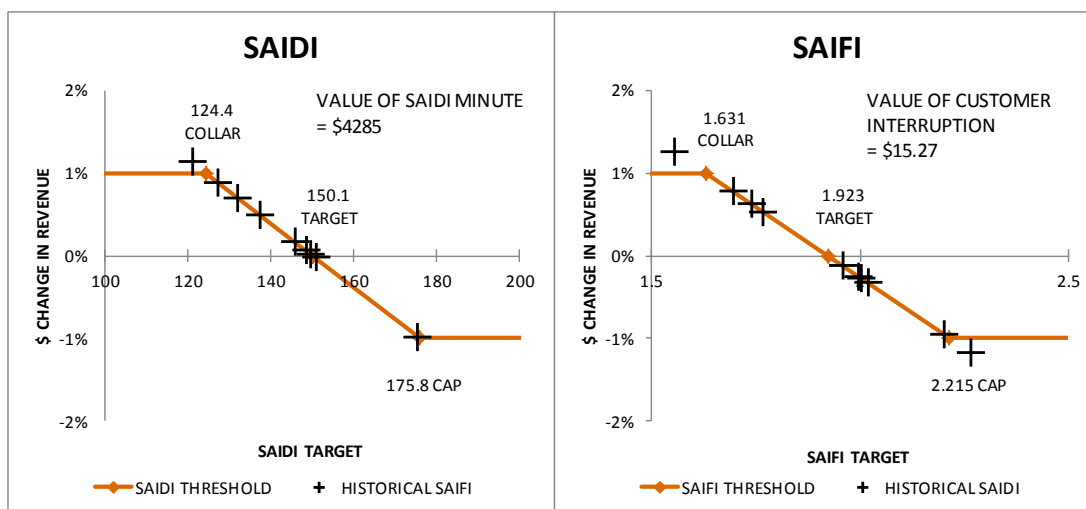


Figure 4.9 - SAIDI and SAIFI Incentive Scheme 2015

The scheme limits the incentive to a plus/minus one percent cap, so over-capitalising to improve reliability beyond the collar threshold is discouraged, and under-performing below the target is penalised, with a cap set on the liability of minus one percent of the revenue.

From the figures above, it can be seen that both Horizon Energy customers and shareholders will benefit from reliability projects that reduce the SAIFI, or frequency of outages. When assessing project priorities, projects that reduce the frequency of outages will get a higher priority than they had previously enjoyed.

For any outage, there is a one minute grace period where the outage does not accumulate any time penalties. This means customers may still see outages within the one minute period as the network is switched to alternative supplies using automated switching processes.

Strategies that can affect the frequency of outages include:

- Projects that reduce the number of customers isolated by an outage, dividing the network into smaller portions by increasing the number of circuit breakers;
- Increased maintenance and capital expenditure on equipment (equipment faults are the single biggest cause of faults);
- Improved asset capture to identify at-risk areas;
- Automated system restoration in the event of an outage;
- Improved vegetation management;
- Better understanding of the 'unknown fault' type of faults;
- Programs to reduce third party damage (predominantly vehicle impacts) by moving vulnerable assets away from road edges;
- Timely replacement of aged assets; and
- Condition assessment and non-destructive testing of cables.

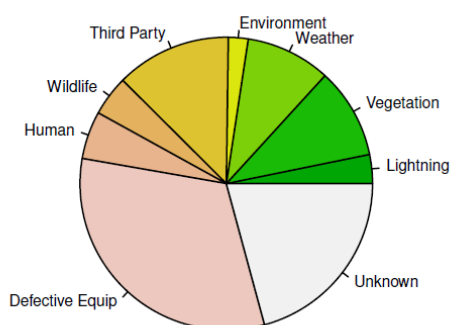
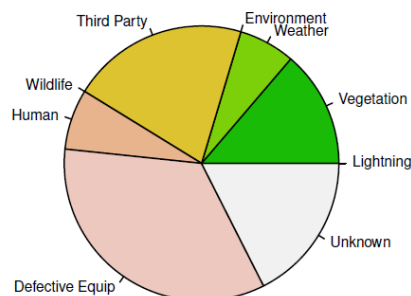
The incentive scheme is set up so that planned outages carry a lesser contribution to SAIDI/SAIFI than unplanned outages. This has the positive benefit of being able to reduce the use of expensive live-line work techniques in favour of taking full outages, where work productivity tends to be higher, and there is far less worker risk.

4.3.6 Network Performance compared to peers

The data in the section below is taken from a paper by Hyland McQueen Ltd; 'Comparative Performance of Horizon Energy Distribution in the FY2013 Information Disclosure Data'.

SAIFI Performance and Trends to Other Networks

Vegetation faults and third party interference are higher than industry averages. Vegetation is directly manageable by Horizon Energy, and Horizon Energy has implemented steps to control this fault condition, whereas third party influences are difficult to manage.

Average fault saifi make-up**Horizon Energy Distribution fault saifi**

From the 2013 information disclosures, Hyland McQueen identified certain trends compared to other networks:

- Vegetation Opex expenditure by circuit length is below average;
- Vegetation expenditure as a percentage of total Opex is higher than average;
- Opex by ICP is just below the median spend for all networks; and
- Horizon Energy's renewal expenditure is above average.

These values are a snapshot of only a single year of data and will vary annually. A more comprehensive comparative is to assess the historical and long term planned data against EDB's and as such, little relevance should be placed on the differences shown above until further years are included in the analysis.

4.3.7 Environmental Standards

Good environmental performance is a key objective of Horizon Energy and close monitoring in this area is vital. Between 2015-2017, Horizon Energy intends to seek certification under ISO 14001 Environmental Management Systems. This is reflected in the following projects:

- Removal of asbestos roof at Kawerau substation
- Planned installation of oil separators at Galatea
- Specifying ester oils for new zone substation transformers
- Preference for SF6 free 11kV switchboards

Oil spill kits are available at all zone substation sites. This proved useful in containing the oil spill during the Kope T1 failure. Environmentally friendly synthetic oil has been specified for the new Kope T2 and Plains T2 transformers, and will continue to be specified for all new zone substation transformers.

The photograph on the right is a typical layout as installed at the East Bank Road substation where an oil spill capture bund has been retro fitted to the pad. An oil separator has also been added to capture any oil that may become present in storm water due to a serious leak occurring.

Full procedures exist in the quality manual for the handling of asbestos, SF6 gas, transformer oil, and other materials deemed hazardous.

New 11kV and 33kV primary circuit breakers are specified as vacuum arc quench although SF6 is still



accepted as an insulation medium.

4.4 Target Levels of Service

The service targets the overall network are scheduled in Table 4.2. This demonstrates that there are some service gaps with the current levels of service. The strategies or programmes to close these service gaps are also detailed.

Horizon Energy has set the target levels through a variety of methods and taking into consideration the impact that they may have on quality of supply, manning levels and cost. The goals are felt to be realistic and achievable whilst providing optimum safety and levels of service.

Future goals are influenced by past performance in meeting regulatory requirements and a desire to provide a safe service. Targets developed are the result of analysis and agreement among the AMP team. All goals are measured in either a formal or informal manner and where not achieved, performance improvement strategies are developed. Where goals are consistently met they are adjusted, where appropriate, to maintain incentives for improvement.

Performance measures and their justification are broadly categorised into the following areas:

Safety	Safety is paramount for both staff and the public. Horizon Energy has a responsibility to ensure that all of its equipment, systems and work places meet the highest of standards. Many of Horizon Energy's electrical assets are located in the public domain and contain hazards that can be fatal. The risks that cannot be eliminated are mitigated by design and by maintenance programmes. Horizon Energy holds AS/NZS 4801 certification for staff safety management systems and AS/NZS 7901 certification for public safety.
Quality	End use customers are becoming increasingly conscious of the characteristics of electricity supply that may impact on equipment they own or on their utilisation of energy.
Environmental Standards	Horizon Energy values a sustainable environment and will set targets that reflect the ongoing management of all activities that affect the environment. Efficiency within the network is a key consideration and components are chosen that will have a low life time impact on the environment. Achieving ISO14001 certification is part of that commitment.
Reliability	A key measure of supply quality, and a critical measure for regulatory compliance, is a progressive improvement in the reliability of supply offered to customers. A large component of the Company's resources goes into the management of this indicator.
Efficiency/Pricing	Horizon Energy is motivated to ensure that its efficiency measures are ranked highly within the distribution industry. These indicators also reflect to a degree how well the Company is operating its assets to meet the needs of its customers.
Responsiveness	Customers expect service in all areas of their dealings with Horizon Energy. The Company is keen to ensure that all processes and interaction with customers are handled in an appropriate, efficient and timely manner.
Financial	Customers expect a reasonably priced service, and shareholders expect a return on investment.

Table 4.1- Identifies the service levels achieved against targets for the previous five years

Key Service Criteria	Quality Characteristic	Target Level of Service	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Actual 2014/15	Strategy or Programme to close Service Gaps
Safety	Safety of general public	No injuries due to equipment failures / design issues	0	0	0	0	0	<p>Health and safety systems continuous improvement program.</p> <p>All hazards within the control of Horizon Energy identified and controlled appropriately.</p> <p>Individual Project hazard and operability assessments (HAZOP) are undertaken for projects that are unique or uncommon for the network.</p> <p>Mandatory tailgate hazard briefings at all worksites.</p> <p>New programme to increase line clearances over state highways.</p>
	Safety of employees and contractors	Zero serious harm incidents	1	1	1	1	1	<p>Health and safety systems continuous improvement program.</p> <p>All hazards identified and controlled appropriately.</p> <p>Individual Project hazard and operability assessments (HAZOP) undertaken for all projects.</p> <p>Mandatory tailgate hazard briefings at all worksites.</p> <p>Worksite audits</p>

Key Service Criteria	Quality Characteristic	Target Level of Service	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Actual 2014/15	Strategy or Programme to close Service Gaps
	Safety of network assets	All unsafe (red tag) conditions rectified within a three month term	N/A	Yes	Yes	Yes	Yes	Increase robustness and accuracy of defect system to ensure that priorities are met. Asset inspections Reporting to change to P1 and P2 defects from 2015 onwards
	Safety of network assets	Reduce the number of low road crossings over State Highways by 8 per annum (new 2012 - 13)	N/A	N/A	3	16	14	Use the GIS and recently captured asset data to identify and prioritise road crossings for removal or reconfiguration. Reduce hazards to public road users as crossings tend to sag over time.
Quality	Voltage	Less than five legitimate voltage complaints per year	0	0	1	0	3	Improve work practices and customer notification of outages
Environmental	PCBs	Zero problems	0	0	0	0	0	No PCB's in the network.
	SF6	Zero problems	0	0	0	0	0	Gas pressure readings taken at regular intervals and a register of SF6 devices and volume of SF6 gas is maintained.

Key Service Criteria	Quality Characteristic	Target Level of Service	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Actual 2014/15	Strategy or Programme to close Service Gaps
	Transformer oil spills	Zero spills	0	0	0	0	0	Covered by specific projects for each facility as required, discussed in Section 5, Network Planning.
	Asbestos	Zero reports	None reported	None Reported	None Reported	None Reported	1	Advised by Commerce St building owner that asbestos is in the building. Tested and confirmed not airborne
Reliability	Faults per 100 circuit kilometres 11kV	5	6.91	6.82	7.25	5.3	6.8	Reliability projects Increased network renewal. Introduce self healing technology
	Faults per 100 circuit kilometres 33kV	2	2.8	2.8	3.45	2.3	2.24	
	SAIDI	145 mins (class B & C)	162.67	174.62	191.6	186.3	173.0	
	SAIFI	1.8 (class B & C)	2.27	2.24	2.3	1.77	2.0	As above.
	CAIDI	81 mins (class B & C)	71.54	77.99	83.3	105.3	86.5	As above.
Service	Approval of Application For Service (NCI)	Less than 14 working days	N/A	N/A	91%	87%	90%	

Key Service Criteria	Quality Characteristic	Target Level of Service	Actual 2010/11	Actual 2011/12	Actual 2012/13	Actual 2013/14	Actual 2014/15	Strategy or Programme to close Service Gaps
	EGCC Complaints reaching dead-lock	0	N/A	1	0	0	0	
	Planned shutdown advertised time off	100% meet planned timeframes +/- 10min	N/A	N/A	72%	82%	92%	

Table 4.2 - Actual Performance and Identified Service Gaps

4.4.1 *Justification for Targets*

The targets presented in this AMP have been mainly based on historic performance and customer engagement. The customer surveys detailed earlier have indicated that both urban and rural customers are generally satisfied with the service provided with regard to availability and responding to outages. However, neither urban nor rural customers were prepared to pay more to improve their supply quality.

The analysis of the worst performing feeders provides another mechanism of validating consumer service levels since they reflect the network architecture.

The justification for the targets are summarised below.

4.4.1.1 *Safety*

Public and employee safety is paramount. Health and Safety legislation has very strong incentives for a company and individuals to provide a safe workplace and environment for employees and for members of the public. Horizon Energy takes its safety responsibilities very seriously, and any safety issue is dealt with promptly. Where equipment is identified as unsafe a replacement or minimisation process is instigated to remove, mitigate, or eliminate the hazard. Internal measures for the effectiveness of these programs are the monitoring of safety defects, red tag pole defects and the introduction or reinforcement of training programs.

Public and employee safety measures include traffic and worksite management, education, hazard identification, competencies management, and re-training schemes. Although Government regulation is not the primary driver for safety, the new requirement for lines businesses to comply with NZS 7901:2008 Electricity and Gas Industries Safety Management is added justification to set and achieve public safety Key Performance Indicators.

Horizon Energy has an active Health and Safety Committee that meets and publishes a regular newsletter to drive and continually improve safety and wellbeing. Incidents, accidents and near miss reports are recorded and analysed. Any corrective actions required are added to the Corrective Action Register (CAR) for tracking.

The target of zero serious harm incidents for workers and the public is a measure of the effectiveness of these programs, and a measure of contractor lost time injuries (LTI) gauges the effectiveness of safety programs instigated by the contractor.

4.4.1.2 *Quality*

Horizon Energy is currently focusing on two key quality areas; customer complaints for voltage quality, and contractor performance with regards to customer satisfaction. Power system quality manifests itself in the following ways:

- Modern electrical equipment is more sensitive to power quality variations than equipment installed in the past. Many new load devices contain microprocessor-based controls and power electronic devices that are sensitive to many types of disturbances;
- The increasing emphasis on overall power system efficiency has resulted in a continued growth in the application of devices such as high-efficiency, adjustable-speed motor drives and shunt capacitors for power factor correction to reduce losses. This is resulting in increased harmonic levels on the power system and is of concern as to the impact this may have on the systems future capability; and
- Increased awareness of power quality issues by the end users. Due to the increased use of electronic power quality devices by consumers, and the ability of these devices to inform of the actual power system characteristics, utility customers are becoming better informed about such issues as interruptions, sags, and switching transients, and are challenging the utilities to improve the quality of power delivered.

Voltage quality affects customers in the ways described above and Horizon Energy will work with customers to resolve voltage complaints.

Customer dissatisfaction with workmanship is occasionally brought to Horizon Energy's attention. When these concerns are raised they are passed on to the contractor to action and repair. A zero re-work target based on customer complaint is a measurable and achievable target.

4.4.1.3 *Environmental Standards*

The following broad targets have been set in this area:

- Certification under ISO14001;
- Zero discharge of any pollutants into waterways, ground or ground water systems;
- Disposal of office and work place waste in an approved manner that will minimise adverse impacts on the environment;
- Manage all discharges to the atmosphere in a manner that ensures minimal impact on the environment;
- Monitor any adverse effects that may be created by the electrical network and work to ensure that the public understand these effects;
- Ensure that consideration is given to the aesthetic and acoustic impact that may be caused during the installation of network components;
- Maintain a prudent approach to electrical efficiency on the network while lobbying to have the regulatory environment recognise and reward lines company investment in reducing technical energy losses; and
- Noise containment or shielding when required meeting target noise levels.

Environmental measurements are easy to monitor and report against. There are legal responsibilities as well as customer expectations that the environment is correctly managed, as well as a social responsibility to be responsible for the environment.

4.4.1.4 *Reliability*

Comparative measures of reliability are SAIDI, SAIFI, and CAIDI. These are separated into two categories, planned and unplanned. Generally Horizon Energy has little control over the number of unplanned events that are influenced by weather or external events. The network operator can influence the reliability measurements by responsiveness to switching, repair time and restoration. Therefore, measurements that address these three issues are a benchmark of how well the network and contractors can respond to faults.

Planned outages are within Horizon Energy's control. Proper planning to include all available works into an outage, meeting outage and restoration times, and adherence to these times, are a measure of efficient planning. There is a cost benefit to customers in the use of outages against using the more expensive live line work alternative to outages.

The measurements planned against these categories are an indication of how well the network is performing, both as a relative measure against other networks, as well as a measure of performance against preceding years.

The targets set for unplanned outages for SAIDI, SAIFI, and CAIDI are set below the regulatory compliance threshold set by the Commerce Commission for Horizon Energy and are based on past performance. Customers appear satisfied with the current level of service. Target numbers have been set lower as the newly installed reliability equipment starts to be effective in reducing the effects of faults.

4.4.1.5 *Responsiveness*

The measures of responsiveness to customer services are self-explanatory, and provide an indication of how service focused the network is towards meeting the expectations of the new customer. These targets are both measurable and achievable, and are currently established targets although no

measurement is made against the target. Once measurement systems are established, processes will be reviewed to enable better compliance to the targets if the targets are not achieved.

4.4.1.6 *Loss Ratio*

A number of networks include loss ratio as a service target. Horizon Energy has opted not to use loss ratio as a service measure as the network has little influence on the technical losses incurred within the distribution network from historical design parameters, and as loads increase technical losses will invariably rise. Technical losses are considered within the design phase of development but are not normally the primary driver for equipment selection especially as the logical relationship between capital investment and cost savings resulting from electrical efficiency gains no longer exists in the current regulated environment.

4.4.2 *Future Targets*

In the future, target service level may be aligned to the Model Use of System Agreement with retailers. The future reliability targets are contained within schedule 12 D of Appendix A2.

5 Network Planning

5.1 Introduction

This Section describes principles and practices used in network development planning. It includes the measurement and analysis methods used, assumptions made, and the sources and confidence levels of data used.

Assets are described in detail in the individual asset sections, along with load profiles, utilisation, operational constraints, development plans and restrictions that the various assets may have. Any changes in load type or profile are discussed and reasons for the changes explained. Works emanating from the studies of the various assets are further expanded throughout Section 5.

The planning process utilises a number of stages to plan and develop the network. The key inputs to the planning process are summarised in Figure 5.1.

Due to the continual review of proposed projects during the planning process, the priority for implementing individual projects proposed in this AMP may alter depending on the evolving needs of the network and its customers.

5.2 Network planning principles

Network planning is a crucial process required to assess the impact future changes have on the network. These changes can be driven by load change, equipment obsolescence, equipment age and condition based replacement, regulatory requirements, worker and public safety, stakeholder requirements, and service level improvements.

Network development planning requires data and asset knowledge to be extracted from various sources, and analytical systems and procedures to ensure reliable data analysis.

In simple terms, project planning involves three phases; discovery or needs identification, feasibility which includes options analysis and cost allocation; and finally detailed planning and design followed by a solution implementation.

This process is shown diagrammatically in Figure 5.1. The purpose of this Section of the AMP is to set out the inputs into the discovery phase, and the drivers that assist with the feasibility study and implementation phases.

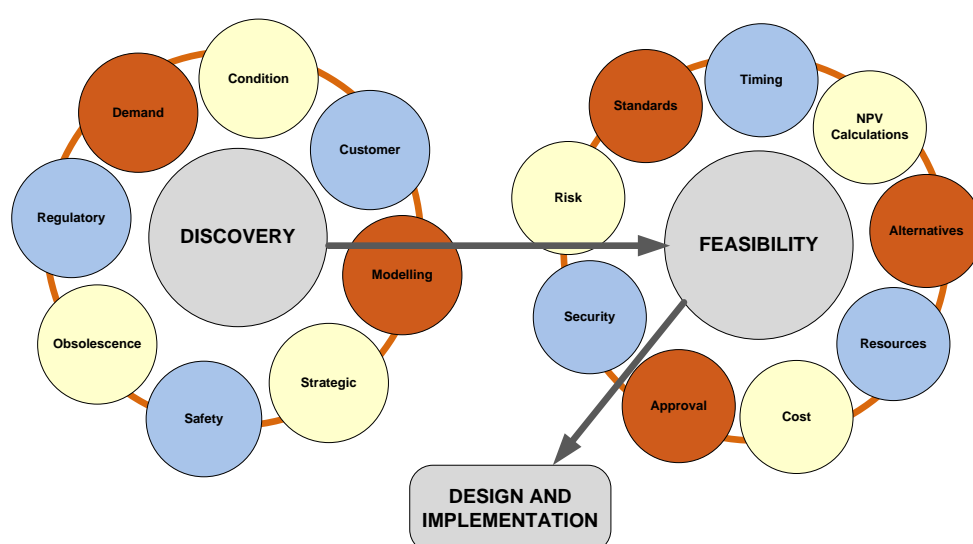


Figure 5.1 - Planning Inputs

5.2.1 Planning Criteria

Security of Supply Classification

Horizon Energy classifies its zone substations on the basis of their ability to supply the peak load without curtailment or interruption. The security classification types for zone substations are:

- N means that the current peak load may only be supplied without curtailment or interruption if all zone substation transformers are operating;
- N minus 1 (or N-1), means that the current peak load may be supplied without curtailment or interruption including if the largest zone substation transformer is not operating;
- N minus 2 (or N-2), means that the current peak load may be supplied without curtailment or interruption including if the largest 2 zone substation transformers are not operating; and
- N minus 1 switched (or N-1 switched), means that the load may be supplied following a brief interruption during which switching is carried out to re-establish supply following an unexpected outage of the largest zone substation transformer.

In addition to the security classification a Participant Outage Plan (POP) is prepared by Horizon Energy Distribution Limited (Horizon) to comply with the participant's obligation in clause 9.6 of the Electricity Industry Participation Code (Code) to prepare and publish a participant rolling outage plan. Further information on the Security of Supply Outage Plan is available on the Horizon Energy website.

Network Security Criteria

Network security is the capability of the network to provide an alternative path of supply in the event of an item of equipment failing, or being removed from service for maintenance. The level of network redundancy required is determined based on the load at risk, the predominant customer type supplied from the network, an appreciation of the value of lost supply to the customer, or by customer agreement. Target design security criteria are summarised in Table 5.1. and planning security levels in Table 5.2

Table 5.1 - Security Criteria

Level	Description
L1	Fully redundant alternative supply that maintains supply without an outage
L2A	Ability to restore load by automated 'self-healing' SCADA controlled switching
L2B	Ability to restore load by manual SCADA controlled switching
L3	Outage that is restorable by alternative supply by manual switching within two hours
L4	Restoration within three hours, except for faulted segments
L5	Restoration after repair

Table 5.2 - Planning Security Levels

Load / Customer Type	Planning Security Levels
Dual transformer bank zone substation	L1
Zone substation pair (e.g. Plains and East Bank)	L2B
Major Industrial Customers (service level by agreement)	L1 or L2B
Major Industrial Customers (standard terms of supply)	L3
Zone substation less than 10MVA	L3
High density commercial load	L3
Urban and rural areas with meshed networks	L4
Urban and rural areas with no meshing	L5

No level L2A systems are installed. Currently there is a feasibility trial in place for self-healing network in the Plains Edgecumbe area. Once proven, and as more projects are implemented that contain SCADA controlled switching devices, then more areas will be able to achieve an L2A level of security. This is planned for implementation around 2017.

The above levels of security are guidelines for design undertaken across the network. By agreement with customers, higher levels of security can be provided if required.

Capacity Criteria

Assets are operated within their technical capacity, allowing for acceptable levels of short term overload in contingency situations. Any short term overload has to be managed to ensure that this does not materially damage the asset or create a hazard. Network reinforcement or other management measures will generally be implemented prior to load exceeding 100% of the assets rated cyclic thermal or fault current capacity.

Asset Type	Overload Capacity
XLPE cable	110% for four hours, four times per year
Paper Lead cable	No overload - 100% of rated capacity
Zone substation transformer	130% four hours @ 20° C ambient temperature
Distribution Transformer	130% two hours
Low voltage cables, PVC	No Overload - 100% of rated capacity

Table 5.3 - Overload Capacities

Transformer overloading is based on IEC 60354 standards. For cables, in emergency situations a higher level of overload may be allowable on the understanding that the asset condition ageing is likely to be accelerated. Any asset that load flow studies show is likely to be overloaded during reinforcement will be scheduled for upgrade.

5.2.2 Asset Building Blocks

All new assets are selected from the suite of standard network building blocks, unless otherwise driven by specific technical or commercial reasons. Standard asset blocks are used wherever possible to minimise costs associated with procurement, design and lifecycle support. Standard network building block elements are summarised below in Table 5.4 – Table 5.8

Distribution Transformers

Transformers are selected according to their connected load. Transformers selected for domestic installations consider the diversity that exists between increasing numbers of customers. Non domestic loads are engineered on a case by case basis. Using the design criteria for domestic loads, the table below details the maximum number of ICP's that would normally be connected to a particular size of transformer for a new installation.

Transformers	Number of Domestic ICP's
1000kVA Ground mount	Industrial use only
750kVA Ground mount	166
500kVA Ground mount	111
300kVA Ground mount	66
200kVA Ground mount	44
100kVA Ground mount or poletop	22
75kVA Ground mount or poletop	16
50kVA Ground mount or poletop	11
30kVA Ground mount or poletop	6
15kVA Ground mount or poletop	3

Table 5.4 - Distribution Transformers

33kV Feeders

Conductor Type	Size (sqmm)	Nominal Capacity (MVA)	Use
AAAC Krypton	158	24 MVA	All new circuits
ACSR Dog	103	17 MVA	Legacy conductor. Not used for new circuits
630 sqmm ² Al, XLPE Cable	630	Determined by defined conditions	GXP exit points
300 sqmm ² Al, XLPE Cable	300	Determined by defined conditions	Sub-transmission incomer cable to zone substations
185 sqmm ² Al, XLPE Cable	185	Determined by defined conditions	Sub-transmission incomer cable

Table 5.5 - 33kV Conductor Sizes

11kV Feeders

Conductor Type	Size (sqmm)	Nominal Capacity (MVA)	Use
Overhead Conductors			
AAAC Krypton	158	8 MVA	New high capacity feeder circuits
AAAC Iodine	124	6 MVA	Replacement for Dog and Wasp conductors
AAAC Fluorine	49.5	4 MVA	Replacement for Squirrel, Mink, Flounder, Ferret conductors
Legacy Overhead Conductors			
ACSR Dog	103	6 MVA	Main route Feeder circuits
ACSR Mink	62.2	4 MVA	Medium Capacity Feeder Circuits Legacy conductor
ACSR Ferret	41.8	3 MVA	Low capacity feeder circuits
ACSR Squirrel	20.7	2 MVA	Spur lines and private lines
Cables 11kV			
300mm ² AL/XLPE Cable	300	7 MVA	Zone substation exit cables and feeder first sections
185mm ² AL/XLPE Cable	185	6 MVA	Feeder sections
95mm ² AL/XLPE Cable	95	4 MVA	Legacy cable. No longer used for feeders. Distribution transformer supply in high fault zone areas
35mm ² AL/XLPE Cable	35	2 MVA	Distribution Transformer supply cable

Table 5.6 - Distribution Conductor Sizes**Earth Conductor**

Conductor Type	Nominal Fault Capacity 1 second rating (kA)
95mm ² Copper	10.5 kA
70mm ² Copper	7.7 kA
35mm ² Copper	3.9 kA

Table 5.7 - Earth Conductors with Ratings

Switchgear

Switchgear Type	Manufacturer/Make
Field Ring Main Units	ABB Safelink, ABB SD Units
Field Circuit breakers	Schneider RM6, ABB Safeplus
Pole top CB	Cooper Power Systems Nova, KFE
Pole top Single Phase CB	Siemens Fuse Saver
Automated Switch	ENTEC, ABB Sectos

Table 5.8 – Distribution Switchgear**5.2.3 Standard Designs**

Standard designs are used for:

- Overhead line structures;
- Pole mounted switchgear;
- Ring main installations;
- Cable termination kits;
- Substation and protection designs; and
- Primary switchgear.

Network policy is to use, wherever possible, equipment that the rest of the industry is using; to leverage the experience and research capability of larger networks and suppliers and to gain the benefits of readily available equipment and supplier support.

5.2.4 Load Flow Measurement

Fundamental to understanding historical load performance and asset utilisation, and as the basis to predict growth, is the accurate measurement of demand and load flow. As a minimum, Horizon Energy has load current measurement at each zone substation for each feeder.

With the transition of communications to industry standard protocol DNP over IP, the gradual replacement of obsolete protection relays with microprocessor based relays (IED relays), and the addition of modern poletop circuit breakers and switches into the network, additional data is becoming available to enable more accurate analysis of the load within the distribution network.

Measurement data from each zone substation is collected by SCADA and stored in a database.

5.2.5 Network Modelling Methods

The network is modelled for load flow geographically using PSS SINCAL network modelling software. The application is capable of undertaking calculations for load flow analysis of conductor loading, voltage drop, substation loading, power transformer loads, and 33kV and 11kV network losses.

Network models have been developed for the 33kV Sub-transmission system as well as for all 11kV Distribution Feeders. There is no modelling at the 400V distribution level except for specialised installations for individual customers. Model accuracy and confidence is described in Table 5.9.

Model	Level of Uncertainty
33kV Sub-transmission system	Low level of uncertainty; <ul style="list-style-type: none"> Modelled results have been verified against source and destination metering data, manual calculations, and models on alternative modelling packages.
11kV Distribution	Te Kaha, Waiotahi, Edgecumbe GXP models are believed to be reasonably accurate. Spot checks of modelled loads and voltage profiles at various sites have been within an acceptable tolerance of predictions. Uncertainties are introduced by: <ul style="list-style-type: none"> Different line build configurations to that modelled; Errors in conductor size; Data update lags; Assumptions on load factors; Loads not fitting average profile assumptions e.g. pump loads; Phasing connection assumptions for single phase transformers; Geographical placement errors; Embedded generation and load equipment assumptions; Unsure locations of large intermittent loads e.g. irrigation pumps; Power factor variations from 0.95; Harmonics are not modelled.
11kV Distribution Galatea	<ul style="list-style-type: none"> High degree of uncertainty with the rural zones modelling; Predominance of summer irrigation loads; Lack of detailed knowledge of the placement of the irrigation pumps.
Modelling Improvement Plans	<ul style="list-style-type: none"> Plans to improve the accuracy of load flow modelling include: Automatic updating of variable data (lines, locations and transformers) from the GIS system; Additional data from intelligent switching devices; Additional user training; Identification of specific load groups such as frost protection, irrigation and industry to enable tailored growth and utilisation patterns to be applied for these groups.

Table 5.9 - Model Accuracy

Protection configuration modelling is done using spreadsheets as well as fault simulation in SINCAL. Parameters modelled are over-current and earth fault elements. Non IEC equipment curves, fuse data, line constants and cable constants are pre-determined and applied using look up tables. Data is peer reviewed for accuracy. Protection modelling on PSS SINCAL is used for verification.

All modelling systems are managed by the Planning team.

5.2.6 Asset Condition Replacement

Planning processes relating to asset replacement based on condition and/or age is covered in Section 6, Asset Lifecycle Management Planning.

5.3 Project Implementation

Projects include capital works programs and larger maintenance projects. Most of the annual works plan is completed using project planning processes.

All projects are assigned a Project Manager who is responsible for managing the project implementation. For a small project the Project Manager may run the project from conception to completion. Larger projects are set up with a Project Manager and a Project Team selected to provide the skill sets required to engineer and implement the project. External resources are engaged when specialised skills are required or the work load capability of the available staff is exceeded.

5.3.1 Long Term Planning

Long term planning addresses projected network growth, strategic initiatives, and obsolescence or condition based asset replacement. The outcomes of network and equipment analysis result in future projects being identified for inclusion in the 10 year plan. As priorities alter, the plan alters, and projects are moved to suit the needs of the network and its customers. Projects are initially entered with high level budgets based on today's dollars. Initial high level project cost estimates are developed from past experience or unit rate prices.

The long term plan is approved by the Board of Directors as part of the AMP but is a guideline planning document only and will alter as network priorities alter.

Main planning trends are:

- An increasing capital requirement to replace line and cable assets ramping up within the next five years as assets average age increases;
- Increased capital spend to resolve network constraint issues and improve reliability; and
- Increased major asset replacements over the next 5 years as zone substation power transformers are replaced due to either age or capacity.

5.3.2 Project Justification

A project cannot proceed unless it passes a number of tests to determine if the expense is justified and warranted. Pre-feasibility checks are carried out at a high level by the Planning team to determine if the concept idea warrants further development. This process can be either informal or formal depending on the level of engineering applied to the pre-feasibility and the value of the proposed project. Projects are initiated by several different drivers summarised below:

- Public safety, staff or contractors;
- Providing capacity to meet demand;
- Customer initiated projects for new connections or capacity;
- Meeting reliability and security targets;
- Improving asset value;
- Improving operational efficiency; and
- Replacement of aged assets.

The basic principle applied to every project is to ask the question ‘Why are we doing this project?’ Major proposed projects will be accompanied by a project feasibility report or strategic plan that identifies:

- The project drivers and issues addressed;
- Key findings from engineering or planning studies;
- A summary of projects and alternative options considered;
- Possible non network options;
- Recommendations ranked in order of priority with reasons for selecting or rejecting various options;
- High level budgets and proposed cash flow;
- Risk assessment, including the risk of not doing the project; and
- Cost or benefit analysis of the main and alternative options.

Horizon Energy recognises that it has a limited engineering resource, so for major projects involving a significant cost, the feasibility study will either be outsourced to an external consultant, or completed in-house and reviewed externally. This ensures an independent check of the project concepts and draws on the experiences of industry specialists who have access to a larger pool of engineering resources and knowledge.

5.3.3 Project Priority

Prioritising a large number of projects is done using a points system. Projects are assessed using a series of yes/no answer questions and each answer is given a point value. The greater the number of points allocated to a project, the greater the priority of the project..

Projects are allocated points according to the following criteria. Each project is further subjected to a capital approval process that considers the economic and technical benefits of each project on a stand-alone basis. The basic scorecard is shown in Table 5.10.

The questions are designed to be a yes/no answer. This is functionally more effective than using a graded number system (e.g. 1-5) which has a tendency for assessors to grade mostly in the midrange region (2-4). Weighting is determined by Management.

The final priority for work is based on financial approvals, the availability of resources, and the directions that the Board, Customers, or Shareholders may determine.

Priority Scorecard

Customer Focus	Score (Yes=1)	Weighting	Examples or assessment criteria
Is this a safety driven job?	0	2	Applies to jobs that are directly safety driven e.g. safety barriers, improved locking, improved earthing, etc. Does not apply to a project that may indirectly improve safety, e.g. a line that is upgraded, improved protection, etc. does not qualify.
Is this job required to comply with legal requirements?	0	2	Applies to jobs required for Company/asset to be compliant, e.g. clearances or prevention of access to ground mounted equipment.

Installing the project provides an estimated potential saving in SAIDI greater than one minute?	0	1	If the existing equipment fails, estimate the SAIDI impact minutes lost. Number of customer's time off/total number of customers.
Is fault response time likely to be improved?	0	1	Any project that reduces the time to sectionalise or restore faults e.g. if automation is installed where previously there was no automation, or if a tie point is installed, this will be one.
Is a customer prepared to contribute some costs?	0	2	
Is SAIDI <0.5 minutes to install?	0	1	If installation SAIDI is too high then the cost of construction goes up which may alter the financial viability of a project.
Is there an improved public visual benefit over an existing installation?	0	1	Is it smaller, less obtrusive and more visually appealing for customers?
Business Focus	Score (Yes=1)	Weighting	Examples or assessment criteria
Is the project strategic or required to support another project?	0	1	Zone substation, tie feeder, communications link, SCADA, line to new substation, condition testing or monitoring, ZS transformer replacement, sub transmission upgrade etc. Any project that must be completed to support a subsequent project.
Is environmental risk reduced?	0	1	Oil containment, noise reduction, vehicle impact reduction, end of life environmental advantage.
Is risk to the sub transmission or 11kV distribution network reduced?	0	1	Applies to main feeder equipment; replacement of main feeder lines in poor condition, spur line fusing, undergrounding, etc.
Is the project technically complex?	0	1	Work that requires a higher level of engineering than 'normal' work; elevates priority to allow resources to be allocated earlier.
Does the project address multiple faults or has overall asset condition been assessed as poor?	0	1	Applies to a project that groups a series of defects or poor condition assets (does not apply to lifecycle replacement of end of life assets).
Does delaying the project by 1-2 years cause a problem?	0	1	Do we have to do it now or can it be delayed without consequence.
Is this a totally new asset?	0	1	Does this project increase the asset base of the company i.e. is NOT a replacement for existing equipment? (This gives some weighting to the non-replacement projects).

Asset replacement	Score (Yes=1)	Weighting	Examples or assessment criteria
Is an asset to be replaced > 90% of its EDB end of life age?	0	1	Elevates older assets in priority for works.
Will this project reduce direct maintenance costs?	0	1	Reduces routine maintenance cost e.g. non-oil enclosed switches have a reduced maintenance requirement compared to an oil filled switch; undergrounding of overhead lines reduces line maintenance costs.
Will operations costs be reduced?	0	1	Measurable operations costs; cost of travel, reduced operation time, less people to operate, reduced losses. Does not include un-measurable costs, possible savings in reduced faults, defects, etc.
Does the piece of equipment being replaced have a history of failure?	0	1	Targets individual pieces of equipment that has had a history of poor performance.
Is the equipment type prone to failure?	0	1	Targets particular equipment class (e.g. And elect series 1 RMU etc. that has a known class type fault.
Does the project address load, overload, or reinforcement constraints?	0	1	Conductor or transformer upgrades due to overloading or reinforcement requirements.

Table 5.10 - Priority Scorecard

5.3.4 Engineering

Detailed engineering is worked on in-house for smaller projects and contracted out for large projects. Horizon Energy uses the following engineering tools and their various characteristics are listed in Table 5.11 below:

Tool	Description	Limitations
Standards	<ul style="list-style-type: none"> Network design and equipment standards 	<ul style="list-style-type: none"> Under continual review Managed as controlled documents
PSS Sincal	<ul style="list-style-type: none"> Network electrical load flow modelling software provides load flow analysis Protection modelling Load development modelling 	<ul style="list-style-type: none"> Requires skilled engineers to use effectively
Catan	<ul style="list-style-type: none"> Overhead line design tool 	<ul style="list-style-type: none"> Specialised skill set required to use effectively
Intergraph GTech	<ul style="list-style-type: none"> Geographical Information System 	<ul style="list-style-type: none"> System replaced in 2013
Autodesk AutoCAD	<ul style="list-style-type: none"> 2D/3D drawing package Industry standard 	<ul style="list-style-type: none"> Requires skilled users
Protection Design Spread sheets	<ul style="list-style-type: none"> Models protection curves Standard IEC calculations 	<ul style="list-style-type: none"> Limited in-built functionality

Table 5.11 - Engineering Design Tools

5.3.5 *Non Network Development Options*

As part of the engineering process all projects need to consider the alternatives that non-network options may provide. Non-network development options are alternative solutions that do not require spending capital on the distribution network.

Table 5.12 below summaries non-network options considered for managing the load. These solutions are generic and are discussed here separately to the individual area issues. Each load driven project, as it is engineered, will be assessed using the following discussions to see if any non-network solutions could be applicable.

Option	Advantages	Disadvantages
Demand Load Management Ripple Control	<p>Ideal solution for short term peaks. Emergency load shedding up to 5%. Assets already owned by network.</p> <p>Horizon Energy is actively studying this option</p>	<p>Not viable as a long term solution for overloading. Customer quality issues if used for long duration per day. Unable to control smaller regional sub areas e.g. a single subdivision, without new meters being installed network wide.</p>
Demand Load Management Smart Metering	<p>Customer empowered to make choices. Some controls can be made transparent to customer. Enables individual small areas to be shut off in emergencies. Ability to control smaller regional sub areas e.g. subdivision.</p>	<p>Requires all customer meters to be replaced. Requires peak load tariff structure or incentive for customers to manage load. Customer behaviour is not consistent. Consistent load reduction not available on short notice. Requires retailer buy-in as meters are (currently) owned by retailers, or a change in meter ownership policy. Requires communication to the meters. No infrastructure currently installed. Requires extensive IP communications infrastructure, probably wireless.</p>
Demand Load Management Customer Education	<p>No network cost for equipment. Empowers customers to make choices to manage their own demand.</p>	<p>Currently there is no financial incentive for customer to manage peak demand. Must be viewed as short term solution. Continuous re-education required to be effective. Customer behaviour is not consistent. Consistent load reduction not available on short notice.</p>
Demand Load Management Smart Homes	<p>No network cost for equipment. Customer empowered to make choices. Some controls can be made transparent to customer. Installed with smart meters allows control to smaller regional sub areas e.g. subdivision. Good long term benefits.</p>	<p>Needs to be built into homes when constructed. Requires customer education. Requires peak load tariff structure or financial incentive for customers to commit. Slow uptake. Customer behaviour is not consistent. Consistent load reduction not available on short notice. Limited quantity of energy smart appliance equipment available in the marketplace. Requires internet connectivity for maximum benefit.</p>

Option	Advantages	Disadvantages
Demand Load Management Major Customers	<p>Ability to reduce large loads for pre-defined periods of time or to reduce peak demand.</p> <p>Established commercial arrangements with the network operator.</p> <p>Some Horizon Energy Major Customers are actively practicing this</p>	<p>Must be planned for in advance.</p> <p>Normally unable to be activated at short notice due to effect on customer's production.</p>
Embedded Small Generation, <2.5kW, User Owned. Solar, Wind	<p>Non network cost.</p> <p>Displaces load from network.</p> <p>Generation at load site reduces losses.</p> <p>No RMA issues for network operator.</p> <p>A small number of solar installations have been installed</p>	<p>Reduces utilisation of network assets.</p> <p>Safety issues with reverse feeds and fault tripping.</p> <p>Affects kWh based pricing methodology.</p> <p>Will have variable utilisation and generation characteristic.</p> <p>Weather dependant.</p> <p>No match to network demand.</p>
Embedded generation, customer owned, or customer owned diesel fuelled pumping stations	<p>Non Network Cost.</p> <p>Especially suitable for peak load support for areas with limited supply capacity.</p> <p>Good redundancy for loss of supply for critical services.</p> <p>Network assets don't need to be sized for the peak loads.</p>	<p>Can improve utilisation of network assets.</p> <p>Safety issues with reverse feeds.</p> <p>Will have variable utilisation and generation characteristics.</p> <p>Cost of ownership high.</p>
Embedded Diesel Powered Generation. Fixed installation Network Owned 300-2000kVA	<p>Economic compared to major sub-transmission asset costs if the load is a short term peak rather than sustained. May be an option for Te Kaha.</p> <p>Auto start and loading can respond to demand load.</p> <p>Minimal RMA impact.</p> <p>Can be partly funded by Avoided Transmission costs if matched to peak demands.</p>	<p>Costly to run.</p> <p>Capital intensive.</p> <p>Short life (in comparison to other network assets).</p> <p>Requires continuous service (Fuel).</p> <p>Medium level maintenance requirements.</p> <p>Assets are stranded.</p>

Option	Advantages	Disadvantages
Portable Diesel Powered Generation. Network Owned. 300 -1000kVA	<p>Economic compared to installing permanent major sub-transmission assets if the load is a short term peak rather than sustained.</p> <p>Auto start and loading can respond to demand load.</p> <p>Minimal RMA impact.</p> <p>Portability allows relocation to other sites as required.</p> <p>Good solution for short term support or planned outages.</p> <p>Horizon Energy is investing in this technology</p>	<p>Costly to run.</p> <p>Short life (in comparison to other network assets).</p> <p>Requires continuous service (Fuel).</p> <p>High maintenance.</p> <p>Requires labour to connect and disconnect.</p> <p>Establishment time to set up if required in emergency.</p>
Wind Power, Large Unit >500kVA, Network Owned	<p>Low capital cost per kW.</p> <p>Environmentally friendly.</p>	<p>Limited areas available with suitable wind resources.</p> <p>Difficult RMA process.</p> <p>Difficulty with voltage regulation when located a distance from zone sub and with local loads on same feeder.</p> <p>May require dedicated lines.</p> <p>Requires alternate source of supply on windless days.</p> <p>No match to network demand.</p>
Wind Power, Small Unit up to 200kVA, Network Owned	<p>Low capital cost per kW.</p> <p>Can be located at smaller load centres.</p> <p>Environmentally friendly.</p> <p>Network can support on windless days.</p>	<p>Limited areas available with suitable wind resources.</p> <p>Difficult RMA process.</p> <p>Requires alternate source of supply on windless days.</p> <p>Some voltage regulation issues if not located at loads.</p> <p>No match to network demand.</p>
Geothermal Generation	<p>High capital cost per kW.</p> <p>Environmentally friendly.</p> <p>Constant output.</p> <p>Large units have lowest installed and operating cost per kW.</p>	<p>High RMA impact.</p> <p>Restricted access to proven resource.</p>
Mini Hydro Generator	<p>Can be made environmentally friendly.</p> <p>Good for voltage regulation and network support.</p> <p>Low running costs.</p> <p>Two private units embedded in the network</p>	<p>Can be difficult RMA process.</p> <p>Limited suitable sites with hydro available close to loads or reticulation system.</p>

Option	Advantages	Disadvantages
Utilisation of customer owned emergency generators for network support	Non network cost. Could be used to support peaks or local outages.	Commercial arrangements would need to be established. Need reverse power and sync capability. Limited network control of availability. Not all known generators are ideal locations. Need to manage loading with local switching.

Table 5.12 - Non-Network Development Options

Additionally, Horizon Energy has joined a New Zealand wide incentive to work on a transform model that is a representation of the electricity distribution network and describes the impact that future scenarios may have on the planning and operation of networks. The model takes real data from participating networks, central government, and other sources with the aim to assess and optimise investment over a range of conventional and smart strategies which involve a wide range of network solutions.

5.3.6 Energy Efficiency and Loss Reduction

The management of voltage and network losses have a number of different effects on load. While these are technically network options, they are alternatives to the conventional network constraint solutions of installing larger or more conductors.

The summary and benefits of these solutions are described briefly in Table 5.13 along with areas where these initiatives have been used to good effect.

Loss Correction Initiatives	Advantages	Disadvantages
Voltage regulators	Reduces the need to increase conductor size for low load, long distance distribution. Low capital cost compared to line upgrades. Used for Voltage correction on factory Feeder at Opotiki	Creates issues in meshed networks across tie points with voltage imbalance and phase angle shift. Shorter service life than line upgrades. Increases power on resistive loads and increased volt drop immediately preceding the regulator.
Capacitive reactive power correction at 11kV	Economic fix to compensate for fixed reactive line losses and inductive loads if installed without switching. May be more economic than line upgrades. Corrects localised reactive power components. Used on Factory feeder	Large step ranges. Can create over-voltages in low load situations if capacitors are oversized. Expensive if switched. Can affect ripple control transmission. Cannot compensate for line i^2r resistive losses.

Loss Correction Initiatives	Advantages	Disadvantages
Increase Zone or GXP Substation Bus Voltages	<p>Gives a higher delivery voltage and more power.</p> <p>Easy and economical to do.</p> <p>Reduces line current in constant power applications.</p> <p>Can reduce line losses slightly.</p> <p>Normally reduces transformer current.</p> <p>Horizon Energy Sets 11kV Zone Substation Voltage at 11.2kV</p>	<p>Can cause voltage quality issues for loads close to the substation.</p> <p>Increases energy for resistive loads.</p> <p>Increase in electrical stress on network if taken too high.</p>
Higher delivery voltage (e.g. stepping from 11kV to 22 or 33kV)	<p>More power for the same conductor size.</p> <p>Longer transport distances.</p> <p>Reduced line losses for the same power.</p> <p>Same easement corridor can be used.</p> <p>Can be built dual circuit with 11kV.</p>	<p>Expensive - requires power transformers, line insulator, and clearances upgrades.</p> <p>Transformers and hardware are more expensive if used for distribution.</p> <p>Issues with meshing to adjoining networks if these are operating at a different voltage.</p>
Parallel Power Transformers	<p>Lightly loaded parallel transformers reduce copper losses by square law.</p> <p>Provides n-1 redundancy.</p> <p>Provides overload resilience.</p> <p>Kope, Station Road, and Galatea are parallel transformer substations</p>	<p>Costly – two sets of switchgear and transformers are required.</p> <p>Large footprint.</p> <p>Increases the number of installed large transformer assets compared to load sharing from adjacent substations.</p>
Parallel operation of sub-transmission or distribution system	<p>Multiple lines can provide better utilisation and provides load balancing of existing assets, improved redundancy, less losses.</p> <p>Can delay load driven expenditure.</p> <p>Provides n-1 redundancy.</p> <p>Currently Practiced at Sub-transmission level into Te Rahu and Galatea substations</p>	<p>Complex protection scheme required.</p> <p>Costly to implement but cheaper than new infrastructure.</p>

Table 5.13 - Non-Network Load Support Options

5.3.7 Projects Planning Timeline

Project timing during the planning year is set to:

- Network priorities;
- Level contractor labour requirements;
- Manage lead time for material delivery; and
- Suit the availability of the network loads.

Potential labour overloads are identified early and external labour is used to supplement the available labour pool where required. The availability of specialist skills may have an impact on project timing as well but the main influence is engineering resources and major equipment delivery time.

Standard times to plan for equipment delivery is in Table 5.14:

Equipment Type	Material Delivery Lead Time
Power transformer 33/11kV	12 months
33kV indoor switchboard	12 months
11kV indoor switchboard	12 months
Building consents	6 months
Building construction	5 months
ESA approval	3 months
Railway crossing approval	6 months
Pole top circuit breakers	3 months
Distribution ground mount switchgear	3 months
Distribution transformers	2 months
33kV and 11kV cable	4 months
Overhead conductor	2 months
Protection relays	3 months

Table 5.14 - Planning Intervals

Where practicable, new customer connection projects are scheduled to meet the requirements of the customer.

5.3.8 Project Controls

- Budget control is managed by the General Manager Network and implementation is managed by the Service Delivery Manager. Expenditure is set by authorised approval levels;
- Project budgets are estimated by Planning team and each project is re-priced prior to project expenditure approval (Capex approval) and issue for construction;
- Major projects are broken down into sub projects to provide better control. Variations to the projects are approved prior to work commencing and there is a variation tracking process;
- Every project has a Horizon Energy Project Manager and a contractor's representative appointed to manage the project;
- All work teams must complete daily hazard assessments and supply these with the completed project documentation;
- There are staff competency controls over who can work on the network;
- All network switching is controlled from the Horizon Energy Control Room; and
- Audits on quality and safety are carried out by the Engineering and Control Room staff.

5.3.9 Construction Planning

The contractor provides construction resources and construction planning. Milestone dates are agreed between Horizon Energy and the contractor tasked with achieving these targets.

5.4 Demand Forecasting

Historical demand and growth rates are only a fair indicator of future capacity needs. Other influences such as population growth, changing use patterns, seasonal variations, step change loads, changing demographics and consumer displacement must also be considered in the prediction of load growth.

Horizon Energy predominantly uses historical load growth and moderates this with known planned major step changes or other knowledge of influencing factors.

5.4.1 Load Forecasting Methodology

Load growth is determined in the first instance by analysing historical load performance for each zone substation and individual feeder. This is then extrapolated using the average historical growth. Any known planned developments, planned network re-configurations or step changes in load are included in future load predictions and modelled accordingly.

Individual feeder sections are checked for overloading across all load scenarios including reinforcement. Network constraints are identified and are loaded into the 10 year development plan for assessment as future projects.

All load data is collected from the SCADA Historian archive. Load studies are taken for each annual period 1 April to 31 March. The various analysis methods used are described in Table 5.15.

Analysis	Method	Limitations
Load Growth	<p>The average load for each 30 minute period for one year using iHistorian data is graphed. Load duration curves are compared against previous years to compare growth change patterns.</p> <p>The fiscal year, 1 April to 31 March, is used.</p>	<p>Assesses the average growth.</p> <p>Does not give a result for short term peak loads within the 30 minute period.</p> <p>Due to different metering methods at each substation different load measurement methods are employed.</p> <p>MW indication is not as useful as MVA as it does not take into account reactive power, which gives a better indication of asset utilisation.</p>
100 Peaks Load	<p>The one hundred highest 30 minute load periods in any one year are averaged to provide a value. This method reduces the effect of transients and short term reinforcement peaks on the load and gives a good value to compare against successive years.</p>	<p>Includes reinforcement loads. Tends to slightly understate the full peak load applied to a substation / feeder.</p>
Load Duration	<p>Load duration determines the load (or utilisation) against the percentage of the total time for the period being studied. Measurement data used is the average load for every 30 minutes over the period being assessed.</p> <p>For most zone substations a one year period is used. If a site is of concern then a shorter period over the peak load season is further analysed.</p> <p>Load duration over successive years is useful for verifying load growth and graphically displays where the growth is occurring as a percentage of asset utilisation.</p>	<p>Does not take into account short term peaks within the 30 minute measurement period.</p>
Maximum Load	<p>Maximum load is the highest 30 minute peak for the measurement period (normally one year). This value is used in the load based asset replacement decision matrix.</p>	<p>Peak load data is not used for growth predictions as the peaks can be controlled using load control, but is monitored to ensure the network is capable of supplying the short term peak loads.</p> <p>Often the peak is a transient so comparison of peak growth per year can lead to erroneous growth predictions.</p>
Load measurement- 3 rd quartile, average, median, 1 st quartile	<p>These values provide additional data to assess the utilisation of the feeders and substations. Data is collected as described above.</p>	<p>Of limited use in network analysis except for highlighting any abnormal load use patterns. Average growth is used to verify load growth in conjunction with the average 100 peaks value.</p>
Power supplied by GXP	<p>Data supplied by Transpower</p>	<p>High level of reliability.</p> <p>Does not include transmission losses</p>

Analysis	Method	Limitations
Technical Losses	System technical losses are calculated from three different sources. 33kV and 11kV load flow modelling. Zone sub power transformer loss modelling. Distribution transformer loss calculated against median load. Low-voltage lines and cable losses (estimated). Total losses are the sum of the individual losses.	Load flow limitations are described above. Distribution transformer losses are calculated from median load and actual transformer manufacturer's data. Low voltage losses are estimated as 1% of the total losses.
Demand Management - Hot Water Heating	Domestic hot water loads estimated from load drop in response to ripple control signals	Not used in demand peak forecasting as the measurement for hot water heating loads have a high level of uncertainty, as well as uncertainty as to whether the load control is actually active for peak periods.
Demand Management - Other	Embedded or distributed generation, line losses management, and alternative energy sources.	The effects of other methods of energy displacement are not identified separately in the forecasting. The peak load measurement at each GXP already includes the load displacement measures applied within the network. The effects of energy displacement, solar, geothermal, etc. are unable to be readily quantified but are not believed to be significant at present.

Table 5.15 – Sources of Data for Load Growth Analysis

5.4.2 GXP and Zone Substation Load Forecasts

Future load predictions for GXP's and zone substations are determined from:

- The maximum 30 minute demand for the previous year; and
- The average growth rate measured over the last four years.

Where the substation data is inconsistent, as is the case for East Bank Road substation due to the influence of generation, an estimate of growth is made based on feeder data or general growth in the region. In any case, background information is sourced from District and Regional Council plans, Statistics NZ and less formally through staff contacts and membership of local business organisations.

Load Predictions			Historic Demand					
Zone Sub	Capacity (MVA)	Average Growth	2010	2011	2012	2013	2014	2015
East Bank	15	1.2%	7.7	6.4	7.1	7.3	7.1	6.4
Galatea	7.5*	1.3%	4.5	5.0	4.8	4.6	5.2	4.6
Kaingaroa	5.3*	0.0%	2.6	2.4	2.3	2.6	2.6	2.6
Kawerau	25*	0.2%	18.3	19.0	17.6	17.2	18.0	17.8
Kope	16*	1.0%	14.9	15.5	15.7	14.5	14.2	15.3
Ohope	5	1.0%	4.6	4.7	4.3	4.5	4.2	4.4
Plains	10	1.2%	6.8	7.8	6.6	6.6	6.6	5.9
Station Road	10*	0.3%	9.2	8.4	10.6	10.1	9.8	10.0
Te Kaha	5	0.0%	1.8	2.1	1.5	1.5	1.5	1.6
Waiotahi	12*	1.5%	9.4	9.1	9.4	11.1	9.3	9.4

Load Predictions			Predicted Maximum Demand (MVA)												
Zone Sub	Capacity (MVA)	Average Growth	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Notes
East Bank	15	2.0%	6.7	6.8	6.9	7.1	7.2	7.3	7.4	7.6	7.7	7.8	8.0	8.1	1
Galatea	7.5*	0.2%	4.7	4.7	4.7	4.7	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8	
Kaingaroa	5.3*	0.0%	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2

Kawerau (GXP)	25*	0.4%	18.2	18.3	18.4	18.5	18.6	18.6	18.7	18.8	18.9	19.0	19.0	19.1	3
Kope	16*	0.1%	15.6	15.7	15.7	15.7	15.7	15.8	15.8	15.8	15.8	15.8	15.9	15.9	4
Ohope	5	1.5%	4.6	4.6	4.7	4.8	4.8	4.9	5.0	5.0	5.1	5.2	5.2	5.3	
Plains	10	2.0%	6.1	6.3	6.4	6.5	6.6	6.7	6.9	7.0	7.1	7.2	7.3	7.5	
Station Road	10*	0.1%	10.2	10.2	10.2	10.3	10.3	10.3	10.3	10.3	10.3	10.4	10.4	10.4	5
Te Kaha (GXP)	5	1.0%	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8	
Waiotahi (GXP)	12*	1.2%	9.7	9.8	9.9	10.1	10.2	10.3	10.4	10.5	10.6	10.7	10.9	11.0	6

Table 5.16 - Zone Substation Load Growth Prediction

NOTES

- 1 Growth is based on average feeder growth.
- 2 Zero growth predicted for Kaingaroa substation.
- 3 Growth based on feeders average growth past 4 years. Expectation is growth will reduce as population reduces.
- 4 Kope substation shows load exceeding firm capacity until load transfer to CBD.
- 5 Station Road substation shows load exceeding N-1 capability.
- 6 No allowance made for possible future step change loads at Opotiki.
- 7 Red Numbers indicate the sub exceeds its firm capability.

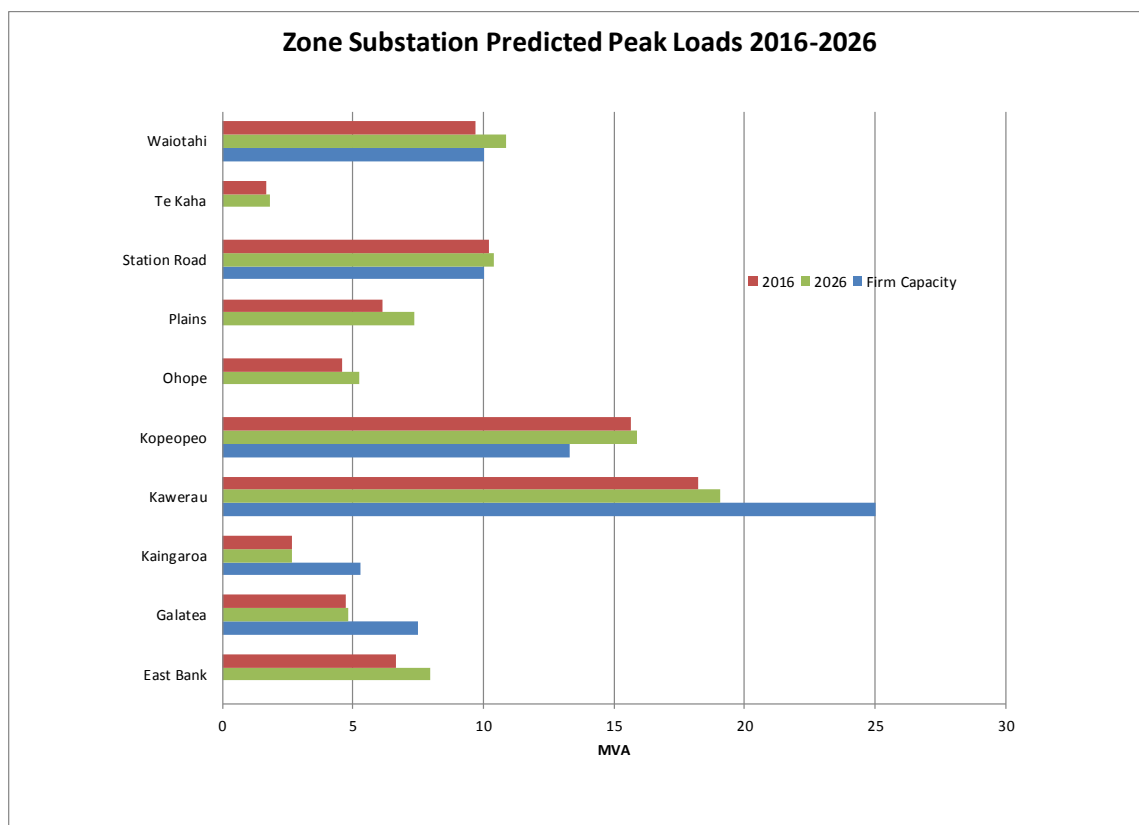


Figure 5.2 - Substation Load Predictions

Substation Capacity

The load prediction against the firm capacity of the sites is graphically illustrated in Figure 5.2. Narrative on the load characteristic of each substation is in the individual zone substation sections that follow.

The substation firm capacity shown is the capacity as at 2014 and does not take into account planned upgrades. Where a substation is a single transformer substation the firm capacity is regarded as zero.

5.4.3 Effect of Non-Network Demand Management Initiatives on Load Forecasts

Methods of demand management are described in some detail in section 5.3.6. Table 5.17 and Table 5.18, describes how the effect of these various initiatives impacts or is likely to impact on future load predictions. The impact or inclusion in load predictions is summarised for each initiative.

Option	Possible impact on load predictions	Effect on Network
Demand Load Management Ripple Control	Used for short term load peak load management. The effect is embedded in the peak load measurements and is therefore implicitly included in the projections.	The estimated instantaneous benefit of implementing ripple control during peak periods is less than 10MW across the whole network.
Demand Load Management Smart metering	Not allowed for as smart meters are owned by retailers and currently Horizon has no agreements in place for demand management.	No impact.
Demand Load Management Customer Education	Not allowed for.	No impact.
Demand Load Management Smart Homes	Not allowed for as uptake and quantum unknown and new home growth is minimal across the region.	No known impact.
Demand Load Management Major Customers	Not allowed for but is an option that can be readily implemented. Currently Whakatane Mill Limited buys into the reserves market and do provide some peak load shedding. This is implicitly included in the peak load measurements that flow into the predicted demand forecasts.	Impact not quantified.
Embedded Small Generation, <2.5kW, User Owned. Solar, Wind	Reduced demand during daylight or wind periods.	Not allowed for separately as the effect of any of these in service is included in the peak load flow data that is used for load predictions.
Embedded generation, customer owned, or customer owned diesel pumping stations	Load reduction dependent on owner utilisation policy.	Not allowed for separately as the effect of any of these in service is included in peak load flow data that is used for load predictions.
Embedded Diesel Powered Generation. Non Portable. Network Owned. 300-2000kVA	Not allowed for as none currently on network with grid connect synchronising.	No impact.
Portable Diesel Powered Generation. Network Owned. 300-1000kVA	Not used for load reduction except during reinforcement. Not currently allowed for in load flow predictions.	Impact not quantified.
Wind Power, Large Unit >500kVA, Network Owned	None on network. No known installations are planned so therefore are not included in load predictions.	No impact.
Wind Power, Small Unit up to 200kVA, Network Owned	No installations on the network and none planned.	No impact.

Option	Possible impact on load predictions	Effect on Network
Geothermal Generation	Effect is included in the load flow measurements. Not included in load flow predictions but the effect of loss of generation is included in feeder load capacity calculations.	Approximately 5MVA on Kawerau network. A further 24MVA planned 2017 will make Kawerau GXP a net exporter of energy.
Mini Hydro Generator	Not allowed for separately as the effect of these being used is be included in peak load flow data.	Approximately 200kW.
Utilisation of customer owned emergency generators for network support	Not allowed for in load predictions separately as currently no commercial arrangements have been made to utilise any of these for load management.	Impact unknown.

Table 5.17 - Impacts on Future Load Predictions

Loss Correction Initiatives	Impact on load predictions
Voltage regulators	Not allowed for separately. Voltage regulators tend to increase demand loads on resistive networks. The effect of these is included in the measured load flow calculations that forms the basis for forecast predictions.
Capacitive reactive power correction-network owned	Although these may be beneficial in line loss and consumer reactive power reduction, currently their benefits are not allowed for in forecast predictions.
Lower Zone Substation 11kV Bus Voltage	Beneficial in resistive networks to reduce load. Not allowed for in load forecast predictions but is an option during emergency conditions.
Increase Zone Substation 11kV Bus Voltage	Currently most zone substations are running a nominal 11.2kV bus. This is good for constant power applications (motors etc.) for reducing current flow and line losses. Not regarded as a viable way to manage load demand.

Table 5.18 - Impacts on Future Load Predictions

5.4.4 Grid Emergency Plans

Operating under the terms of the Electricity Industry Participation Code, Horizon Energy operates an Automatic Under-Frequency Load Shedding System (AUFLS) to automatically shed load by tripping pre-selected feeders. Load shedding is a regional or national action designed to help prevent a total grid system collapse under major grid disturbance conditions. Which feeders are selected is based on use priority, with residential feeders having higher priority to shed than industrial or commercial feeders.

AUFLS are set up in two groups; group one is designed to shed 16% of the load when the frequency falls lower than 47.8 Hz and group two a further 16% when the frequency falls below 47.5 Hz. This system is under review by Transpower.

In addition to the AUFLS system, Horizon Energy operates a Security of Supply Outage Plan (SOSOP), which includes a schedule of rolling feeder outages. Rolling outages are a last resort measure for managing severe energy shortages. Rolling outages will, wherever possible, disconnect feeders following the priority published on the Horizon Energy website. The number of feeders and the outage period for every week will depend on the level of saving required to meet target.

The MVA shedable load quoted is the averaged load across all seasons using four hourly actual measured average data.

Note that the Kawerau and Te Kaha are Transpower GXP and Horizon Energy has no direct control of the feeders exiting of these grid exit points.

Transpower is currently in the process of reviewing the AUFLS scheme and replanning it with an extended reserves marketplace. This is expected to have significant structural changes to the way the system operates and Horizon energy is actively participating in the consultation process for this change.

5.4.5 Edgcumbe GXP Demand

Edgcumbe load growth has averaged 2.9% over the last 10 years and 1.2% for the last five. Weighted individual zone substation growth rates indicate an organic growth rate of 1.6% for the complete Horizon Energy network. The dominant influence on the Edgcumbe GXP load is Whakatane Mill Limited, a directly connected industrial customer. This consumer draws around 50% of the Edgcumbe GXP loads.

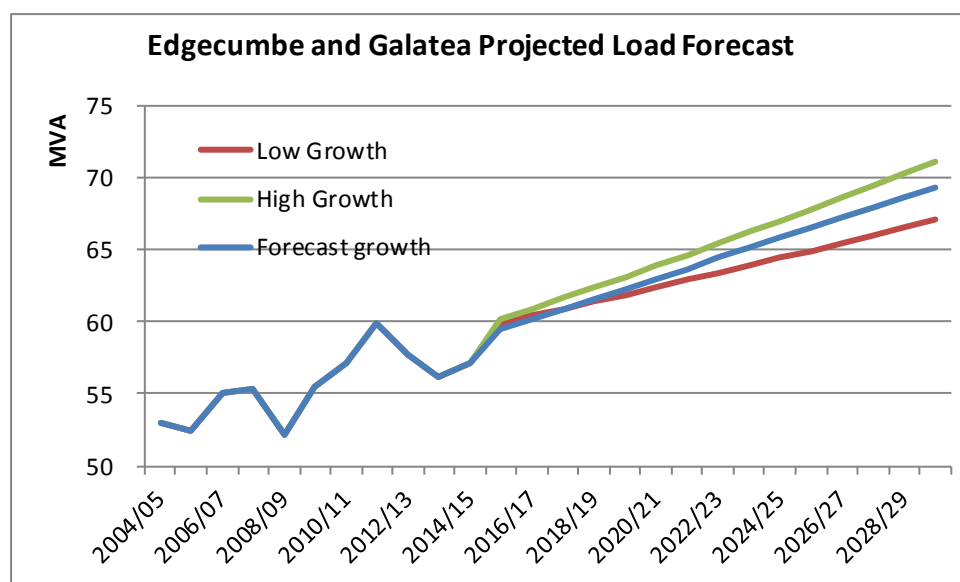


Figure 5.3 - Edgcumbe GXP Load Growth Predictions

Forward predicted growth rates are shown in Figure 5.3 giving a high/low prediction of zone substation average load growth rates

The chart shows the combined Galatea and Edgcumbe region loads due to Galatea being supplied from Edgcumbe since 2009

5.4.6 Feeder Load Forecasts

Forward projections of feeder loads are shown in Table 5.19. The effect of planned load balancing and load re-allocation between feeders is not shown on this Table. Section 5.12, Kope Substation, further describes the plan to balance load between Kope, Station Road and the proposed Gateway substations.

Feeder 10 Year load predictions (MVA)to 2026					
Substation	Feeder	Growth rate	2015	2026	Notes
EAST BANK	ANCHOR 1	0.0%	0.0	0.0	1
	THORNTON	1.2%	2.1	2.4	2
	WEST BANK	1.2%	3.3	3.7	
GALATEA	GALATEA	0.0%	1.5	1.4	
	JOLLY ROAD	1.8%	1.6	1.9	
	MINGINUI	1.8%	0.6	0.7	
	MURUPARA	1.8%	1.1	1.3	
KAINGAROA	DUNN ROAD	0.0%	1.3	1.3	
KAWERAU	PAPER	1.1%	9.5	10.7	
	PULP	1.1%	1.8	2.0	
	KAWERAU	1.1%	2.7	3.1	4
	ONEPU	0.0%	4.3	4.3	3
	PLATEAU	1.1%	2.3	2.6	4
KOPE	KING STREET	1.0%	2.3	2.6	
	REX MORPETH	1.0%	3.0	3.3	
	STRAND NORTH	1.0%	3.1	3.5	
	STRAND SOUTH	1.0%	3.4	3.8	
	VICTORIA AVENUE	1.0%	2.9	3.2	
OHOPE	HARBOUR	1.0%	1.9	2.1	
	POHUTUKAWA	1.0%	1.8	2.0	
PLAINS	AWAITI	1.2%	2.2	2.4	
	AWAKERI	1.2%	1.2	1.4	2
	ANCHOR 2	1.2%	0.0	0.0	
	MANAWAHE	1.2%	1.2	1.4	
	TE TEKO	1.2%	1.7	1.9	2
	WEST BANK	1.2%	3.3	3.7	
STATION ROAD	ANGLE ROAD	1.1%	1.5	1.6	2
	CITY SOUTH	1.0%	1.2	1.3	
	MOKORUA	1.0%	2.4	2.6	
	PIRIPAI	1.2%	2.0	2.3	
	RUATOKI	1.0%	1.7	1.8	
	TANEATUA	1.0%	0.9	1.0	
TE KAHA	TE KAHA	0.0%	0.2	0.2	

	WAIHAU BAY	0.0%	1.1	1.1	
WAIOTAHU	FACTORY	1.2%	2.7	3.1	3
	HOSPITAL	1.2%	2.4	2.7	3
	OPOTIKI	1.2%	2.6	2.9	3
	WAIMANA	1.2%	1.8	2.0	

Table 5.19 - Feeder Growth Predictions**Notes**

- 1 Industrial load with no organic growth
- 2 Peak loads and peak growth driven by reinforcement
- 3 Growth used is the zone substation average over three years
- 4 Kawerau feeders highly loaded

The feeders supplying Fonterra have been excluded from this table as the loads are driven by the generation on the factory site. Various sub sections of feeders have been identified for load driven upgrades and these are detailed in the zone substation sections later in this document.

Commentary and forward work plans on the individual feeder utilisation, including maintenance, more detailed load analysis and support and development plans are covered under the feeder sections for each zone substation later in this document.

5.4.7 Kope, Station Road, and Gateway Aggregate Loads

With the continued integration of function between Kope and Station Road, loads are being reallocated between the substations. With the proposed future development of a CBD substation, further loads will be re-distributed from Kope to reduce the loads at each of the substations. The CBD substation is tentatively scheduled for 2026 but could come forward if any step load increases are identified or requested.

Until then, substation load distribution will be reviewed as feeders between substations are upgraded to improve their load carrying capacity, and load growth patterns and supply risks are further studied.

5.4.8 Customer Growth

There has been a rapidly decreasing rate of new connections over the last five years.

Long term predictions for all regional councils supplied by Horizon Energy are for a likely population drop beyond the 10 year planning period. The Eastern Bay of Plenty region has a population that is older than the national average, and average income levels lower than the national average. This is likely to mean less long term housing replacement growth, and load displacement as rural populations move into urban areas.

Net connections per year are shown in Figure 5.4.

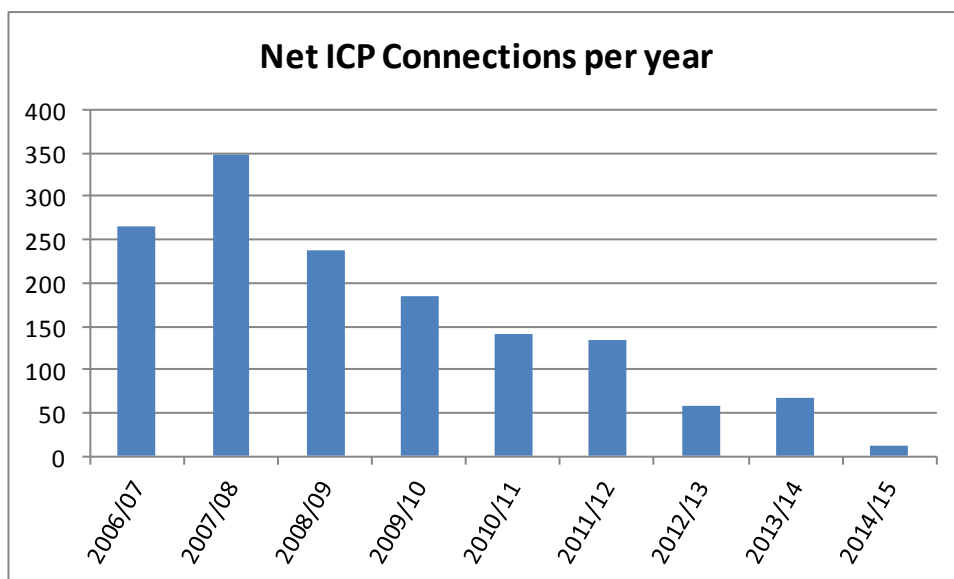


Figure 5.4 - Net Connections per year

The reducing rate of new connections is in line with area population statistics and long term population growth predictions released by Statistics NZ. On average, the annual rate of new connections has been 0.3 % per annum over the last five years and is declining.

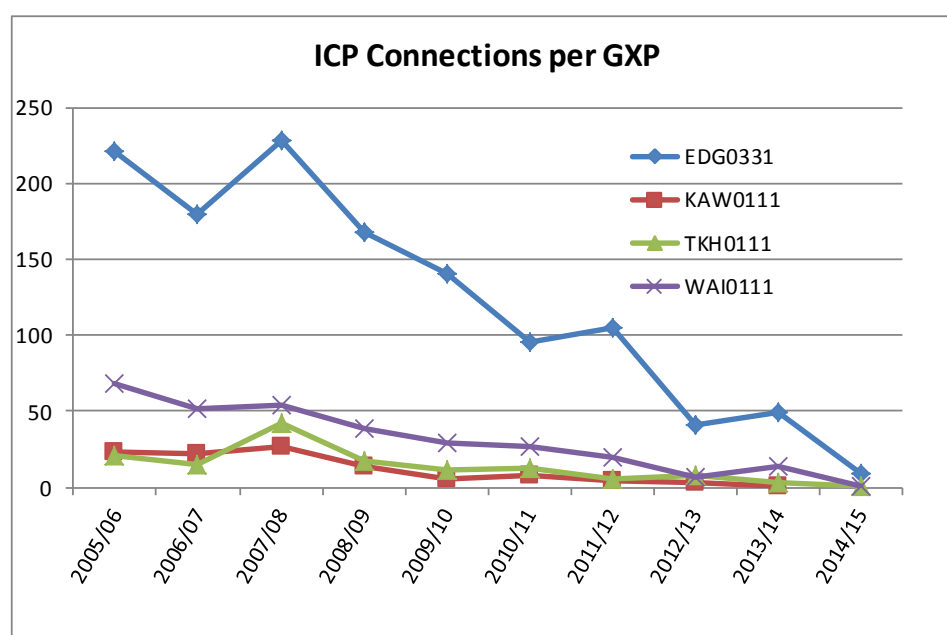


Figure 5.5 - Customer Connections per GXP

New connections per grid exit point per year over the last 10 years are shown in

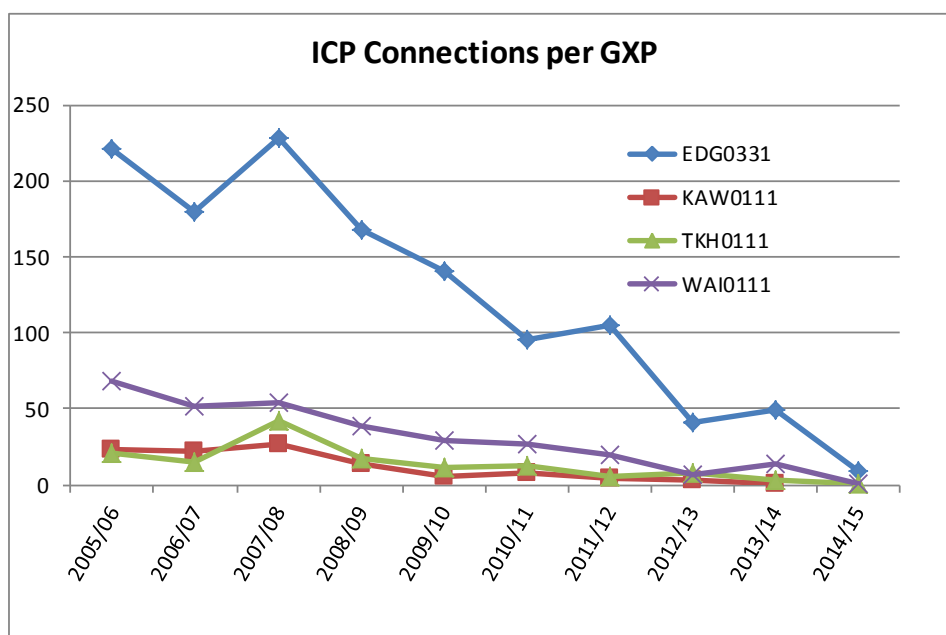


Figure 5.6 – The connection rate is reducing in line with population predictions

Figure 5.7 summarises the annual average ICP growth rate per zone substation for the last ten years. The influence of these on the load at each substation is discussed further in each zone substation section.

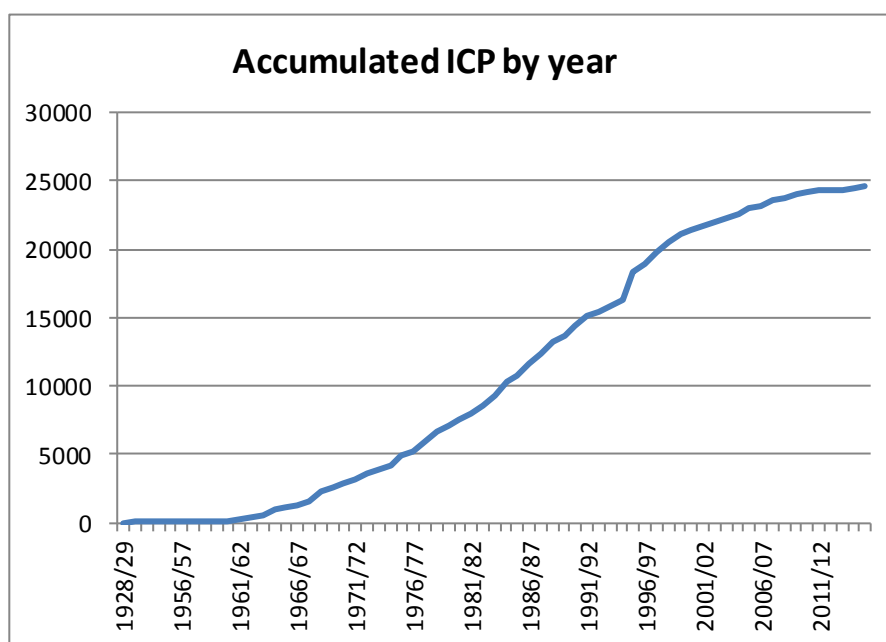


Figure 5.7: Graph above shows accumulated connections across the years.

5.4.9 Population Growth – Whakatane and Ohope Urban Areas

The Whakatane District Council Urban Growth Strategy document identifies areas of likely population growth within the Whakatane and Ohope regions. These areas are shown in Figure 5.8.

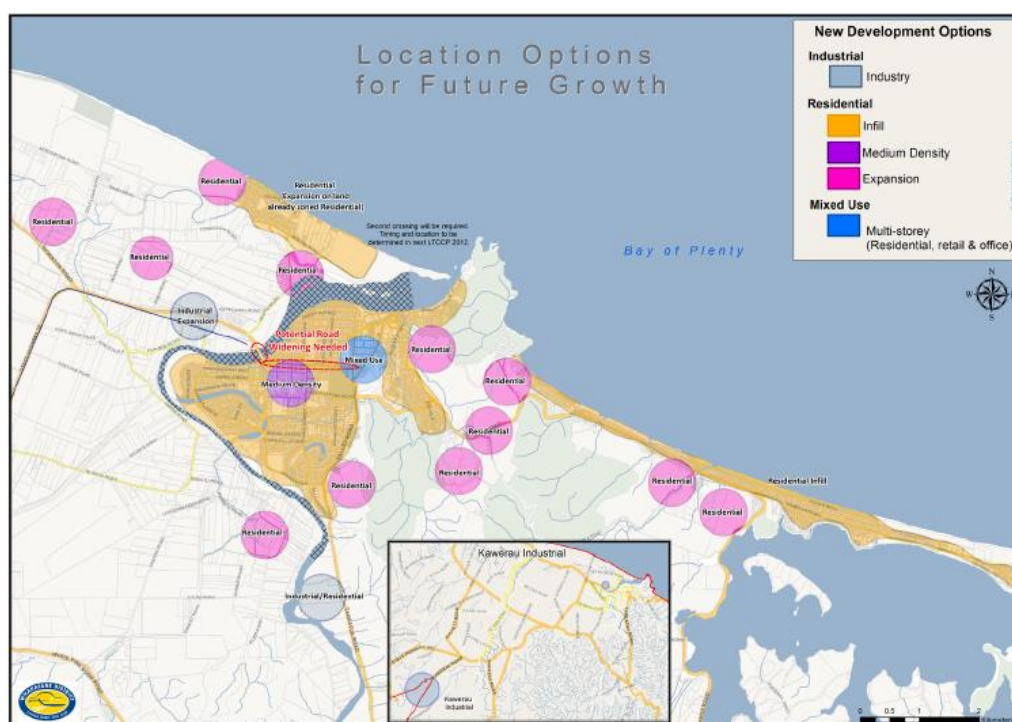


Figure 5.8: Whakatane and Ohope Urban Area

Census Year	National Population	Percentage Increase	Whakatane Population	Number Growth
2010	4,382,000	1.3	17,525	225
2011	4,442,000	5	18,401	876
2016	4,700,000	5.4	19,210	809
2021	4,954,000	5	20,171	960
2026	5,204,000	4.5	21,079	907
2031	5,442,000	4	21,922	843
2036	5,665,000	3.7	22,733	811
2041	5,879,000	3.5	23,528	795
2046	6,090,000	3.4	24,327	799
2051	6,298,000	3.2	25,105	778
2056	6,502,000	3.1	25,883	778
2061	6,708,000			

By 2050, Whakatane District Council (WDC) are projecting dwelling growth at an additional 2354 units in Whakatane and 1486 in Ohope.

At the existing peak demand per dwelling of 2.5kW, the additional load imposed on the network would be in the region of 10 MVA. This figure does not include the commercial growth that would arise to support the increased population but is well within the load capacity of the existing and planned zone substations to supply the Whakatane region, but the Ohope loads need to be considered more carefully. A potential increase of 1486 dwelling units, especially on the Harbour

feeder, would put an additional load of 3.7 MVA onto Ohope substation, which is well beyond the capability of providing adequate reinforcement at 11kV.

The average population growth rate predicted by WDC is slightly below the Whakatane region demand load growth forecast by Horizon Energy.

5.4.10 Future Loads-Electric Vehicles, Heat Pumps and Distributed Generation



There is a lot of literature, mostly centred on Europe, discussing the likely effect of the growth of electric vehicles and small consumer distributed generation, mainly photovoltaic, on distribution network utilisation and stability. A number of the studies are academic or small base case studies, without any large volume installation experiences to call upon, but they all agree on the fact that electric vehicle uptake will increase with time, as batteries become more reliable and fossil fuels become more expensive, and that there will be requirements for distributed high capacity fast re-charging stations within locations where vehicles are congregated; parking buildings, supermarkets, places of assembly, as well as in the domestic sector.

Charging systems fall into two categories; fast charge for short term charges, mostly in city centres, and slower, demand managed charges for longer stay vehicles. A number of discussions consider the integration of vehicle smart charging with domestic smart homes to help balance demand, plus various methods of metering and charging for energy. One paper discussed using the energy stored in the vehicles batteries as a potential supply source for peak lopping.

Many studies consider that the development of electric vehicle infrastructure will drive the uptake of vehicles, rather than the other way around, and that the uptake could well start within the 10 year period; initially in larger urban areas as infrastructure gets developed. There is very little discussion on how this infrastructure will be funded when required. Currently there are no legislative guidelines in New Zealand around any of these issues.



New Zealand is also starting to see an increase in trial systems using small photovoltaic domestic installations. Studies around these tend to focus on the effect of network low voltage instability issues rather than demand reduction, with concerns with reinjection into the low voltage network during outages, and how to manage fault conditions, since photovoltaic systems tend to be constant current devices and will therefore not trip conventional overcurrent elements, and voltage stability. At present the uptake of domestic photovoltaic systems is low due to high capital costs, but as solar panel manufacturers increase manufacturing capacities and costs reduced, the uptake is expected to increase.

However, heat pump uptake in New Zealand has been occurring for some time. The BRANZ report⁵ on heat pump growth predicted a 7.1 times increase in summer heat pump load and 2.5 times increase in winter heat pump load for the Bay of Plenty region by 2020. Initial Horizon Energy network studies indicate that across the network the summer load will still remain at levels below the winter loads. A study of load flows during summer 2010 determined that load increases of around 2 MVA through Te Rahu substation can be expected once the ambient temperature exceeds 27-28 deg. C.

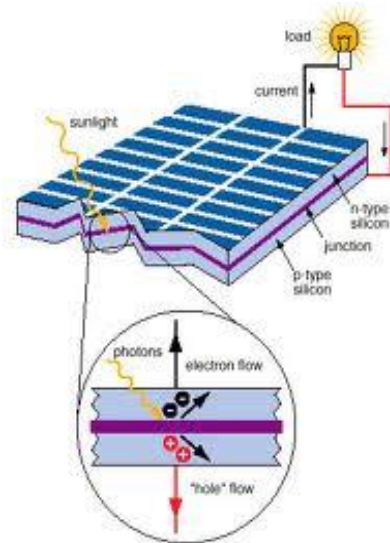
⁵ E528 Regional Heat Pump Energy Loads, (Page, Ian, 2009).

Currently, Horizon Energy has no reliable, measurable way of determining heat pump uptake within the network.

None of these considerations are currently included separately in Horizon Energy's future load predictions within the 10 year planning window, and cannot reliably be considered until there is more certainty around consumer uptake volumes and time frames for this to occur. Horizon Energy is part of a nationwide project to determine future profiles for uptake of disruptive technologies.

However, due to forward load growth predictions being based predominately on historical load demand, the increasing influence of these technologies on network loads during peak time periods is inherently included in the peak demand measurements that form the basis for predicting future growth

What is unknown is whether these technologies will alter the time of peak loads and methods on how to effectively manage these loads to move the demand into non-peak periods have not yet been considered; nor when it is likely to start affecting the network.



Embedded Generation Connections

Embedded generation connections (connections of less than 10kW) connected at low voltage to the network have been increasing steadily since 2011. Figure 5.8 below shows the connections per year and a 10 year forward projection based on the last 5 year rate of connections

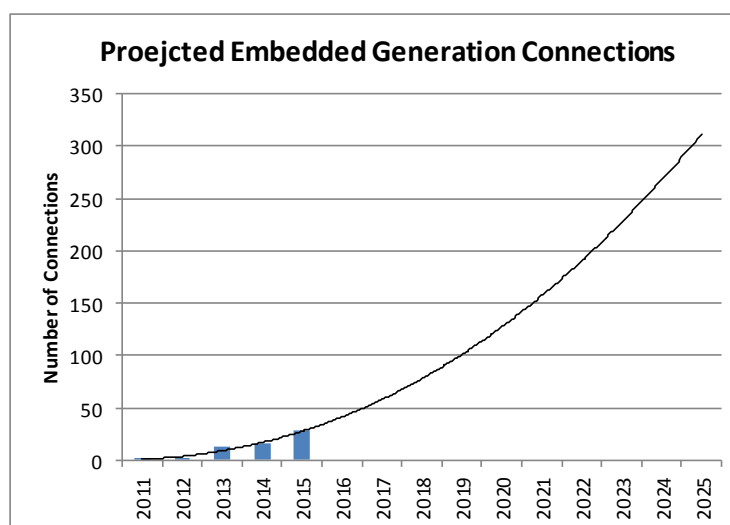


Figure 5.9 Embedded generation connections per year

Horizon Energy has joined a New Zealand wide incentive to work on a transform model that is a representation of the electricity distribution network and describes the impact that future scenarios may have on the planning and operation of networks. The model takes real data from participating networks, central government, and other sources with the aim to assess and optimise investment over a range of conventional and smart strategies which involve a wide range of network solutions. The Network strategy in response to disruptive technology is to continue to monitor uptake and to:

1. Deploy an enhanced, more flexible and resilient communications network starting in 2015 for SCADA field devices;
2. Work with national bodies to determine the impact on NZ distribution networks;

3. Deploy an enhanced SCADA system 2016 to allow the use of smart meter data to indicate outages and issues on the network as well as allow dynamic load transfer; and
4. Monitor selected LV assets to provide insight into changes in consumer demand.

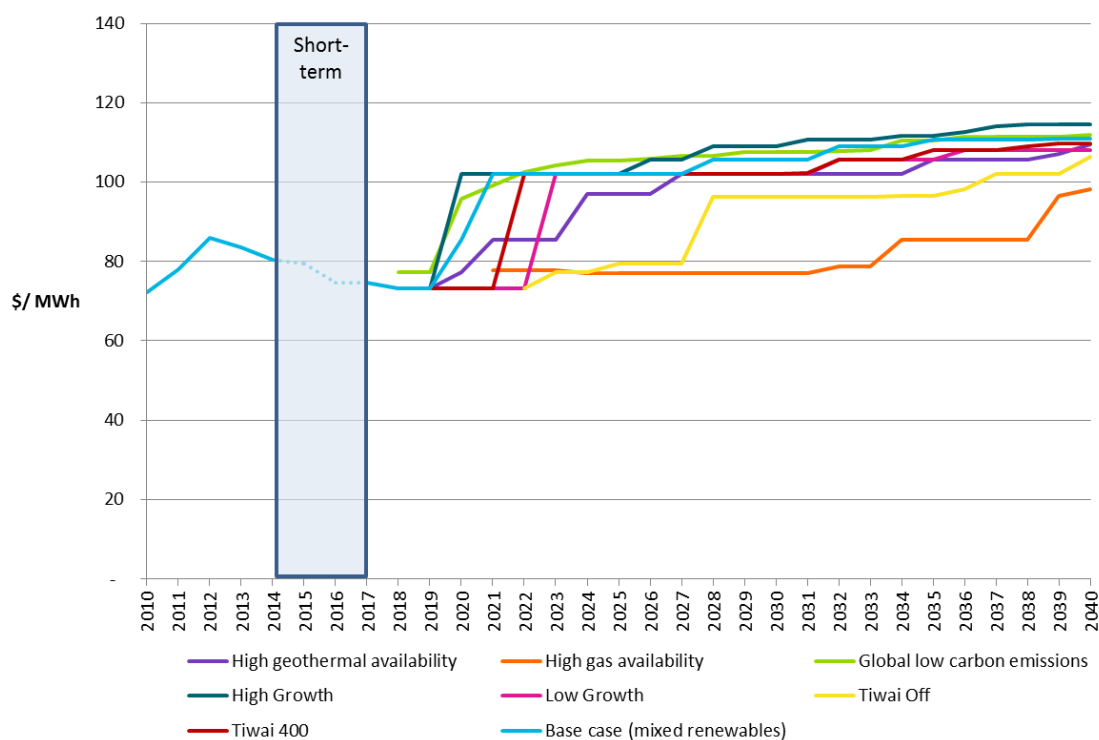


Figure 5.10 Wholesale electricity price indicators (\$/MWh) as forecast by Ministry of Business Innovation and Employment

5.5 Grid Exit Points

5.5.1 Supply Points

Horizon Energy is supplied by four Transpower owned Grid Exit Supply Points (GXP). A fifth supply point is the Southern generation owned Aniwhenua power station.

A Prudent Discount Agreement exists for the Matahina and Aniwhenua generating stations that make them part of the Edgumbe GXP for transmission pricing. Aniwhenua has a limited 33kV direct electrical connection onto the Horizon Network.

Edgumbe GXP supplies the network at 33kV; the other three Transpower owned grid exit points, Kawerau, Waiotahi and Te Kaha supply the network at 11kV.

The five bulk supply points are shown in Table 5.20 below:

Site	Capability	n-1	Constraint	Connection
Transpower Kawerau	110/11kV, two transformers T1, 20/26/27 MVA T2, 20/25/25 MVA	Yes	Transpower owns the 11kV distribution switchgear that Horizon Energy directly connects to.	11kV
Transpower Te Kaha	50kV/11kV, 4 x 1 phase transformers 2.5/2.5/2.5 MVA Upgrade to 7.5 MVA in 2013	No (a)	Te Kaha supplied from a single 50 kV circuit from Waiotahi GXP. Transpower owns the 11kV distribution switchgear.	11kV
Transpower Waiotahi	110/11kV, 2 transformers T1, 10/12/13 MVA T2, 10/12/12 MVA T5, 11/50kV transformer 2.7/2.7/2.7 MVA	Yes (a)	Waiotahi is supplied from a single 110kV circuit from Edgumbe GXP.	11kV
Transpower Edgumbe	220/33kV transformers T7, 50/66/67 MVA T8, 50/60/60 MVA	Yes	50MVA rating exceeded for less than 1% of the time per year. 33kV Switchgear is programmed for replacement by Transpower	33kV
Southern Generation Aniwhenua	33kV, two transformers T1, 8/14 MVA T2, 8/14 MVA	Yes (a)	Aniwhenua has two transformers but only one outgoing 33kV feeder. One unit has been out of service for most of 2012-2013.	33kV

Table 5.20 - GXP Supply Points

Notes:

Transpower transformer ratings **/**/** are for continuous/summer/winter respectively as published by Transpower.

Note (a) Duplicate distribution elements that are constrained by a single restriction as described in the comments.

5.5.2 Edgumbe GXP

Edgumbe has two 220/33kV fixed tap transformers supplying the Transpower owned 33kV bus system which supplies Horizon Energy's 33kV sub-transmission circuits. These transformer ratings are detailed below:

Transformer	Voltage	Continuous rating	Summer 24 hour overload	Winter 24 hour overload
T7	220/33kV	50 MVA	66.5 MVA	66.8 MVA
T8	220/33kV	50 MVA	66.8 MVA	66.8 MVA

Edgumbe transformers exceeded their n-1 continuous rating for 144 periods. 0.8% of the time in 2013-14 with a maximum measured MVA of 56.4 MVA. This is within the acceptable levels of overload for these transformers.

Edgumbe 33kV bus

The 33kV supply from the Edgumbe Transpower substation is taken from an indoor bus installed in 2015.

Network Vector Group

The 11kV system supplied from the Edgumbe GXP, Plains, East Bank, Station Road, and Kope substations is set up as a Dyn3 vector group. There is a mixture of transformers in the system configured as Dyn11 or Dyn3. Dyn11 transformers have phases rolled 120 degrees to provide a Dyn3 vector group for the Edgumbe supplied network.

5.5.3 Kawerau GXP

Kawerau has two Transpower owned on-line tap 110/11kV transformers and 11kV switchgear that Transpower have scheduled to replace in 2018-20 (Transpower 2012 AMP). Transpower has also signalled a replacement of the indoor 11kV switchgear likely 2016-18. Kawerau has no loading issues.

Transformer	Voltage	Continuous rating	Summer 24 hour overload	Winter 24 hour overload
T1	110/11kV	20 MVA	25 MVA	27 MVA
T2	110/11kV	20 MVA	26 MVA	27 MVA

Horizon Energy feeders are directly connected to the Transpower 11kV assets. Due to the single stage of transformation from 110kV to 11kV the vector group of the 11kV network supplied from Kawerau is out of phase with the Edgumbe network.

5.5.4 Waiotahi GXP

Waiotahi has two Transpower owned on-line tap 110/11kV transformers. These have momentarily exceeded their continuous N-1 capability during 2012 and Transpower has identified these transformers for replacement 2019-21 (Transpower 2012 AMP).

Transformer	Voltage	Continuous rating	Summer 24 hour overload	Winter 24 hour overload
T1	110/11kV	10 MVA	12 MVA	13 MVA
T2	110/11kV	10 MVA	12 MVA	12 MVA
T5	11/50kV	3 MVA	3 MVA	3 MVA

The n-1 continuous rating was exceeded for 25 periods during 2013 with peak load on the transformer banks 11.25 MVA. This is within the acceptable levels of overload for these transformers.

Transpower have stated that future investment at Waiotahi will be customer driven.

The vector group of the 11kV network supplied from Waiotahi is out of phase with the Edgumbe network connections to Ohope and Station Road substations because of the direct conversion from 110 to 11kV at Waiotahi. This is likely to be rectified with future developments at Waiotahi and Ootiki.

5.5.5 Te Kaha GXP

Transpower replaced the aged Te Kaha transformer bank in 2014 with a 50/33kV to 11kV transformer. There are no load constraints with Te Kaha.

Transformer	Voltage	Continuous rating	Summer 24 hour overload	Winter 24 hour overload
T1	50/11kV	4.5 MVA	4.5 MVA	4.5 MVA

Horizon Energy has entered into discussions with Transpower regarding the future ownership model for the Waiotahi and Te Kaha assets.

5.5.6 Customer Connections

The number of customers per GXP supplied from these grid exit points as at 31 March 2015 are detailed in Table 5.21.

GXP	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Edgumbe	15971	16066	16171	16212	16261	16270
Kawerau	2933	2941	2945	2948	2949	2949
Te Kaha	1019	1032	1037	1045	1048	1049
Waiotahi	4219	4246	4266	4273	4287	4288
Total	24142	24285	24419	24478	24545	24556

Table 5.21 - Customer per GXP

5.5.7 GXP Load Growth

Load growth and load predictions for the GXP sites are included in Section 5.4.

5.6 Sub Transmission

5.6.1 33kV Sub-transmission



Figure 5.11 - Edgumbe GXP 33kV Sub-transmission

- Seventeen 33kV sub-transmission circuits network wide;
- Total length of 178km;
- Three circuits from the Edgumbe GXP supply the Whakatane urban region and are redistributed at the Te Rahu substation;
- Two circuits dedicated to Whakatane Mill Limited;
- Two circuits supply zone substations at Edgumbe;
- One circuit is a backup supply to Galatea; and
- One feeder runs from Aniwhenua power station to Snake Hill and then splits into two feeders to supply Galatea with a further single feeder from Galatea to Kaingaroa.

The Edgumbe GXP load curves are shown in

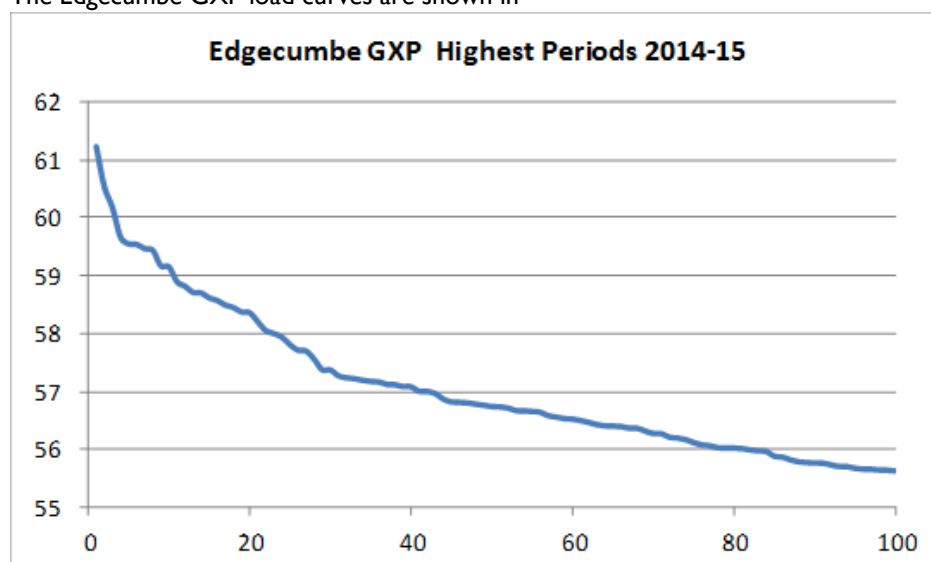


Figure 5.12 and Figure 5.13. The data is taken from the actual load current from the Edgumbe feeders.

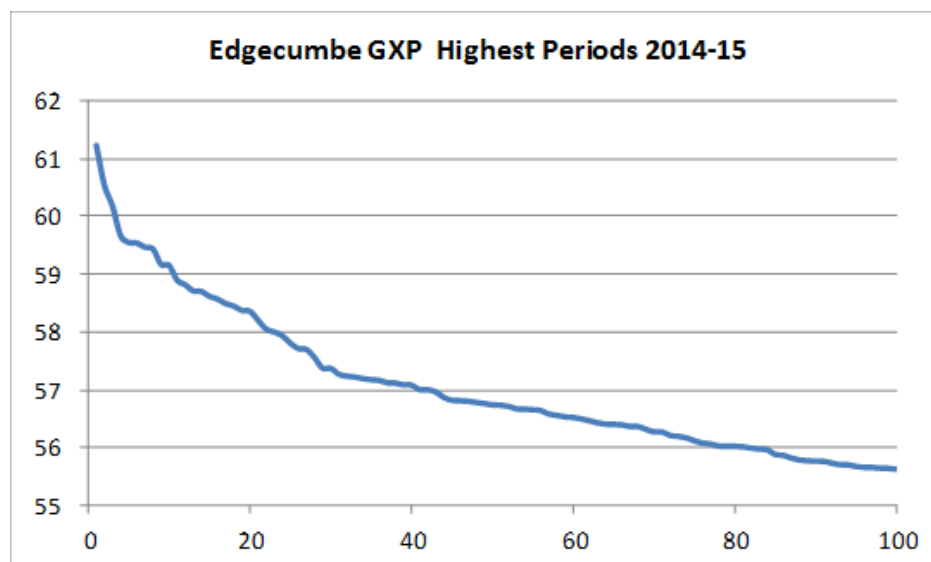


Figure 5.12 - Edgecumbe GXP 100 periods load profile

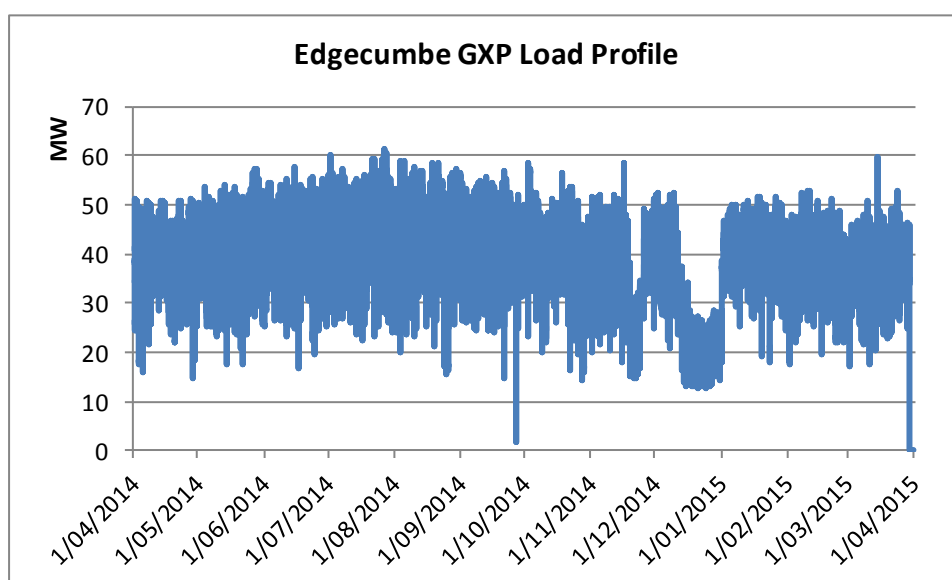


Figure 5.13 - Edgecumbe GXP Load Profile

Comments on sub transmission:

- During most of 2009-11 Galatea loads were connected to the Edgecumbe GXP following the failure of a transformer at Aniwhenua. This added around 4-5 MVA onto the Edgecumbe bus. This is not a normal configuration and was restored to the normal configuration briefly in August 2011, but was subsequently returned to Edgecumbe to allow work on the second Aniwhenua transformer and has remained the same since then;
- The Edgecumbe 33kV system has no reinforcement interconnection to other sub transmission systems apart from the circuit to Galatea and its connection to the Aniwhenua supply point;
- Te Rahu South and WBM South feeders share common structures; and
- Te Rahu Central and Te Rahu North share structures. Under certain fault conditions this arrangement was believed to cause dual feeder trips due to line clash. This fault condition was verified in 2013 and remedial works instigated to prevent the lines from clashing.

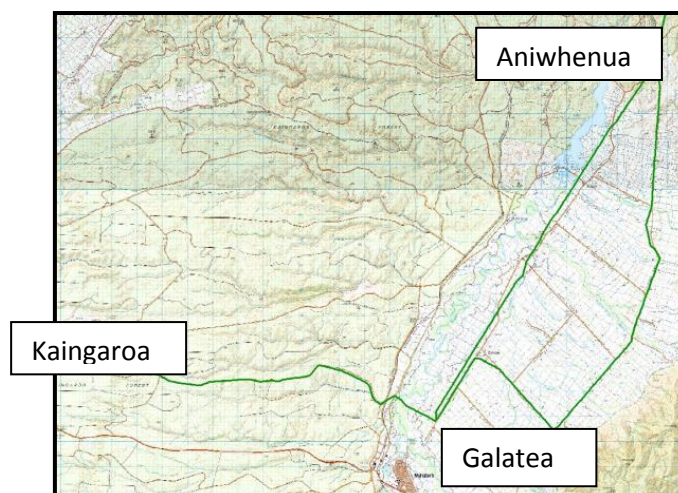


Figure 5.14 - 33kV Sub-transmission from Aniwhenua to Galatea and Kaingaroa

5.6.2 Snake Hill Circuit

The Galatea region is connected to both Edgecumbe GXP and Aniwhenua power station, with Aniwhenua historically the primary connection point and Edgecumbe the back-up supply. During 2009 Aniwhenua T1 failed and the 33kV supply was switched to Edgecumbe whilst the transformer was out of service for repair.

The Snake Hill feeder connected to Edgecumbe was always considered the back-up supply to Galatea. During 2013, power station operator Nova Energy informed Horizon Energy that it would not make the supply available due to technical issues with the Aniwhenua transformers. This condition elevates the priority of the Snake Hill feeder out of Edgecumbe to being the primary source of supply to the region rather than the back-up supply. Consequently, a number of projects that have been planned to improve the reliability of this regional supply are being accelerated and are listed below. Agreement to connect comes into force April 2016 where Aniwhenua will again become the primary supply.

Constraints on the existing snake hill circuit are:

- The Snake Hill sub-transmission feeder from Edgecumbe has load limitations due to voltage drop at full load when supplying Galatea and Kaingaroa. It is functionally only capable of supplying about 6.5MVA before the 33kV voltage drop at Galatea and Kaingaroa exceed the transformers tap changers capability to maintain the 11kV voltage; and
- Similarly the ability to transmit beyond 15MW from Aniwhenua across the 33kV to Edgecumbe is limited by voltage limits.

There are a number of projects completed, planned or underway to improve the system resilience:

- 2014: Improved protection at Snake Hill switching station to reduce damage risk to the Aniwhenua transformers;
- 2014-2015: Enhanced maintenance of the Snake Hill circuit configuration to improve resilience;
- 2017: A second line into Aniwhenua to connect to the Kopuriki circuit providing two direct feeders into Galatea; and
- 2015: Creating a bus section at Galatea to supply Kaingaroa.

Aniwhenua Connection

Options to secure the Galatea region supply if a permanent connection is unable to be secured from Aniwhenua could include:

- Do nothing and increase the maintenance works;
- Install a 110/33kV transformer at Aniwhenua to the Aniwhenua-Matahina line;
- Voltage step up transformer or regulator onto the Snake Hill circuit;
- New 110kV line from Matahina to Galatea;
- Voltage support using capacitor correction;
- Second 33kV line from Edgecumbe to Galatea or dual circuit the existing feeder;
- Local generation;
- Procure new transformers to replace the Aniwhenua transformers;
- Connection to adjoining Unison network;
- Upgrade Snake Hill feeder conductor size;
- New 220kV GXP off the Transpower Kawerau-Ohakuri circuit; and
- Install new ultra wide range tapchange transformers at Galatea and Kaingaroa.

None of these options have been assessed for feasibility or costs. It is recognised that some are impractical and/or too technically difficult but they are included for the discussion.

33kV Schematic

The 33kV schematic is shown in Section 5.6.3. The proposed Gateway (or CBD) substation is shown on Figure 5.15.

5.6.3 33kV System Schematic

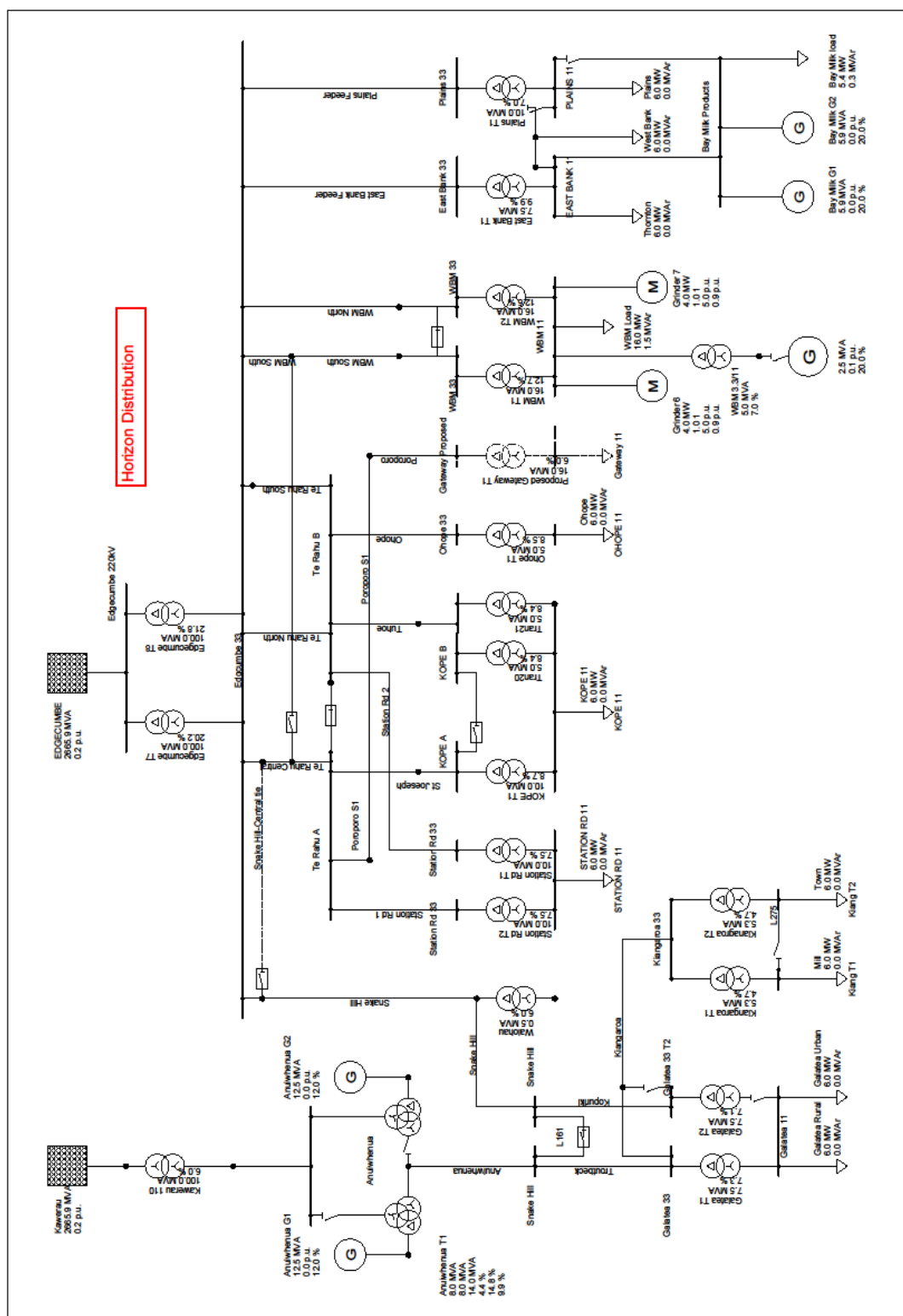


Figure 5.15 - 33kV System Schematic

5.6.4 Summary of 33kV Distribution Assets

Sub-transmission Assets

Table 5.22 below summarises Horizon Energy's sub-transmission line assets.

33kV Feeder	Source	Supply CB	Destination	Conductor	Rating (MVA)	Length (km)	Date	Comments
Aniwhenua	BOPE Aniwhenua power station	A34	Snake Hill	120mm ² DOG 7/1.57 ACSR	17.1	2.2	1977	Single line to Aniwhenua. A project has been identified to add a second line into Aniwhenua to support additional load at Galatea or Kaingaroa.
East Bank Road	Transpower Edgecumbe	112	East Bank Road Sub	185mm ² 3 x 1c Al XLPE	20.1	1.7	1987	No issues.
Kaingaroa	Galatea	270	Kaingaroa	105mm ² WASP AAC	5.3	17.7	1995	Single line, no redundancy. No plans to add additional line. Protection grading issue with Aniwhenua.
Kopuriki	Snake Hill	NA	Galatea T2	120mm ² DOG 7/1.57 ACSR	17.1	17.2	1969	No issues.
Ohope	Te Rahu substation	TR19	Ohope	120mm ² DOG 7/1.57 ACSR	7.1	9.6	1974	Single line, no redundancy. Management plan is to improve maintenance on the line and to support Ohope at 11kV.
Plains	Transpower Edgecumbe	162	Plains Substation	185mm ² 3 x 1c Al XLPE	14.4	0.1	1965	No issues.
Snake Hill	Transpower Edgecumbe	52	Snake Hill	120mm ² DOG 7/1.57 ACSR	20.1	35.7	1960	Restricted in ability to support additional load at Galatea and Kaingaroa. Very long feeder through some rugged terrain. Total load capability around 6.5MVA before Galatea voltage drop exceeds tap changer range. CB 52 has sync capability.
St Joseph's	Te Rahu substation	TR13	Kope T1	105mm ² WASP AAC	17.4	4.2	1989	Soil thermal resistivity issues reduce load capacity of cable sections entering Kope Substation to 13MVA.
Station Road I	Te Rahu	TR11	Station Road T1	300mm ² 3 x 1c Al	13.3	0.3	2010	Replaced overhead line 2010.

33kV Feeder	Source	Supply CB	Destination	Conductor	Rating (MVA)	Length (km)	Date	Comments
	substation			XLPE				
Station Road 2	Te Rahu substation	TR20	Station Road T2	300mm ² 3 x 1c Al XLPE	13.3	0.3	2010	Replaced overhead line 2010.
Te Rahu Central	Transpower Edgecumbe	102	Te Rahu substation TR14	122mm ² HARE 7/1.86 ACSR	23.0	12.1	1969	Shared structures with Te Rahu North.
Te Rahu North	Transpower Edgecumbe	82	Te Rahu substation TR16	158mm ² CRICKET 7/5.36 AAC	22.9	11.9	1980	Shared structures with Te Rahu Central.
Te Rahu South	Transpower Edgecumbe	142	Te Rahu substation TR18	122mm ² HARE 7/1.86 ACSR	20.2	11.7	1974	Shared structures with WBMS.
Troutbeck	Snake Hill	NA	Galatea T1	120mm ² DOG 7/1.57 ACSR	17.1	23.7	1982	No Issues.
Tuhoe	Te Rahu substation	TR17	Kope T2	Part 105mm ² WASP AAC and part 120mm ² DOG ACSR	17.4	3.7	1996	Soil thermal resistivity issues reduce load capacity of cable sections entering Kope Substation to 13MVA.
WBM North	Transpower Edgecumbe	62	Whakatane Mill	158mm ² CRICKET 7/5.36 AAC	22.9	12.7	1975	No Issues.
WBM South	Transpower Edgecumbe	122	Whakatane Mill	120mm ² DOG 7/1.57 ACSR	20.1	13.2	1980	Insufficient capacity to support Mill full load. Shared structures with Te Rahu South.

Table 5.22 - Summary of 33kV Distribution Assets

Notes:

Line ratings are the protection pick-up settings. Actual conductor ratings are listed in the standard conductor components section of this AMP.

5.6.5 Te Rahu Switching Station

Commissioned in 2010, Te Rahu is an indoor ten panel 33kV switching station which enables the three lines supplying Whakatane and Ohope to be run in a parallel configuration onto a distribution bus re-distributing 33kV supplies to Kope, Station Road and Ohope substations.

The project was reliability driven to address single circuit overloading issues with Kope and Station Road. This configuration provides a full-time n-1 redundancy to the 33kV sub transmission circuits into Station Road and Kope zone substations, as well as providing improved load distribution across the three feeders which reduces network losses.

The Figure 5.16 and Table 5.23 show the Te Rahu site load for 2011 to 2015. Te Rahu supplies power to about 10,800 customers 44% of the network customers.

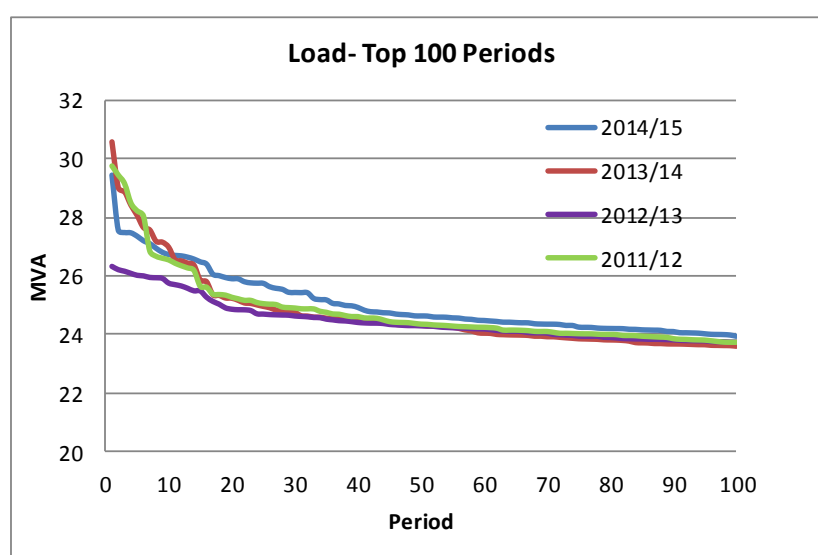


Figure 5.16 - Te Rahu Peak Load Curves

Utilisation and load growth at Te Rahu are shown in Table 5.23 and Figure 5.17. These values give the most accurate indication of the actual load growth for the Whakatane and Ohope urban region. There is some low level reinforcement onto adjacent zone substations via the distribution network which can affect the peak, but the peak load is predominantly driven by load control restoration following periods of load control.

Te Rahu Load Statistics (MVA)						
	2011/12	2012/13	2013/14	2014/15	% increase 2014/15	Ave incr per year
Maximum	29.8	26.3	30.6	29.4	-3.7%	5.9%
Average	13.2	13.4	13.2	13.7	4.0%	1.2%
Average-Top 100 Periods	24.8	24.5	24.7	25.1	1.4%	1.2%

Table 5.23 - Te Rahu Load Statistics

The average load growth indicates an average growth rate for the Whakatane region of 1.2%. The load profile below shows the connection of the Poroporo feeder in October 2014 supplying the Whakatane Mill.

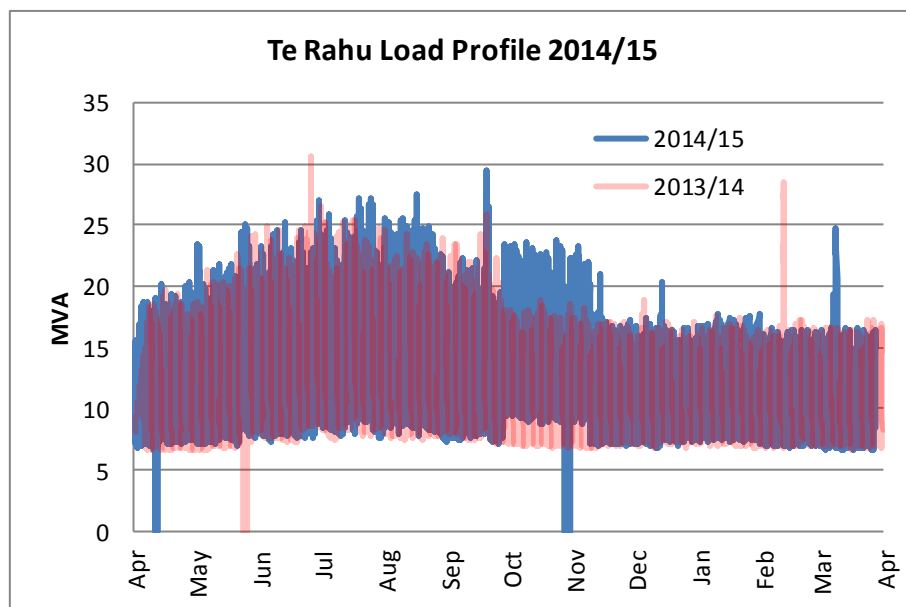


Figure 5.17 - Te Rahu Load Profile

Table 5.24 summarises the major assets within the Te Rahu Substation:

Asset	Description	Rating Data	Date of Manufacture	Comments
33kV switchboard	Areva GHA, non-withdrawal, Vacuum, gas insulated, 10 panel, extensible	36kV 25kA 630 Amp feeder 2000 Amp bus	2010	No Issues.
Incomer 33kV cables	630sqmm ² Al XLPE 3 x 1c 4 feeders	28 MVA	2010	Thermal backfill installed to increase cable ratings.
Outgoing feeder cables	300sqmm ² Al XLPE 3 x 1c 5 feeders	16 MVA	2010	Thermal backfill installed to increase cable ratings.
Local service	Supplied from Station Road	200kVA		Dual changeover supply installed.
Control Building	Concrete block construction, colour steel roof	56 square meters	2010	No Issues.
Protection	SEL 351S mirrored bit relays	na	2010	No Issues.
SCADA	SEL 3530 signal processor	na	2010	Fibre optic connection to Station Road.
DC Battery Bank	Eaton APS3 24V DC	110 Ah	2010	No Issues.

Table 5.24 - Te Rahu 33kV Substation Assets

5.6.6 Te Rahu and Station Road Substations – Lifeline Risk Assessment

Risks and vulnerability of the Te Rahu and Station Road substation sites from a CDEM lifelines perspective are summarised in Table 5.25 below:

Service	Vulnerability
Critical Services	Te Rahu is integrated with Station Road for the supply of services. Local service power and communications are shared. Te Rahu does not have any staff amenities as these are located at the adjacent Station Road substation. Station Road substation also houses the disaster recovery site for the network operations, as well as the critical commercial computer data backup systems.
Disaster Recovery SCADA System	The disaster recovery system is a fully operational remote site for the Horizon Energy network operations and control function and provides SCADA access to the control systems if the main operations control room in Commerce Street, Whakatane is rendered inoperable.
Communications	Primary communications to the two sites are by a meshed private microwave radio network and fibre optic network. The network runs from a site located at Commerce Street to Station Road and Edgecumbe. The network is self-healing, so data can feed in either direction if one of the links is down for any reason.
Site Access Requirements	Both sites have full automation for control of the distribution network equipment located at each site. Communication to the sites for control purposes is by private radio network described above. As long as the radio network remains running the sites can be controlled from the Commerce Street control room. Access is required in the case of: 1) Loss of communications. 2) Abandonment of Commerce Street control room. 3) Maloperation of equipment.
Road Access	The Te Rahu site has been built above the 100 year flood inundation level. Main roads accessing the site are Te Rahu Road to the East and North by Paroa Road onto Te Rahu Road, and from the South by Station Road via White Pine Bush Road. Egress from Whakatane to the North is across the Landing Road bridge and to the South by Taneatua Road and White Pine Bush Road.
Alternative Access	There is sufficient clear land to land a helicopter on the Te Rahu site.

Service	Vulnerability												
Total Loss of Te Rahu	<p>Total loss of Te Rahu would result in a sustained outage of power to Whakatane, Taneatua, Ohope, and surrounding districts. There is limited redundancy/capacity from adjacent 11kV supplies fed from either Waiotahi or the Edgecumbe Plains and East Bank Road substations, but these are of low capacity.</p> <p>There will be some security of supply offered by the proposed Gateway switching and zone substation in the case of a half bus outage but this project will not be complete until 2015.</p> <p>Contingency plans include holding sufficient materials to erect temporary 33kV lines to bypass the substation. This is detailed in the contingency planning risk assessment documentation.</p> <p>Long term this risk is planned to be mitigated by the development of the Gateway 33kV substation.</p>												
Natural Hazards	<p>Natural hazards that the sites could be exposed to are:</p> <table> <tr> <th>Hazard</th><th>Risk</th></tr> <tr> <td>Flood</td><td>Low</td></tr> <tr> <td>Earthquake</td><td>High</td></tr> <tr> <td>Tsunami</td><td>Low</td></tr> <tr> <td>Volcanic activity</td><td>Low</td></tr> <tr> <td>Wind</td><td>Low</td></tr> </table> <p>Disaster recovery plans are held in the Horizon Energy disaster recovery quality manual.</p> <p>All switchgear is located within the building and is protected from environmental effects. The design of the switchgear is such that there should be no appreciable heat build-up in the building. The incoming supply and feeder lines are cable connected to overhead lines. The overhead lines are exposed to the elements, and as such, the lines are regarded as providing a lower level of security than the equipment at Te Rahu.</p>	Hazard	Risk	Flood	Low	Earthquake	High	Tsunami	Low	Volcanic activity	Low	Wind	Low
Hazard	Risk												
Flood	Low												
Earthquake	High												
Tsunami	Low												
Volcanic activity	Low												
Wind	Low												
Human Habitation	<p>Te Rahu and Station Road are unmanned sites. Manning is required only if communications are lost, or if the Commerce Street control room is unusable. Station Road substation has no facilities apart from ablutions so long term habitation is unsustainable without external support.</p>												
External Services	<p>At Station Road tank water is available from the roof and sewage is septic tank. Power is supplied from the Station Road substation local service transformer. There is no telephone at either of the substations. Un-interruptible power supplies installed to provide power system resilience to the computer systems. All critical services are on 24 volt battery banks and the site is configured for the connection of a generator.</p>												

Table 5.25 - Te Rahu and Station Road Lifeline Risk Assessment**5.6.7 Proposed Gateway Substation**

Development of a substation at Gateway Drive has been discussed for some time in preceding AMP's. The driver for this substation has been:

- Projected urban load growth in Whakatane around the Hub/Piripai area;
- Load displacement from the Kope substation to the Gateway region;
- Gateway Drive is centrally placed for expected future load growth within the Whakatane, Gateway, Keepa Road, Piripai and Coastlands regions;
- Backup supply to Te Rahu substation; and
- Direct benefit to a major connected customer.

The two 33kV feeders that supply the Carter Holt Harvey Paperboard Mill (Whakatane Mill) run in close proximity to the Gateway site. One of these circuits does not have an all-time rating suitable to meet the full load requirement of the Mill so that the integration of these feeders into the Gateway 33kV bus will provide additional support for the Mill supply as well as providing support for Gateway and Te Rahu Road.

Both the 33kV and the 11kV development of Gateway have been deferred until 2024 in favour of developing a CBD substation, unless there is significant load increase in the Piripai area. With the existing loading, a Gateway substation would only supply about 4MVA with most of the load being displaced from Station Road substation.

5.6.8 Proposed CBD Substation

A study of load flows and projected growth indicates that an 11kV substation located to supply the central business district (CBD) has a more beneficial effect than an 11kV substation at Gateway is likely to have. A substation in the CBD region has:

- Easy access to five feeders;
- Located close to load centres;
- Support from Kope substation;
- Positioned in an area that is actively developing and has the potential to be further developed;
- Currently there are a number of properties available that have low improved capital value that would be suitable as a substation site;
- Reduces the load driven need to upgrade feeder cables between Kope and CBD; and
- Provides the ability to balance load between Kope and CBD and reduces the total load on Kope substation.

Sizing of the Kope replacement transformers has been done based on the assumption that a CBD single transformer substation will be developed and that Kope and a CBD substation will provide mutual support to each other.

5.6.9 Whakatane Mill Limited (WML)

Whakatane Mill Limited is a major consumer on the network, with two dedicated 33kV lines supplying the site and a peak demand of 25MVA. The demand is very cyclic due to a batch wood pulp grinding process, which applies a variable load of 11MW due to motor driven log grinding machines.

Peak load growth on the site had been static following a step change in 2004 after a machine upgrade, and a step change in the 2009-10 year when the load growth was 6.5%. However, total kWh consumption in latter years has been reducing.

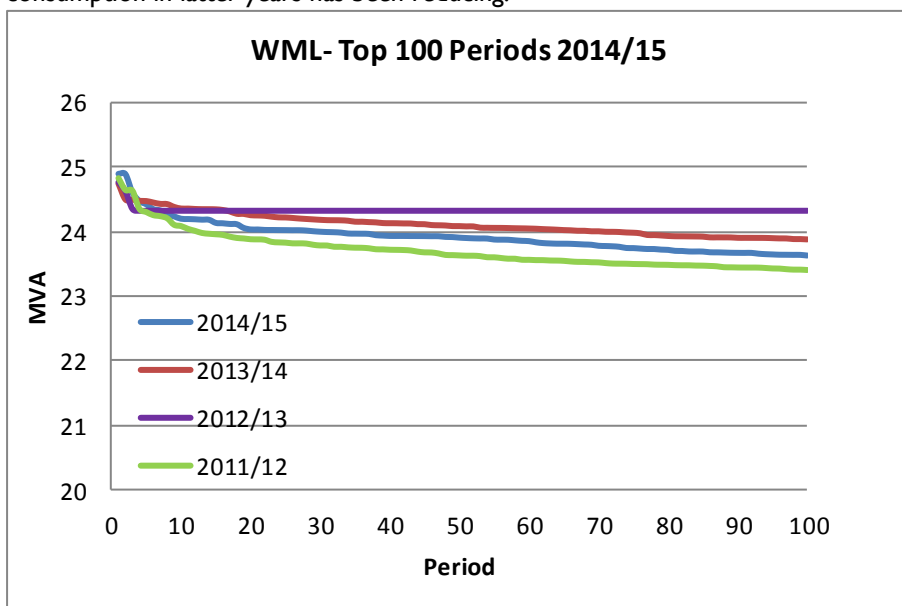


Figure 5.18 - Top 100 Load Periods

For future load growth (until further data or step change in utilisation is applied for), 0% growth is used for forward load prediction.

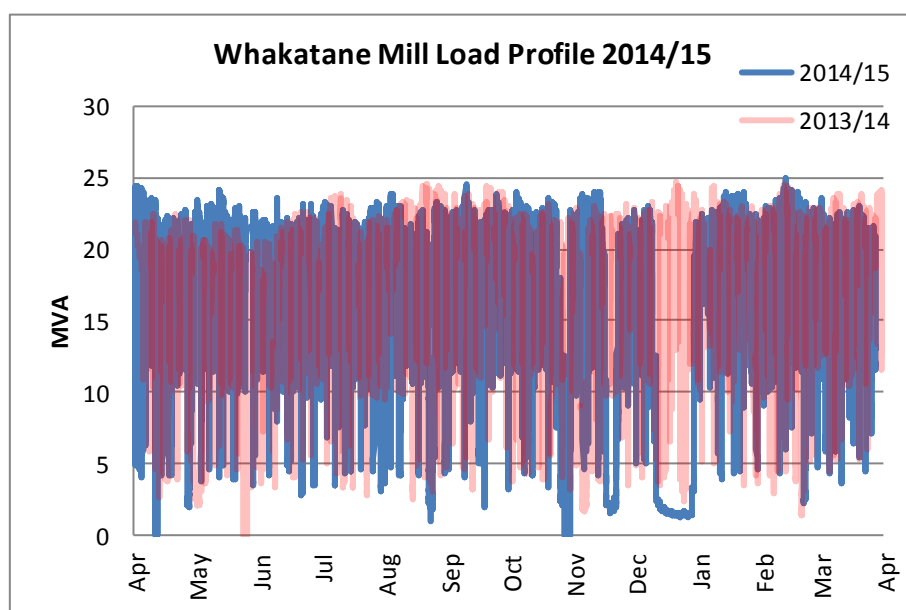


Figure 5.19 - WML Annual Load Profile

5.6.10 System Zone Substation Cross Support Capability

A meshed 11kV distribution system provides the ability to support zone substations from adjacent substations using 11kV feeders. This flexibility of supply is strong in the Edgecumbe Plains and Whakatane areas but further out in Waiohahi and Galatea there is no ability to mesh between

substations. Kawerau and Waiotahi are zone substations adjacent to Edgumbe GXP supplied sites but are out of phase, and are able to be meshed after an outage.

The Figure 5.20 shows the overlapping interconnectivity between the substations and Table 5.26 gives the approximate level of reinforcement that each interconnected substation can provide to its neighbour.

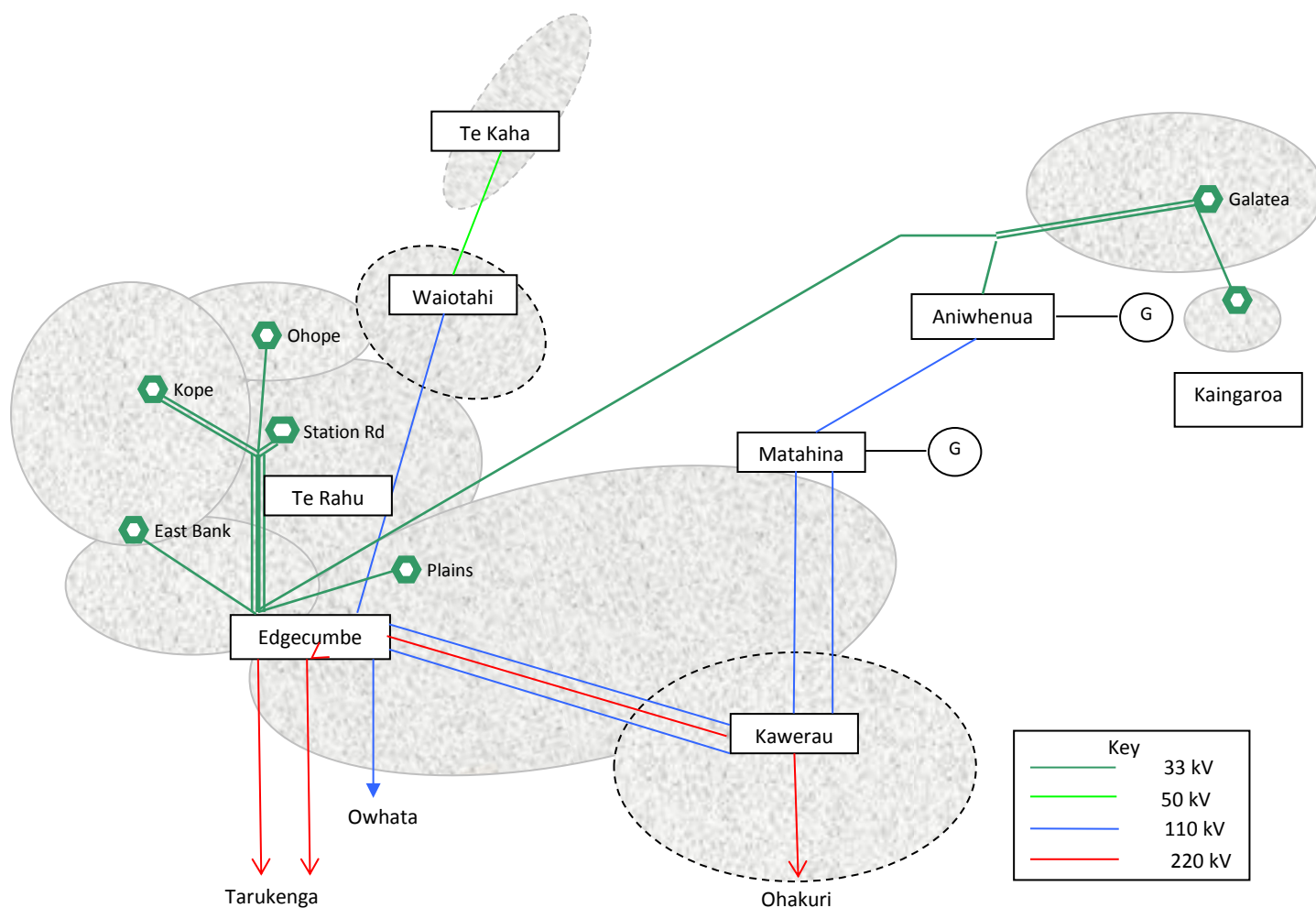


Figure 5.20 - Cross support capability of 11kV network

	Te Kaha	Waiotahi	Ohope	Station Road	Kope	Plains	East Bank Road	Fonterra	Kawerau	Galatea	Kaingaroa
Max Demand (MW)	2	11	4.5	9.6	15	6.4	7	7	18	5	2.5
Te Kaha											
Waiotahi			1*	1*							
Ohope		1*		3							
Station Road		1*	3		12	2	1				
Kope				12							
Plains				2			11	4	2*		
East Bank Road				1		11		8			
Fonterra						4	8				
Kawerau						2*					
Galatea											
Kaingaroa											

Table 5.26 - Zone Substation 11kV link capacities

* Indicates that a phase shift exists

Studies to improve meshing and reinforcement options are being reviewed at least annually with a focus on the interconnect ability between Kope and Station Road being a major component of the Kope reinforcement plan.

5.6.11 Sub-transmission and Zone Substation Development Plans

Sub-transmission and major zone substation projects are covered in Appendix C. Each project is summarised along with alternative options considered and plans for implementation or further engineering study requirements.

A series of development plans for Waiotahi are also included with the proposal to develop a new substation at Opotiki at either 110kV or 33kV. This proposal is discussed in further detail in the Opotiki Section 5.14

5.7 Zone Substations

The following sections describe in detail the zone substations and feeders that comprises the Horizon Energy network.

Substation	Section
East Bank	5.8
Galatea	5.9
Kawerau	5.10
Kaingaroa	5.11
Kope	5.12
Ohope	5.13
Opotiki	5.14
Plain	5.15
Station Road	5.16
Te Kaha	5.17
Waiotahi	5.18
Waiohau	5.19
Fonterra	5.20

Table 5.27 - Zone Substations, Section References

An independent inspection by Mitton Electronet was commissioned for each zone substation that made a number of recommendations to bring the substations up to current industry standard and identified a number of risks that require mitigation. These recommendations have largely been incorporated into the zone substation upgrade capital plan.

A common theme across substations is fire risk caused by having transformers installed too close to each other or too close to control buildings, based on AS2067⁶ specifications. Some fire risk mitigation projects have been initiated and in other substations the risk will be engineered out as the substation transformers and switchgear are upgraded.

Projects identified from the 2011 report are:

Sub	Issue	Status
Kope	Replace T2 and T2A	Complete
	Install Operator doors on 11kV switchgear	Complete
	Assess 11kV fire risk- building to T1	Scheduled 2017 with 33kV switchgear upgrade
	Assess 11kV fire risk- T1 to T2	Complete

⁶ AS2067-2008 'Substations and high voltage installations exceeding 1kV a.c.' is an Australian standard that has not been adopted in New Zealand.

East Bank	Install safety doors on 11kV switchgear	Complete
	Assess 11kV fire risk	Scheduled 2015
Plains	Rebuild security fence with barbed wire and one hot wire	Fence meets standards as at time of build ⁷
	Move T1 spare to create more room for T1	Transformer replacement project 2016
	Relocate T1 unite to create more room between transformers	
	Rehouse T1 NCT into a more space economical enclosure	
	Install bund and oil separator for T1	
	Extend two pole 33kV structure	Complete
	Install operator safety doors on 11kV switchgear	Complete
Ohope	Replace T1	Entered in 10 year plan as transformer replacement project 2018
	Make T1 11kV structure MAD safe	
	Install T1 11kV restricted earth fault protection	Part of transformer replacement project
	Replace CB80	Entered in 10 year plan 2015
Kaingaroa	Carry out a transformer fire risk analysis	Remediation of most of these issues at Kaingaroa would require a substantial amount of work. Due to direct connect customers agreements the cost of works is passed on to customers as additional charges, requiring customer agreement for the additional works to proceed.
	Review the substation 11 kV configuration	
	Consider installing a fence around front of switchroom	
	Segregate transformer HV and control cables	

⁷ Plains fence is low according to 'AS2067 2008-Substations and high voltage installations exceeding 1kV ac'. This standard has not been adopted in New Zealand

5.8 East Bank Zone Substation

5.8.1 System Description



The East Bank Road substation, built in 1987 to support the then Anchor dairy factory, is located about one kilometre from Edgumbe along East Bank Road, directly to the East of the Fonterra dairy processing plant and is the primary connection point for the Fonterra site. The Fonterra factory has a 10MW cogeneration facility onsite that supplies the site electricity and steam requirements. During the production summer period, excess generation is exported from the site as indicated by the negative readings on the load duration graphs. The manufacturing plant is closed during the winter season; however the cogeneration plant is operated at times to assist the generator in meeting their demand reduction contract that applies for the Edgumbe GXP.

5.8.2 Service Area Covered

East Bank substation supplies the Thornton area through to Matata, Edgumbe town, and Fonterra. East Bank is connected to the Plains substation with a high capacity 630 amp 11kV tie feeder and this enables each substation to support the other in the event of a loss of 33kV supply.

Thornton Feeder	Rural Thornton feeder runs along the East side of the Rangitaiki River to Thornton, and to Matata. It has tie points to Manawahe and Awaiti feeders supplied from Plains substation. Angle Road is supplied from Station Road substation, and to West Bank feeder. Tie points are being automated as part of the series of reliability projects.
West Bank Feeder	West Bank feeder supplies Edgumbe town. It has tie points to Awaiti and Thornton feeders. West Bank feeder is a 12MVA capacity link feeder that connects Plains and East Bank substations. Edgumbe town is supplied from a mid-point tee on the interconnection cable.
Anchor I	Direct link to the Fonterra dairy factory site..

5.8.3 Description of Assets

Table 5.28 summarises the major assets within the East Bank Substation:

Asset	Description	Rating Data	Date of Manufacture	Comments
33kV Cable	East Bank 33kV Feeder	3 x 1 core 33kV XLPE 185sqmm Al Rated 16.4 MVA	1986	Direct connect to Transpower Edgecumbe 33kV CB 2179. Cable tested 2015 condition appropriate for age.
33/11kV Transformer T1	3 phase Tyree	7.5 MVA ONAN 15 MVA OFAF 9.93% Z Dyn11	1987	No known issues
T1 Tapchanger	Ferranti	33kV 300 amps (CER 480 amps) 11 steps	1987	Tap change drive mechanism partially flooded during 2004 storm requires increased level of maintenance
11kV Distribution Switchboard	Reyrolle, LMVP vacuum circuit breakers, 6 panel including bus coupler	Circuit breakers 630 amp Fault rating 25kA 3 sec Bus rated 1250 amps	1986	Blast doors installed 2011 Trip circuit monitoring installed 2013
Control Building	Wooden frame, wooden clad building		1986	Good Condition
SCADA	SEL 2411 RTU		2013	
DC Battery Bank	Switchtech 48V			
Local Service	ABB	200kVA	1987	
Transformer Protection	SEL 787		2013	

Asset	Description	Rating Data	Date of Manufacture	Comments
Feeder Protection	SEL 751A		2013	
33kV Protection	SEL751A		2013	
Tap Change Controller	Reg DA		2009	
Communications	Fibre optic		2013	

Table 5.28 - East Bank Substation Assets

5.8.4 Substation Utilisation

The following table and figures show the load characteristics for the East Bank substation:

East Bank -Load Statistics MW							
	2011	2012	2013	2014	2015	% increase 14-15	% Increase 3 years
Maximum	6.3	8.1	7.2	7.0	6.4	-8.4%	-5.6%
Average	1.32	0.75	0.61	0.36	0.77	113.3%	13.3%
Average-Top 100 Periods	5.58	7.22	5.59	4.83	5.72	18.3%	1.2%

Table 5.29 - East Bank Substation Load Statistics

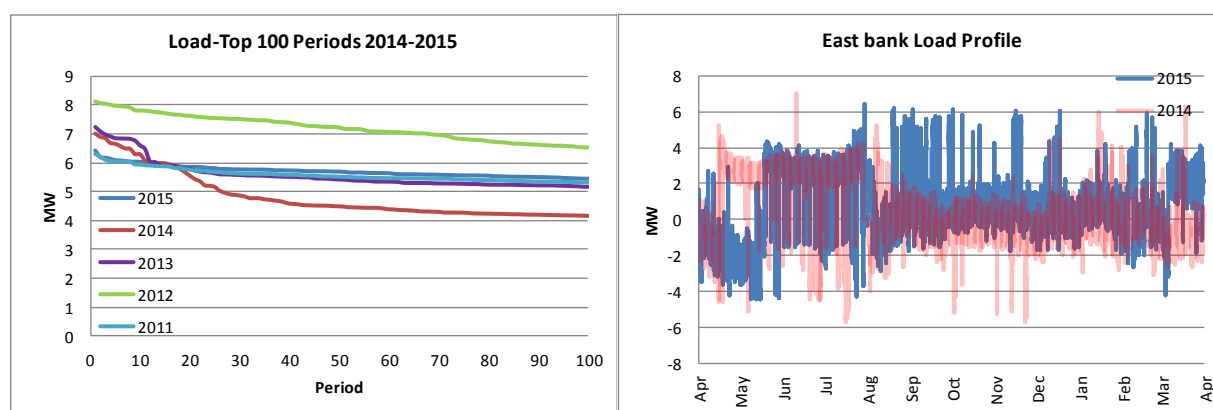


Figure 5.21 - East Bank Load Curves

The load variability is driven by the changing Fonterra production, generation, and load control restoration meaning that substation load growth figures for this substation are meaningless

5.8.5 Load Growth

The domestic load growth is determined at the feeder level for the two feeders supplying the rural and domestic consumers; Thornton and West Bank.

5.8.6 Constraints

There is a high capacity 650 amp tie between Plains and East Bank substations on the West Bank feeder that also supplies Edgecumbe urban loads. This feeder, when operated in parallel with Plains and East Bank, increases the fault level on the West Bank feeder to 13kA and up to 8kA in parts of Edgecumbe town. Some installed components are not rated to this fault level so even though this mode of operation is used very infrequently, remedial work is included in the plan.

Plains and East Bank power transformers have miss-matched impedances and tap steps. This can cause high circulating currents when the substations are operated in parallel. Intelligent tap change controllers were installed to manage this.

Lifeline Risk Assessment

Risks and vulnerability of the East Bank substation site from a CDEM lifelines perspective are summarised in Table 5.30 below:

Vulnerability	East Bank	Mitigation
Total Loss of East Bank Substation	East Bank substation is a single feeder substation with one three phase transformer.	There is a high capacity 11kV link between East Bank and Plains substations in case the 33kV supply is not available. There is 11kV meshing to provide support at the 11kV feeder level.
Communications	Primary communications to East Bank substation is by redundant fibre loop. On site switch is a single point of failure.	Redundant loop provides failover to back-up communication path.
Site Access Requirements	Access is required in the case of: <ul style="list-style-type: none"> • Loss of communications • Abandonment of Commerce Street control room • Non operation of equipment 	Roads accessing the site are East Bank Road North from Edgecumbe, and East Bank Road South from Thornton. There is sufficient clear land to land a helicopter near the East Bank substation site if required.
Natural Hazards	Natural hazards that the sites could be exposed to are: <ul style="list-style-type: none"> • Flood • Earthquake • Tsunami • Volcanic activity • Wind 	Risk: <ul style="list-style-type: none"> • High • High • Medium • Low • Low Disaster recovery plans are available to all staff.
Network Impact Risk	Supplies 5% of the network customers, mostly rural.	Fonterra has on site generation that can run in island mode to supply the site in an outage of the supply network.
Human Habitation	East Bank is an unmanned site.	Access window and door alarms to SCADA.
External Services	All critical services are on 48 volt battery banks.	

Table 5.30 - East Bank Lifeline Risk Assessment

5.8.7 East Bank Substation Feeders

East Bank substation feeders are summarised in Table 5.31 below:

Feeder	Thornton	West Bank	Anchor I
Type	Rural	Urban	Industrial
Overhead (km)	61.4	7.3	0
Underground (km)	5.6	4.4	0.3
ICP Connections	363	770	1
Substations	92	32	na
Installed Tx Capacity (MVA)	5.6	4.4	na
Maximum Load (Amps)	145	286	368
100 Peak Load (Amps)	111	172	340
5 year average growth rate	-5.3%	20.9%	19.0%
Feeder Utilisation at Average 100 Peaks	40%	62%	85%

Table 5.31 - East Bank Substation Feeders

Thornton Feeder

- Growth rate shows load transfer to Westbank feeder during 2014
- All tie points to adjoining feeders are 4MVA or better

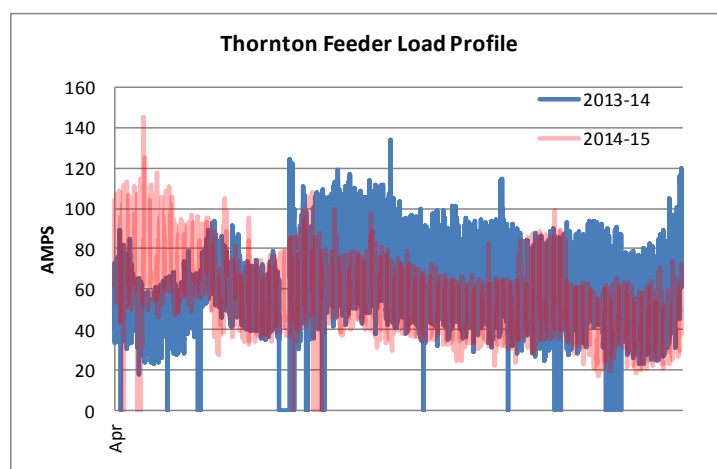


Figure 5.22 - Thornton Feeder Load Curves

West Bank Feeder

- No load constraints with the West Bank feeder;
- Change in growth rate is because of a load shift from Thornton to Westbank feeders
- The peak load is approaching the design limit of the overhead Dog conductor

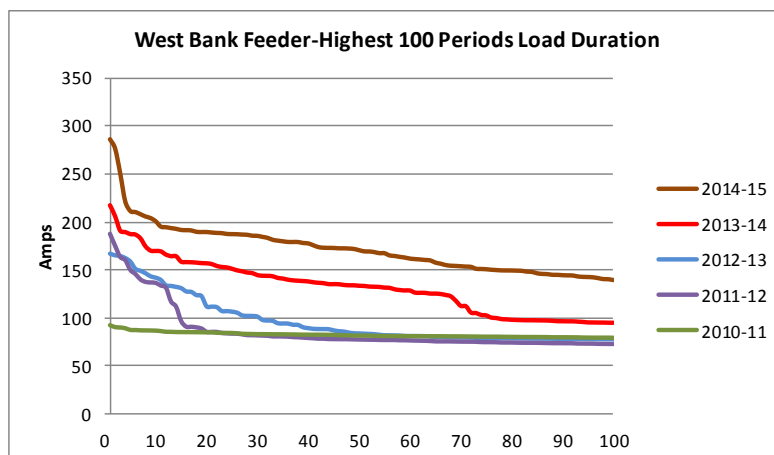


Figure 5.23 - West Bank Feeder Load Curves

Anchor I Feeder

- Primary supply to Fonterra processing plant;
- Anchor feeder is limited to 400 amps, which is below the generation capability of the site. There are no plans to increase this rating and Fonterra manage the generation to suit the feeder capacity when required.
- In 2015 Fonterra requested a proposal to increase the back-up feeder capacity

5.9 Galatea Substation



5.9.1 System Description

Galatea substation is a dual transformer substation located about two kilometres north of Murupara, on Galatea Road. The site is fully rural and has five 11kV feeders used to supply approximately 1550 customers. It is supplied from two 33kV feeders from Snake Hill switching station that is in turn fed by one feeder connected to the Aniwhenua power station and one feeder connected to the Edgumbe GXP.

5.9.2 Service Area Covered

Galatea substation supplies the Galatea region from four feeders, ranging from the North of the Galatea valley to Ruatahuna in the South East and includes the towns of Murupara and Minginui. The Galatea substation also contains a switching station for the 33kV spur line to the Kaingaroa substation.

The five 11kV feeders are as follows:

Minginui Feeder	Minginui feeder runs past Murupara and supplies Minginui and Ruatahuna. This area is very rugged, running through forest and native bush. Being a spur line there is no ability to mesh the system to Minginui to provide additional support from other feeders. Some generator connection points have been installed in strategic locations on the feeder to aid in restoration of supply or maintenance activities.
Murupara Feeder	Murupara feeder supplies the town of Murupara and is a mixture of overhead and underground conductors. Murupara feeder is supported through its connections to the Golf Road feeder.
Jolly Road	Jolly Road feeder runs East then North from Galatea substation substantially along Troutbeck Road. The feeder is predominantly a Dog conductor and supplies rural customers. This feeder is inherently reliable and is meshed in several places with the Galatea feeder.
Galatea Feeder	Galatea feeder is a rural supply feeder. It is connected to Jolly Road feeder with five tie points and to the Murupara feeder by one tie point. It has a small 100kW embedded hydro generator at Anuiwhenua on the extreme end of the feeder.
Golf Road Feeder	Golf Road feeder was created out of splitting Galatea feeder and it supplies the southern end of Murupara town. It is connected to Murupara feeder to provide support to Murupara town and Galatea feeder.

5.9.3 Description of Assets

Galatea substation is a two transformer 7.5MVA 33kV/11kV zone substation. The two 33kV incoming lines are bussed together by a normally open tie switch using an overhead bus structure that also supplies the 33kV line to Kaingaroa. Preferred configuration for Galatea is to run the two transformers in parallel from Snake Hill.

When switched from Edgecumbe to Anuiwhenua the different length of each circuit causes volt drop issues due to line losses when switching between Edgecumbe and Anuiwhenua, although this is managed operationally. The line from Edgecumbe is 58km long and from Anuiwhenua it is 19 km.

Galatea has high technical losses (predominately line losses) when being supplied from Edgecumbe, with technical losses calculated from 12.3% to 15.5% as shown on Figure 5.24.

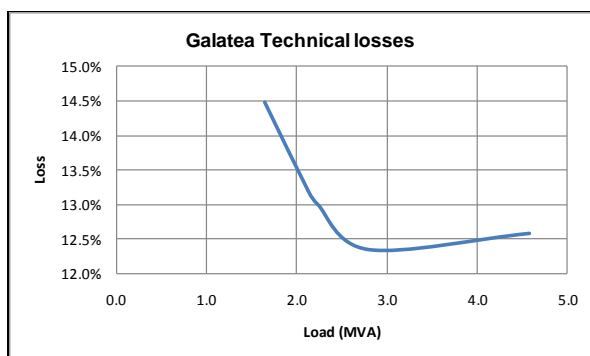


Figure 5.24 - Galatea Technical Losses

A project to install 33kV circuit breakers at Snake Hill was completed in 2014 and allows the two feeders supplying Galatea from Snake Hill to be run in permanent parallel, reducing line losses and improving reliability. A project in 2015-16 to install 33kV line circuit breakers and to run the Kaingaroa line as a live 33kV bus section will improve the supply quality to Kaingaroa and will allow the two 33kV lines into Galatea to be run in full parallel in conjunction with the Snake Hill 33kV circuit breakers.

A full replacement of the 11kV system was completed in 2014 using an indoor arrangement. The outdoor 33kV switchyard is scheduled for replacement in 2016.

Both Galatea power transformers are 7.5 ONAN MVA three phase transformers. The transformers were installed in 1980 and are currently considered at over half life. There have been recent issues with tap changer arcing that is managed with an increased level of servicing. Transformers will be assessed for early end of life replacement around 2025 unless further maintenance issues require a more accelerated replacement program.

Galatea Substation Assets

Table 5.32 summarises the major assets within the Galatea Substation:

Asset	Description	Rating Data	Date of Manufacture	Comments
33kV Bus	Overhead	Not available		Replacement 2015-16
33kV Circuit Breaker CB124, 127	GEC JB424 Bulk Oil	33kV, 400 Amp, 8.76kA 3 sec	1972	Scheduled replacement 2016
33/11kV Transformer T1 and T2	3 phase Tolley	7.5 MVA ONAN Z 7.92 % T1, 7.11 T2 Dyn11	1980	No current issues.
T1 Tap changer	Associated Tap Changer type F323 33/300	33kV 76 amp 23 steps	1980	No issues.
T2 Tap changer	Associated Tap Changer type F323 33/300	33kV 76 amp 23 steps	1980	Failed 2010 due to faulty tap step resistor. Two subsequent failures attributed cause is most likely inferior previous repairs.
11kV Bus	Indoor Schneider Genie EVO	1250 amp	2013	
11kV Feeder Circuit Breakers	Indoor Schneider Genie EVO	630 amp	2013	
Control Building	Block construction		1960	Contains ripple control only
11kV building	Portacom		2013	
SCADA	SEL relays		2015	

Asset	Description	Rating Data	Date of Manufacture	Comments
DC Battery Bank	Eaton	450ah	2013	
Local Service	Ground mount 30kVA transformer	30kVA	2013	
33kV Protection	SEL 75 I		2013	
Feeder Protection	SEL 571A		2013	
Transformer Protection	SEL 787		2013	
Tap Change Controller	SEL 2414		2013	
Load Control	Mitsubishi PLC		1993	No Issues.
Communications	4RF Aprisa UHF		2013	
Ripple Injection Plant	Motor Generator	750 Hz	1969	Obsolete equipment and frequency. Concept plan to install smart metering being investigated.

Table 5.32 - Galatea Substation Equipment

5.9.4 Substation Utilisation

Galatea Load Statistics (MVA)							
	2011/12	2012/13	2013/14	2014/15	% increase 2014/15	Ave incr per year	2014/15 n-1 utilisation
Maximum	4.7	4.5	5.1	4.6	-10.1%	-1.1%	61%
Average	2.1	2.4	2.2	2.1	-7.1%	-0.1%	28%
Average-Top 100 Periods	4.32	4.31	4.31	4.28	-0.7%	-0.3%	57%

Table 5.33 - Galatea Load Statistics

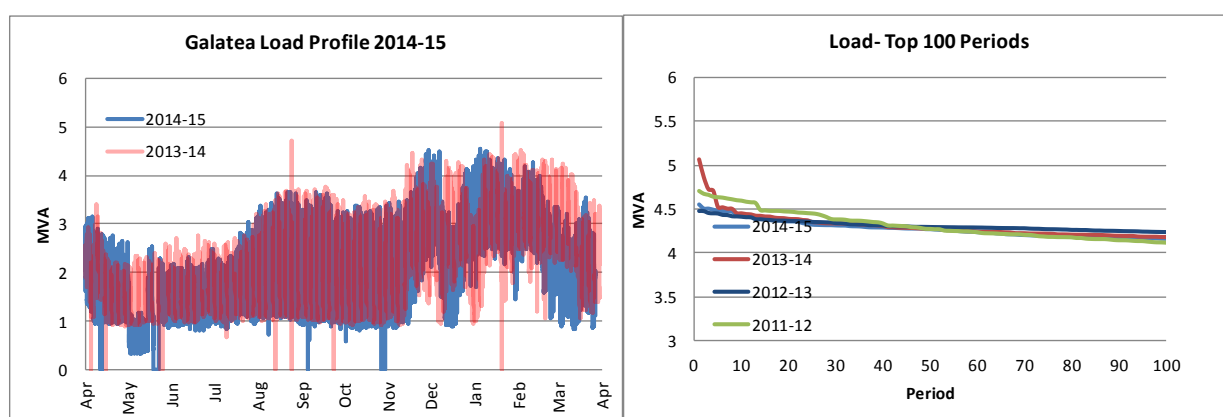


Figure 5.26 - Galatea Load Profile

Figure 5.25 - Galatea Load Duration

- Galatea region load is predominantly rural with some urban load;
- The rural load is dominated by summer peaks due to irrigation and is variable depending on the prevailing weather conditions and length of the dry season; and
- The start of the dairy milking season in mid-July to August creates a seasonal peak during spring prior to the irrigation load starting in November.

5.9.5 Load Growth

There is zero growth over the previous 4 year period. Peak load during summer is self-managed to some degree by the consumers who have set up their pumping systems to irrigate at night. Daily load curves show the night time load is greater than the daytime load with an extended evening peak during summer. Load is driven by climatic conditions.

Load growth and the ability of the substation equipment to supply will not be a concern for several years. What is of concern is the ability to supply Galatea from Edgumbe via the Snake Hill circuit and maintaining voltage within tolerance with the increasing load. This issue is expanded on in Section 5.9.6.

5.9.6 Constraints

When supplied from Edgecumbe the losses on the 33kV circuit are very high; when the combined loads Kaingaroa and Galatea approaches 7 MVA the transformers voltage regulators saturate and are no longer able to control the 11kV voltage at either bus. This restricts the additional load that can be added to the network at these locations and still maintain quality of supply. Various options have been considered to remedy this including 33kV capacitor banks, 11kV capacitor banks and/or an additional sub-transmission line between the Snake Hill switching station and Aniwhenua. A second line to Aniwhenua provides the best technical solution. This has been scheduled for 2017 pending agreement with the generator owner, Nova Energy.

Food hygiene regulations are due to come into force 2016 which will require dairy farms to further chill their milk production. Initial estimates are that additional farm loads could vary from 12-22kW. This will have an impact on summer loads and will become a further constraint on the supply from Edgecumbe, but the full impact of this has not yet been assessed.

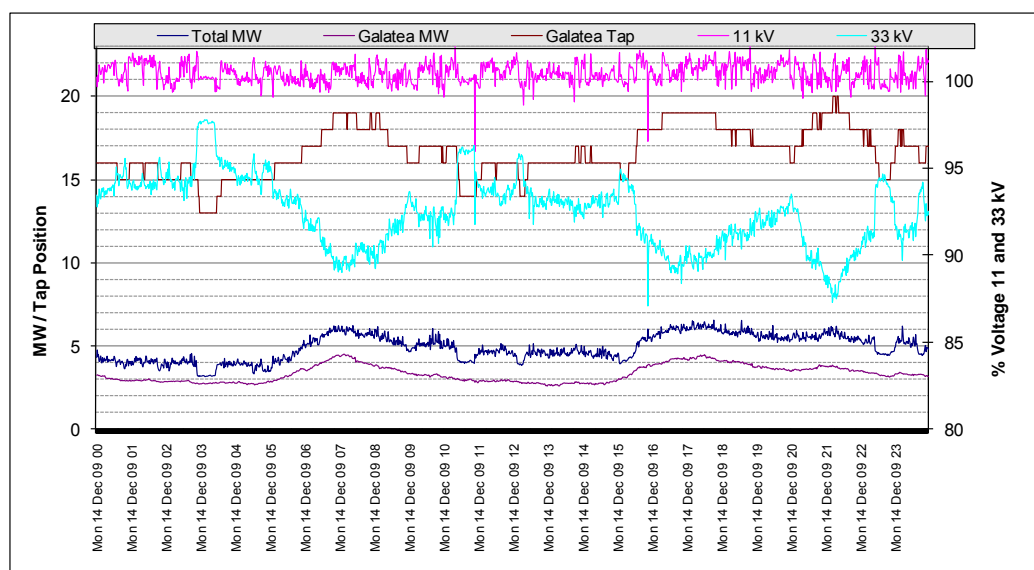


Figure 5.27 - Tap Position

The figure above shows the tap position compared to 33kV line voltage when supplied from Edgecumbe. Full transformer tap range is 23 taps.

5.9.7 Lifeline Risk Assessment

Risks and vulnerability of the Galatea substation site from a CDEM lifelines perspective are summarised in Table 5.34 below:

Vulnerability	Galatea	Mitigation/Risk
Total Loss of Galatea Substation	The substation is a dual feeder substation with two three phase transformers	No ready solution in place. Temporary large generator for each feeder or rolling outages.
Partial loss	Fully redundant site	Built in.

Vulnerability	Galatea	Mitigation/Risk
Communications	Primary communications is by a single link UHF radio from Mount Putauaki repeater radio site. Communication is used for remote control of switching operations, load and security monitoring.	Not critical for operation as systems can be operated manually, with delays.
Site Access Requirements	Access is required in the case of: <ul style="list-style-type: none"> Loss of communications Abandonment of Commerce Street control room Non operation of equipment 	Vehicle access via Galatea Road, past Matahina Dam. There is sufficient clear land to land a helicopter near the substation site if required.
Natural Hazards	Natural hazards that the sites could be exposed to are: <ul style="list-style-type: none"> Flood Earthquake Tsunami Volcanic activity Wind 	Risk <ul style="list-style-type: none"> Low High None Low Low Disaster recovery plans are held in the Horizon Energy disaster recovery quality manual.
Network Impact Risk	Supplies 7% of the network (including Kaingaroa) mixed urban and rural	
Human Habitation	Galatea is an unmanned site	Access door alarms to SCADA.
External Services	All critical services are on 48 volt battery banks	

Table 5.34- Galatea Lifeline Risk Assessment

5.9.8 Galatea Substation Feeders

Galatea substation feeders are summarised in Table 5.35 below:

Feeder	Minginui	Murupara	Galatea	Jolly Road	Golf
Type	Rural	Urban	Rural	Rural	Rural
Overhead (km)	80	22	60	64	
Underground (km)	0.5	5	1	2	
ICP Connections	286	585	189	250	224
Substations	84	76	109	98	
Installed Tx Capacity (MVA)	3.1	5.9	4.2	3.0	

Feeder	Minginui	Murupara	Galatea	Jolly Road	Golf
Maximum Load Amps	38	65	96	89	72
100 Peak Load Amps	30	56	76	84	31
5 year average growth rate	-1%	-7.5%	0.0%	1.8%	NA
Feeder Utilisation at Average 100 Peaks	11%	20%	27%	30%	11%

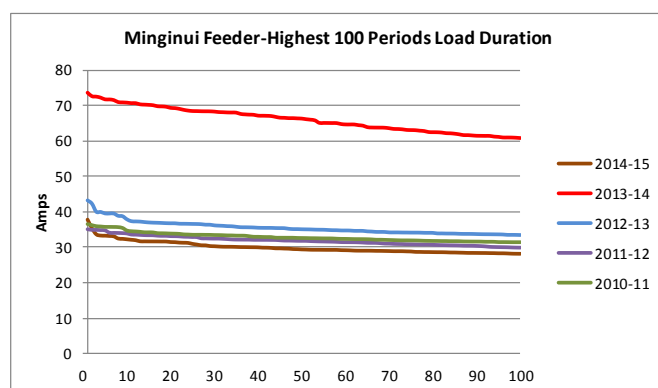
Table 5.35 - Galatea Substation Feeder

Minginui Feeder

- Low growth;
- Large irrigation loads on this feeder;
- End of line voltage levels are not seriously affected by this level of load; and
- New circuit breakers installed on the line to Minginui, just past Murupara.

A customer initiated project to install a new line into a remote village was being planned for 2010-11 but is delayed due to financial constraints and easement issues. If it proceeds, this line will connect to the Ruatahuna line and will be constructed as a single wire earth return circuit. Horizon Energy would have preferred a non-network option but the customer wanted grid connection.

The Minginui feeder is older than most in the network but, due to its inland location away from salt air, is in very good condition for its age. There are no reinforcement options for the remote end of Minginui feeder apart from generation. The chart below shows the support for Jolly Road feeder during the 11kV board replacement project.



Murupara Feeder

- Load growth is below average for the network and likely to remain so due to urban population displacement; and
- Additional SCADA controlled devices installed to provide remote switching and sectionalising in the event of any fault.

Galatea Feeder

- The Galatea feeder has a number of irrigation schemes installed which have contributed to the load growth;
- This feeder is unusual in that the main backbone of the feeder is a Ferret conductor, rated at 4MVA, instead of the more common 6MVA rated Dog; and

- This is not an issue at this stage due to the low loads supplied although it does cause additional losses and volt drop at the end of line.

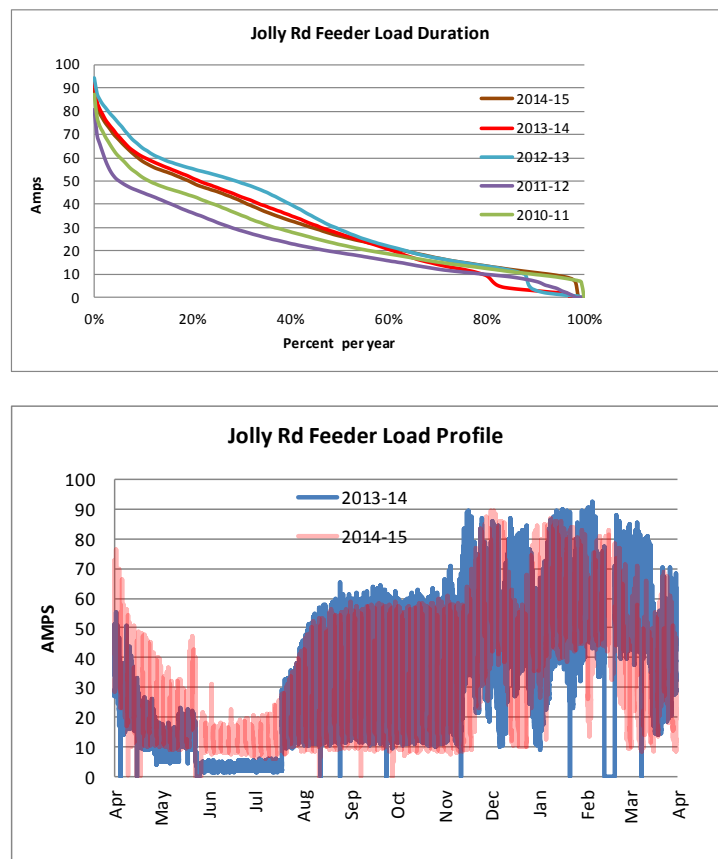


Figure 5.28 - Jolly Feeders Load Profile

Jolly Road feeder comparing two years loads, showing the effect of weather on irrigation loads.

Jolly Road Feeder

- This feeder has had above average load growth due to irrigation;
- There are no load constraints with this feeder; and
- Two of the tie lines to other feeders are constructed from smaller conductor, Squirrel and Ferret, which at this stage do not provide restrictions for load reinforcement by the Galatea feeder. There are two larger conductor tie lines available for reinforcement.

Golf Feeder

- Constructed 2015 as a logical geographical split from Galaeta feeder
- Low level of connected load. Provides a back-up to Murupara feeder

5.9.9 *Fault Analysis*

- The Galatea region has a relatively low rate of faults, as the network is generally in good condition; Most recent faults have been caused by trees.
- Due to the remoteness of the region from support staff, it suffers from high fault duration times; and
- This remoteness has been the key driver in the extensive reliability enhancement projects being undertaken in the region.

5.10 Kawerau Substation

5.10.1 System Description

The Kawerau GXP substation is a Transpower owned 110kV to 11kV substation with the Horizon Energy 11kV distribution network directly connected to Transpower assets. Horizon Energy substation assets are located in a small building adjacent to the Transpower site. Dedicated Transpower assets supplying the distribution network comprise an 11kV, 10 circuit breaker bus and two 110/11kV transformers. The Kawerau system has six distribution feeders summarised below.

The Kawerau system load is dominated by large industrial loads and 4.5 MW of Embedded Generation. The variation in load for the commercial and domestic base is very small in comparison to the industrial load.



Due to the transformer arrangement of 110/11kV the Kawerau feeders are out of phase with any 11kV feeders sourced from the Edgecumbe GXP.

Being in a geothermal area, Kawerau has a high level of H₂S induced corrosion, especially in the areas to the North of Norske Skog and Tasman paper mills, and in the lower lying areas in the town. Air break switches tend to have a higher than average failure rate due to environmental induced corrosion and high fault levels. Fully enclosed line switches are a good option for the Kawerau environment.

In 2013 a preliminary request to connect a large geothermal generator was received. This project is still undergoing feasibility connection studies in 2015 by the proposer.

In 2013 Transpower CB13 Mt. Edgecumbe feeder failed in service and repairs require a full bus outage for an extended period. An extended outage is unacceptable so the CB13 load has been transferred to the Kawerau feeder. Transpower have indicated the 11kV bus will be replaced by June 2019. There would be benefits in Horizon building and owning the 11kV assets.

5.10.2 Service Area Covered

Kawerau	The Kawerau feeder supplies the urban area of Kawerau. The Kawerau feeder is tied to the Plateau feeder at three places.
Plateau	Plateau feeder is the second feeder into the Kawerau town and the primary supply to the commercial area.
Onepu	<p>The Onepu feeder is rural and runs North from the substation along SH30. It is connected to a 300mm² cable that is installed under the Norske Skog log yard to connect the geothermal generator TG2. This feeder also supplies the CHH Lumber site and the Norske Skog effluent treatment ponds, which both act as a 'load soak' for the generation supplied to the feeder. The Onepu feeder is supported by the Plateau feeder which can also provide an alternative path for the generation and provides reinforcement in supply for the treatment ponds.</p> <p>Plans for splitting the Onepu feeder to reduce overload risks when the embedded generation is not available are on hold following the failure of Kawerau CB13.</p>
Paper	The high capacity Paper feeder was released by SCA in 2009. It has been re-configured to supply the Kawerau industrial zone and also still serves as a back-up supply for SCA. The load is light on this feeder which has a summer rating of 650 amps.
Pulp	The Pulp feeder is the primary supply to SCA Hygiene. A back-up supply is available from the Paper feeder. Reducing to a single feeder in 2009 reduced the fault level on the SCA Hygiene site from 13kA to approximately 8kA.

5.10.3 Description of Assets

Table 5.36 summarises Horizon Energy's major assets within Kawerau Substation:

Asset	Description	Rating Data	Date of Manufacture	Comments
Control Building	Wooden frame metal clad building		1988	No issues.
SCADA	Leeds and Northrup (Foxboro)		1992	Hardware has exceeded its nominal life.
DC Battery Bank	Switchtech 24V		1988	No issues.
Local Service	ABB transformer	200kV	1988	No issues.
Ripple Injection Plant	Zellweger static inverter 315/750hz Type SFU-G		1988	Study underway for replacement alternatives.
PLC – Load Control Plant	Mitsubishi AIS with RCS RC02 Conitel comms. interface		1999	Non-standard communications system. Seems to work okay with no issues.

Asset	Description	Rating Data	Date of Manufacture	Comments
Communications	Exicom Hawk 450Mhz UHF radio			Retire with ICCP connection

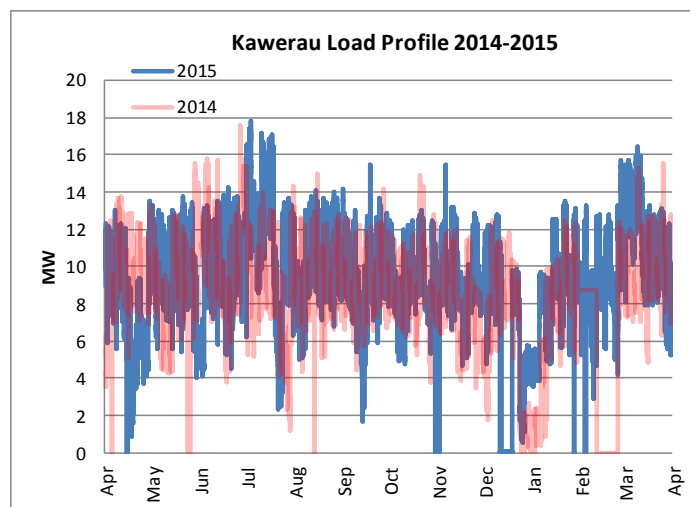
Table 5.36 - Kawerau Substation Assets

5.10.4 Substation Utilisation

Kawerau substation utilisation is affected by the industrial demand and embedded generation. Actual domestic consumer growth is shown at feeder level in the feeder Section 5.10.5. Overall utilisation is below the firm capacity of the GXP.

Kawerau -Load Statistics MW						
	2012	2013	2014	2015	% increase 2014-15	% Increase 3 years
Maximum	17.2	16.9	17.6	17.8	1.5%	2.7%
Average	10.54	9.53	8.51	9.27	8.9%	-1.4%
Average-Top 100 Periods	16.19	15.13	15.25	16.28	6.8%	3.8%

Table 5.37 - Kawerau Load Statistics



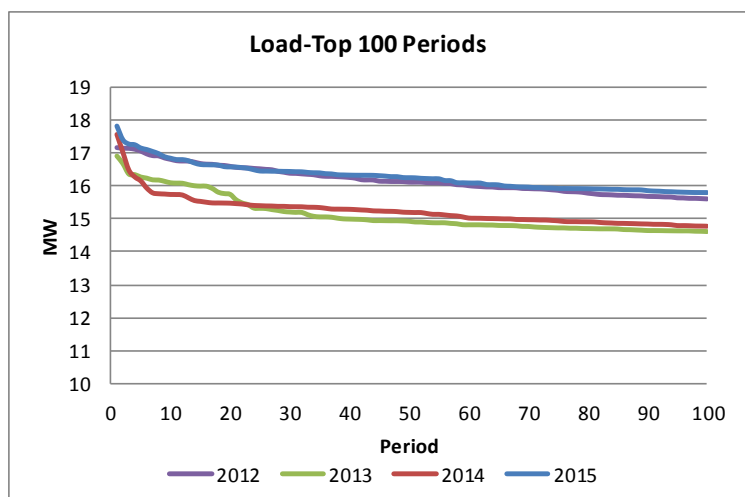


Figure 5.29 - Kawerau Load Profile

5.10.5 Load Growth

Load growth has increased due to the closure of TGI embedded generation plant. Longer term, it is expected that a further reduction in load from this supply point is probable as pulp and paper manufacturing industries retrench. The industry has not yet signalled any timing for this change.

Domestic growth is still upwards in the Kawerau region with a growth rate slightly above the network average.

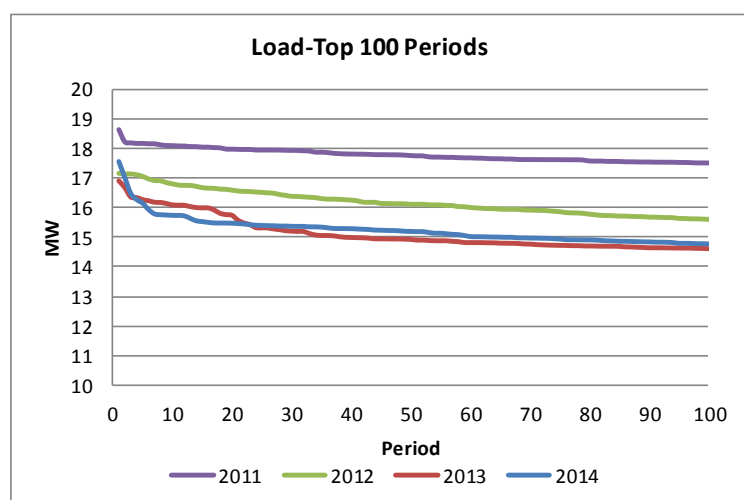


Figure 5.30 - Kawerau Load Profile

5.10.6 Constraints

The Kawerau substation 11kV bus has a very high fault level which requires high fault rated cables and equipment to be used close in to the substation. Some of the equipment and cables identified on the Kawerau, Plateau and Onepu feeders are marginal for the fault levels that they are required to manage.

Management of the fault current is possible by running with the 11kV bus open and removing the supply transformer parallel. Longer term management of the fault levels is possible with the Transpower upgrade of the 11kV switchboard and installation of neutral earthing resistors which reduces the earth fault currents to manageable levels. A bus reactor would also be advantageous to limit fault currents.

Peak loads of the combined Kawerau and Plateau feeder loads are approaching the full feeder capacity during reinforcement.

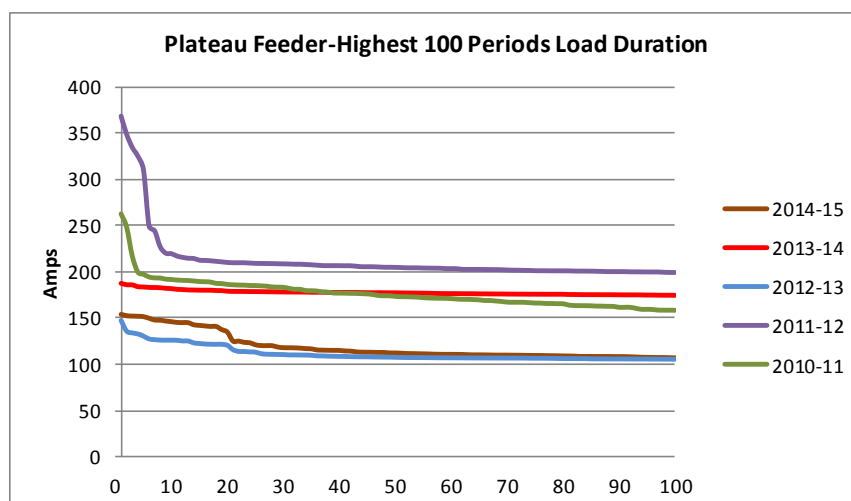
5.10.7 Kawerau Substation Feeders

Kawerau substation feeders are summarised in Table 5.38.

Feeder	Kawerau	Mt Edgecumbe	Onepu	Plateau	Paper	Pulp
Type	Urban	Out of Service	Rural	Urban	Industry	Industry
Overhead (km)	6.7	-	10.0	8.6	1.3	2.8
Underground (km)	8.7	-	4.2	13.3	0.7	0.1
ICP Connections	1674		66	1222	40	3
Substations	43		34	53	-	-
Installed Tx Capacity (MVA)	12.1		7.04	10.07	-	-
Maximum Load Amps	168		241	154	510	103
100 Peak Load Amps	142		225	119	496	94
Growth Rate	2.0%		-4.2%	-0.2%	4.4%	na
Feeder Utilisation at Average 100 Peaks	51%		81%	42%	76%	14%

Table 5.38 - Kawerau Substation Feeder

Kawerau and Plateau Feeders



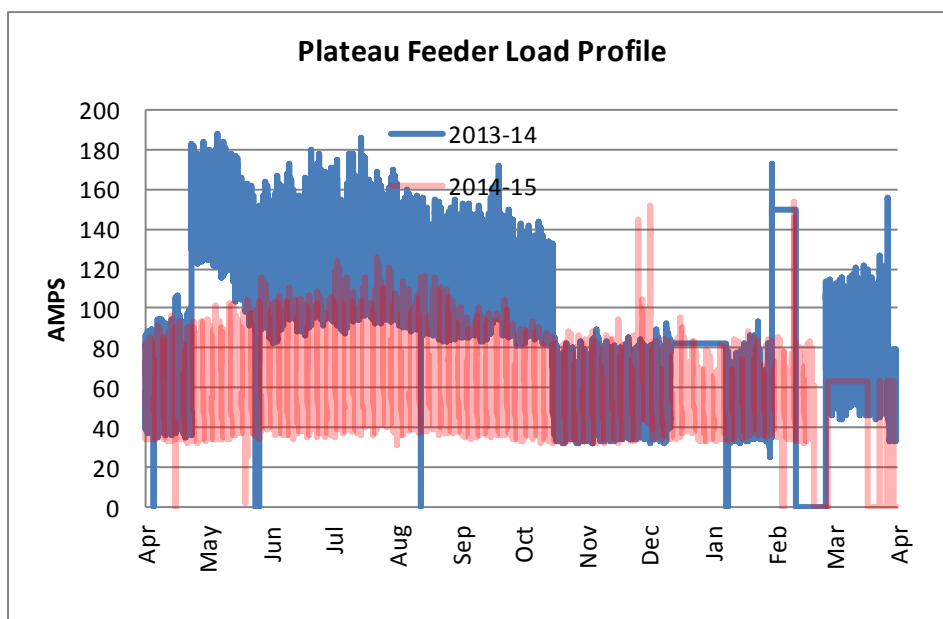


Figure 5.31 - Plateau Feeder Load Curves

- Plateau feeder showing Onepu loads May to October;
- Kawerau and Plateau feeders show moderate growth consistent with average network growth patterns;
- Load growth will continue to be monitored to ascertain if feeder upgrades are required. Load growth has been increasing but long term predictions are for a population decline that is predicted to be faster than organic load growth;
- Kawerau and Plateau feeders have high fault levels close to the substation. The feeder cable from the Kawerau substation is rated below the maximum fault level presented from the 11kV bus. This will be corrected when the Transpower 11kV board is replaced.
- Poor soil thermal resistivity due to the volcanic pumice nature of the soil lowers the full load rating of all the cables installed in the Kawerau region. This is not an issue at this stage except during peak load reinforcement periods. The soil resistivity exceeds 3Km/W around the substation;
- There are a large number of Magnefix Ring Main units in Kawerau that have been scheduled for condition based replacement during the next 15 years. Priority is given to replacing units on the main feeders or where the units are difficult to maintain due to number of customers supplied and outage availability;
- When supplying reinforcement loads both Plateau or Kawerau feeders can be loaded up to 90% of the feeder's full rated capacity.

Onepu Feeder

- Onepu feeder load profile is driven by generation;
- The industrial load is a timber mill adjacent to the TG2 generation plant and the Norske Skog effluent treatment ponds;
- Onepu feeder has a restriction on capacity if all load is off and the generation is operating to maximum. This is managed operationally by feeding some of the generation into the Plateau feeder. A no-load situation is rare due to the 24 hour continuous operation of the local industry;
- A project started in 2013 to split Onepu into two feeders and upgrade the cable to TG2 and the lumber plant is stalled due to the failure of Kawerau CB13;
- Kawerau District Council is working to re-zone land as industrial along SH30, North of Kawerau. This area is supplied by the Onepu feeder and, if the development proceeds, the feeder loading and utilisation will be looked at as a step change;
- The supply cable connecting the feeder to the Kawerau bus is marginal for the fault level incurred; and
- The Norske Skog aeration ponds are supplied by Horizon Energy owned transformers. These are predominantly open bushing ground mounted IMVA transformers in fenced enclosures. The enclosures are in poor condition and are being refurbished. The transformers are 25-30 years old.

Mt Edgecumbe Feeder

- This feeder has been disestablished due to a faulty CB13 and is connected to the Kawerau feeder.

Pulp and Paper Feeders

- These feeders were originally installed to supply the Caxton Paper Mill, subsequently renamed SCA Hygiene, then Asaleo Care
- Pulp feeder supplies the Kawerau industrial park and is a back-up supply to Asaleo Care. Paper feeder is dedicated to Asaleo Care.

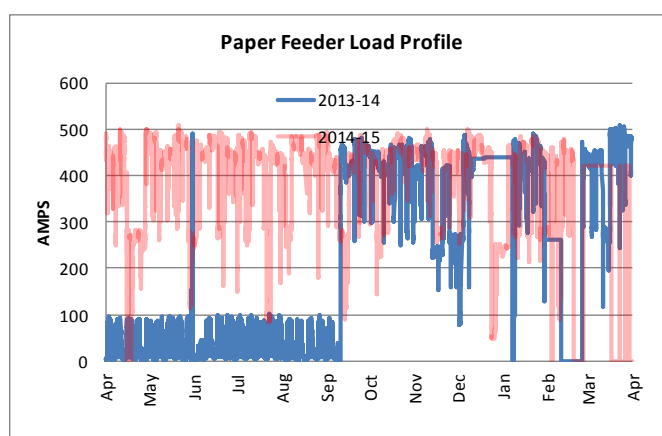


Figure 5.32 - Paper Feeder Load Profiles

5.10.8 Faults and Outages

- In January 2014 a Yorkshire Ringmaster ring main unit at the substation failed after being inadvertently closed to earth onto a live cable;
- Historically the Kawerau feeders have had a low number of faults; but
- Due to the number of customers on the feeder and remoteness from support fault staff, any faults that do occur on Plateau or Kawerau incur high numbers of SAIDI minutes;

- Sectionalising circuit breakers were installed in urban Kawerau in 2010-11 to reduce the impact of faults;
- The Kawerau area was one of the first underground areas in the network using XLPE cable and there have been some recent failures with older XLPE cables. A number of cables have been replaced and further replacements are scheduled for arterial route cables; and
- Replacement of a number of problematic Magnefix ring main units has been scheduled.

5.10.9 Major Projects

Transpower 2015 Transmission Planning Report tentatively schedules a replacement of the Transpower 11kV indoor board and 110/11kV supply transformers for the years 2017-2019. There is likely to be a significant network cost associated with this project in providing opportune betterment for network assets and relocation or upgrade of network cables to the new switchboard location. Transpower also habitually installs neutral earthing resistance on the transformer neutral star points which results in a higher phase to ground voltage during faults, necessitating replacement of 11kV lightning arrestors, especially those that are close to the source of supply.

Due to the tentative nature of the project a provisional cost expenditure amount has been allocated into the 2016/17 budget year. Beneficially, neutral earthing resistors will reduce the phase to ground fault levels which will reduce fault damage.

Horizon has entered into preliminary discussions regarding possible connection of a large embedded generation connection. This may trigger the above 110/11kV transformer and 11kV switchboard replacements.

5.11 Kaingaroa Substation

5.11.1 System Description

Kaingaroa substation is located approximately 80km from Whakatane. It supplies the small town of Kaingaroa and two timber processing plants; KLC Ltd which produces re-manufactured timber products and Timberlands Ltd that produces whole logs and wood chips. These two processing plants dominate the load, where the load within the Kaingaroa village is very small in comparison to the industrial base. In 2012 KLC expanded their manufacturing plant.

Kaingaroa substation was built in 1994 and is constructed on the Timberlands property. Access to the substation is through the Timberlands Kaingaroa Processing Plant site which was done to reduce the incidence of vandalism on the site.

Distribution of the 11kV supplies after the 11kV circuit breakers is by an ABB five switch SD Ring Main unit which serves as an 11kV bus system.

The station is normally operated with one transformer supplying the Timberlands mill load while the other transformer supplies the village and KLC. This arrangement was proposed from commissioning to ensure the common point of coupling between the village and the Mill is on the 33kV system to reduce the volt drop annoyance that the village may see from the operation of the Mill site. The impedance of the transformers was also chosen to assist in the reduction of this impact.

A project is underway in 2016 to supply Kaingaroa from a 33kV bus section at Galatea which provides a greater level of security and improved quality of supply to the Kaingaroa circuit.

5.11.2 Service Area Covered

There are four feeders; Dunn Road feeder that supplies the town and KLC, and three feeders that supply the Timberlands plant. The Dunn Road feeder services 187 consumers.



5.11.3 Description of Assets

Table 5.39 summarises the major assets within the Kaingaroa Substation:

Asset	Description	Rating Data	Date of Manufacture	Comments
33kV Bus	Overhead aluminium conductor	Not available	1994	
33kV Circuit Breaker KAI02 and KA202	Cooper Power VWVE38X With Form 4C controller	38 kV 560 amp Fault rating 12kA	1994	No issues.
33/11kV Transformer T1 and T2	3 phase ABB ground mount open 33kV bushing	4 MVA ONAN 5.33 MVA ONAF 4.68% Z Dyn11	1994	No Issues.
Tap Changers	ABB UBBDT 200/150 Range +8% to – 16%	33kV 200 Amp 25 steps	1994	Transformer tap changer failed early in the transformer life. An increased frequency of maintenance is recommended by ABB on these tap changers. Maintenance interval 100,000 operations, tap life 500,000 operations. Currently tap operations exceed 300,000
Tap Change Controller T1	RMS model 2VI62K4		1994	
Tap Change Controller T2	RMS model 2VI64S – BBBA		2010	Replaced failed controller.

Asset	Description	Rating Data	Date of Manufacture	Comments
11kV Distribution Switchboard KA31 and KA32	Reyrolle, LMVPT/QMRC vacuum circuit breakers	Circuit breakers 630 amp Fault rating 25kA 3 sec Bus rated 1250 amps	1994	Blast doors unable to be fitted to these circuit breakers due to space constraints in the building
Control Building	Portacom metal clad building		1994	No issues
SCADA	Leeds and Northrup (Foxboro) C50		1994	Hardware has exceeded its nominal life. Replacement scheduled 2016
DC Battery Bank	Switchtech 24V			No issues
Local Service	ABB transformer	30kVA	1994	No Issues
33kV Protection	Cooper Power Kyle form 4C		1994	No issues
Feeder Protection	Reyrolle NEI GAD		1994	Relays have no metering capabilities
Transformer Protection	Reyrolle 5B3		1994	No issues
Communications	Exicom 159Mhz VHF radio		1994	Radios are scheduled for replacement 2016

Table 5.39 - Kaingaroa Substation Assets

5.11.4 Substation Utilisation

Kaingaroa -Load Statistics (MW)							
	2012	2013	2014	2015	% increase 2014-15	Avg incr per year	n-1 Utilisation
Maximum	2.3	2.5	2.5	2.6	2.8%	4.8%	49%
Average	1.28	1.32	1.39	1.43	2.6%	3.8%	27%
Average-Top 100 Periods	2.1	2.3	2.3	2.4	1.5%	4.4%	45%

Table 5.40 - Kaingaroa Load Statistics

Load growth in Kaingaroa is above network average is mainly driven by industry.

There have been pre-feasibility requests for an additional IMVA load and an embedded generating connection but these requests have not been formalised yet.

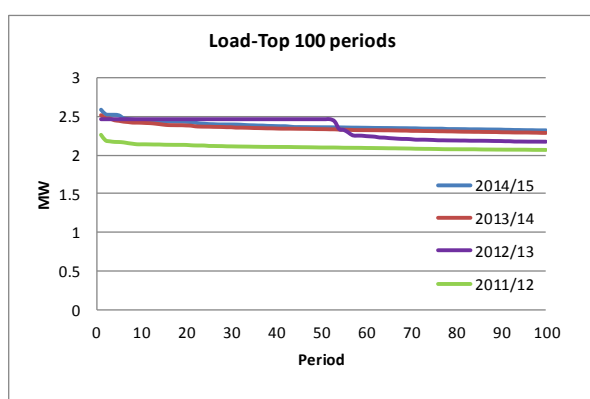


Figure 5.33 - Kaingaroa Load Curves

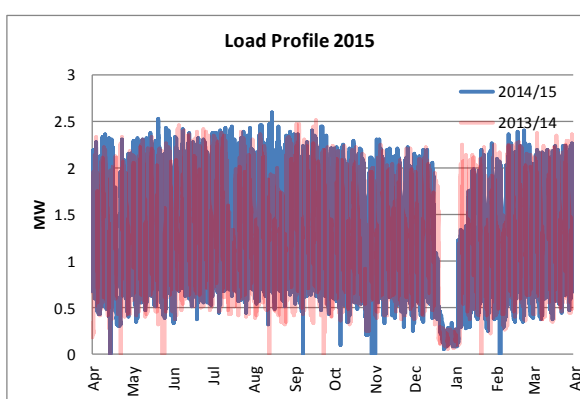


Figure 5.34 - Kaingaroa Load Profile

Constraints

If a reserved load of 2500kW at Kaingaroa is ever uplifted the complete 33kV system including Galatea, will suffer voltage compliance issues when supplied from Edgecumbe during high load periods.

The single 33kV line from Galatea to Kaingaroa provides no redundancy. Reliability of this circuit is managed by regular line inspections and vegetation control. There are no load restrictions at Kaingaroa apart from the issue of support when the normal supply from Aniwhenua is disrupted and the alternate supply from Edgecumbe is used. A project in 2016 to convert Galatea 33kV to a live bus system will improve reliability to Kaingaroa.

5.11.5 Faults

Due to the remoteness of Kaingaroa and the response time from Whakatane, faults tend to take a long time to resolve but have a low SAIDI impact due to the low number of customers served. There is only one fault response person located in Murupara.

5.12 Kope Substation

5.12.1 System Description

The Kope (Kope) substation is a two transformer 33kV/11kV zone substation located in the Whakatane Kope business area on the King Street service lane. The Kope substation was partially redeveloped in 1991 when the control building was constructed and new 11kV switchgear installed adjacent to the transformer site. The site is bounded by residential housing on three sides.

The two 33kV incoming supplies are connected to an overhead 33kV bus that is run normally open. T1 transformer is a 10/13.3 MVA transformer. T2 was replaced in 2013 with a 12/16 MVA unit.

In 2015 T1 failed due to a 33kV bushing failure. The transformer suffered little damage in part to recently installed neutral earthing resistors at Edgecumbe, and high speed inzone differential protection at Kope.

5.12.2 Service Areas Covered

Kope substation supplies the Whakatane urban region from five feeders; Strand North, Strand South, Rex Morpeth, Victoria and King Street feeders as shown in Table 5.41 below:

Strand North	Primary supply to the Whakatane CBD. Supplies a mix of domestic and commercial customers. This 11kV feeder is completely underground.
Strand South	Primary supply to the Whakatane CBD. Supplies the Heads and Hillcrest. This 11kV feeder is completely underground apart from a small section up Waiewe Street and supplies a mix of domestic and commercial customers.
Rex Morpeth	Supplies domestic and commercial customers on Goulstone Road and Commerce Street. This feeder is mostly underground. There are two schools supplied by this feeder.
Victoria Avenue	Load is predominantly domestic. There are two schools on this feeder. Mostly overhead conductor but the Awatapu end from Kowhai Street is underground.
King Street	Supplies the Kope commercial area, the hospital, and domestic loads in the lower King Street region to the South. Mix of overhead and underground.

Table 5.41 - Service Areas Covered



Kope Substation 2013 showing new T2 transformer behind T1 transformer

5.12.3 Description of Assets

Table 5.42 summarises the major assets within the Kope Substation:

Asset	Description	Rating Data	Date of Manufacture	Comments
33kV cable	Tuhoe feeder St Joseph's feeder	3x 1 core 33kV XLPE 185sqmm ducted aluminium conductor Defined conditions rating 13MVA	1986	Soil thermal resistivity rating is 3Km/W, tested in 2010. This de-rates the cables capacity by 0.76 to 13.2 MVA.
33kV Circuit Breaker KS10	3 phase ASEA type HLC36/630B Serial number 2177/514	33kV 600 amp Fault rating 11.6kA 3 seconds	1967	No known issues. Replacement with indoor equipment scheduled
33kV Circuit Breaker KS4	3 phase ASEA type HLC36/630B Serial number 2177/513	33kV 660 amp Fault rating 11.5kA 3 seconds	1967	No known issues. Replacement with indoor equipment scheduled
33/11kV Transformer T1	3 phase ASEA	10 MVA ONAN 13.3 MVA ONAF 8.69% Z Dyn11	1986	Transformer has no oil containment. Transformer connected as Dyn3
T1 Tapchanger	Ferranti DS300	33kV 300 amps (CER 480 amps) 15 steps	1986	No issues.
33/11kV Transformer T2	ABB 3 phase transformer ABB 3 phase unit with Reinhausen vacutap	12MVA ONAN 16MVA ONAF 11.47% Z@ 16MVA Dyn11	2013	ABB Biotemp environmentally friendly synthetic transformer oil installed. Transformer connected as Dyn3

Asset	Description	Rating Data	Date of Manufacture	Comments
11kV Cable	Transformer T1 to switchgear	6 x 1c 630sqmm AL XLPE	2010	
11kV Cable	Transformer T2 to switchgear	6 x 1c 630sqmm AL XLPE	2013	
11kV Distribution switchboard	Reyrolle, LMVPT/QMRO vacuum circuit breakers, 8 panels 7 circuit breakers and bus coupler	Circuit breakers 630 amp Fault rating 25kA 3 sec Bus rated 1250 amps Incomer 800 Amp	1991	Without upgrading the 800 Amp incomers limits the maximum usable single transformer size Kope to 16MVA
Control Building	60m ² wooden frame metal clad building		1991	No issues.
SCADA	SEL 2411 RTU		2013	
DC Battery Bank	Eaton 48V	450Ah	2013	
Local Service	ETEL	50kVA		A re-design of local service completed 2012
33kV Protection	SEL751		2013	
Feeder Protection	SEL751A		2013	
Transformer Protection	SEL 787 and 751A relays		2013	Earth fault and transformer differential
Tap Change Controller	SEL 2414		2013	

Table 5.42 - Kope Assets

5.12.4 Substation Utilisation

Kope substation is the most heavily loaded substation within the Horizon Energy network. The following table and figures below indicate the load profile and load duration data for 2011 to 2015. Load growth is lower than the network average.

Kope -Load Statistics (MW)							
	2012	2013	2014	2015	% increase 2014-15	Avg incr per year	n-1 Utilisation
Maximum	15.4	14.2	13.9	14.4	3.2%	-2.2%	108%
Average	6.48	6.82	6.57	6.91	5.1%	2.2%	52%
Average-Top 100 Periods	12.8	12.7	12.9	13.0	0.4%	0.4%	98%

Table 5.43 - Kope Load Statistics

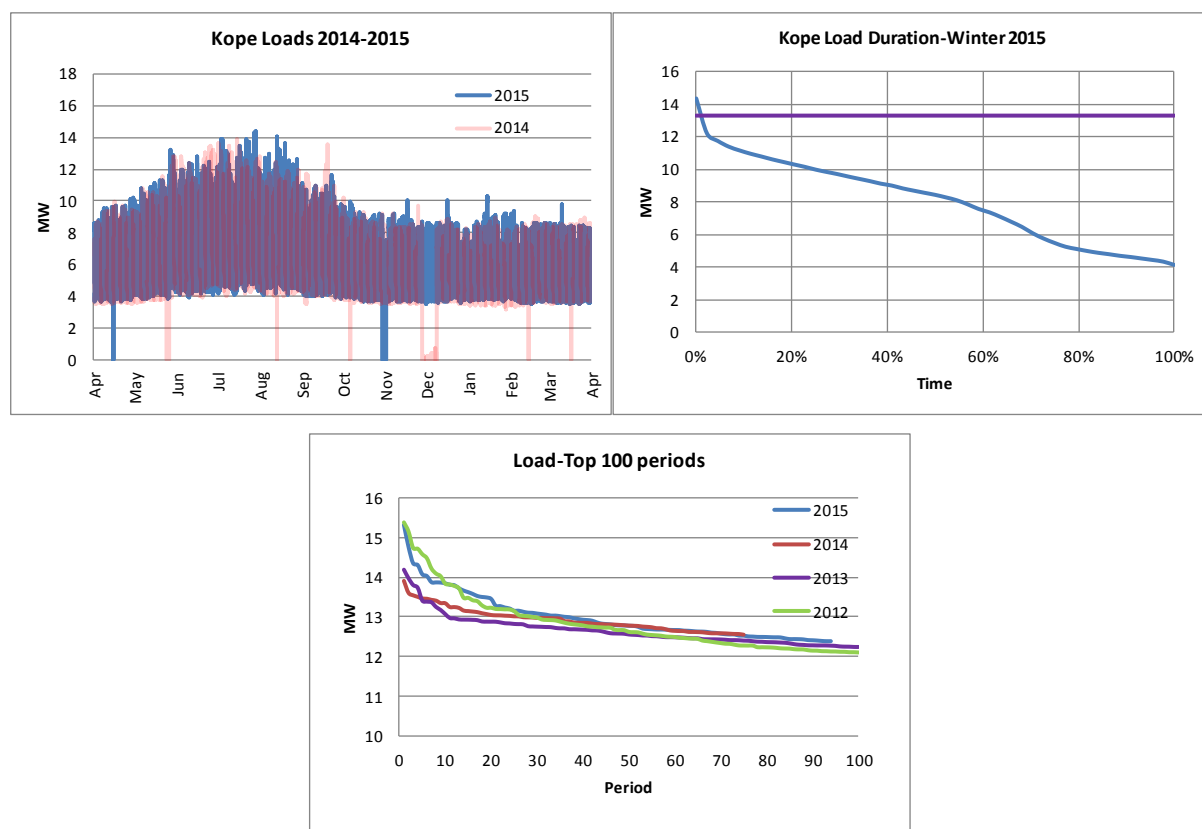


Figure 5.35 - Kope Load Duration Charts

5.12.5 Notes on Load Growth

- Population growth within the town is restricted to infill housing or apartments. A Whakatane District Council report in 2007 indicated there was the potential to develop approximately 200 residential dwellings within the Whakatane town but in the last three years there has been little building activity;
- The Whakatane Urban Growth Strategy, issued by the Whakatane District Council, has identified the Kope area bordered by Stewart Street, Hinemoa Street, Victoria Avenue, and King Street as an area for high density (Intensification) population growth for up to 25 dwelling units per hectare; and
- Significant commercial developments include a 2013 refurbishment at the Whakatane Hospital and the Te Whare Wananga o Awanuiarangi expansion completed in 2012.

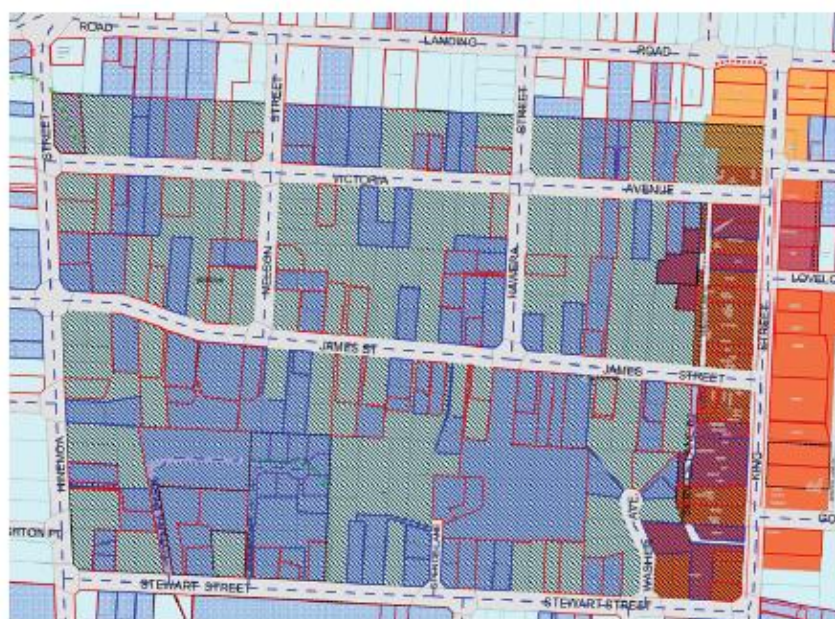


Figure 5.36 - WDC Kope Intensification Area

- As growth around the Kope supply area increases, further load will be shed from Kope substation onto the adjoining Station Road substation, and the proposed substations at Gateway Drive and the CBD substation.

5.12.6 Constraints

- Soil thermal resistivity at Kope was tested in 2010 with the resultant fully dry thermal resistivity exceeding 3.0Km/W. This lowers the thermal full load rating of all the 33kV feeder cables into Kope substation to 13.2 MVA. Large lengths of the 33kV feeder cables and 11kV feeder cables are installed under asphalt and the soil condition is totally dry in these areas. A project has been identified to correct this; and
- Incomer circuit breakers are 800 amps (15.2MVA @ 11kV). There is no plan to correct this at this stage.

5.12.7 Substation Vulnerability

Risks and vulnerability of the Kope substation site from a CDEM lifelines perspective are summarised in Table 5.44 as follows:

Vulnerability	Kope Substation	Mitigation
Communications	Communication is used for remote control of switching operations, load and security monitoring.	A fibre optic ring to provide communication resilience and mesh Kope, Station Road and Gateway has been laid.
Site Access Requirements	Access is required in the case of: <ul style="list-style-type: none"> • Loss of communications • Abandonment of Commerce Street control room • Non operation of equipment 	<p>Risk of loss of urban road access is low.</p> <p>Roads accessing the site are King Street service lane accessed from either Victoria Avenue or James Street.</p> <p>There is sufficient clear area to land a helicopter close to the Kope substation site.</p>
Total Loss of Kope Substation	<p>Total loss of Kope substation, or the two 33kV feeders supplying Kope, or the two transformers, would result in a sustained power outage to the complete Whakatane urban area, including the CBD.</p> <p>Limited supply is available from adjoining substations but with insufficient capacity to fully supply all customers.</p>	<p>Connection of 11kV to adjoining substations.</p> <p>Probability of rolling outages to manage load.</p>
Partial Loss of Kope Substation	Partial loss of one Kope transformer, or one of the two 33kV feeders supplying Kope, could result in a short power outage to the complete Whakatane urban area, including the CBD.	Connection to adjoining Station Road substation.
Natural Hazards	<p>Natural hazards that the sites could be exposed to are:</p> <ul style="list-style-type: none"> • Flood • Earthquake • Tsunami • Volcanic activity • Wind 	<p>Risk:</p> <ul style="list-style-type: none"> • Low • High • Medium • Low • Low
	Disaster recovery plans are held in the Horizon Energy disaster recovery quality manual.	
Network Impact Risk	Kope is critical to Whakatane urban area and supplies 21% of the network.	Limited support from Station Road.
Human Habitation Risk	Kope is normally an unmanned site.	<p>Electrified security fence to deter unauthorised access.</p> <p>Access door alarms to SCADA.</p>
External Services	<p>Power is supplied from the Kope substation local service transformer.</p> <p>There is no telephone at the substation. All critical services are on 24 volt battery banks.</p>	

Table 5.44 - Substation Vulnerability

5.12.8 Kope Substation Feeders

Kope substation feeders are summarised in Table 5.45 below:

Feeder	Rex Morpeth	Strand North	Strand South	King Street	Victoria Avenue
Type	Urban	Urban	Urban	Urban	Urban
Overhead (km)	0.6	0	0.24	0.6	5.6
Underground (km)	5.3	6.3	6.8	4.2	2.6
ICP Connections	878	1085	921	1000	1388
Substations	23	24	18	15	18
Installed Tx Capacity (MVA)	6.3	6.9	6.1	4.5	3.9
Maximum Load Amps	170	182	217	140	177
100 Peak Load	154	163	179	121	151
5 year average growth rate	-1.8%	2.3%	1.4%	7.2%	-0.6%
Feeder Utilisation at Average 100 Peaks	55%	43%	54%	43%	40%

Table 5.45 - Kope Substation Feeders

5.12.8.1 Rex Morpeth Feeder

- Urban supply feeder, mostly underground;
- The feeder supply cable exiting from Kope substation was upgraded to 300sqmm in 2012;
- The Rex Morpeth feeder had shown an above average load growth over the past three years but this growth has slowed down with load re-allocations to Strand North;
- The region supplied by Rex Morpeth has been predominantly zoned business 1 and business 2 within the Whakatane District Council District Plan; and
- Peak maximum loads are due to reinforcement of the Strand South feeder by this feeder.

Constraints

- The Rex Morpeth feeder is approaching its maximum rating when used for supply reinforcement for the Strand South feeder. The Strand South feeder does not have sufficient spare capacity to fully reinforce Rex Morpeth feeder whilst supplying its own load;
- A new 185sqmm tie cable was installed in 2011-2012 along Douglas Street onto the high capacity Mokorua feeder supplied from Station Road. This link provides a second reinforcement option for the Rex Morpeth feeder. Some existing sections of the 95sqmm cable restrict full 100% level of reinforcement; and
- Load sharing between Mokorua and Strand South does provide full reinforcement.

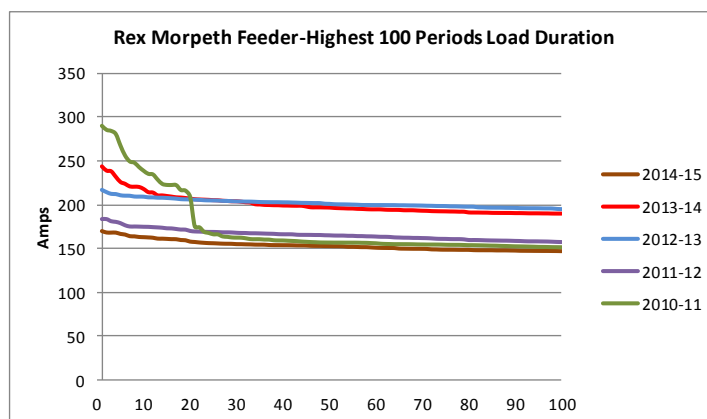


Figure 5.37 - Rex Morpeth Load Curves

5.12.8.2 Strand North Feeder

- Strand North feeder has seen positive load growth as commercial confidence increases and empty commercial premises are occupied; and
- The Strand North and Strand South feeders provide reinforcement support to each other at four separate tie points.

Constraints

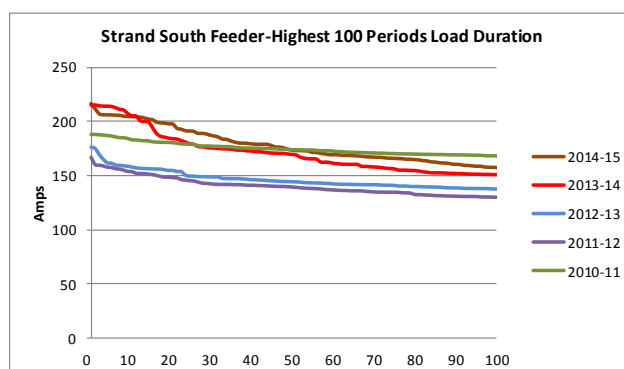
- There are currently no constraints with this feeder.

5.12.8.3 Strand South Feeder

- Steady annual growth is predominantly commercial driven

Constraints

- During peak periods Strand South does not have sufficient capacity to fully reinforce Rex Morpeth feeder. Some sections of the 95sqmm conductor have been scheduled for loading driven replacement.

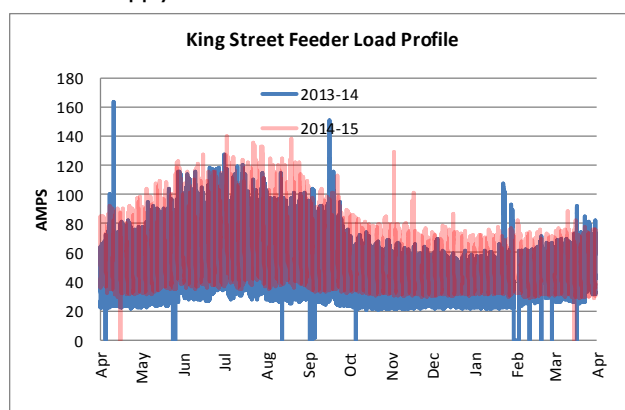


5.12.8.4 Victoria Feeder

- 6MVA tie cable across the Landing Road Bridge to the Piripai feeder provides reinforcement to the Hub and Coastlands domestic loads from Kope;
- Load is predominantly domestic. There are two schools on this feeder;
- Load growth has been above average over the past few years, attributable to infill housing, and re-distribution of load at the hospital. Winter load is increasing which may be driven by domestic heat pump installations; and
- The Victoria feeder has no known supply constraints.

5.12.8.5 King Street Feeder

- Load growth is due to hospital refurbishment additional load;
- King Street feeder supplies the Whakatane Kope business and local domestic areas;
- Primary feeder to the Whakatane Hospital; and
- There are no known supply constraints.



- King Street feeder has had addition allloads installed following the hospital rebuild

5.12.8.6 Faults and Outages

- Rex Morpeth feeder has had no equipment failure outages during the previous ten years; and
- Partial discharge testing of ringmain units has identified a number of potential faults that have been averted by proactive repairs.

5.12.9 Kope Substation and Feeders Development Plans

Kope loading

The load management plan for Kope substation is to distribute the existing load between Kope and Station Road substations in the short term, and once completed, the proposed CBD substation in the longer term. The Kope substation will be predominantly re-configured to supply the Whakatane CBD from the three existing 11kV feeders that run to that area.

The new Kope T2 transformer installed 2013 was sized using a 50 year expected life. Loading calculations determined that two 24MVA transformers were the appropriate sizes to support the future loads, but for Kope substation to support a 24 MVA transformer the switchgear, 33kV, and 11kV feeders would all need replacing, as well as additional distribution feeders installed. A better solution that provided more versatility and had a better NPV return is to procure smaller 16MVA transformers for Kope that match the existing installed distribution, and to develop a 16MVA substation located in the Whakatane CBD to cater for additional loads in the future.

Until a CBD substation is established, load sharing between Station Road and Kope substations will be used to manage load. Load prediction data for the combined substations is included in Section 5.4, Demand Forecasts. If Station Road and Kope are considered as four separate transformers supplying common loads then the n-1 capability of the two sites combined is 33MVA.

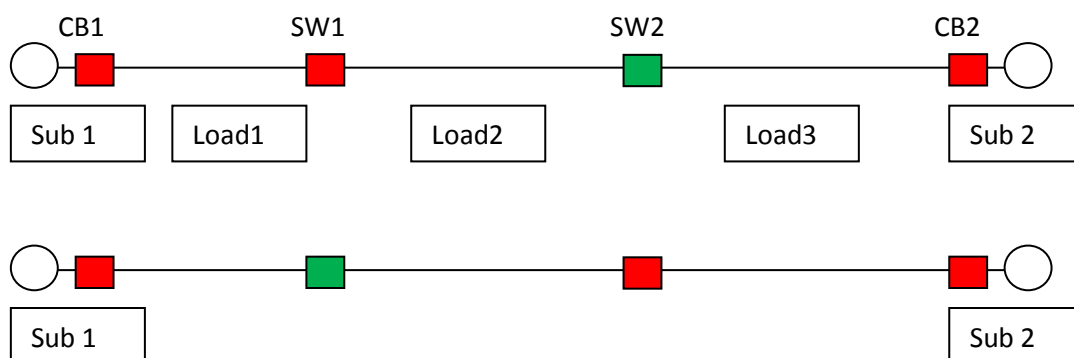
To enable the load to be moved between Station Road and Kope, various sections of feeder conductor have been identified for upgrade to enable greater load carrying capability. Ultimately, automated switches and/or circuit breakers with intelligent protection schemes between the three substations will enable the operators to selectively switch load as required in the case of overload or loss of main supply.

Automated Load Transfer and Fault Restoration

A simple way to describe this principle to share the load is shown below. Automated switches or circuit breakers at I/3 or similar points on feeders between the substations allow the load to be shifted between substations by opening or closing the switching devices.

If the devices are circuit breakers with intelligent protection the line could be run in an open or closed ring configuration with both ends live, with the protection controlling the switching. If switches are used, SCADA can provide the intelligence and operate switches if the load exceeds predetermined levels.

In the following sample, SCADA, monitoring the load at both Sub 1 and Sub 2, detects that load has exceeded the pre-set parameter at CB1, and that CB2 has capacity to take the load beyond SW1, so automatically closes SW2 then opens SW1 to transfer load 2 to Sub 2.



The same principle can be applied to faults on meshed circuits. If the load through each switching point is known then logical decisions can be made to transfer the load to match the supply availability.

All switchgear currently being installed is either capable of SCADA control or capable of being upgraded to SCADA control.

Feeder Development

Certain feeder conductor sections have been identified for upgrade as the load approaches the reinforcement capability of the feeders. Replacement is scheduled when feeders, under reinforcement, exceed 110% of the cable section capacity. Load growth is continually monitored to determine timely scheduling for replacement of cable sections.

Horizon Energy runs an overhead to underground conversion plan in conjunction with the Whakatane District Council and the Eastern Bay Energy Trust.

Kope T1 and T2 Replacement

Kope T2 transformer was replaced in 2013 with a 12/16 ONAN/ONAF transformer.

With the substation peak load exceeding 15MVA the substation still does not achieve a 100% N-1 capability. The only way to achieve this is to replace T1 and continue with the off-loading of loads to other substations. Replacing the T1 transformer would provide an opportunity to have matched low impedance transformers for improved load sharing. This project, coupled with removal of the outdoor 33kV bus and installation of 33kV indoor circuit breakers. This would transform Kope into a modern, n-1 capacity substation with a planned life of 50 years.

The T1 transformer, scheduled for replacement in 2044, could easily be relocated and is a good match for:

- New CBD substation; or
- New Gateway Substation; or
- Ohope Substation T1 replacement.

Current planning is to complete a Kope 33kV indoor conversion, freeing up real estate to install a matching transformer for T2, and relocating Kope T1 to Ohope.

The 33kV indoor conversion is driven by a risk assessment completed in 2011 which identified a number of issues with the Kope substation. In summary, the major risks identified are:

- a) The small spacing between the two 33/11 kV transformers and proximity to the control building creates a common fire/explosion risk. This has been partially resolved with the placement of the new T2 transformer.
- b) There are no oil containment bunds for the T1 33/11 kV transformer.
- c) The 33kV bus section minimum access clearances are an identified risk.
- d) The 33kV circuit breakers are minimum oil breakers.
- e) Age of the 33kV circuit breakers

Procurement of a transformer matched to T2, complete with bio-degradable synthetic oil which is fire retardant would resolve the fire risk as well as reducing the environmental impact.

5.13 Ohope Substation

5.13.1 System Description

The Ohope substation is a bank of four single phase 1.33 MVA 33kV/11kV transformers located at Maraetotara Road, Ohope. The 9.3km, 33kV Dog conductor sub-transmission circuit that supplies this site is supplied from the Te Rahu substation.

Pohutukawa and Harbour feeders are supplied from Ohope substation.

5.13.2 Service Area Covered

Pohutukawa	West from Ohope substation. Predominantly overhead but underground along West End. This feeder has a tie point connection to the Station Road substation via Mokorua feeder.
Harbour	Supplies the region East of the Ohope substation and supplies about 1500 customers. This feeder is also a mix of overhead and underground and supplies the Cheddar valley rural as well as the Harbour/Ocean Road urban areas of Ohope. This feeder is supported by its connection to the Pohutukawa feeder and an out-of-phase connection to Waimana feeder supplied from Waiotahi substation.

Table 5.46 - Service Areas Covered



There have been issues with the tap changer mechanism and controls over recent years with contactors, motors mechanism failures and a number of persistent oil leaks.

The substation is being considered for a full rebuild with new 33kV bus, indoor 11kV with four feeders, and Kope T1 transformer relocation to Ohope.

5.13.3 Description of Assets

Table 5.47 summarises the major assets within the Ohope Substation:

Asset	Description	Rating Data	Date of Manufacture	Comments
33kV Circuit Breaker CB80	English Electric OKW3, minimum oil	600 amp, 17.5kA Is		Poor condition. Scheduled for age/condition based replacement.
33/11kV Transformer T1	4 * 1 phase Bonar Long	1.667 MVA ONAN 8.46%, Dyn11	1962	Current plan is Kope T1 relocation to Ohope around 2018
T1 Tap changer	4 * Fuller Electric type EH	33kV, 76 amps 15 steps – 6.25+12.5%	1962	Will be replaced with Transformer mounted tap changer.
11kV CBs	Cooper Power Nova 15		2014	
Control Building	60m ² Concrete block building		1978	No issues.
SCADA	Leeds and Northrup (Foxboro)		1991	Replacement with industry standard DNP3 capable devices has been scheduled.
DC Battery Bank	Switchtech 24V			No issues.
Local Service	ABB transformer 30kV		1980	
33kV Protection	GEC Multilin SR760	Transformer Protection	1999	Due for replacement by 2019
Tap Change Controller	Reyrolle SuperTapp RVM/5m		1991	Tap change controllers are approaching end of service life, although no reliability issues are being experienced.
Communications	Exicom Hawk 450Mhz UHF radio			Radios are scheduled for replacement to IP radios on the same frequency

Table 5.47 - Ohope Substation Assets

5.13.4 Substation Utilisation

Peak demand is above the network average and load growth is seteady. A 32 home subdivision is currently under development on Harbour feeder.

Ohope -Load Statistics (MW)							
	2012	2013	2014	2015	% increase 2014-15	Avg incr per year	n Utilisation
Maximum	4.2	4.4	4.1	4.4	7.5%	2.2%	89%
Average	1.53	1.61	1.59	1.59	0.4%	1.3%	32%
Average-Top 100 Periods	3.6	3.8	3.7	3.8	1.4%	1.3%	76%

Table 5.48 - Ohope Load Statistics

5.13.5 Load Growth

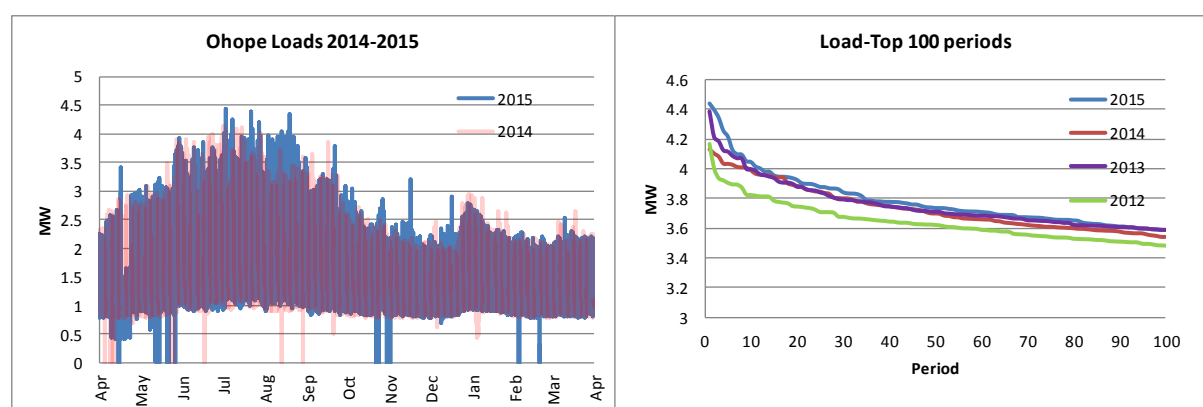


Figure 5.38 - Ohope Load Curves

There is potential for up to 250 domestic residences at the harbour end of the Ohope spit. Once developed, this could add another 6-800kW of peak demand to Harbour feeder. In the longer term higher density domestic developments could be expected for Ohope, especially on the Pohutukawa feeder.

There is on-going development of lifestyle blocks and quality housing being built in the peninsulas that overlook the Ohiwa Harbour. The Ohope load demonstrates a peak over the December-January holiday period.

5.13.6 Constraints

- The 33kV feeder to Ohope is a single point of supply risk; and
- Ohope has reinforcement from the Station Road substation via the tie between the Mokorua and Pohutukawa feeders which are low quality, with voltage support issues duiring high load periods.

The Mokorua feeder was upgraded in 2009 to help improve the voltage profile when supplying Ohope. However, during high loads there is likely to be voltage quality issues at the Eastern end of the Harbour feeder under reinforcement conditions.

Enhanced maintenance of the Ohope 33kV feeder is still the most cost effective means of providing security of supply to Ohope, although the strengthening of ties between both the Station Road and Waiotahi substations is still required to improve support to Ohope.

A possible new substation between Ohope and Whakatane in the Mokorua region would provide support for Ohope as well as catering for any development on the land block between Otarawairere and Whakatane. Any such substation would only be developed if the load in the area dictated.

There are no load constraints with the Harbour feeder supplying the domestic region, but the harbour side of this feeder has no alternative supply. A project to split the feeder and install a third feeder out of the Ohope substation as support started 2013 and is partially installed. This will be factored in to any substation development works.

The section of the Harbour feeder through to Waimana is small Ferret conductor and whilst the conductor is physically capable of carrying the Ohope load the full load voltage drop makes this an unsuitable feeder for supplying the full Ohope substation load. Support is really only available for the Harbour feeder load with some loss of quality along the harbour end of the feeder. There is also a phase shift between these two feeders which requires a break before make scenario.

A second feeder has been planned to split the heavily populated Ohope Harbour feeder. This was started in 2012 but will not be able to be completed until the development of Ohope indoor 11kV switchboard, scheduled for 2021.

5.13.7 Lifeline Risk Assessment

Vulnerability	Ohope	Mitigation
Total Loss of Ohope Substation	Ohope substation is a single feeder substation with one three phase transformer.	Limited reinforcement at peak loads from Station Road and Waiotahi.
Communications	Primary communications to Ohope substation is by a single link UHF radio from Putauaki radio repeater site. Communication is used for remote control of switching operations, load and security monitoring.	Not critical for operation as systems can be operated manually.
Site Access Requirements	Access is required in the case of: <ul style="list-style-type: none"> • Loss of communications • Abandonment of Commerce Street control room • Non operation of equipment 	Roads accessing the site are Pohutukawa Avenue East from Wainui, Opotiki and West from Whakatane. There is sufficient clear area to land a helicopter near the Ohope substation site if required.

Vulnerability	Ohope	Mitigation
Natural Hazards	Natural hazards that the sites could be exposed to are: <ul style="list-style-type: none"> Flood Earthquake Tsunami Volcanic activity Wind 	Risk: <ul style="list-style-type: none"> Low High High Low Low Disaster recovery plans are available to all staff.
Network Impact Risk	Supplies 8% of the network customers, mostly urban.	
Human Habitation	Ohope is an unmanned site.	Access door and window alarms to SCADA.
External Services	All critical services are on 24 volt battery banks.	

Table 5.49 - Lifeline Risk Assessment

5.13.8 Ohope Feeders

Ohope substation feeders are summarised in Table 5.50 below:

Feeder	Harbour	Pohutukawa
Type	Urban, Rural	Urban
Overhead (km)	44.4	4.0
Underground (km)	14.0	6.6
ICP Connections	1291	739
Substations	127	20
Installed Tx Capacity (MVA)	7.2	3.1
Maximum Load Amps	114	112
100 Peak Load Amps	98	95
Growth Rate	-5.4%	8.8%
Feeder Utilisation at Average 100 Peaks	35%	34%

Table 5.50 - Ohope Substation Feeders

Both feeders are a mix of overhead and underground. The growth rate is positive which is consistent with organic growth. There are no load constraints with either feeder. The feeders cross support each other adjacent to the substation and network configurations in 2014-15 have allowed the feeder loads to be better balanced as can be seen from the growth rates above.

5.13.9 Fault Analysis

Faults on these feeders have a high SAIDI impact due to the population density. Restoration time is relatively short for Pohutukawa due to the ability to mesh with Harbour and Station Road, but the Harbour feeder has no ability to reinforce the urban section.

5.13.10 Ohope Development Options

Ohope is a difficult area to reinforce with a single 33kV feeder into the area and having a single transformer substation. With the eventual load driven upgrading of Ohope TI there are different options to upgrade the transformers and to address the Ohope support issue.

The table below introduces considerations to different options for Ohope reinforcement alternatives.

	Upgrade Options	Advantages	Disadvantages
1	Replace TI with a larger transformer	Most economic option. Good fit onto existing site. Can be installed while the existing bank is still in service.	No transformer redundancy. No 33kV redundancy.
2	Install a second 5MVA bank at Ohope	Provides good redundancy but will not provide redundancy at peak load beyond 2017 (load control will extend this to 2022).	Existing site would need to be expanded to accommodate two three phase banks.
3	Install two 7.5/15MVA transformers (or larger)	Provides ideal solution for transformer redundancy. Good security of supply beyond 2050. Can fit on the existing substation site if staged.	Costly option. Low transformation utilisation ratios. Does not solve the single 33kV supply issue.
4	Install one 7.5/15 MVA transformer at Ohope and one 7.5/15MVA transformer at Mokorua	Provides split substations. Provides backup supply from a separate 33kV sourced transformer. Mokorua transformer can be used to support Mokorua and Hillcrest area through to the Whakatane Heads. Mokorua substation can be used to reduce load at Kope.	More costly than option 3. Requires new 33kV line to Mokorua. This can be along existing 11kV route. Would require upgrade of Pohutukawa feeders to be able to support Harbour feeder.
5	Install 110kV supply to Ohope off the Waiotahi line and install 110kV/11kV sub or 110/33/11kV sub	110kV Line route relatively easily achieved. Could provide better reinforcement to Waiotahi if established at 33kV. Very long term lifecycle solution.	Very high cost. Potential easement issues with 110kV line. 110/11kV introduces phase shift to Station Road but eases phase shift to Waiotahi. Cannot be considered in isolation to Waiotahi and Kope development plans.

	Upgrade Options	Advantages	Disadvantages
6	Install one 7.5/15MVA transformer at Ohope, one 5MVA at Mokorua, and one 5MVA at Kutarere	<p>Would integrate well with Waiotahi, Ohope and Kope development plans.</p> <p>Provides support from two auxiliary substations in case of a loss of 33kV to Ohope.</p> <p>Ohope can also support both other substations.</p> <p>Can be staged over several years.</p>	<p>High cost. Possible to contain costs by re-using Kope 5MVA banks, although these are old and not recommended.</p> <p>Requires Waiotahi/Opotiki project to be completed.</p> <p>High cost for 11kV and 33kV conductor upgrades to move energy between the three sites.</p>
7	Install diesel generation to support the load	<p>Relatively easy solution.</p> <p>Can be used for peak lopping.</p>	<p>High capital cost.</p> <p>High ownership cost.</p> <p>High kWh generation cost.</p> <p>Would require additional support as load grows.</p> <p>Creates stranded assets.</p> <p>Noise and consents.</p>

Table 5.51 - Ohope TI Load Driven Replacement

The preferred option is to replace Ohope bank with a single transformer, Option 1. This single transformer would work well in conjunction with Option 6, staged over a number of years, to provide a long term solution that would provide firm reinforcement for Ohope until beyond 2040. The Kope TI 10/13 MVA transformer could be used instead of a new 7.5/15 MVA.

As the existing bank can sustain a 130% overload for up to 4 hours without damage (per IEC60354), then a load driven upgrade can be deferred well into the 2020's. Tap-changer reliability will invariably be a principal driver for replacement.

Alternatively, Option 1 is installed initially, and a second transformer can be installed at Ohope once the load increases beyond the capability of the 11kV reinforcement from Station Road to support the load. This enables the existing single phase transformers at Ohope to be retired.

5.14 Opotiki Substation

5.14.1 System Description

Opotiki substation is a proposed development located at Opotiki to address load and quality constraints currently identified with the Waiotahi system. The project is triggered by two large Kiwi Fruit packing plants at Opotiki planning expansions of their local operations. They have requested from Horizon Energy Distribution Limited (Horizon Energy) a combined increase in supply of approximately 1 MVA in 2015 and another potential 1 MVA within two years.

Following several options studies an 11kV distribution bus is being established in 2016 to put in place the infrastructure for a subtransmission supply and transformers by 2019.

The first stage (Stage 1) of the project maximises utilisation of the existing distribution feeders by meshing them onto an 11 kV bus in Opotiki. This requires development of a green-field substation site and installation of an indoor 11 kV switchboard. Stage 1 allows an additional 3-4 years extension before the need to implement Stage 2.

The second stage (stage 2) is a long term solution for reinforcement of the transmission at either 33 kV or 110 kV.

Stage 1 of this project is required to be completed by November 2016, followed by Stage 2 in 2018-19. The ultimate configuration includes the establishment of a two transformer substation site.

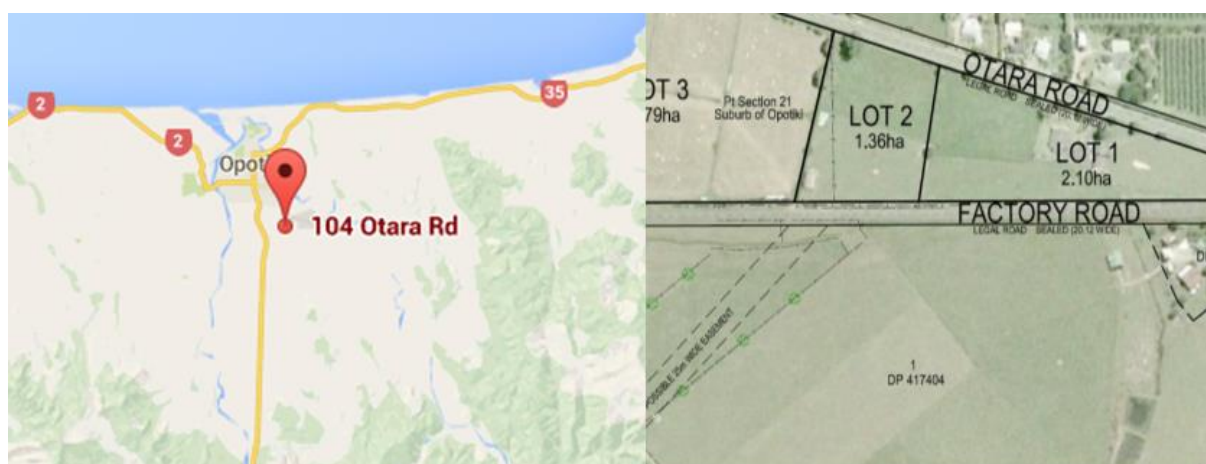


Figure 5.39 – Location of Opotiki Substation

5.14.2 Feeder Description

The location of the site provides ready access to three feeders, two of which can be split into two, providing 5 feeders. Three of the feeders will initially be connected to Transpower's Waiotahi GXP providing the supply to the 11kV board until the sub-transmission is established.

5.14.3 Sub-Transmission

Subtransmission has not been finalised for the site, so the site development plan has several options for configuration depending on the ultimate development. Factors affecting the sub-transmission decision include:

- Accessibility to the existing 50kV Transpower line.
- Transpower willingness to provide sub-transmission supplied from Waiotahi.
- Ownership of the existing Transpower assets, including Te Kaha assets.

- Relative development costs between 110kV or 33kV, or other viable voltages, including associated easement costs.
- Relative costs and quantity of large power transformers.
- Load growth assumptions affecting the anticipated life of a single 33kV feeder before a 2nd feeder is required.
- Regulatory Asset Base (RAB) costs differences between a Transpower funded development and Horizon Energy investment to provide the best result for the customer.
- Valuation of the Transpower assets.

5.15 Plains Substation

5.15.1 System Description

Plains substation, located adjacent to the Transpower Edgecumbe grid exit point is used to supply the surrounding rural area, parts of Edgecumbe town, and is a back-up supply to the Fonterra milk products factory.

The rural load profile is dominated by the influence of dairying which sees a load increase in August each year and a summer peak profile. There is little urban load connected to this substation. Due to the proximity to Edgecumbe GXP 33kV bus the fault levels are high.

Plains substation is made up of three single phase transformers with a fourth transformer available on site as a spare. Transformers are scheduled for replacement 2016 with a three phase 12/16MVA unit.



5.15.2 Service Area Covered

Plains supply the wider Edgecumbe rural area from four feeders.

Awaiti Feeder	Awaiti feeder supplies the Plains area through to Braemar Road. There are a large number of small farm and lifestyle blocks supplied by this feeder. The feeder has tie point connections to Manawahe and Te Teko feeders as well as East Bank Road substation, West Bank and Thornton feeders.
Awakeri Feeder	Rural feeder that covers the area from SH30 Awakeri to McDonalds Road, has tie points to Te Teko and Thornton feeders. Predominantly small farm and lifestyle blocks.
Manawahe Feeder	Manawahe feeder runs to the West from Plains substation to Matata and beyond. The first section has very few customers with the customer base closer to Matata and to the West, and inland to Manawahe. The feeder has full capacity tie points to the Awaiti feeder and Thornton feeders.
Te Teko Feeder	Supplies the village of Te Teko and surrounding rural areas. Connection points to Kawerau Onepu feeder (phase shift applies) and the Awaiti and West Bank feeders.
Anchor 2	Alternative low capacity (4MVA) tie to Fonterra.
West Bank Feeder	Alternative high capacity (12MVA) tie to the East Bank Road substation.

5.15.3 Description of Assets

Table 5.52 summarises the major assets within the Plains Substation:

Asset	Description	Rating Data	Date of Manufacture	Comments
33kV Cable	Direct connect to the Transpower 33kV switchgear	240 mm ² Copper, XLPE insulated		No Issues
33/11kV Transformer T1	4 * 3.3 MVA single phase transformers Electromechaniche, 6.94% impedance	10MVA ONAN	1966	Distance between the transformers and to the switchroom does not provide sufficient space as an effective fire barrier. Transformers have no oil containment Replacement transformer scheduled 2015/16
T1 Tapchanger			1966	There have been problems in the past with the tap change mechanisms falling out of step.
11kV Distribution Switchboard	Reyrolle, LMVPT/QMRO vacuum circuit breakers, 8 panels 7 circuit breakers and bus coupler	Circuit breakers 630 amp Fault rating 25kA 3 sec Bus rated 1250 amps	1999	Blast resistant doors fitted 2011.
Control Building	Two structures, one 60m ² Wooden frame metal clad building and the other portacom		1991	
SCADA	Foxboro	P2	1991	System is obsolete with no spares. Scheduled for upgrade 2016
DC Battery Bank	Switchtech 24V		1991	No issues.
Local Service	ABB transformer	200kVA		No Issues.

Asset	Description	Rating Data	Date of Manufacture	Comments
Feeder Protection	SEL 351A		1999	IP conversion scheduled 2015
	SEL351		2015	P62 and P92
Tap Change Controller	Aeberle Reg DA		2009	
Communications	Fibre Optic loop Microwave radio to Pukehoeko		2013	
Ripple Control	Zellweger SFU-G/120	33kV injection	1989	Injected at 33kV controls all zone substations supplied out of Transpower Edgumbe. System is being assessed for upgrade options.
Ripple Control PLC Controller	Mitsubishi		1999	

Table 5.52 – Plains Substation Assets

5.15.4 Substation Utilisation

Plains –Load Statistics MW							
	2011/12	2012/13	2013/15	2014/15	% increase 2014-15	Avg incr per year	n-1 Utilisation
Maximum	6.5	6.5	10.1	5.9	-41.5%	-2.9%	59.2%
Average	3.17	3.41	3.20	3.21	0.3%	0.4%	32.1%
Average-Top 100 Periods	5.5	5.6	7.6	5.4	-28.5%	-0.3%	54.4%

Table 5.53 – Plains Load Statistics

Plains substation has a very flat annual profile due to the mix of dairy and domestic loads. There is a slight load increase due to irrigation between December and March. There are a large number of lifestyle blocks in the region which contribute to the domestic profile offsetting the rural demand.

Plains is a support substation for East Bank and Fonterra, and the high load seen in 2013/14 Table 5.53 above and Figure 5.40 below is when Plains supported East Bank substation during the East Bank substation rebuild outage in August 2013 and this does not occur in other years.

5.15.5 Load Growth

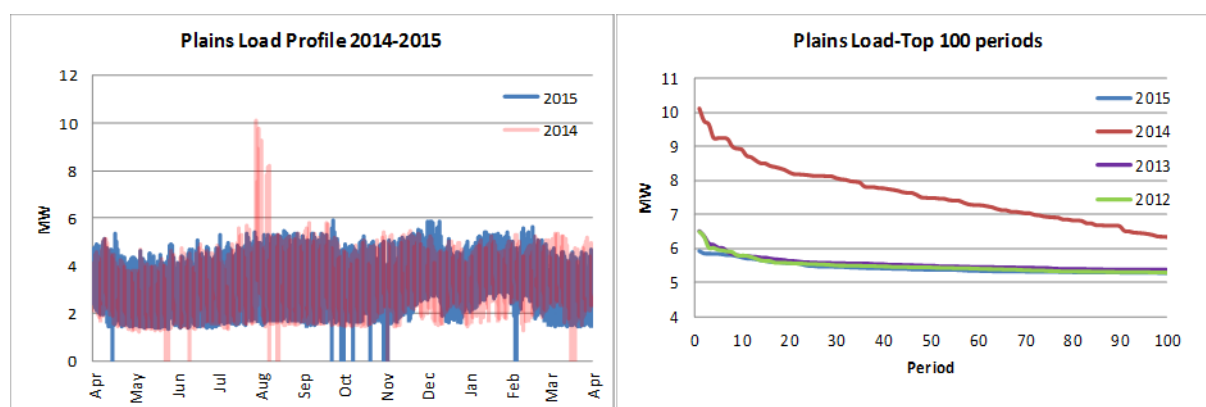


Figure 5.40 - Plains Load Curves

Organic growth is on par with the network average.

Constraints

If Plains is required to support East Bank with no Fonterra embedded generation available the total load exceeds 14MVA.

The Plains transformer bank has been scheduled for an early upgrade due to:

- Fire risk mitigation;
- Lack of oil containment;
- Potential overload during reinforcement; and
- Unreliable tap changer operation.

5.15.6 Lifeline Risk Assessment

Risks and vulnerability of Plains substation site from a CDEM Lifelines perspective are summarised in Table 5.54 below:

Vulnerability	East Bank	Mitigation/Risk
Total Loss of Plains Substation	The substation is a single feeder substation with one, three phase transformer bank.	Linked to East Bank Road substation at 11kV to provide full redundancy.
Partial Loss	Spare single phase transformer held on site.	Eight hour restoration onto spare bank.
Communications	Primary communications is by a single link UHF radio from Putauaki radio repeater site. Communication is used for remote control of switching operations, load, and security monitoring.	Not critical for operation as systems can be operated manually, with delays.
Site Access Requirements	Access is required in the case of: <ul style="list-style-type: none"> Loss of communications Abandonment of Commerce Street control room Non operation of equipment 	Roads accessing the site are Hydro Road South from Edgecumbe, and Hydro Road North from SH 30. There is sufficient clear area to land a helicopter near the substation site if required.
Natural Hazards	Natural hazards that the sites could be exposed to are: <ul style="list-style-type: none"> Flood Earthquake Tsunami Volcanic activity Wind 	Risk: <ul style="list-style-type: none"> High High Low Low Medium Disaster recovery plans are available to all staff
Network Impact Risk	Supplies 11% of the network – Rural plus urban Edgecumbe.	-
Human Habitation	Plains is an unmanned site.	Access door alarms to SCADA.
External Services	All critical services are on 24 volt battery banks.	-

Table 5.54 – Lifeline Risk Assessment

5.15.7 Plains Substation Feeders

Plains substation distribution feeders are summarised in Table 5.55 below:

Feeder	Awaiti	Awakeri	Manawahe	Te Teko
Type	Rural	Rural	Rural	Rural
Overhead (km)	77.7	40.6	133	94.8
Underground (km)	6.2	9.0	6.9	7.8
ICP Connections	538	446	769	871
Substations	183	146	224	215
Installed Tx Capacity (MVA)	8.1	7.75	6.7	8.2
Maximum Load Amps	129	82	70	93
100 Peak Load Amps	112	64	63	86
Growth Rate	2.4%	-8.6%	-3.7%	-0.8%
Feeder Utilisation at Average 100 Peaks	40%	23%	23%	31%

Table 5.55 – Plains Substation Feeders

Manawahe Feeder

Progressively upgraded since 2009, Manawahe feeder condition has progressively improved with a reduction in equipment related faults; however the feeder continues to be affected by vegetation faults. This feeder has winter peaks.

Te Teko, Awakeri and Awaiti Feeders

- Load growth is average compared to the rest of the network;
- Load is all rural with a mix of lifestyle and dairy farm blocks;
- There are a number of lifestyle developments along Braemar Road, as well as a water bottling and a water pumping scheme. Some irrigation has also been installed on the Awaiti, Awakeri, and Te Teko feeders. Awaiti feeder annual profile is shown in Figure 5.41 below; and
- High utilisation on all feeders is due to reinforcement to adjacent feeders.

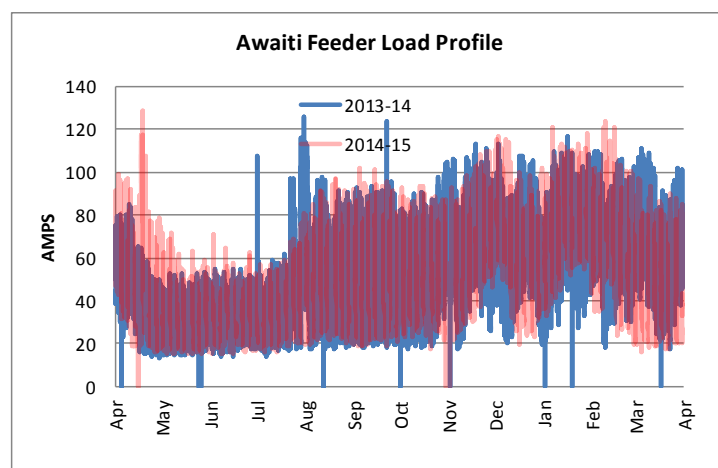


Figure 5.41 – Awaiti Load Profile

5.15.8 Faults and Outages

Manawahe

Historically, Manawahe feeder has been a poor performer. Due to its historical performance the Manawahe feeder was targeted in 2009 for a high level of expenditure on reliability improvement initiatives. The feeder has long sections of line that are rural and run through forested land so although the number of faults may not reduce, the SAIDI impact should improve.

Te Teko

The Te Teko feeder has had a number of vehicle impacts on SH30 between Te Teko and Kawerau in the past, as well as some intentional damage incidents.

Awaiti, Awakeri

Awaiti has traditionally been a poor performer with a number of the faults being due to vehicle impact. Tree and possum contacts are common around the Braemar Road area where there is a high density of vegetation.

Awakeri feeder covers flat ground and is relatively free of vegetation.

5.15.9 Plains Development Plans

Manawahe, Awaiti, and Te Teko are historically poor performing feeders, hence the high level of planned expenditure on these feeders.

5.15.10 Plains T1 Transformer replacement

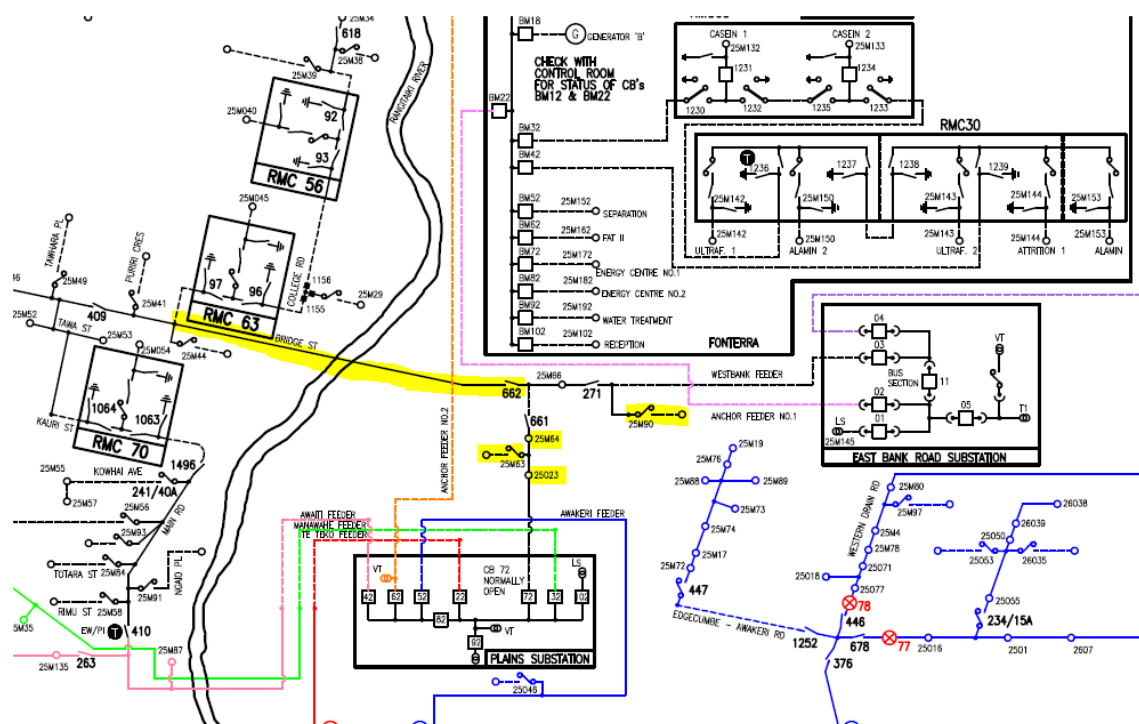
A risk assessment of the Plains substation in 2011 identified a number of issues. In summary, the risks identified are:

- a) The narrow spacing between the four 33/11kV transformers creates a common fire/explosion risk.
- b) There is no oil containment for the 33/11kV transformers.
- c) The ripple injection 33kV structure is too complex and busy with MAD issues.

Operationally the transformers are 49 years old as at 2015 and a new transformer has been ordered for installation in 2015-16.

5.15.11 Plains-East Bank tie feeder

There is an 11kV tie feeder between Plains and East Bank that provides the cross-substation support to each substation. Although used rarely, this feeder requires a high level of security as befitting an L2 supply. With the existing configuration of the West Bank feeder being supplied as a spur off this feeder, and having a number of transformers on the feeder as well, the supply is not as secure as it could be.



A project is under consideration to make the tie feeder a dedicated back-up feeder between the substations, reducing the feeder exposure risk by removing transformers and loads. Also under consideration is to provide a high capacity alternate feed to Fonterra off this feeder.

5.16 Station Road Substation

5.16.1 System Description

Station Road substation is a two transformer 10MVA 33/11kV zone substation located about three kilometres from Kope substation in the rural area of Poroporo, servicing around 3,400 customers. Station Road 33kV was direct cable connected to Te Rahu substation in 2010.



This substation services a mix of rural and urban customers.

Strong integration with Kope substation through the development of increased capacity 11kV circuits provides dual support between the two substations. A series of projects to strengthen the distribution feeders between the two substations was started in 2009 and will continue for some years to come.

Station Road substation is also the primary reinforcement substation for Ohope.

Te Rahu substation is integrated with Station Road for communications and provision of local service supplies. The communications network uses the Station Road node as a switching node to provide alternative routing between the communication repeater sites. The Station Road substation also houses the SCADA system disaster recovery equipment, which comprises a remote master station terminal and IT data backup equipment.

5.16.2 Service Area Covered

Station Road substation supplies the areas of Taneatua, Ruatoki, Mokorua, Coastlands, the Plains area out to Angle Road, SH30 to Awakeri and the Hub commercial development. Parts of the southern suburbs of Whakatane are supplied up to the open points on the feeders that interconnect to the Kope substation feeders.

The Mokorua Feeder was rebuilt in 2010 from an existing spur line off one of the existing feeders. Constructed with Krypton 152sqmm aluminium conductor, this feeder supplies the Mokorua domestic load and will provide a high capacity link to Ohope and to the Rex Morpeth feeder for reinforcement of Kope.

Angle Road	Angle Road feeder supplies the rural area around SH30, Angle Road, Powdrell Road, and provides a tie to support Coastlands. There are tie points to the Awakeri and Thornton feeders.
City South	<p>This feeder currently supplies the Valley Road and Mokorua domestic loads. Recent conductor upgrades have increased the capacity of this conductor to 8MVA but the 185sqmm aluminium cable at the substation limits the feeder to 6MVA. There are no plans to upgrade the 185 cable at this stage.</p> <p>The upgraded City South feeder will be used to supply some of the domestic loads currently supplied by the King Street feeder which will take some load off the Kope substation. It will also provide reinforcement to the Victoria feeder.</p>
Mokorua	<p>This feeder was constructed in 2010 from a spur line off the Piripai feeder and re-conducted with Krypton 152sqmm aluminium conductor.</p> <p>The purpose of this feeder is to provide a dedicated feeder to the Mokorua subdivision and then continue as a reinforcement feeder for the Ohope Pohutukawa feeder.</p> <p>Mokorua feeder has a 4MVA link to the Kope substation Rex Morpeth feeder to provide reinforcement to the Rex Morpeth and Commerce Street loads.</p> <p>City South is connected to Mokorua by a weak (35mm²) link at Hillcrest that provides limited support to the CBD and Heads area.</p>
Piripai	<p>Heaviest loaded feeder. Piripai feeder supplies the Hub commercial development and the Coastlands residential area. Has tie points to the Angle Road, City South, and to Kope's Victoria feeder.</p> <p>Tie points are automated between Piripai and Thornton feeders.</p>
Ruatoki	Ruatoki feeder supplies the Ruatoki rural region. This feeder is tied to the Taneatua feeder to provide cross feeder support. This feeder also has a low capacity tie to Waiotahi substation via the Waimana feeder but this supply is out of phase so the supply must be isolated prior to resupply.
Taneatua	Taneatua feeder supplies the Taneatua township and has a mix of domestic and rural loads. The Taneatua feeder is relatively lightly loaded. There are tie points to the Ruatoki and Mokorua feeders.

5.16.3 Description of Assets

Table 5.56 summarises the major assets within Station Road Substation:

Asset	Description	Rating Data	Date of Manufacture	Comments
33kV Cable	Station Road 1 Station Road 2	400A	2010	Soil thermal resistivity rating is 3K.m/W, tested in 2009. This de-rates the cables to 0.76 of their full load rating.
33kV Circuit Breakers	Areva GHA non withdrawable gas insulated	33kV 630 amp Fault rating 40 kA 3 seconds	2010	Circuit Breakers are located at the Te Rahu switching station.
33/11kV Transformer T1	Bonar Long	10 MVA ONAN 7.5 Z Dyn11	1966	Transformer has oil containment with an on-site oil water separator system.
33/11kV Transformer T2	Bonar Long	10 MVA ONAN 7.5 Z Dyn11	1966	Transformer has oil containment with an on-site oil water separator system.
T1 and T2 Tap Changer	Fuller Electric type F311-33/200	33kV 300 11 steps	1966	Maintained 2014
11kV Cable	Transformer T1 to switchgear	2 runs of 3 x 1c 185sqmm Al	1996	
11kV Cable	Transformer T2 to switchgear	2 runs of 3 x 1c 185sqmm Al	1996	

Asset	Description	Rating Data	Date of Manufacture	Comments
11kV Distribution Switchboard	GEC VMX Vacuum withdrawal circuit breakers	Circuit breakers 630 amp CB Fault rating 20kA, 3sec Bus rated 1250 amps 13.1kA	Board 1983 Circuit breakers 1996	Retrofitted with SEL 351A relays 1999. Switchboard has no forward arc flash containment for operator protection and is under consideration to improve operator safety. Bus kA rating is marginal for fault currents.
11kV Distribution Switchboard CB29	Reyrolle LMVP	630 amps 1250 Amp bus bars 25kA, 3sec	2010	Coupled to GEC switchgear with a busbar joggle chamber.
Control Building	77m ² concrete block building		1984	Good condition
SCADA	Leeds and Northrup (Foxboro)		1991	Hardware has exceeded the design life. Total data throughput capacity is limited by Foxboro proprietary communication protocol. Replacement with industry standard DNP3 capable devices has been scheduled 2014.
DC Battery Banks	Intergy Invensys 24V Switchtech 48V			Batteries replaced 2011.
Local Service	ABB transformer	200kVA		Local service transformer is connected to an ABB SD RMU onto Piripai feeder, with an alternative connection to Taneatua feeder.
33kV Protection	SEL 351S		2010	Located at Te Rahu switching station.
Feeder Protection	SEL 351A		2003	
Transformer Protection	SEL 787 differential relays		2010	
Tap Change Controller	Reyrolle RVM/5, RTMU/I		1991	Tap change controllers are approaching end of life, although no reliability issues are being experienced.

Asset	Description	Rating Data	Date of Manufacture	Comments
Communications	Exicom Hawk 450Mhz UHF radio Fibre Optic ring			Radios are scheduled for replacement with fibre optic link 2015.

Table 5.56 – Station Road Substation Assets

The switchboard is under consideration for risk mitigation over a number of safety issues;

- Bus fault withstand rating is too low;
- No arc containment for the front of the switchboard for operators;
- Some instances recorded in the UK with the circuit breaker resin housing failing with rapid degradation if potential discharge starts occurring;
- Control box needs to be replaced if any protection is replaced or arc flash detection equipment is installed

5.16.4 Substation Utilisation

Station Road –Load Statistics MW							
	2012	2013	2014	2015	% increase 2014-15	Avg incr per year	n-1 Utilisation
Maximum	10.4	9.9	9.6	10.0	4.3%	-1.4%	100.0%
Average	4.52	4.41	4.26	4.29	0.7%	-1.7%	42.9%
Average-Top 100 Periods	9.5	8.0	7.9	7.7	-2.6%	-6.5%	76.8%

Table 5.57 – Station Road Load Statistics

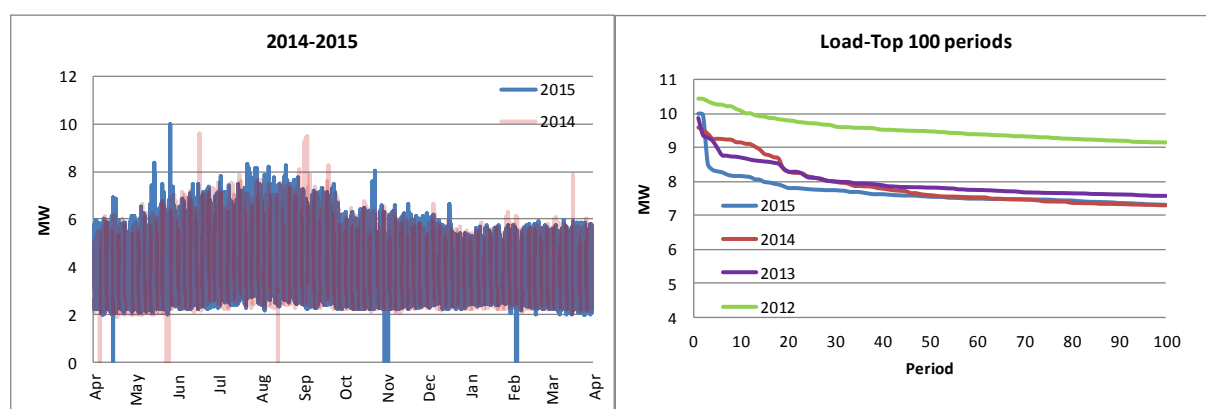


Figure 5.42 - Station Road Load Curves and Load Profile

The high increase in load growth 2011-12 was attributed to load shifting between Kope and Station Road.

For assessing organic load growth the total loads through Te Rahu are used to determine future load predictions due to the inter-dependencies and load transfers between Station Road and Kope substations.

5.16.5 Constraints

Station Road is a crucial substation for providing reinforcement support to Kope substation. Station Road has no load related constraints. Station Road load is being managed as part of an integrated load management policy with Kope and the future Gateway substations.

5.16.6 Lifeline Risk Assessment

Risks and vulnerability of Station Road substation are included in the Te Rahu substation section.

5.16.7 Development Plans

- The plan for load growth management is to share load between Kope, Station Road and the proposed future Gateway substation. This will be achieved by conductor replacements to increase the line capacity between Station Road and Kope to enable dynamic load transfer between the substations;

- The longer term view for the four sites, Kope, Station Road, and proposed Gateway or a CBD substation are to treat these as separate transformers with sufficient distribution capacity between the sites to enable any single transformer to be taken out of service, and have the other transformers carry the load. The current combined transformer capacity of Kope and Station Road is 49MVA with the combined load around 24MVA; and
- Transformers are scheduled for replacement 2022 and 2023.

5.16.8 Station Road Feeders

Station Road feeders are summarised in Table 5.58 below:

Feeder	Angle Road	City South	Mokorua	Piripai	Ruatoki	Taneatua
Type	Rural	Urban	Urban	Rural/Urban/Commercial	Rural	Rural
Overhead (km)	48.6	16.4	-	24.5	97.0	40.8
Underground (km)	6.5	7.0	-	8.4	7.4	1.5
ICP Connections	460	478	624	729	633	474
Substations	120	58	*	78	185	84
Installed Tx Capacity (MVA)	6.6	7.8	*	7.3	5.6	3.7
Maximum Load Amps	148	74	213	118	128	78
100 Peak Load Amps	76	61	124	106	86	46
Growth Rate	-0.4%	-7.5%	41.9%	-5.6%	0.4%	-4.3%
Feeder Utilisation Average 100 Peaks	27%	22%	44%	16%	31%	17%

Table 5.58 – Station Road Feeders

Angle Road

There are no issues with loading on Angle road feeder

City South

City South load has reduced because of load transfer to the Mokorua feeder. This feeder is a main tie feeder between Station Road and Kope and in 2011 the Mokorua urban loads were transferred to the Mokorua feeder.

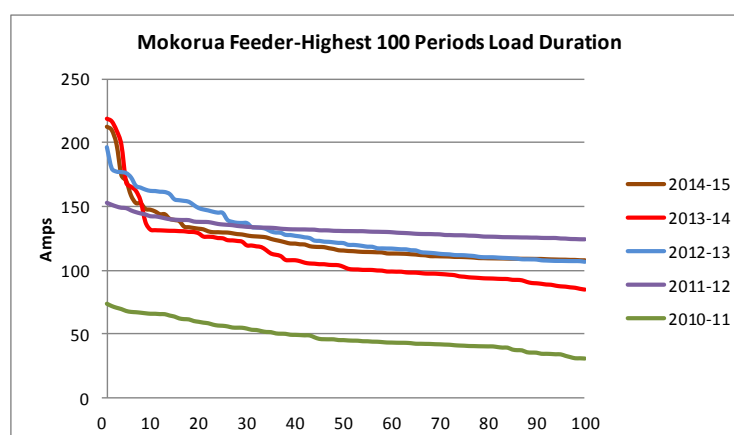


Figure 5.43 – Mokorua Load Profile

Upgrading the 185sqmm feeder supply cable at Station Road will allow the feeder to be used to capacity to support Kope via King Street and Victoria feeders.

Piripai Feeder

There are no load constraints with the Piripai feeder. The domestic region of Coastlands is supplied by Piripai which is reinforced by a high capacity cable tie to Kope substations Victoria feeder. Piripai has a commercial load profile, driven by the Hub commercial centre.

Ruatoki and Taneatua

These rural feeders have shown minimal growth. Ruatoki is more rural than Taneatua feeder which supplies the town of Taneatua. Peak load is driven by those times where the feeder is used for reinforcement of others and this is shown on the load duration curves. Utilisation is well within the capability of the feeders. Taneatua load growth is not expected to increase beyond the network average. Ruatoki is rural with a spring peak and load driven by dairy farming.

Mokorua Feeder

The Mokorua feeder was commissioned in August 2010 supplying initially an industrial pump load. Mokorua subdivision domestic loads have been added in 2011. Mokorua is the primary support feeder to Ohope from Station Road and high loads on figure 5.43 are from supporting Ohope loads.

5.16.9 Faults

Ruatoki feeder was a poor performer and more circuit breakers and sectionalisers were recently installed to improve the response to faults. The remaining feeders are performing well although Taneatua and Ruatoki have tended to have a number of vehicle impacts.

5.16.10 Station Road Development Plans

Station Road substation is relatively modern and in good condition and has had some major investment over the previous years. Projects planned for Station Road substation within the 10 year planning period are:

- RTU upgrade;
- Feeder integration with Kope substation;
- Protection relays age driven replacement; and
- Age driven replacement of T1 and T2.
- 11kV switchboard safety driven replacement is probable within the planning period

5.17 Te Kaha Substation

5.17.1 System Description

Te Kaha substation is a Transpower owned GXP substation located close to Te Kaha settlement on the East Cape peninsula, about 100km from Whakatane. The Te Kaha substation is supplied directly from a single Transpower owned 50kV line from the Transpower Waiotahi GXP. The Transpower substation supplies two Horizon Energy feeders; the Te Kaha feeder that runs to the South West and the Waihau Bay feeder that supplies the coast to the North East.

The Te Kaha system displays a relatively flat normal load profile but the peak is driven by the influx of visitors over the summer holiday period. The graph in Section 5.17.4 shows the impact of visitors to the area during the Easter and Labour weekend holiday periods.

The system suffers from some reliability issues due to the long Transpower line that supplies this location, the terrain that it runs through and the difficulty for staff to access the area due to its remoteness. Due to the small permanent load, small embedded generation plants may provide a viable short-term solution to quality of supply issues and short term peak loads. At this stage, apart from the use of temporary diesel generation, no generation systems have been installed within the distribution system.

Due to the line being located mostly in a coastal environment, there is an accelerated rate of corrosion and degradation of the conductors and transformers.

Transpower completed a transformer bank replacement at Te Kaha in 2014.

5.17.2 Service Area Covered

Te Kaha substation services approximately 1,020 customers and covers a region from South of the Motu River to East Cape, approximately 60 kilometres from end to end and supplies the coastal settlements of Te Kaha and Waihau Bay. The network has no links to other networks.

Te Kaha Feeder

The Te Kaha feeder runs South West from Te Kaha to West of the Motu River. A lot of the line is built over rugged terrain and is built parallel to the coast road but inland on private property.

Waihau Bay Feeder

The Waihau Bay feeder runs North East from Te Kaha, past Waihau Bay and on to East Cape. There are no alternative supplies for this feeder.

5.17.3 Description of Assets

Te Kaha Substation Assets

Horizon Energy owns no assets at Te Kaha. Communications to the site is planned for the Transpower Inter Control Centre communications project (ICCP) due to be commissioned winter 2015.

5.17.4 Substation Utilisation

The Table 5.59 and Figure 5.44 below show the load profile and load data for Te Kaha substation:

Te Kaha –Load Statistics (MW)						
	2012	2013	2014	2015	% increase 2014-15	Avg incr per year
Maximum	1.7	1.5	1.4	1.6	15%	-4%

Average	0.64	0.66	0.66	0.66	0.0%	0%
Average-Top 100 Periods	1.4	1.2	1.2	1.2	-3%	-3%

Table 5.59 – Te Kaha Load Profile

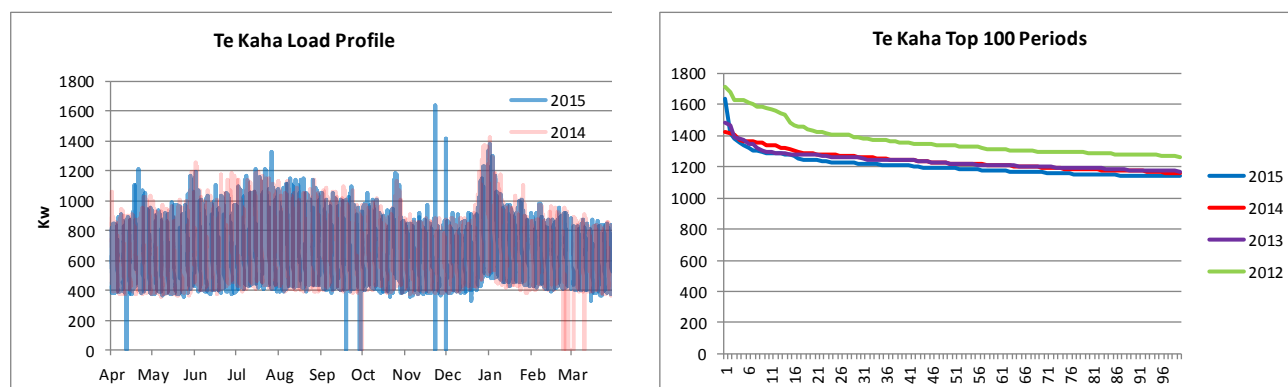


Figure 5.44 – Te Kaha Load Profile

5.17.5 Load Growth

There is limited capacity in the system to support additional large loads. At this stage the only indication of additional load to be added is 600kW due to a proposed irrigation scheme. Growth is 0% for the last three years.

5.17.6 Constraints

- The long 11kV distribution line of the Waihou feeder has end of line supply quality issues particularly at high loads;
- Due to the distance from the supply source and the manner that the 50kV is created at Waiotahi substation, the system has a low fault level. This poses issues in the clearance of earth faults on the system and is managed through the installation of intermediate sectionalising re-closing circuit breakers;
- There are high levels of line corrosion due to the proximity of the distribution lines to the coastal environment;
- The Transpower 50kV supply line has a poor performance history due to its nature of construction, the terrain through which it passes and land use issues;
- Summer load exceeds winter load; and
- Network is not meshed. Mobile generation can support the feeders. Horizon Energy owns one IMVA and two 300kVA generators, located in Whakatane.

5.17.7 Development Plans

Te Kaha substation is supplied at 50kV. This voltage is uncommon within the Transpower system and there has been discussion between the parties related to the conversion of the supply voltage to either 33kV or 66kV. This would allow for the line to be used as a feed to the Opotiki substation. The transformer installed by Transpower in 2014 has a dual wound primary winding, 33 and 50 kV.

The two 11kV distribution feeders are protected by Cooper Power KF circuit breakers owned by Transpower. Improved metering on the feeders is also being discussed with Transpower.

Horizon Energy has a set maintenance allocation budgeted for the Te Kaha distribution feeders each year to enable the progressive upgrade and replacement of sections of the lines to improve reliability.

5.17.8 Te Kaha Feeders

Table 5.60 below summaries the feeders out of Te Kaha substation:

Feeder	Te Kaha	Waihau Bay
Type	Rural	Rural
Overhead (km)	33.5	77.0
Underground (km)	0.3	0.4
ICP Connections	413	610
Substations	83	168
Installed Tx Capacity (MVA)	2.7	4.2

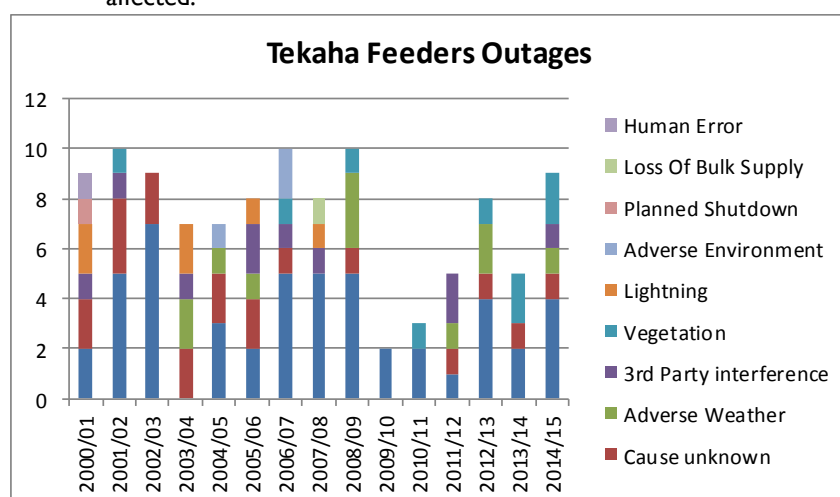
Table 5.60 – Te Kaha Feeders

The individual feeders are not metered. Load flow modelling indicates that the Te Kaha feeder is around 1/3 of the load flow of the Waihau Bay feeder. Feeder load is not an issue, but fault levels and voltage drop at the end of the lines are.

5.17.8.1 Fault Analysis

Due to poor communications, distance from support staff, and no meshing capability, all faults in the Te Kaha region tend to be long duration. Equipment issues have been cracked insulators or conductor faults. The fault level is very low so there is often insufficient energy available to actually destroy a cracked insulator meaning that it can take some time to find and resolve the fault. Increased maintenance started in 2009 on these lines appeared to have an effect on reducing the fault rate, but the indication from the chart below is that a further uplift in maintenance expenditure would be beneficial.

Additional feeder sectionalisers and circuit breakers have been installed over the period 2010-14 to enhance the ability to identify the location of faults and ensure that the least number of customers are affected.



5.18 Waiohahi Substation

5.18.1 System Description

Waiohahi substation is a Transpower owned 110kV to 11kV grid exit point substation. It is supplied by a single circuit 110kV line from Edgecumbe. The substation has two 10MVA 110/11kV transformers to provide an n-1 capability beyond the 110kV line.

Transpower has tentatively scheduled the end-of-life replacement of the transformers between 2019-2021.

Horizon Energy has four feeders supplying the Opoiki region supplied from this substation, providing power to over 4000 customers. The Opoiki area, to the East of Waiohahi, is fed via three 11kV feeders. The longest feeder is the Factory feeder that supplies the loads east of Opoiki. A fourth feeder runs west from the Waiohahi substation and supplies the Waimana Valley rural load.

Due to the location of Waiohahi with respect to the load centre that it supplies there are quality of supply issues at the ends of the feeders, especially when large loads are introduced to the system.

Waiohahi has no links to any other distribution systems to the East and only a weak 11kV connection to Ohope and Station Road substations to the West. This, along with the phase shift that exists to the West, leaves the network with limited additional support. Maintenance on the 110kV line requires a full line outage with a consequential extended area outage approximately every four years. Due to the loads generation is not a viable support option except for essential services. The next outage is scheduled for 2018.

5.18.2 Service Area Covered

Waiohahi substation services the Opoiki District from Waimana to Hawaii, including the Waiohahi, Waioeka, Motu and Otara valleys. The major town in the supply region is Opoiki, which is approximately eight kilometres from Waiohahi. The Waiohahi supply area is the largest geographical area covered by any single substation within the Horizon Energy system.

Factory Feeder

The Factory feeder is the longest feeder in the network with 266 kilometres of line. The dominant load on the Factory feeder is a Kiwifruit processing plant and cool store. This feeder is sectionalised and protected by three line breakers installed after Opoiki which isolate the various spur lines in the event of faults.

The Factory feeder includes two SWER circuits that extend supply into the inland regions of the area. The Waioeka SWER line was constructed in 1965, it is 37km long with 85 structures. The Toatoa SWER was constructed in 1966, it is 25km long with 63 structures. Both these circuits were constructed using predominantly larch poles. These poles are now 45 years old and are in poor condition, although a replacement project has replaced a large number of the worst condition poles.

There are a number of large kiwifruit frost protection pumping stations installed to the East of Opoiki which, when they operate, are affected by the low voltage levels created. These sites are required to be available to operate during the kiwifruit budding season of September to October if there is a likelihood of frost occurring. A voltage regulator was installed in 2010 to improve voltage regulation following a low voltage issue that occurred during the winter of 2009.

There are a number of large dairy installations and a small number of irrigation systems on the feeder but these do not appear to be causing issues for the network at this stage.

Hospital Feeder	Hospital feeder supplies the Northern part of Opotiki town and the Ohiwa and coastal region west of Opotiki. During winter the feeder has also been switched to supply the coastal region loads of part of the Factory feeder.
Opotiki Feeder	Opotiki feeder supplies the Southern part of Opotiki town and the Eastpack processing plant. When built, sections of this line were constructed to 33kV clearances, but insulated at 11kV. The feeder is one of the more reliable feeders in the network due to its predominantly urban load.
Waimana Feeder	Waimana feeder supplies the Waimana and Matahi Valley regions, and Ohiwa Harbour to Waiotahi beach. It has tie points on to Ohope substation Harbour feeder, Station Road substation Ruatoki feeder, Hospital and Factory feeders. The Harbour and Ruatoki feeder ties are automated. Both tie points are limited in their support capacity by sections of 50sqmm Ferret conductors but can provide full support for the Waimana feeder but not for the full Waiotahi substation loads.

5.18.3 Description of Assets

Waiotahi Substation Assets

Table 5.61 summarises the major assets owned by Horizon Energy within the Waiotahi Substation:

Asset	Description	Rating Data	Date of Manufacture	Comments
11kV Feeder CBs	Cooper Power KFE pole mounted	400 A; 6kA	1976	Replacement scheduled.
11kV CB129	Ripple Plant supply breaker, MK1A	Unknown		Obsolete circuit breaker. To be replaced
Control Building	Wooden frame metal clad		1976/1992	Average condition.
SCADA	Foxboro P2CPU			Retirement when Transpower ICCP project is completed
Local Service	ABB transformer ground mount	200kVA		Good Condition
DC Battery Bank	Switchtech 24 Volt			Good Condition
Feeder Protection	Cooper Power KFE electronics		1976	Scheduled for replacement. Timing is dependent on the development of Opotiki substation.
Communications	Exicom Hawk 450Mhz UHF radio			Retirement when Transpower ICCP project is completed
Ripple Injection Plant	Zellweger static inverter 315/750hz Type SFU-G3		1992	Study underway for replacement options.
PLC – Load Control Plant	Mitsubishi AIS with RCS RC02 Conitel communications interface		1996	Non-standard but no other issues.
PLC – Auto Reclose	Mitsubishi FI-60MR-ES			Obsolete. Tied to CB replacement.

Table 5.61 – Waiotahi Substation Assets

5.18.4 Substation Utilisation

Waiotahi – Load Statistics (MW)							
	2011/12	2012/13	2013/14	2014/15	% increase 2013/14	Avg incr per year	n-1 Utilisation
Maximum	11.0	9.2	9.6	9.4	-1.7%	-3.51%	94%
Average	5.1	5.2	5.1	5.2	1.9%	0.44%	52%
Average-Top 100 Periods	9.2	8.7	8.5	8.8	4.2%	-0.92%	88%

Table 5.62 – Waiotahi Load Statistics

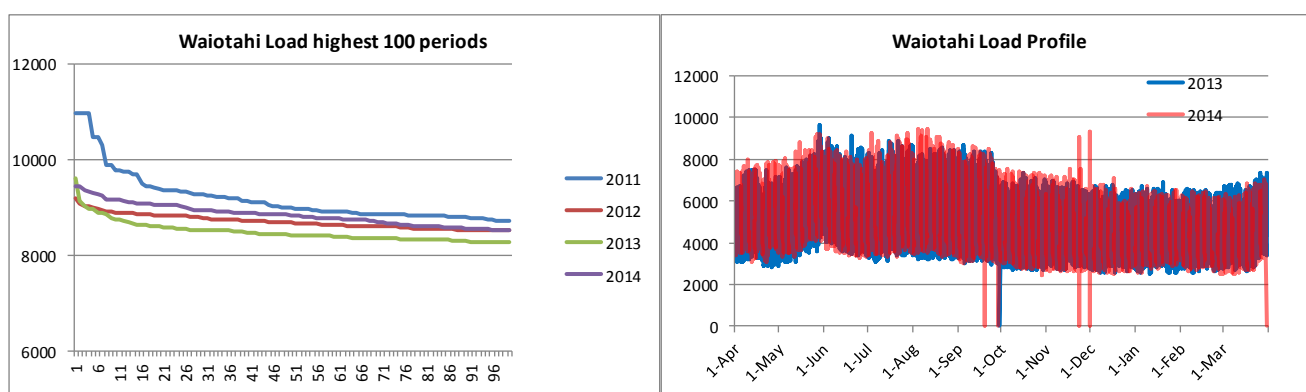


Figure 5.45 - Waiotahi Load Duration and Load Curves

Although the region has a mix of urban and rural loads, the load pattern is typically urban with higher winter and reduced summer loads. There are peaks in September and October that are driven by kiwifruit frost protection, which can add 1.8MVA of load to the network.

The majority of the frost protection is on the Factory feeder and this creates its own problems with voltage support.

There is a small amount of irrigation load on this system at this stage.

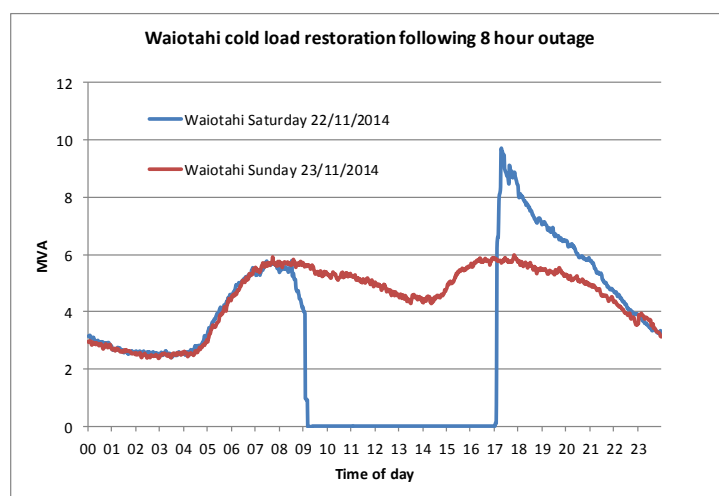


Figure 5.46 – Waiotahi Cold Load

Restoration

There is a small amount of irrigation load on this system at this stage.

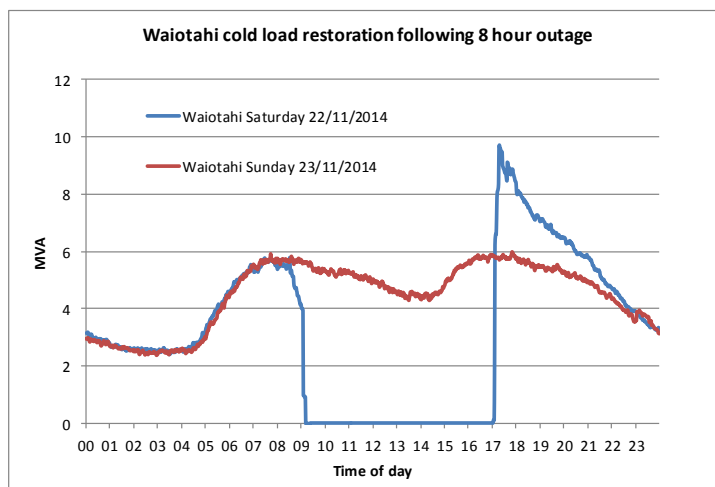


Figure 5.46 shows Waiotahi load before and after restoration following an 8 hour maintenance outage in November 2014, showing the cold load restoration spike after power was restored.

5.18.5 Load Growth

Waiotahi region kWh growth has averaged 1.5% per annum since 2003, but peak demand has averaged 2.9% per annum over the same period, with the last 5 years average being 0.9% per annum.

Two packaging plant chiller loads have been installed in 2015 with IMVA additional load at Opotiki with a further IMVA identified as being required in another two years.

Potential step load increases that have been proposed in the Opotiki region are an aqua farm development, up to 3MVA, a wood processing plant, IMVA, and if the Opotiki harbour development occurs to support the proposed off-shore mussel farm, there may be a growth associated with this.

Opotiki population growth is growing at a rate of 0.5% (Statistics NZ). Opotiki has seen growth due to kiwifruit and kiwifruit processing from 2015 onwards.

5.18.6 Constraints

The load to the East is increasing on the Factory feeder to the point that isolated cases of voltage collapse have occurred when frost protection systems are operating. This is currently managed by diverting load to the Hospital feeder and with the installation of a voltage regulator during 2010. This is only seen as an interim measure.

There is limited capacity to supply additional loads due to voltage support issues. Also the ability of the feeders to support each other is becoming limited at periods of peak load. An additional load of IMVA at Opotiki due to any of the possibilities identified above would severely strain the system.

The Waiotahi GXP has a summer peak loading capability of 12MVA per transformer. Peak load has exceeded 10MVA and is predicted to exceed 12MVA by 2016.

5.18.7 Development Plans

The location of a substation at Waiotahi is historical and does not reflect the optimal supply point for the system load as it now stands. The ideal location is to have a GXP or zone substation located in Opotiki. This is discussed further in Section 5.14

Voltage regulators are an option to support the voltage but these in isolation have limited use unless used away from the major loads to support remote areas. They do nothing to reduce feeder loading into Opotiki town, and they actually increase the peak load current and consequently voltage drop in the lines before the regulator.

Scheduled upgrades within the planning period:

- Waiotahi substation feeder circuit breakers;
- Ripple control unit;
- Local service supply;
- RTU and communications retirement; and
- Poletop circuit breakers around Opotiki.

These have all been identified as projects in the AMP 10 year project plan but are deferred until final decisions are made on the Opotiki/Waiotahi substation development projects.

5.18.8 Waiotahi Feeders

The Waiotahi feeders are summarised in Table 5.63 below:

Feeder	Factory	Hospital	Opotiki	Waimana
Type	Rural	Rural/Urban	Rural/Urban	Rural/Urban
Overhead (km)	258.3	39.0	17.3	124.0
Underground (km)	7.7	7.8	1.4	4.6
ICP Connections	1163	1344	937	869
Substations	414	110	34	228
Installed Tx Capacity (MVA)	16.8	9.3	7.0	7.3
Maximum Load Amps	167	139	179	101
100 Peak Load Amps	142	124	136	94
5 year average growth rate	1.0%	-6.6%	-1.1%	-1.7%
Feeder Utilisation at Average 100 Peaks	51%	44%	48%	33%

Table 5.63 – Waiotahi Feeders

Due to the load management between the feeders involving the re-allocation of loads to maximise the use of the voltage regulator, individual feeder load growth historical measurements are meaningless for forward prediction.

Factory Feeder

Peak loading of the Factory feeder is over 50% of the line rated current. Load has constantly increased on this feeder each year. Additional loads for kiwifruit packaging has been added in 2015 with more load planned in 2016. Planned 2016 load increases will require generation top provide voltage support during peakloads.

Opotiki Feeder

Utilisation growth during peak periods is high, as it is for all of the Opotiki area feeders. This feeder reinforces the Hospital and Factory feeders.

Hospital Feeder

Loads have dropped with loads being transferred to Opotiki feeder

The main concern with all three feeders is the peak load on the feeders and ability for the feeders to reinforce each other during high load periods without suffering excessive voltage drop. The planned Opotiki substation will remove these constraints by providing a central point to distribute from close to the load centre.

Waimana

The Waimana feeder has had minimal load growth over the five year period. Feeder loads are low and there are no load restraints on the feeder. If the regional development plan ends up with no 11kV substation at Waiotahi, which is an option, then voltage regulators will support the Waimana feeder supplied from the new Opotiki substation.

5.18.9 Faults Performance

Overall, the total number of faults had lowered significantly since 2002. The spike in faults 2009-11 were vegetation, which has been addressed with increased vegetation management. Overall the faults per 100km of feeder indicate that the recent strategies applied at Waiotahi are working.

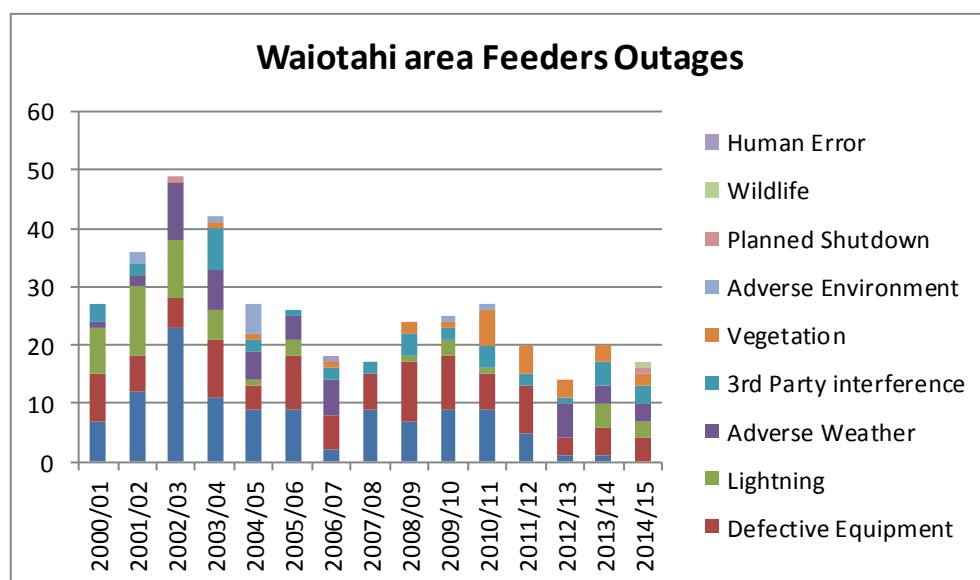


Figure 5.47 – Waiotahi Number of Faults

There were a number of lightning faults in 2013-14 that increased the fault count for Waimana this year, and an increased number of termination equipment failures on Factory. The number of defective equipment faults has been reducing.

5.18.10 Constraints

The Factory feeder is heavily loaded and suffers from voltage quality issues at the extreme ends of the feeder. Voltage swings between high load and low load are approaching the maximum voltage variation limits. A regulator was installed in 2010 to regulate the voltage on the Factory feeder East of Opotiki.

Reinforcement support for the Factory feeder is provided by both the Hospital and Opotiki feeders. With all feeders approaching 50% utilisation during peak periods, and predicated system load growth,

cross support between the feeders will require careful management during high load periods. Development of the Opotiki substation will alleviate these issues.

The Waimana 11kV system is out of phase with its two tie points to the Ohope and Station Road substations.

5.18.11 Asset Condition Assessment

Due to the Factory feeder running along the coastal region to the East of Opotiki the feeder does have some localised degradation where the assets are exposed to the coastal environment.

The Factory feeder has had a high percentage of its length condition assessed. The SWER lines have not been assessed, but of the 1259 sites assessed 65 (5.1%) were marked as requiring work within five years. A number of these are pole replacements, predominantly replacing river run poles. The rest are crossarm or guying issues. The map below (Figure 5.48) shows assets identified as requiring work within five years. Red dots are poles, blue dots are crossarms. The circled areas show assets that have been grouped into projects to overhaul complete line sections. As more condition data is received other areas will be grouped into projects.

In the Waiotahi network such projects are difficult due to the lack of meshed reinforcement and consequently a lot of the work will be completed using live line work crews and generation to maintain supply.

Four steel lattice towers on the Factory feeder are in poor condition. Maintenance will give the towers an estimated working life of 15 years. In lieu of maintaining the towers consideration is being given to replacing the towers with 23 metre concrete poles. These have a longer life and a smaller footprint.

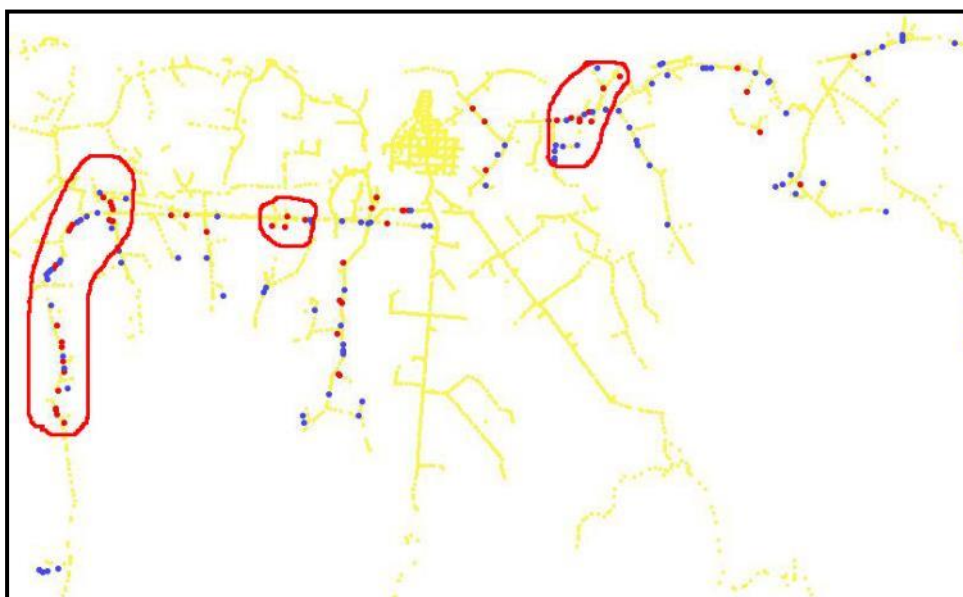


Figure 5.48 – Factory Feeder Pole Condition

5.18.12 Development Plans

Due to the Opotiki substation development proposed in section 5.14, planned upgrade works for all the feeders around Opotiki and exiting Waiotahi are held until the Opotiki substation concept plans are finalised. Continuing remedial work on existing assets, based on condition, are being scheduled, especially in areas where the work at Opotiki will not affect the feeder configuration. Where possible, tie points are being established around Opotiki to assist the meshing capability of feeders to enable work in developing the Opotiki substation to be completed with minimal disruption to supplies.

Reliability projects around Opotiki are deferred until decisions on the development of the Opotiki substation are finalised as this will likely alter the final configuration of the distribution system out of Opotiki. Reliability devices on the coastal part of the feeder will still be required and are scheduled to be installed from 2013 onwards.

5.19 Waiohau Transformer – Snake Hill Line

5.19.1 Description of Assets



A 500kVA, 33/11kV transformer is installed at Waiohau North in the Galatea valley, connected via fuses to the Snake Hill 33kV feeder. The valley where the substation is located is normally supplied from Plains Substation via the Te Teko feeder. The transformer was installed due to the radial and remote nature of this system in order to provide an alternative supply to this valley during contingency scenarios.

There are a number of operational restraints that need to be considered when this alternative arrangement is used. The Snake Hill 33kV line runs between the Edgecumbe 33kV bus and the Snake Hill switching station. Also terminated at Snake Hill are the two feeders that supply the Galatea and Kaingaroa substations and the line that runs down to the Aniwhenua Power Station. The supply configuration for Galatea is normally through the Snake Hill switching station from Aniwhenua.

The Waiohau transformer is energised at all times with a SCADA controlled breaker on the 11kV side of the transformer open. If the substation is required to be used for an alternative supply to the Te Teko feeder then this breaker can be remotely closed.

No on-load tap change provision is available on this transformer and the transformer is only used as an abnormal supply arrangement.

5.19.2 Development

There are no development plans for this substation.

Table 5.64 summarises the major assets within the Waiohau Substation.

Asset	Description	Rating Data	Date of Manufacture	Comments
33kV Bus	Snake Hill feeder	280 amps		
33kV Cable	185 sqmm AL 1x3c XLPE	33kV	1998	Used as connectors for the transformer to the line fuses.
33/11kV Transformer T1 25V011	Three phase Turnbull and Jones	500kVA ONAN 25.25 Amp 5.97% Z, Dyn 11	1966	Fixed tap 2.5%, 5 steps, 0-10%. Run energized with no load flow.
11kV Cable	25sqmm AL 3x1 core XLPE	11kV	1998	Used as connector between transformer and 11kV breaker.
11kV Circuit Breaker CBI77	Poletop mounted Cooper Power KFE with SCADA control			
Local Service 25V010	Poletop transformer	7.5kVA 1 phase		
Transformer Protection	33 kV Fuse			
Communications	Tait E band VHF radio			New 2012.

Table 5.64 – Assets Installed at Waiohau Substation

5.20 Fonterra Substation

5.20.1 Description of Assets

Fonterra substation is an 11kV substation supplying the distribution assets for Fonterra Edgecumbe. The 11kV distribution assets are owned by Horizon Energy with the demarcation point being the 400V terminals at the transformers.

The site has undergone various name changes over the years and is referred to in various documents both current and historical as Fonterra, Anchor Products, or Bay Milk Products, and abbreviations of the above.

The Fonterra system was developed in two stages. The initial development in 1988 included the development of East Bank Substation and comprised 11 circuit breakers and distribution transformers. The Cogeneration plant was added in 1997 along with a further two circuit breakers.

The Cogeneration is owned and operated by Nova Energy (formally Bay of Plenty Electricity) with ownership of the synchronising and protection system by Horizon Energy.

A summary of assets located at Fonterra:

Asset	Description	Rating Data	Date of Manufacture	Comments
Switchroom	Block construction naturally vented, owned by Fonterra			
11kV Circuit breakers BM14, BM18	Yorkshire YSF6 SF6 gas insulated, withdrawable	12kV, 25kA, 630 amp	1996	
11kV Circuit breakers BM12, BM22	Yorkshire YSF6 SF6 gas insulated, withdrawable	12kV, 25kA, 1250 amp	BM12, 1996 BM22, 1987	No spare parts available for BM22 A retrofit circuit breaker is available
11kV Circuit breakers BM16, BM32, BM42, BM52, BM62, BM72, BM82, BM92, BM102,	Yorkshire YSF6 SF6 gas insulated, withdrawable	12kV, 25kA 630 amp	1987	Obsolete, no spare parts available. A retrofit circuit breaker is available
Transformers	13 * 11kV distribution Transformers.	1.5 MVA *6 1 MVA *3 500 KVA *2 750 KVA *2	1987 to 2009	Some transformers are heavily loaded and are being monitored
SCADA	SEL Axion		2015	
Protection elements	SEL 7 series		2015	

Asset	Description	Rating Data	Date of Manufacture	Comments
DC supplies	48V DC Switchtec		1987	Replacement scheduled 2016

5.20.2 Condition of Assets

During 2013 an on-site inspection of all the 11kV assets was completed. It was identified that the 11kV YSF6 circuit breakers installed in 1987 are now obsolete with spare parts no longer available. These circuit breakers use SF₆ gas as an arc quenching medium.

The UK Energy Networks Association NEDeRS faults database indicates that older YSF6 switchgear has:

- An issue with hoses from the SF₆ tank to the pressure gauge becoming brittle with time and require replacement.
- Spring charge motors can burn out due to dry grease on the clutch and drive sprockets causing ratchet pawls to stick.
- Recorded a large number of VT failure incidences on their data base against this switchgear (12 of 41 recorded instances were VT failures.)
- A number of mechanical failures are recorded, mostly related to units with a high number of operations

A project to retrofit the SF6 circuit breakers with Vacuum units has been identified in the AMP for later in the planning period although this will be a client driven initiative.

Nova Energy owned generator circuit breaker BM18 was replaced in 2015 following failure.

Obsolescence details per age of YSF6 equipment.

Brand	Range	Type	Last year sold	Obsolescence Year	Qty
Obsolete equipment- Spare parts no longer available					11
Merlin Gerin	YSF6	-	2001	2002	11
Equipment no longer sold but spare parts still available					2
Merlin Gerin	YSF6	-	2001	Date not defined	2

Part of the upgrade project has been to commission a review of the system, using IEC/IEEE/PAS 63547 guidelines, of the protection scheme installed, which included a review of an extensive inter-trip scheme between Edgumbe GXP, Plains and East Bank substations and Fonterra. The review recommended a simplification of the protection scheme and elimination of the functional and operational interdependencies between the distribution network and the generation, so that each can service its specific function without the distraction of meeting the needs of the other.

The key recommendations from the report are:

- The existing incomer protection at Fonterra 11kV bus should be upgraded to modern, numerical relays that can provide the recommended protection elements and logics; Completed 2015
- Anti-islanding protection should be installed at the Fonterra 11kV bus using the communications network to transmit system phase and frequency to the incomer relays; Scheduled 2016
- The existing cascading inter-trips can be removed, as they will no longer be necessary when the new scheme is implemented; Scheduled 2016
- Protection grading should be reviewed across the whole network, including Fonterra's 11kV feeders and Nova Energy's generators, as well as Horizon Energy's network protections; Completed 2015

- The neutral grounding arrangements for the 33/11kV transformers and the generators should be upgraded; Nova energy would be assessing this.
- The generator synchronising system ownership should be transferred to Nova Energy, and an upgrade of generator controls should be considered to suit the new protection arrangements; and
- Horizon Energy and Nova Energy should enter into an operating agreement which explicitly recognises the roles and responsibilities set out in IEC/IEEE/PAS 63547.

This project started during winter 2015 and will be completed Winter 2016.

5.21 Distribution Reliability Projects

A study in 2009 identified 236 individual projects, with a total value of \$5.3M, to improve the reliability of the rural distribution networks. Over 90% of the projects have now been implemented.

The projects range from circuit breaker replacements, new installations, tie point switch automation, line sectionalisers, drop out sectionalisers and line fuses.

Engineering trials have started on implementing fully automated self-healing meshed networks, controlled by SCADA, with minimal controller intervention. .

The viability of each individual reliability project and the equipment type selection is based on:

- An assessment of feeder reliability and the SAIDI performance of the feeder;
- The expected saving in SAIDI minutes by completing the individual installation;
- There is a regulatory incentive to better manage the frequency of interruptions (SAIFI) and this measurement is factoring more in assessing reliability projects.

Priority Order

The priority order for installing reliability projects is based on the overall reliability of individual feeders and the planned installation order is summarised in Table 5.65 below:



Year/Substation	Project Cost
2015-16	\$774,302
Ohope	\$479,642
Plains	\$233,546
Waiotahi, around Opotiki	\$61,115

Table 5.65 – Reliability Projects Priority Order

Further opportunities to improve network reliability being assessed are:

- Meshing opportunities for urban and rural feeders;
- Automated self-healing controls where devices on the network can identify faulted sections, and a control algorithm can make logical decisions to automatically switch the network to restore healthy sections;
- More remote control devices in the urban networks;
- Splitting large feeders, Harbour and Plateau feeders; and

- Identifying and scheduling at-risk cables for replacement.

There is a cost-benefit crossover in improving reliability between spending on increasing automation and replacing poor condition assets. As the network is sectioned into smaller areas with automated switching devices, identifying feeders in poor condition and instigating replacement, or increased maintenance expenditure on assets is likely to provide more benefit in overall reliability results than installing further automation. Line replacement and upgrade projects are prioritised using network criticality, overall condition, and feeder performance.

5.22 Zone Substation Circuit Breaker Upgrades

There are a number of zone substation circuit breaker upgrade projects scheduled in the 10 year plan. These circuit breaker replacements are driven by obsolescence and reliability of the existing equipment, with Waiotahi substation the last substation having distribution pole top bulk oil KFE circuit breakers being used as primary switchgear.

Horizon Energy intends to standardise on one type of switchgear and a full evaluation process was carried out during 2012. It is planned that some of the switchgear will be pre-loaded into transportable buildings and some will have block or pre-cast buildings. It is appropriate with existing sites to consider pre-loaded transportable buildings in order to reduce the construction time on site and the need to extend existing buildings. All new 11kV primary distribution will be indoor switchgear.

Outdoor equipment will still be considered for 33kV switchgear but indoor may be preferred for aesthetic or security reasons, especially in the case of a substation in urban areas.

The first of these modular 11kV substations was designed in 2012 and installed in 2013-14 at Galatea.

The earliest start planning schedule for these projects is below:

Zone Substation	Year	Number of Circuit Breakers	Status
Waiotahi		5	Proposal to Transpower 2013. Deferred pending Opotiki development
Kaingaroa		7	Deferred pending risk assessment
Opotiki	2016/17	10	Switchgear ordered 2015
Whakatane CBD	>2020	6	Hold pending load growth trigger
Gateway	>2020	9	Hold pending load growth trigger

Table 5.66 – Project Planning Schedule



Galatea 11kV switchroom being lifted into position March 2014.

5.23 Zone Substation Transformer Fleet Management Plan

Zone substation transformers are reaching an age and condition where the majority of the transformer fleet will need to be replaced over the next few years. Although mentioned in detail in the individual substations in section 5, a summary of the replacement plan is below

- **East bank T1**
East Bank T1 was installed in 1987 with no replacement work scheduled in the planning period
- **Galatea T1 and T2**
These transformers were installed in 1980 and have excessive tap changer use. The taphangers are scheduled for a higher level of maintenance.
- **Kaingaroa T1 and T2**
Installed 1993 with no replacement work scheduled in the planning period. High tap changer use may prompt premature replacement
- **Kope T1 and T2**
Kope T1 was installed in 1989. A transformer matching Kope T2 will be installed and this transformer will be relocated to Ohope. Prerequisites to this are a 33kV indoor conversion of Kope outdoor yard to clear space for the new transformer, and also development of the Ohope site to accept the relocated transformer.

Kope T2 was installed 2012 and no replacement work is scheduled for the planning period.
- **Ohope Substation T1**
Current planning is that Ohope T1 will be replaced by Kope T1 in 2018
- **Plains Substation T1 and T2**
Plains T2 is scheduled to be installed in 2015. A second Plains transformer will be scheduled for installation only if load driven- this is currently outside of the planning period.
- **Station Road T1 and T2**
Installed 1966 these transformers are scheduled for a load and condition driven replacement in 2020 and 2021

6 Asset Lifecycle Management Planning

6.1 Maintenance Practices

6.1.1 Introduction

This Section of the Horizon Energy Asset Management Plan describes the policies relating to the design, maintenance, operation and renewal of network assets. Also included is specific asset lifecycle information for major asset groups that outlines maintenance and replacement strategies and practices that are applied to them.

The operational practices used by Horizon Energy to operate and maintain the network are described first, followed by a description of each asset category and discussion on specific asset types, their overall condition, and any policies developed around these assets. This is followed by individual projects and work plans that have been identified to replace or refurbish the assets.

6.1.2 Lifecycle Asset Management Concepts

The main objective of maintenance is to keep an asset in service to reach its design life and purpose. Maintenance drivers include:

- Ensuring safe operation;
- Ensure regulatory compliance;
- Maintaining or improving network reliability;
- Minimising asset lifecycle costs;
- Extending asset lives; and
- Ensuring the asset is fit for purpose.

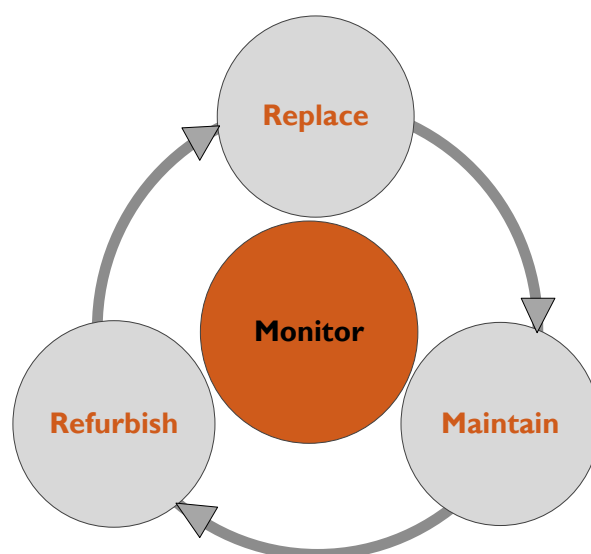


Figure 6.1 – Asset Ageing Lifecycle

The asset lifecycle infers that a continuous process keeps the asset functional throughout its life. It is this *function* that is maintained throughout the lifecycle. As technology evolves and new equipment is made available to the industry the equipment may be replaced or upgraded to maintain the *function* that is required of the system. The purpose of maintenance is to keep the asset functional until such time as it becomes uneconomic to refurbish. Replacement options are then assessed to determine the best replacement method, equipment, or system.

Monitoring or condition assessment of assets triggers its own set of questions; the answers then determine the lifecycle management policy appropriate to that particular asset or asset group.

Is the asset to be:

- Maintained?
- Run to failure?
- Refurbished?
- Replaced?
- Replaced when?
- Replaced with a better product?
- Can the asset be improved? Or
- Is the asset still required?



Figure 6.2 – Asset Decision Wheel

Asset renewal strategies are based around the need to replace assets that have either failed, are at high risk of failure, a safety hazard or are obsolete. A lot of replacement work is driven by load or capacity upgrades, and a lot of remedial work is condition driven. The table below summarises the primary asset renewal strategies currently in place.

Asset type	Run to Failure	Risk and Condition	Age and Obsolescence	Load Driven
Communications equipment			X	
Buildings, fences		X		
Earthing systems		X		
Battery chargers		X		
Batteries			X	
SCADA			X	
Crossarms		X		
Poles		X		
LV Substations		X		
Pillar boxes, link boxes		X		
Low voltage cables	X	X		X
Polemount transformer > 100kVA		X	X	X
Groundmount transformer > 100kVA		X	X	X
Polemount transformer < 100kVA	X	X		X
Ground mount transformer < 100kVA	X	X		X
Surge arrestors	X			
Ring Main Units		X	X	
Overhead expulsion fuses	X	X		
Pole Mount circuit breakers			X	
11kV Overhead lines		X		X
11kV PILC Feeder cables			X	X
11kV XLPE/PILC to single transformer	X	X		
11kV XLPE feeder cables			X	X
Protection			X	
Zone substation switchgear		X	X	
Zone substation transformers		X		X
Ripple Control plant	X		X	
Air break switches		X	X	
Sub-transmission lines		X		X
Sub transmission cables		X		X

6.1.3 Routine Maintenance

The baseline equipment maintenance schedule is determined according to the criteria in Table 6.1 below:

Operational History	Frequency of use is used to trigger maintenance for the following equipment types: <ul style="list-style-type: none"> • Tap changers • Oil filled Poletop circuit breakers • Voltage regulators 																						
Time Based Servicing	Items that are not monitored for operational history are serviced either on a time based routine or by exception. Time based routine inspections include: <table border="0"> <tr> <td>• Zone substation inspections</td><td>2 Monthly</td></tr> <tr> <td>• Earth bank testing</td><td>10 year</td></tr> <tr> <td>• Protection testing (mechanical relays)</td><td>3 year</td></tr> <tr> <td>• Protection testing (electronic relays)</td><td>5 year</td></tr> <tr> <td>• Zone substation transformer oil/DGA tests</td><td>Annual</td></tr> <tr> <td>• Thermal imaging critical circuits</td><td>Annual</td></tr> <tr> <td>• Partial Discharge testing RMU</td><td>2 year</td></tr> <tr> <td>• Poletop devices battery replacement</td><td>3 year</td></tr> <tr> <td>• Radio system compliance testing</td><td>Annual</td></tr> <tr> <td>• 33kV lines and terminations</td><td>Annual</td></tr> <tr> <td>• Vegetation control</td><td>Species related</td></tr> </table>	• Zone substation inspections	2 Monthly	• Earth bank testing	10 year	• Protection testing (mechanical relays)	3 year	• Protection testing (electronic relays)	5 year	• Zone substation transformer oil/DGA tests	Annual	• Thermal imaging critical circuits	Annual	• Partial Discharge testing RMU	2 year	• Poletop devices battery replacement	3 year	• Radio system compliance testing	Annual	• 33kV lines and terminations	Annual	• Vegetation control	Species related
• Zone substation inspections	2 Monthly																						
• Earth bank testing	10 year																						
• Protection testing (mechanical relays)	3 year																						
• Protection testing (electronic relays)	5 year																						
• Zone substation transformer oil/DGA tests	Annual																						
• Thermal imaging critical circuits	Annual																						
• Partial Discharge testing RMU	2 year																						
• Poletop devices battery replacement	3 year																						
• Radio system compliance testing	Annual																						
• 33kV lines and terminations	Annual																						
• Vegetation control	Species related																						
Load Based Maintenance	No individual assets are subjected to load based maintenance routines at this stage. Horizon Energy does not routinely perform cable condition or transformer assessment tests due to load, unless a specific issue has been identified.																						
Visual Condition	Asset condition assessment is being integrated into proactive maintenance and replacement policies. With the remaining life inspection program that is presently used, condition is based on a 1 year, 2 year, 5 year, >10 year visually assessed remaining life. Maintenance and planned replacement schedules or projects are individually adjusted based on the condition assessment process.																						
Measured Condition	Recent partial discharge testing of oil filled ring main units has been used to defer time based servicing. A number of faults have been detected and remedial actions put in place, including repair and/or replacement. Thermal Imaging is used to assess assets on critical feeders and zone substation assets. Test results have initiated works to repair assets prior to failure.																						
Reactive	Equipment classes that have no specific scheduled routine maintenance activities and tend to be maintained in a reactive manner include: <ul style="list-style-type: none"> • 400V pillar boxes, excluding concrete boxes • 400V switchgear • Distribution transformers < 200kVA • 400V lines and poles • 400V customer connections • 400V cables • 11kV cables (excluding terminations) 																						

Proactive Replacement	Proactive equipment replacement, upgrade or maintenance is driven by a number of different criteria. These include: <ul style="list-style-type: none"> • Load • Condition • Planned obsolescence • Customer driven • System enhancement • Known faulty equipment types e.g. concrete pillar boxes and stainless steel DDO's
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Table 6.1 – Asset Maintenance Criteria

6.1.4 Faults Management

Horizon Energy operates a 24/7 fault response system. Control functions are undertaken by the control room manned from 7:00am until 9:00pm Monday to Friday, and by an operator callout system outside of these hours. The on-call network controller has remote SCADA access from home and a VHF radio to allow fast response to network faults.

In the event of a network fault, the SCADA system is programmed to send an alarm message to the network controller's home SCADA console, and to call the operator's cell phone. If this message is not responded to within a defined time period the SCADA escalates the message to the next operator and continues this process until the message is acknowledged.

An outage management system has been trialled in 2015 which records customer reported outages, and operator switching to graphically display areas suffering an outage. The visual representation of the outage areas will be available to consumers via a web portal in 2016.

Vehicle tracking has been implemented to identify the location of service vehicles in close proximity to lines and assets, and to allow for rapid re-deployment of service staff based on location if required. Monitoring location, working hours, and having service staff logging in to control for the start and end of works, is part of the strategies to keep staff safe.

Feeder automation and self-healing trials have started in 2015 for implementation 2017

Field fault response is provided by Horizon Services staff and contractors. Energy retailers use a call centre to reports faults from consumers in various areas. The dispatched faultmen are able to work directly for the customer if the problem is on their system, or, in the event of a network fault, are coordinated in the restoration process by the Horizon Energy network controller.

Faults are logged in a work management system. Individual faults have no assigned priority; the priority is determined by the network controller depending on the criticality of the service, number of customers who may be affected by the incident and other events on the network.

The controllers maintain a list of essential services and these get priority of restoration.

Priority services include:

- Whakatane Hospital;
- Zone substations;
- Regional and district council sewage and water pumps;
- Flood pumps;
- Major industrial customers;
- Commercial zones; and
- Customers with identified medical equipment reliant on supply.

Horizon Energy has within its Quality System details of the essential services that require attention. The system also identifies the load shedding priority order and process that must be undertaken in either a network or grid emergency, or as instructed by the Transpower system operator.

Currently the management of data for electrical supplies to medical equipment is with energy retailers. Horizon Energy is looking at control procedures that will provide a higher level of confidence in the management of essential services, and the management of supplies to medical equipment users will be incorporated into these procedures.

6.1.5 Control Practices

In addition to the fault activities defined above the other core functions of the control room are:

- Monitor contractor safety when working on the network;
- Monitor the distribution system for quality compliance;
- Manage load flow;
- Respond to and manage network faults;
- Process switching requests, write switching schedules, direct switching operations for planned maintenance and issue permits to work;
- Manage new customer connections and disconnections for revenue or safety reasons;
- Manage the MARIA metering and ICP registry;
- Manage metering reconciliation for retailers; and
- Manage any works undertaken near network assets e.g. a high load that may pass through the area.

6.1.6 Defect Management

Defects are urgent or non-urgent faults, or damaged equipment, that are identified by staff and are raised on a notification of defect form. Any member of Horizon Energy staff or contractors can raise a defect. The public can also advise defects through either their retailer or by direct contact to Horizon Energy. The latter is being encouraged with stickers being added to public assets that advise a safety warning and give an 0800 contact number.

Defect priorities are assessed as follows:

Priority	Definition	Action
Red Tag Priority 3	Defected item (normally a pole) has a red tag affixed to the pole when it is deemed unsafe to climb. Once the pole is red tagged no person may climb the pole.	Red tag poles must be replaced within three months.
Priority 1 Immediate repair required	The equipment is unsafe, non-functional or about to cause a loss of supply.	Work is required to start as soon as practicable and be complete within 48 hrs.
Priority 2	Asset is defective or below standard but is not an immediate hazard nor likely to cause an imminent loss of supply.	Work is planned and scheduled but must be complete within one month.
Priority 3	Asset is defective or below standard but is not an immediate hazard nor likely to cause an imminent loss of supply.	Work is planned and scheduled. Work required within three months.
Priority 4	Asset is defective or below standard but is not an immediate hazard nor likely to cause a loss of supply within six months.	Work is planned and scheduled. Work required within six months.
Priority 5	Asset is below standard condition with no visible defects and is not likely to become a hazard or cause an outage in the near future.	Work is included in the AMP to monitor the condition and inspect again after five years.
No action required	Asset is not a hazard and is unlikely to become a hazard or cause a loss of supply.	Close defect in defects register.

Table 6.2 – Defect Priorities

6.1.7 Vegetation Control

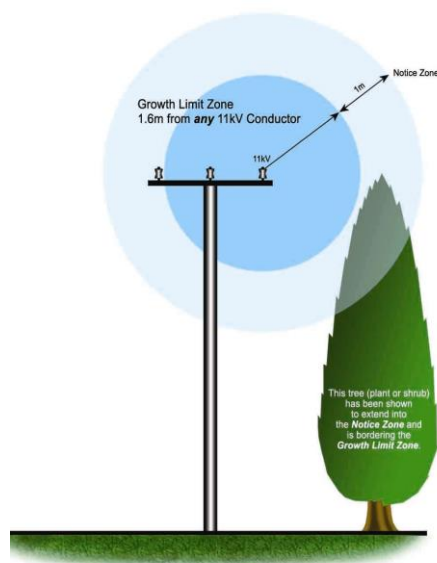
Vegetation is managed according to the following practices:

- Horizon Energy has a vegetation management team within its contracting subsidiary;
- A database is maintained of hazardous trees and vegetation that encroaches within the control zone for all 11kV and 33kV lines;
- High risk trees outside the control zone are also logged in the data base;
- Vegetation inspections are scheduled six monthly for 33kV lines and annually for critical 11kV lines. Difficult to access areas are patrolled aerially;
- In some cases, for high growth areas, a more regular inspection may be undertaken; and
- Results from the vegetation patrols drive the cut plan and letters are to be issued to the tree owners.

The management of trees is prescribed by the Electricity (Hazards from Trees) Regulations 2003

Trees found to be causing a hazard from within the growth limit zone are trimmed, and owners of trees within the notice zone are notified in writing.

The tree legislation gives little control over trees that are outside the notice zone and yet may pose a threat to the line due to a fall hazard. The majority of recent outages have been caused by trees that have been outside of the notice zone.



The control zone for vegetation is:

GROWTH LIMIT ZONE		
Line Voltage	Growth Limit Zone	Notice Zone
33kV lines	2.5m	3.5m
11kV lines	1.6m	2.6m
400/230V lines	0.5m	1.5m

Table 6.3 – Growth Limit Zones

6.2 Asset Lifecycle Management

The lifecycle of any particular asset is determined by making an assessment of its:

- Existing condition;
- Age in service compared to design life;
- Known history of that particular asset (make and model);
- History of asset type;
- Service conditions to which the asset is exposed;
- Environmental conditions the asset is subjected to;
- Maintenance regime undertaken;
- Criticality to the network for that specific asset and asset type; and
- Functionality of the asset.

End of life asset management relies heavily on planned maintenance carried out, linked to age and condition. The following sections describe the policies used to determine asset replacement.

6.2.1 Standard Asset Replacement Policies

Asset life used as a reference point is the asset standard life as defined in the Commerce Commission Handbook for Optimised Deprival Valuation, issued in 2004. The asset replacement policies for each asset class are summarised below:

Zone Substation Transformers

Horizon Energy's policy is to maintain all zone substation transformer assets to the manufacturer's specifications throughout their life. In general the transformers are operating well below their designed full load capacity; therefore we have adopted the extended transformer life as defined in the handbook. Replacement review is scheduled when either of the following conditions is reached:

- Asset age > 55 years. (ODV Handbook standard life 45 years, extended to 60 years for well-maintained assets);
- Peak load during reinforcement exceeds 110% of the n-1 capability of a dual bank or 110% N capability of a single bank;
- Condition monitoring shows signs of increasing deterioration.

Transformers are rated according to IEC60354 which defines the allowable overload capability of transformers for two and four hour overload periods.

Ring Main Units

Standard life 40 years modified by condition, maintenance history, partial discharge testing and known industry type issues. Horizon Energy changes the planned life by the following amounts:

- | | |
|----------------------|---|
| • Andeact Series one | Accelerated replacement program |
| • ABB SD | -4 to +4 years |
| • Magnefix | -5 to 0 years |
| • ABB Safelink | 0 years (1 st installation 2008) |
| • Schneider RM6 | 0 years (1 st installation 2009) |
| • RTE | 0 years |
| • All others | 0 years |

Distribution Transformers

Standard life is 45 years, 55 years with a formal maintenance regime. Horizon Energy has no formal maintenance program for distribution transformers. Replacement is scheduled:

- Under 100KVA run to failure, replaced on defect;
- Pole mounted 100 KVA and over, 45 years scheduled replacement. All pole top transformers 100kVA and over are replaced with ground mount transformers due to the increased costs and complexity of pole mounting; and
- Ground mount transformers 45 years; most ground mount transformers of this age are attached to Magnefix or RTE units and are being replaced when the switchgear has reached its lifecycle replacement date. When replaced, these Magnefix or RTE units are generally being replaced with transformers with 11kV switchgear attached as an integral unit.

11kV XLPE Cables

Standard life 45 years. Horizon Energy's replacement policy is:

- Load driven;
- Type specific for known faulty cable batches; and
- Scheduled age based replacement is not addressed at present.

11kV PILC Cables

Standard life is 70 years. No cables this age have been identified on the network. 1957 is the first recorded PILC cable installation which is due for replacement in 2027.

Lines, Poles, and Low Voltage Assets

No age replacement policy has yet been determined. Currently all replacement work is condition based via inspection, defects or faults.

Poletop Circuit Breakers

Standard life is 40 years.

- Horizon Energy's policy is 40 years; all existing field devices over 40 years old are scheduled to be replaced by 2014 (excludes devices in Zone substations).

Zone Substation 11kV Switchgear – Outdoor

All poletop outdoor oil filled 11kV switchgear scheduled to be replaced by 2017.

Zone Substation 11kV Switchgear – Indoor

Standard life is 45 years.

- The oldest indoor switch gear (East Bank Substation) reaches 45 years old in 2031;
- Reyrolle LMVP (RPS) circuit breakers are being returned to the manufacturer at 25 years of age for a half-life refurbishment.

ABS

ABS switches are being replaced with hot-stick operated, fully insulated, enclosed switches, to reduce the effects of atmospheric contamination, and to eliminate the need for earth banks. The switches are capable of retrofitting automation controllers if required. A priority list for switch replacements, at the rate of 10 per year, targets switches in critical services and older switches for priority replacement.

33kV Zone Substation Switchgear (Outdoor)

Standard life is 40 years.

- All except Kaingaroa are due for replacement now. Ohope and Kope have been scheduled

Low Voltage Cables PVC/XLPE

Standard life is 45 years.

- Load driven; or
- Run to failure.

Vacuum Circuit Breakers

There are various manufactures of circuit breakers using vacuum interrupters on the network. All vacuum circuit breaker manufacturers suggest a bottle life of 25 years, but practice suggests that this is very conservative and bottles will last considerably longer. However, UK experiences are showing an increasing degree of failure after 40 years of age.

There is only one set of substation vacuum circuit breakers aged more than 25 years, so a condition monitoring and mid-life refurbishment policy has been adopted to ensure the reliability of this equipment class.

6.2.2 Condition Assessment

Condition assessment is used to drive asset replacement according to the following criteria:

- By using both asset age and condition to determine the priority for replacement means that no asset is arbitrarily replaced just on age alone;
- Due to the volume of assets in the system, and the unknown ultimate life of certain asset types, a simple age based asset replacement program is not sustainable, nor is it good maintenance practice;
- The age/condition priority is further refined by the importance of the particular asset to the network reliability;
- Assets close to zone substations in the feeder arterial routes are assigned higher priorities than assets further out, or at lower voltages, as the number of customers affected reduces with distance;
- Assets that can introduce human risk if they fail in service e.g. poles, are prioritised based on the defect red tag system; and
- Condition assessment of poles, conductors and crossarms is used to ascertain the general overall condition of groups of assets. When there are clusters of assets identified with a high number of defects, or have a high concentration of assessed low condition assets, then these are being grouped into projects and a full upgrade is scheduled for that cluster. These projects are designed using new technology, to be fit for purpose. It is not always true that a like-for-like replacement is the best option.

The following tables generally describe the priorities given to assets or clusters of assets for either replacement or refurbishment. A higher number of points are prescribed for higher priority works.

Condition Assessment	Description	Points
0	Assessed condition good for > 10 years	0
1	Assessed condition replace within 5 years	1
2	Assessed condition replace within 3 years	2
3	Assessed condition replace within 1 year	3

Table 6.4 – Condition Assessment

6.2.3 Reliability

A reliability factor is added to the asset replacement priority. The reliability factor is assessed according to the previous performance history of the asset and reflects the needs of the network to remove or replace the asset class.

Reliability Factor Description	Priority
Equipment that has no history of failure or is very reliable, lightly loaded, well maintained, and the asset group is expected to have a life longer than the ODV handbook defined life.	0
Equipment that is reliable, lightly loaded, has had average maintenance, minor or few faults and the asset group is expected to reach ODV life.	1
Equipment that has had a history of failure, has operational faults, has been heavily loaded, poorly maintained, and the asset class is not expected to reach	2

Reliability Factor Description	Priority
its design life.	
Equipment that has been identified for accelerated replacement.	3

Table 6.5 – Reliability Factor

6.2.4 Safety Factor

All equipment is assessed for safety. This assessment is applied to each asset type to provide a benchmark for operational safety, and the safety hazards that the asset may pose to workers and the general public.

The first principle of safety management is to eliminate, isolate or minimise any risk. Any asset that is identified as a potential hazard, or likely to become a hazard, is defected in the first instance. Assessment of the asset will then determine the appropriate action to manage the hazard. This may be accomplished through altering the operational procedures in the way the asset is operated, or an engineering solution may be applied where the asset is repaired, upgraded, or replaced as appropriate.

Non-defected assets are assessed using the safety factor assessment below:

Safety Factor Description	Priority
Equipment has no known safety related issues and meets all currently applicable manufacturing and safety codes.	0
Equipment has no known safety issues and meets codes applicable at date of manufacture, but may not comply with existing codes or standards.	1
Equipment has safety or operational issues that can be managed operationally.	2
Equipment has safety or operational issues that cannot be managed operationally but does not pose a hazard in normal operation.	3
Equipment type is classed unsafe in operation and has a 'do not use' status but is not an immediate hazard.	4

Table 6.6 – Equipment Safety Assessment

6.2.5 Network Criticality

Network criticality is an assessment of the importance of an individual piece of equipment to the overall reliability of the network. This is determined by the number of customers that would be affected if the equipment were to fail in service and the time it would take to restore service. Considerations are:

- The ability to bypass equipment or to re-supply the network;
- The distance from fault support personnel; and
- The ease of access is factored into the criticality assessment.

This score is used to help set the priority of works for replacement, and is used to determine the frequency of routine maintenance and inspections.

Description	Points
-------------	--------

Less than 100 customers affected, or less than 300 customers affected but able to be bypassed either automatically or manually.	1
More than 100 but less than 300 customers. No ability to bypass.	2
Between 300 and 500 customers. Ability to restore from alternate means within one hour.	3
More than 500 customers, able to restore from alternate sources within one hour.	4
More than 500 customers, restoration time greater than one hour.	5

Table 6.7 – Network Priority

6.2.6 Asset End of Life Re-use Policy

Retired assets will be considered for reuse in less critical services if they are in good condition and are refurbished prior to use. Certain quantities of units will be retained for spares. Reuse policies for equipment that is retired due to condition modified age are in Table 6.8.

Equipment	End of life – Reuse Policy
Nine-insulator air break switch	Scrap
Magnefix	Spares only
RTE	Spares only
Andelect series I	Scrap
ABB Series 2 SD, SD3, SDAF	Anywhere except main feeders
Pole – River Run	Scrap
Pole – Tauranga	Scrap
Pole – Hardwood	Scrap
Pole – Softwood	Scrap
Pole – Larch	Scrap
Pole – Concrete pre-stressed	Anywhere if in undamaged condition
Crossarms, insulators	If under 10 years old, anywhere
KF, KFE Circuit breakers	Spares only
Power Transformer >1MVA	Assessed on a case by case basis
Transformer – tub sub	Scrap
Pole mount Distribution Transformer >75kVA	No re-use except as spares if in good condition. (75kVA max on poles)
Transformer 3 ph <30kVA	Scrap
Transformer 1 ph <15kVA	Scrap
Transformer others	Detailed condition assessment
Protection equipment	Spares only
Primary circuit breakers	Assessed on a case by case basis

Table 6.8 – Equipment Reuse Policy

6.3 Management of Asset Classes

Planned maintenance intervals and the activities undertaken are tailored to suit each different type of asset. The task definition and interval is based on an assessment of the age of the equipment, overall condition,

historical performance and consequences of failure. The following sections summarise the maintenance regime for major equipment classes by type.

6.3.1 Primary Switchgear

Primary switchgear comprises the switchgear located in zone substations at 11 or 33kV. Primary switchgear is generally a more robust design, has more versatility or configurability, and may carry higher rated loads than distribution switchgear.

6.3.1.1 Schneider GHA 33kV



Description

Schneider GHA is a 33kV rated indoor SF6 gas insulated, fixed form non withdrawable, single busbar, modular switchgear with vacuum interrupters. It is maintenance free with a compact footprint. The gas compartments are sealed for life.

There is one board on the network with 10 circuit breakers

Maintenance schedules

The switchgear is regarded as maintenance free for its life. Maintenance is limited to visual inspections and surface cleaning where required. 5 yearly PD inspections are scheduled.

Circuit breakers functional operations are tested on a 5 yearly basis with protection tests.

In the event of a switchgear malfunction the faulty module can be disconnected and removed from adjacent panels with a half bus outage.

Lifecycle management

There is one GHA board installed at Te Rahu, commissioned in 2010. The board has a manufacturer's recommended life of 40 years and Schneider operate a gas recovery and re-cycle service for end-of-life equipment.

Known Problems

To date there are no known problems with this switchgear.

6.3.1.2 Reyrolle (RPS) LMVP 11kV

Description

LMVP switchgear is indoor metal enclosed withdrawable 11kV air insulated circuit breakers with vacuum interrupters. The oldest units were installed in 1988. Circuit breaker sizes in use are 630, 800, and 1250amp units.

Bus bars are air insulated continuous bus.

Arc flash protection has been added to Kope substation circuit breakers. There are 3 switchboards on the network with 23 circuit breakers.

Maintenance schedules

Circuit breakers are tested on a 5 yearly basis with protection tests. Circuit breakers are removed and cleaned, insulation tested, and lubricated.

PD tests are 5 yearly.

After 20 years the circuit breakers are scheduled to be removed from service, and sent to the manufacturer's facilities for a full clean and refurbishment.

Lifecycle management

Manufacturer's stated life exceeds 20 years. With a mid-life refurbishment of the circuit breakers the service life is expected to exceed 40 years.

Known Problems

The switchgear was upgraded to IEC62271-200 with the addition of new blast doors in 2010. Due to space restrictions Kaingaroa substation circuit breakers were unable to be upgraded.

There have been issues with circuit breaker limit switches and control switches with intermittent operation in recent times, and with some of the circuit breaker closing mechanisms. A full manufacturer's overhaul is expected to correct these issues.

6.3.1.3 GEC VMX 11kV

Description

VMX switchgear is indoor metal enclosed withdrawable 11kV air insulated circuit breakers with vacuum interrupters. The switchboard was installed in 1983 with vacuum circuit breaker retrofits in 1996. Circuit breaker sizes in use are 630, and 1250amp units.

Bus bars are air insulated continuous bus.

There is one switchboard at Station Road with eight circuit breakers.



Maintenance schedules

Circuit breakers and protection are tested on a 5 yearly basis with protection tests. Circuit breakers are removed and cleaned, insulation tested, and lubricated.

Historical PD tests were 5 yearly but this schedule is increased to 2 yearly after reports from the UK about failures of this style of circuit breaker

Lifecycle management

Expected life is 40 years.

Known Problems

Apart from some limit switch issues, Horizon Energy has had no problems with the VMX board located at Station Road, but the UK based ENA National Equipment Defect Reporting Scheme (NEDeRS) system reports that the switchgear uses cast resin mouldings and these are prone to

partial discharge problems that can cause rapid failure in older units. Once PD in a resin cased circuit breaker starts, the circuit breaker must be promptly replaced to before a disruptive failure occurs. This is managed by regular PD testing.

6.3.1.4 *Schneider GeiniEVO 11kV*

Description

Schneider GHA is an 11kV rated epoxy resin insulated, fixed form non-withdrawable, single busbar modular switchgear with vacuum interrupters. It is maintenance free with a compact footprint.

There is one switchboard at Galatea installed in 2014 containing eight circuit breakers.

Maintenance schedules

The equipment is considered maintenance free.

Circuit breakers are tested on a 5 yearly basis with protection tests.

Electrical partial discharge tests 5 yearly.

Maintenance is a general surface clean and removal of dust from MV cable box and LV cabinet.

Lifecycle management

Manufacturer's stated life is 25 years minimum. This is expected to be closer to 40 years in a clean air conditioned dry environment.

Known Problems

There are no known problems with this switchgear.



6.3.1.5 *Yorkshire YSF6 11kV*

Description

Indoor metal enclosed withdrawable SF6 circuit breaker, single bus, located in Fonterra with 13 circuit breakers.

Maintenance schedules

Annual inspections are recommended. Servicing includes lubrication and cleaning the moving mechanism, removing and cleaning the isolating contacts and the moving portion insulators.

Microprocessor relays protection tests are completed 5 yearly.

Manufacturer 10 yearly major service requires a full strip down, clean and lubricate, plus repeating the 5 year service.

Lifecycle management

Switchgear life is 35-40 years. Schneider has a roll-out, roll-in replacement Vacuum circuit breaker retrofit option to extend the life of this switchgear.

Known Problems

The UK NEDeRS faults database indicates that older switchgear has an issue with hoses from the SF6 tank to the pressure gauge becoming brittle with time and requires replacement.

Spring charge motors can burn out due to dry grease on the clutch and drive sprockets causing ratchet pawls to stick. This is manageable by completing a full 10 year service.



The NEDeRs database also has a large number of VT failure incidences on their data base (12 of 41 recorded failure instances with this switchgear were VT failures.)

Schneider no longer has spare parts for some of the switchgear in service.

In 2014 BM18, owned by Nova Energy, failed in service and would not mechanically latch closed, and has been replaced.

6.3.2 Ring Main Units

The following details the various types of Ring Main units installed on the network and the lifecycle management practice that is applied to each type of unit.

Horizon Energy has approximately 256 ring main units, from seven different manufacturers, installed across the network.

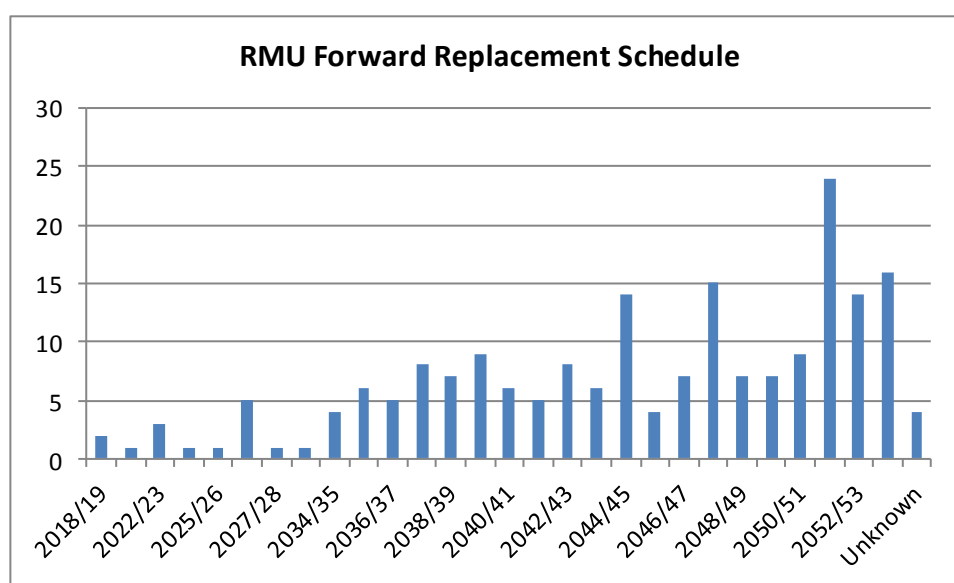


Figure 6.3 – Ring Main Replacement Program

Figure 6.3 shows the condition modified end-of-life replacement program for all ring main units based on their standard life. Actual replacement is assessed on a unit by unit basis depending on the project priority assessment criteria, and due to either condition or network improvement plans there are several units planned for replacement before the times indicated in Figure 6.3.

Partial discharge testing of Ring Main Units has determined a number of defects with cables terminations and switchgear. A number of assets have been accelerated for replacement and a number of defects entered to repair cable terminations.

6.3.2.1 Holec Magnefix Ring Main Units Maintenance

Magnefix switchgear is a compact fully insulated Ring Main Unit for application in 12-15kV distribution networks. The unit is epoxy resin insulated, and is modular in construction such that it can be configured to meet the needs of specific switching applications. The most commonly used units consist of isolating links and fused load-break links. The following photo shows a unit that is equipped with four isolating links on its left and fuse combination on the right. This fuse unit would generally be used to connect a local transformer to the network. The nominal current of the links is 400 Amp.

Modern variants of the Holec Magnefix units are still being manufactured.



Figure 6.4 – Typical Magnefix Arrangement

Maintenance Schedules

All Magnefix switchgear is inspected on a bi-annual basis. The inspection is carried out to determine the overall condition of the switchgear, the condition of the terminations and vegetation and insect infestation control. Past experience with the Magnefix units show that an accumulation of moisture and dust on the surface of the Magnefix switchgear causes electrical discharge and eventual breakdown if left uncleaned. Failure of the terminations is also common unless regular cleaning is carried out.

These bi-annual outages are costly due to the work required to connect generation to support the loads during the cleaning process, and this maintenance cost plus overall condition is driving a replacement program. Due to the relatively short work durations, and the general acceptance that planned outages are less inconvenient than unplanned outages, equipment outages instead of generation are being planned for this work from 2016 onwards.

Lifecycle Management

Using the criteria referred to in tables 6.5 to 6.7, the lifecycle management assessment criteria for this switchgear type are determined in Table 6.9 below.

Quantity on Network	33
Reliability Factor	1
Safety Factor	3
Network Criticality	Assessed Per Unit

Table 6.9 – Typical Magnefix Assessment

Magnefix units are operated by removing the link caps on the circuits being disconnected. The biggest disadvantage operationally is that each phase is isolated individually by physically removing the links. As such Magnefix units rate at a lower operator safety factor than equipment that is fully enclosed and breaks and makes all three phases together. The units will be proactively removed from service in less than the expected life for 11kV switchgear.

Figure 6.5 shows the replacement schedule for Magnefix switchgear based on age and condition assessment. Units in good condition will be considered for reuse as emergency spares. The actual replacement schedule is slightly different to Figure 6.5 due to some Magnefix replacements being accelerated to fit in with cable and transformer replacement projects.

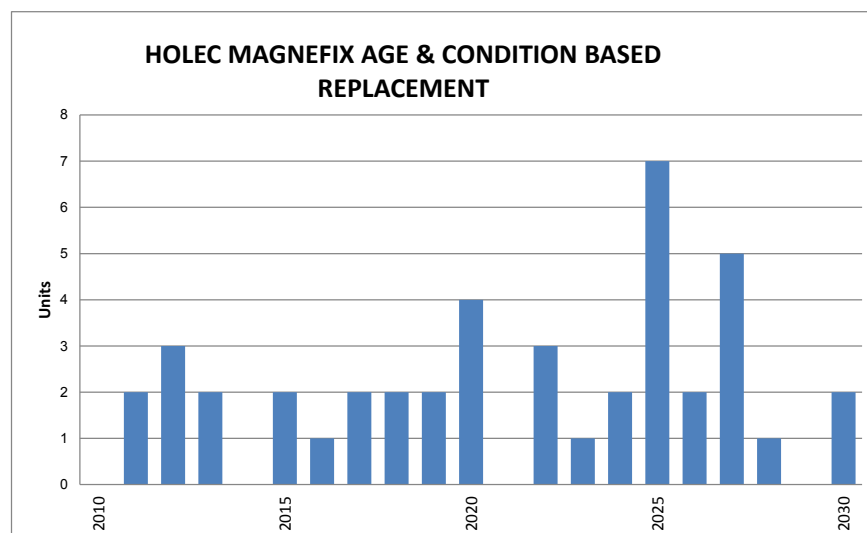


Figure 6.5 – Magnefix Replacement Schedule

6.3.2.2 ABB/Andelect SD Series

The ABB SD Series 2 oil filled switch range is designed for use on distribution systems to switch 3-phase currents of 400-600A at voltages up to 12kV. SD switches were available in a variety of configurations made up from either a switch or an automatic tripping switch fuse (activated by a fuse striker). The range was discontinued from August 2012.

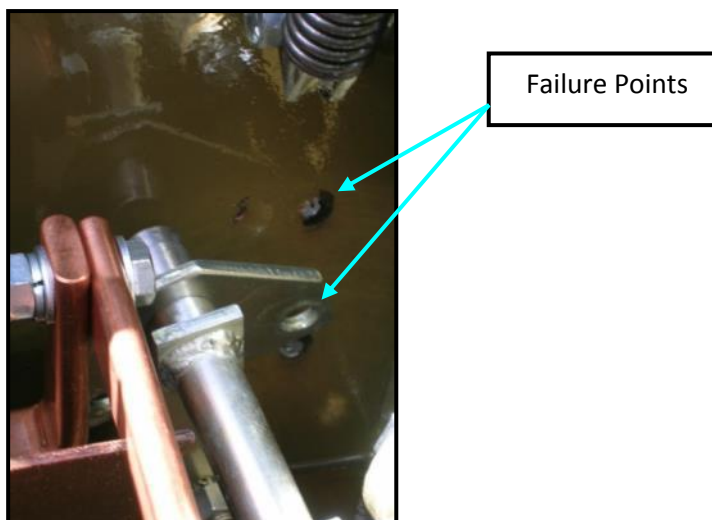
The unit was available as a Ring Main Unit (RMU) comprising of two switches and one fuse switch within the one tank, or as separate units of single, double and triple switches and a single fuse switch that can be connected in any combination required. Each switch or fuse switch has an associated cable earthing switch as part of the module.

There are two series of SD switches installed on Horizon Energy network. The earlier Series 1 switch was manufactured by Anderson Electrical under the brand name Andelect. These differ from the later ABB Series 2 switches by having a common cable chamber for all cables, whereas the Series 2 has a separate chamber for each cable connection. This improves the fault containment between chambers.

Known Problems

The SD series Ring Main Unit can be extended by bolting a second unit to a bus extension on the first unit, normally to extend a three unit assembly into four units. The interconnection bus chamber can be subject to electrical failure if not sealed correctly against water ingress. In 2009 a program was completed to re-pack the bus connection chamber on all RMU's of this type with an ABB supplied waterproof compound. A reduction in the frequency of faults from this weakness is expected but PD testing has determined that the bus extension is still a continuing source of failure.

Instances have been reported in New Zealand of some Series 1 units faulting when being operated due to the failure of a welded stud that holds the switch operating mechanism. This fault is apparent by a failure to close correctly. One industry incident recorded that the SD unit caught fire, and a recommendation was issued to the industry not to use the Andelect Series 1 switches when attempting to live onto suspected faults.



Horizon Energy has a policy of prioritising early replacement of in-service Andelect Series I switchgear. A switching procedure has been implemented for their operation to ensure the safety of the operator. Where these units have been identified as being in critical switching locations within the network, they have been programmed for replacement.

A number of these units have recently been identified with varying levels of electrical partial discharge on either the cable terminations, bus extension bushing, or internal. Any Andelect series I Ring Main Unit that requires remedial work is scheduled to be replaced rather than repaired.

Maintenance Schedules

SD units are inspected annually. This inspection covers, among other things, oil loss, rust, termination condition, weed and bug infestation, ground condition or slumping, and graffiti, as well as earth bank testing.

SD units are categorised into two categories for maintenance of the insulation oil. Units on main feeders that are potentially subjected to fault passage are scheduled for an oil change every five years. Units on spur lines or secondary feeder lines are programmed for a 10 yearly oil change.

ABB recommends the oil be changed if the switch is used three times to switch onto fault current. Horizon Energy does not currently have a method of recording the number of operations of these switches, hence the time based maintenance schedule above for RMU's. Planned integration of switching schedules with the proposed asset management, SCADA, and GIS systems should enable this detail to be obtained to record usage and drive the maintenance program.

Lifecycle Management

SD Series 2 units are expected to reach or exceed their ODV life. Very few units are switched onto faults. Horizon Energy has no centralised recording system to track the number of close-on-fault operations of RMU's so it is not possible to determine if units are degrading due to fault switching. The main driver for replacement will be the desire to install increased automation, as SD units cannot be retrofitted for automation.

Series I Andelect Units will be prioritised for replacement over the Series 2 Units due to the cable box arrangement and the potential failure of the internal mechanism.

Quantity on Network	5
Reliability Factor	1
Safety Factor	3
Network Criticality	Assessed Per Unit

Table 6.10 – Andelect SD Series I Ringmain Units

Quantity on Network	106
Reliability Factor	1
Safety Factor	1
Network Criticality	Assessed Per Unit

Table 6.11 – ABB SD Ringmain Units

There are five single switch Andelect series 1 units bus coupled to series 2 units. Changing these will require an upgrade for both switch units.

Figure 6.6 below shows the unmodified age replacement profile for ABB ringmain units. Due to the accelerated replacement policy for earlier Series 1 Andelect switches there are more replacements scheduled for 2015-2017 than are showing on this chart which is based on age alone.

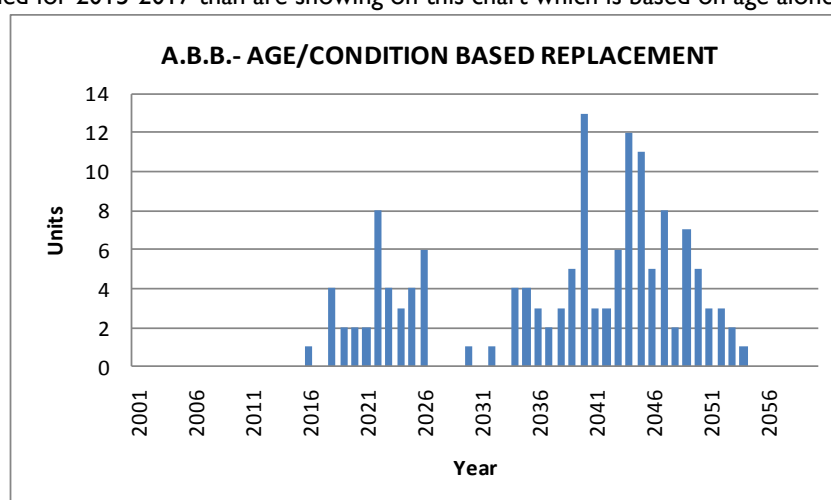


Figure 6.6 – ABB SD Replacement Schedule

6.3.2.3 ABB Safelink SF6 Ring Main Unit

ABB Safelink Units have been installed on the network since 2008. They were selected for their ability to be automated and their low maintenance requirements due to replacing the insulating oil with SF6 gas. ABB also provides backup support for its locally manufactured products. The units installed on the Horizon Energy network have a modified locking arrangement on the mechanical interlocks to enhance operational safety of both the operator and the network.

The ABB SF6 insulated Safelink switch enclosure is a gas-tight welded stainless steel compartment. All components within the SF6 insulated tank are maintenance free for the life expectancy of the unit. Units are manufactured as either a three or four switch/fuse unit assembly depending



on what is required for the specific location requirement. The units can also be supplied with an environmental enclosure that fully encloses the unit for tidy installation within a public environment. ABB operates a worldwide gas recovery network for the disposal of SF₆ gas at the end of life of the unit. The manufacturer recommended life span exceeds 30 years for indoor service.

All units are installed with cable fault indicators to assist with fault finding.

The ABB series 2 SafeLink Units with full automation was released in August 2012. These units have been selected to be installed at tie points in line with Horizon Energy's feeder automation program.

Lifecycle Management

Maintenance is limited to annual inspection, vegetation control, and general overall condition of the switch unit and kiosk. SF₆ gas pressure is monitored by a pressure gauge and will not allow any operation if a low gas pressure is detected. The ABB Safelink Units are new to the network and therefore there are none due for replacement within the current planning period.

6.3.2.4 ABB SafePlus SF₆ Switchgear

Horizon Energy has two SafePlus circuit breaker units installed in Kawerau on an industrial site used for the control of one 1MVA and one 2MVA transformer.



SafePlus is a modular, completely sealed extendable SF₆ system with a stainless steel tank containing all the live parts and switching functions. A sealed tank with constant atmospheric conditions ensures a high level of reliability as well as personal safety and a virtually maintenance free system. The pressure system is defined as a sealed for life system with an operating life time of 30 years. The leakage rate is stated as less than 0.1% per year.

The unit is unsuitable for outdoor use unless fitted into a building or shelter

Maintenance Schedules

All components in the SF₆ tank are maintenance free for the declared life expectancy of the unit. If the panels sustain any scratches or damage, these must be repaired with paint to prevent corrosion. Mechanical parts are positioned outside the tank and behind the front panel. This enables easy access and replacement if required.

The protection relays installed on the circuit breakers are scheduled for testing as per the maintenance schedule for electronic relays.

The units are inspected on a yearly basis with the standard checks made to ensure condition and operation is appropriate.

6.3.2.5 *Schneider RM6*

Merlin Gerin/Schneider RM6 switchgear comprises one to four integrated, low dimension functional units. This self-contained, totally insulated unit comprises a stainless steel, gas-tight metal enclosure, sealed for life, which groups together the live parts, switch-disconnector, earthing switch, fuse switch or the circuit breaker, one to four cable compartments for connection to the network or to a transformer.

Horizon Energy has three RM6 units recently installed as roadside Ring Main Units on the network, enclosed in aluminium enclosures for weather protection. Two of these have been set up as feeder circuit breakers to provide mid-point circuit protection and automated tie point connection, controlled through the SCADA system. The other has been installed to provide circuit breaker protection to a 1000kVA transformer installed at Whakatane Hospital.



Maintenance Schedules

The RM6 switchgear is regarded as maintenance free apart from annual inspections to control weeds and insects, and five yearly testing of the electronic protection relays. Due to the high H₂S environment in Kawerau the inspection will entail a full assessment of the condition of the internals, cable connections and overall condition of the RTU unit.

Lifecycle Management

The RM6 has a published life span of 30 years. In Kawerau, due to the atmospheric conditions, this may be shortened but future condition assessment will influence any replacement decision.

6.3.2.6 *CANZAC RTE Switchgear*

The CANZAC RTE units are in-line oil insulated rotary 11kV transformer switches directly connected to a distribution transformer. Horizon Energy has a small number of RTE units in the Whakatane urban region. The switches are reliable in operation but must be operated using a hot stick. The transformer/switch assembly is mounted in a fibreglass cubicle. This means the cable terminations are not sealed against vegetation growth as is the practice with modern switchgear. The mechanical cable support is in an awkward location and in many instances the cable has been installed with limited mechanical support. There are also no arc containment or explosion barriers between the incoming and outgoing cables, as can be seen in the accompanying photograph. The transformer fuse links tend to be a weak point with the switchgear.



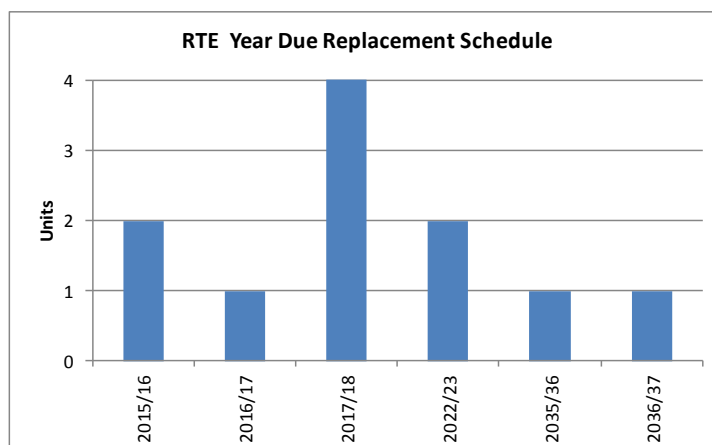
The RTE also has no means of integral earthing for the incoming and outgoing cables.

Maintenance

Maintenance is limited to bi-annual inspections and clearing away of any debris and vegetation.

Lifecycle Management

Due to the lack of cable earthing, in installations where RTE's were installed adjacent to each other, one of the units has been replaced with a switch unit that does have earthing capability. The balance of the inventory is scheduled for replacement as per the age modified condition replacement schedule shown below. Actual replacement will depend on condition, transformer load, capital constraints, and unit risk assessment.



6.3.2.7 Merlin Gerin Ringmaster

There are two Yorkshire/Schneider Ringmaster Ring Main switch units installed on the Fonterra site installed in 1997. Following a destructive failure of a similar unit in Kawerau in 2014 the two units located in Fonterra have been issued a 'do not operate live' status until further information is received from the manufacturer.

Schneider advised (2014) following analysis of the fault data that the failed unit in Kawerau was subjected to a current that was in excess of the rated peak-peak current (50kA) of the device.

The Ringmaster is gas insulated MV outdoor 11kV switchgear in two switch and one circuit breaker configuration. The gas insulated switches are sealed for life and require no maintenance. Maintenance is limited to periodic inspection of the physical condition of the housing and gas pressure checks.



Lifecycle Management

The two units in Fonterra will be maintained as off-load operational switches until it is determined that they be replaced. Nominal life of these units is 35 years, giving an end of life replacement year of 2023. Any earlier replacement will be client driven.

6.3.3 Overhead Assets

6.3.3.1 Poles

Horizon Energy has over 23,200 poles in the network. These are a mix of concrete and wooden poles from various manufacturers with varying age. Nominal expected life of a concrete pole is 60 years and a wooden pole is 40 years.

All poles are individually numbered to assist in their lifecycle management.

Figure 6.7 below is a list of pole by material extracted from GIS.

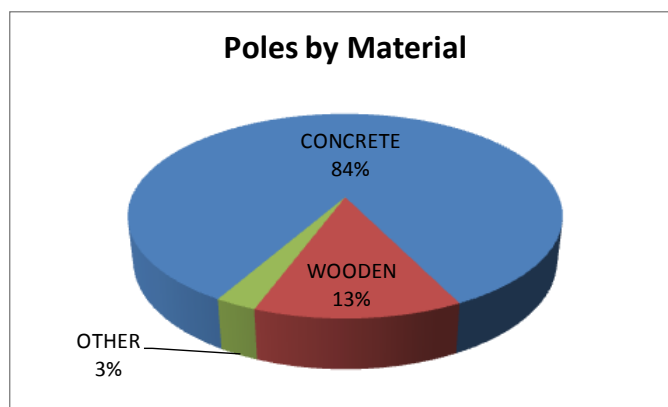


Figure 6.7 – Pole Material Schedule

Poles Lifecycle Management

Condition assessment of a sample of 3806 poles identified that 202 poles, or 5.3% of the poles inspected, have defects of some sort. Pole inspection includes all connected assets:

- Chipped concrete;
- Crossarm or insulator faults;
- Loose or poor condition guys;
- Exposed aggregate; and
- Timber splitting or rot.

Areas having a high density of assets with low remaining life are being grouped into specific projects, as it is more cost effective to upgrade complete sections of feeders between isolation points rather than replace assets individually. This approach sets a new baseline for condition for the whole section of the upgraded feeder.

Figure 6.8 summarises the asset inspection condition assessment of all network poles, which includes pole hardware. If all poles with a life of < 10 years to be replaced, an average of 115 poles per year are to be replaced. If poles have an average life of 60 years, an average annual replacement of 383 poles is required. Figure 6.8 shows an average of 106 poles per year have been replaced in the last 8 years. This level is consistent with the age profile of the assets at this time but will require a step up over the next 10 years.

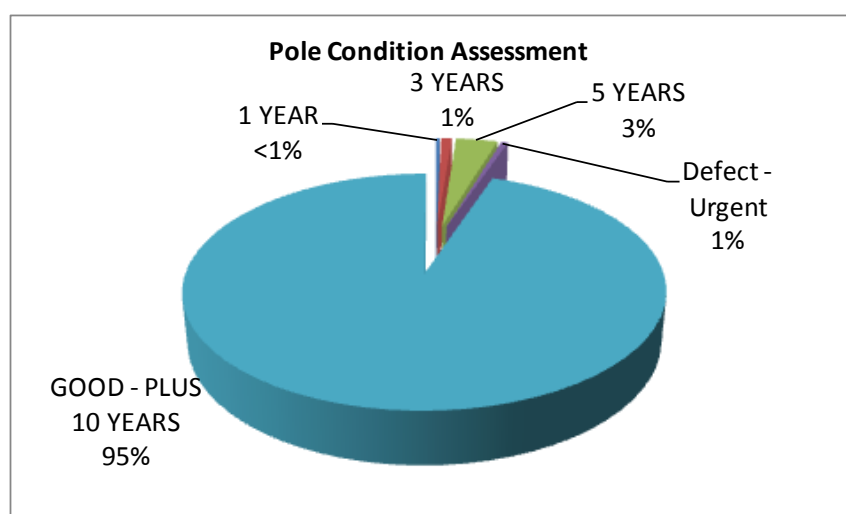


Figure 6.8 – Pole Condition Assessment

Larch poles (0.3% of the asset base) are mainly used for low voltage road crossings and SWER lines. These poles have a tendency to rot below ground level and split longitudinally. They have generally been replaced in the past in area projects. Future replacement priority will be by condition.

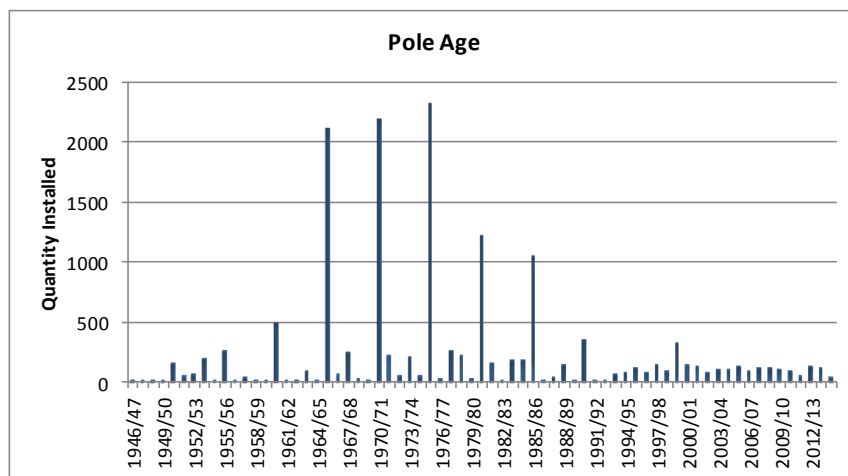


Figure 6.9 – Pole installed by year

Figure 6.9 shows the poles installed by year. Figure 6.10 graphs the poles replaced by year and the accumulated pole replacements required if the poles have a 60 year asset life is shown on Figure 6.11. This indicates an increasing spend requirement from 2024 through to 2044, which has been allowed for in the forward planning.

Spikes in figure 6.9 above are due to historical data resets aligned to specific dates, and do not represent the actual asset age.

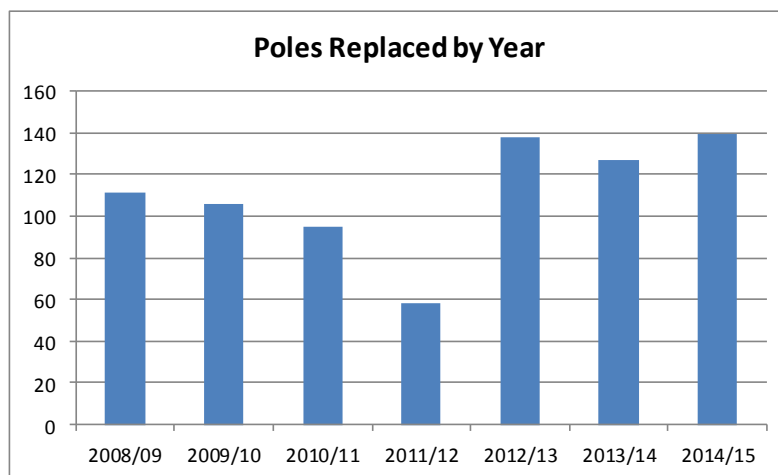


Figure 6.10 – Poles replaced by year

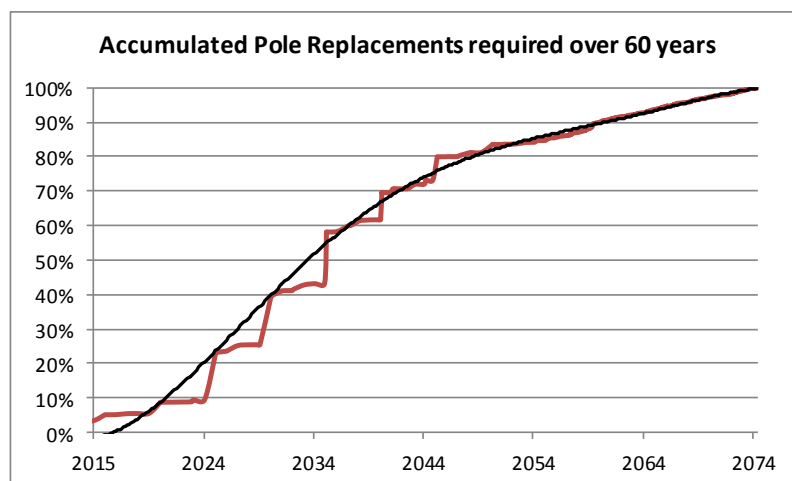


Figure 6.11 – Accumulated pole replacements required

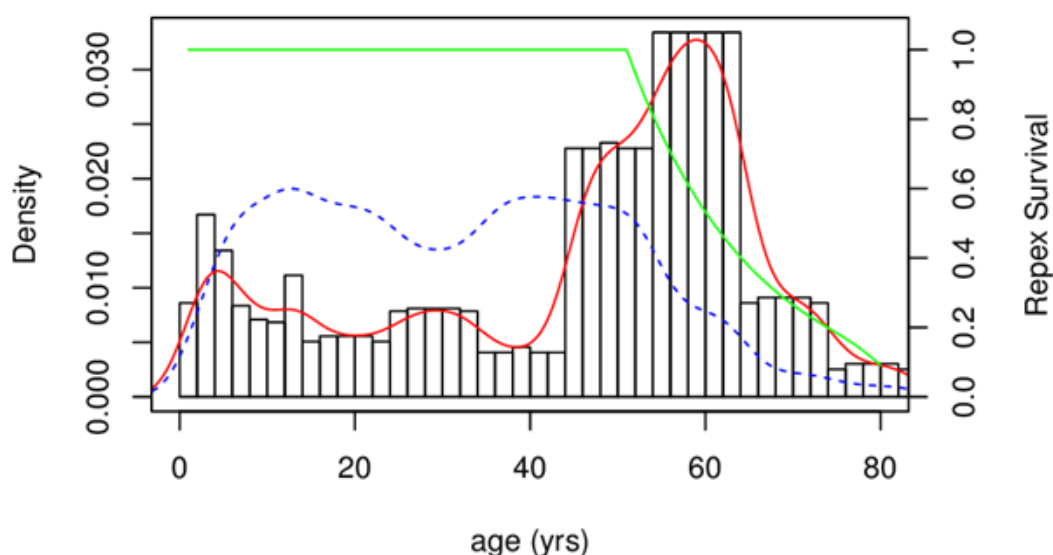


Figure 6.12 - Wooden pole age profile

Figure 6.12 above highlights the age of wooden poles against their anticipated survival rate. The green line is the survival rate line, the blue line the industry average age profile. This chart identifies that there are a large number of wooden poles that are beyond their nominal life and need to be scheduled for replacement. Some of these are captured in underground conversions, and a number of larch poles have been specifically identified and have been scheduled.

6.3.3.2 Overhead Asset Ownership

Horizon Energy asset ownership policy is to own all 33kV, 11kV and low voltage distribution assets. Low voltage distribution assets are owned up to property boundaries unless they supply two or more customers or by agreement with the landowner.

As part of the asset inspection process, land owners are informed if the assets on their property are defective or at risk and a refurbishment service is offered to the property owner.

6.3.3.3 Crossarms, Conductor and Insulators

Crossarms, insulators and the conductor they support make up the components that form the pole assemblies for overhead lines. Their condition and their lifecycle management have a large bearing on the overall reliability of the network.

Each component on a pole assembly has a different life expectancy:

- Hardwood crossarms tend to have an expected life about half that of concrete poles, and invariably fail due to rot, splitting and insulator hole enlargement;
- Insulators degrade due to the interference from pollution and/or lightning;
- Galvanised fitting and guy wires corrode and work harden, resulting in a need to be replaced, especially in coastal regions. A program of replacement has been scheduled; and
- Hard Drawn Bare Copper (HDBC) tends to corrode and work-harden and areas with small diameter HDBC conductors have been scheduled for replacement.

Failure mode analysis has identified one series of 11kV insulators used on the network that has been causing problems. These insulators have a tendency to develop hairline cracks between the top of the pin and the insulator binding which cause intermittent faults, especially when they get wet after an extended dry period. The cracks in many cases may be due to lightning 'puncturing' through the insulation at the top of the insulator. These insulators were used extensively across the network and it is not feasible to replace them in bulk except during a planned area upgrade.

Conductors have a theoretical age profile similar to poles. The actual life expectancy is dependent on a number of conditions:

- Environment;
- Loading stresses;
- Corrosion;
- Vibration;
- Binding failure;
- Tension;
- Interference from trees; and
- Arcing faults from clashing.

A large proportion of the Horizon Energy network is located in a coastal environment and due to corrosion these coastal assets tend to age faster than inland assets. This is recognised in a higher planned refurbishment program scheduled for works in coastal regions.

Aluminium conductor steel reinforced (ACSR) cables in coastal environments can develop stress corrosion due to a slow galvanic reaction once the insulating grease between the aluminium and the steel is washed away. Horizon Energy has new works being built using All Aluminium Alloy Conductors (AAAC) which have no steel core to replace ACSR. AAAC has a number of advantages:

- Higher current carrying capacity;
- Lower volt drop per meter;
- Easier to handle for installation;
- No dissimilar metals, eliminating galvanic action corrosion; and
- A lower ultimate tensile strength.

Horizon Energy has a network wide replacement policy for galvanised steel conductors and copper conductors in coastal regions.

A project started in 2012 to raise the clearance of overhead lines across roads, starting with state highways. Horizon is currently undergrounding all low voltage road crossings for high loads travelling from Tauranga to Kawerau.

Horizon Energy's installation standards specify that lines are to be installed one meter higher than the legal minimum clearance; however a number of road crossing lines do not meet the Horizon Energy standard, even though they do meet the minimum legal requirement, and these will be worked on as a priority.

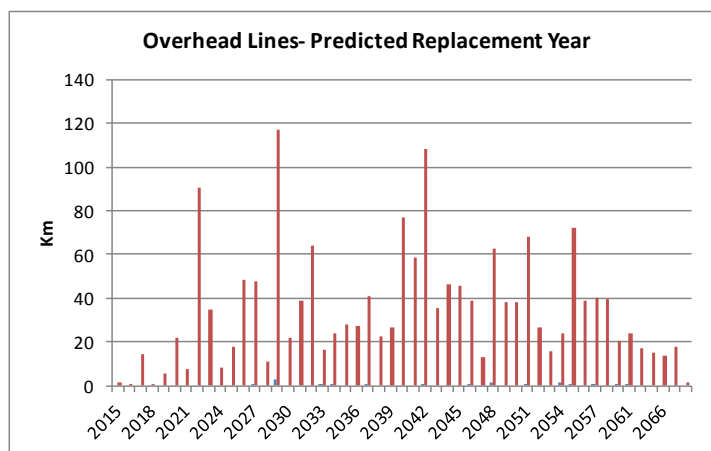


Figure 6.13 – Overhead Lines Replacement Profile

Forward predictions for overhead line replacement are shown on Figure 6.13 above, based on a nominal 60 year life expectancy. Average replacement length required per annum is 34 kilometres, although it is expected inland conductors will exceed this life expectancy. Figure 6.14 below shows the asset age against survival profile. Due to the public risks associated with conductor failure an active replacement program has started, initially targeting high density bare copper (HDBC) and galvanised wire conductor.

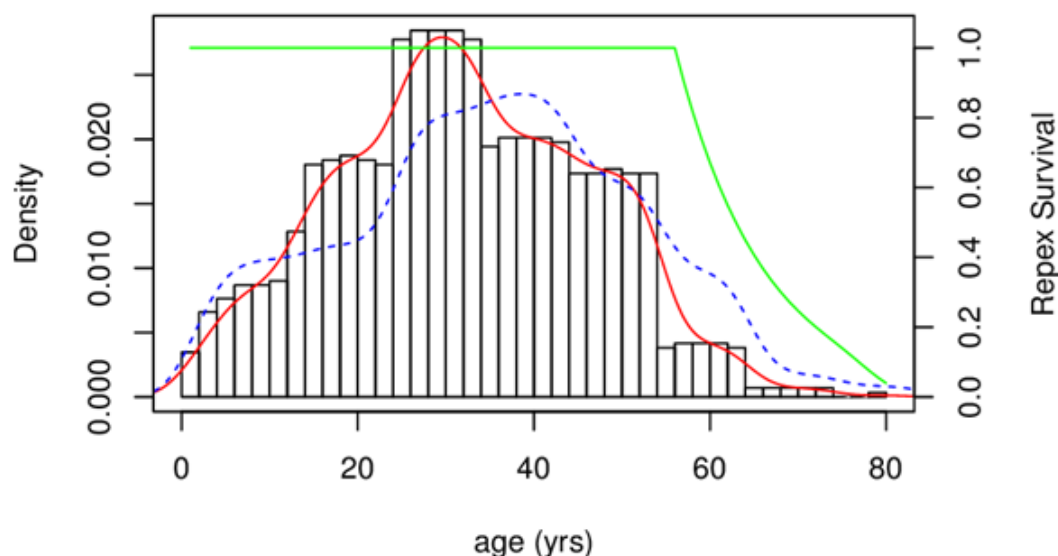


Figure 6.14 - Overhead Lines age profile

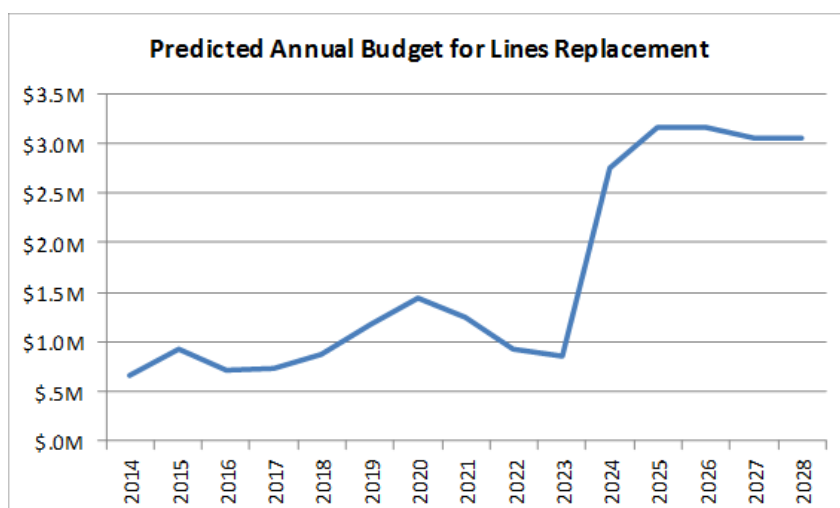


Figure 6.15 – Projected spend on line replacement

Figure 6.15 shows the projected spend on line upgrade works with the spend profile following the age profile of the assets. The reduction in spend from 2019 to 2024 is to balance cash flow for zone substation transformer replacement projects.

6.3.3.4 Air Break Switches

There are approximately 450 11kV air break switches on the network. Most of these are non-load break switches.

There is no specified maintenance practice for air break switches in rural networks and they are replaced or repaired on a condition or failure basis.

Switches that are inspected using thermal imaging are:

- Zone substations;
- 33kV switches;
- 11kV in Kawerau on Pulp, Paper and Onepu feeders; and
- Others as identified due to condition or customer requirements.

Lifecycle Management

ABS switches are replaced with hot-stick operated, fully insulated, enclosed switches, to reduce the effects of atmospheric contamination, and to eliminate the need for earth banks. The switches are capable of retrofitting automation controllers if required. A priority list for switch replacements, at the rate of 10 per year, targets switches in critical services and older switches for priority replacement.

6.3.3.5 Voltage Regulators

There is only one voltage regulator in the network, located at Opotiki on the Factory feeder.

Maintenance is scheduled as:

- Two yearly inspection and functional operational verification; and
- Five yearly full service including oil tests and insulation resistance.

The maintenance schedule is modified by the number of operations count and a full service is scheduled for regulators that have completed 100,000 operations.

Lifecycle Management

These units have a standard handbook life of 55 years.

6.3.3.6 Capacitor Banks

There are two capacitor banks in the network, one located at Opotiki on the Factory feeder and another on Galatea Troutbek feeder..

There are no active components on the Factory feeder unit and hence no maintenance requirement for these units apart from inspection as part of normal lines inspections.

The Galatea unit has a controller and switch so maintenance is scheduled for every 3 years

Lifecycle Management

There is no planned end of life replacement policy for capacitor banks. It is anticipated capacitor banks will last for 40 years and will be replaced on a defect or condition assessment basis.

6.3.4 Distribution Substations and Transformers

There are over 3,300 transformers on the network.

Distribution transformer failure rates are very low, with most overhead transformers being changed either due to failure from being damaged by lightning, or changed due to a larger unit required to cater for customer load increases.

The majority of rural transformers damaged by lightning are either at the end of spur lines or before open switches on tie points. There appears to be no obvious failure trend related to age for transformers damaged by lightning strikes.

The tendency for end of line transformers to be damaged is thought to be caused by the voltage doubling affects due to the reflection of the voltage surge. Data on lightning damaged transformers is still being collected following storm events, and the cost benefit of installing surge arrestors on all end-of-line transformers, to reduce the likelihood of failure, has been assessed using this data. When new transformers are >30kVA installed at the end of lines they are now being fitted with surge arrestors.

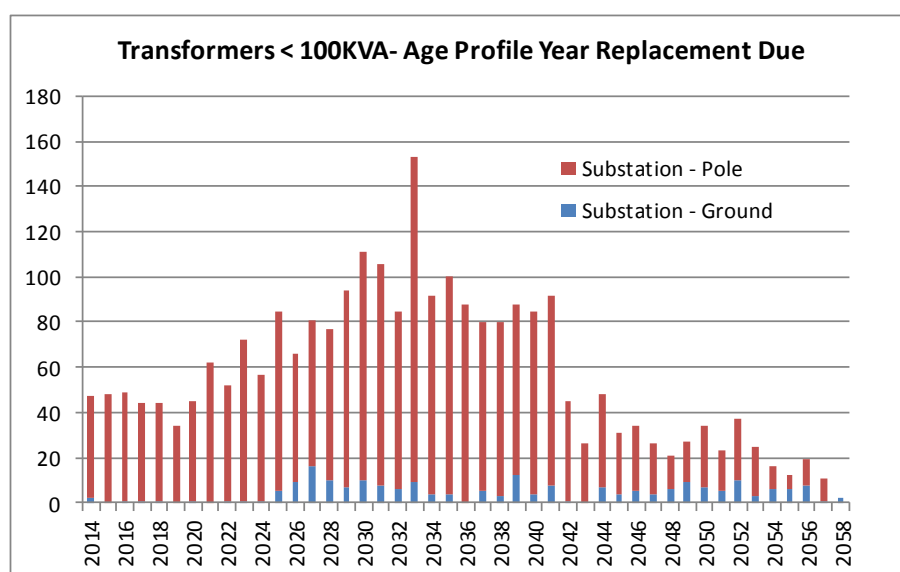


Figure 6.16 - <100 kVA Transformers Predicted end of life profile

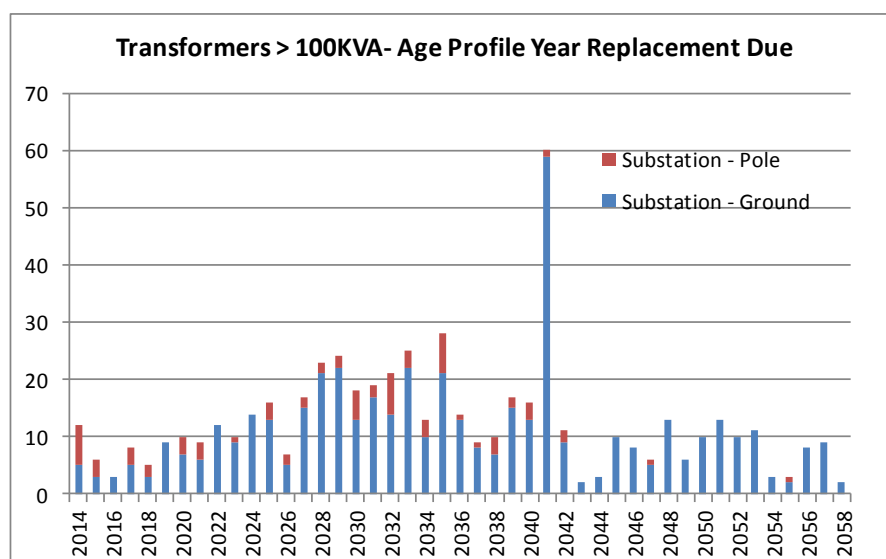


Figure 6.17 - >100 kVA Transformers predicted end of life profile

The transformer predicted end of life profile (Figure 6.16 and Figure 6.17), indicates a future liability as transformers continue to age, and it is expected that annual maintenance spending on transformer replacement and overhaul will increase over the next 20 years. This has not currently been factored in detail into forward budget forecasts as the steep rise in end of life is towards the end of the planning period.

Figure 6.17 shows the predicted end of life for transformers over 100kVA. The spike at 2041 is due to a data reset period being carried forward. The replacement of pole mount transformers will incur significant cost as the network policy is to ground mount transformers 100kVA and over. Average annual replacement requirement for transformer 100kVA or greater is eight transformers, which includes an average of two ground mount transformers per year scheduled for replacement as part of the RTE and Magnefix replacement program over the next 30 years.

A significant number of transformers are currently beyond their expected life. Some have been scheduled for replacement with the Magnefix and RTE upgrades. Large poletop transformers have been scheduled for replacement with ground mounted transformers. Ground mounted units will be assessed for condition and risk, and scheduled for replacement if this is warranted.

Transformers older than 45 years						
Rating (kVA)	100	150	200	250	300	Total
Ground	5	4	13	7	1	30
Pole	7	2	3	5		17

Transformer Lifecycle Management

The transformer refurbishment policy for transformers that are returned from service due to load driven changes, maintenance replacement, or damage is summarised below:

- Small pole mount transformers with external galvanising in good condition and no visible damage and which have not been removed due to a fault can be free issued for installation on the network after simple insulation resistance and continuity tests without further work;
- All transformers with cores built pre 1978 are written off due to their high no-load losses;
- Any pole mount unit less than 50kVA that has been removed due to an electrical fault condition, or if the unit is over 30 years old, is written off;
- All other pole mount transformers are assessed for repair. If the expected repair cost (including transport), is greater than 75% of the replacement cost, then these are to be written off;

- All ground mounted transformers less than 100kVA are assessed on both electrical and mechanical characteristics. If the case is in poor condition or of a design that would no longer be approved then the whole unit is written off. If the case and paint are in good condition and the unit has not faulted then it can be treated the same as a small overhead unit;
- Any transformer less than 100kVA that is assessed for repair, and if the expected repair cost (including transport) is greater than 75% of the replacement cost, then the transformer will be written off; and
- Pad mount units 100kVA and above are assessed for repair. If the expected repair cost (including transport) is greater than 75% of the replacement cost, then the transformer is written off.

As part of the assessment process the future use of the transformer is considered. If a transformer is of a type that would only be used as spares and not for new installations, e.g. open bushing type that would normally be replaced with a pad mount; if stock levels of that type and size are adequate then the unit will be written off.

Transformer Service Life

Horizon Energy has no evidence of any age induced failure patterns with transformers. Transformers are a thermal device and their load carrying capacity and actual electrical life is influenced by load. Rural transformers peak utilisation factor average is between 18 to 23 per cent, and the range for urban transformers is between 35 to 80 per cent. With these levels of utilisation the transformers can be expected to exceed their standard ELB life as defined in the ODV handbook. It is generally physical condition or the need to service connected load that drives asset replacement.



Consideration is being made to instigate a program to condition test the larger ground mounted transformers. The use of transformer metering is also being trialled but at present no decisions to implement either of these policies has been made.

The transformer installation policy has the maximum size of pole mounted transformer as 75kVA. The cost and convenience that is provided by micro subs now means that more often transformers are ground mounted even in rural areas. A number of aged pole mounted transformers greater than 100kVA have been identified for replacement with ground mounted units. These are scheduled based on age, condition, the number of customers and utilisation factor. The majority of these transformers are located in urban regions.

Small pole mount transformers are generally managed on a run to failure mode due to:

- Limited impact on the network of individual small pole mounted transformers;
- Relatively low replacement cost of individual units;
- Uncertainties of loading and utilisation; and
- Costs and difficulties of actually completing electrical condition testing on these transformers.

Asset Data Capture

Close to 10% of transformers were marked as either defective, or with less than five years of life remaining. The majority of defects noted are tank or kiosk corrosion and the five year life assessment related more to the surface condition of the transformer or kiosk than the electrical condition of the transformers.

A small rural transformer will generally not be replaced due to surface rust unless significant deterioration is detected. Larger ground mounted transformers that have serious corrosion are replaced with a new or refurbished unit and the old unit assessed, and if suitable due to age and type, sent to a service agent for refurbishment. The service agent assesses the cost of refurbishment and a decision is made to either accept the repair or to scrap the asset.

Transformer Load Assessment

A method of assessing the estimated peak load of the transformers based on total kWh supplied to customers has been developed, and by using this tool with verification by actual load measurement, a number of overloaded transformers, or transformers at risk, have been identified for upgrade. Priority has been given to transformers 100kVA or greater.

Projects

Larger distribution transformers identified for refurbishment or replacement are identified in the 10 year projects list.

A future project in the latter part of the 10 year plan is to install load and condition monitoring equipment on to larger ($\geq 300\text{kVA}$) transformers. This project is intended to make use of communications systems to monitor transformer utilisation and operating temperatures as a means of predicting ultimate life and asset condition.

6.3.5 Network Automation Devices

Network automation devices used in the network include;

- McGraw Edison KFE/KF circuit breakers, circa 1970's are being phased out and replaced by Cooper Power Nova 15 circuit breaker;
- New tie and sectionalising switches being installed were fully enclosed Entec LBS switches, which being fully sealed from the effects of environmental corrosion and having a non-arcing switching environment, are expected to have a longer lifecycle and better reliability than air break switches;
- ABB Sectos switches are being installed in lieu of Entec switches from 2016
- Schneider RM6 units are installed when ground mounted circuit breakers are required; and
- ABB fully automated Safelink gas insulated switches

A number of installed pole top circuit breakers have no SCADA control due to there being poor radio coverage into various remote sites. This has improved on some sites with the installation of new VHF radio frequencies and some of these previously uncontrolled devices have been identified for upgrade to SCADA control.



Sectionaliser

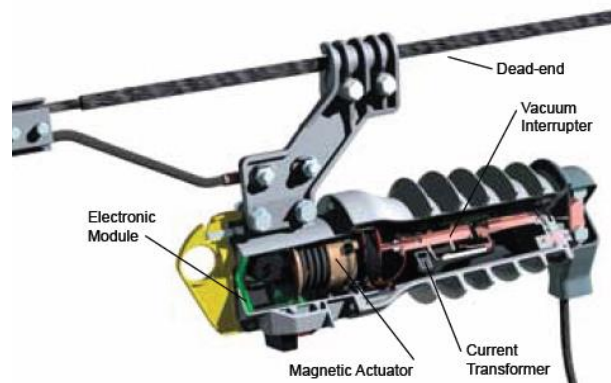
Other protective devices used are line mounted sectionalisers and drop out sectionalisers. These devices work on the principle of detecting a fault current passing through the device that exceeds a pre-defined threshold, and then relying on the upstream circuit breaker to isolate the fault. Once the fault has been isolated by the circuit breaker, the sectionaliser opens (or drops out in the case of a drop out device) and the upstream circuit breaker then closes to restore power to the line before the sectionaliser. If the sectionaliser has no communications to the SCADA master station then the consumer is relied on to identify the power outage.

The AK drop-out sectionalisers have proven to be intermittent in operation and their use has been discontinued.

Fuse saver

A new device on the market in 2011 is a fuse saver. The FuseSaver™ is a self-powered, electronically controlled, single-phase fault interrupting device that is installed in series with a fuse to protect that fuse from transient faults. The fuse saver operates on the first fault passage. If the fault re-occurs within a defined time the fuse operates to isolate the faulty section from the supply.

These have been trialled successfully and are approved for installation on the network. Recent development has been a communications package that allows the fuse saver to communicate to a master station.



Fuse Saver

SCADA Controlled Devices Maintenance Policy

Maintenance Activities

- Remote controlled devices have their battery changed on a five yearly cycle as part of their routine maintenance;
- Circuit breakers have protection elements tested 5 yearly; This routine was adopted to reduce the number of equipment failures due to battery failure and allows more economic batteries to be installed;
- Oil Breakers (Cooper Power KFE, KF, GN) have the oil changed and are protection tested every three years; and
- The modern gas insulated switches and circuit breakers are classed as maintenance free so their maintenance program is to cycle the switch and continue the five yearly battery replacement cycle, and to give the units a general condition inspection.

Life Cycle Management

- Poletop devices are being replaced on an age modified condition basis;
- All existing KFE oil filled devices will be replaced by 2017;
- Nominal life for modern equipment is 35 years although this is probably optimistic for the electronic controllers and these can be expected to be replaced once during the devices lifetime; and
- Fuse savers have a nominal battery life of 10 years and are replaced complete with the communications module.

6.3.6 11kV Cables

- There is extensive cable reticulation in the Kawerau and Whakatane urban areas, mostly XLPE cable;
- No routine cable testing program in place at present;
- A cable replacement program has been set up for main feeders in Whakatane based on projected load growth and estimations of when the cables are likely to either become overloaded, or be unable to support reinforcement loads;
- A batch of early generation XLPE cable in the network has had water treeing failures in the past and a section of this cable on the Ohope/City South tie feeder was tested with a Tan-Delta tester in 2010. This cable was found to have a low tan-delta test but passed a VLF test, and was recommended for monitoring and retesting in the near future. Due to its criticality as a tie feeder to Ohope, this cable has been scheduled for replacement; and
- Other batches of this cable in Kawerau are scheduled for replacement.

Cables Maintenance

The asset condition assessment process currently excludes underground assets. As the cables age some form of condition testing will be required to determine failure likelihood and to establish replacement priorities. XLPE cables most at risk are those manufactured prior to 1970, due to a lack of understanding at that time of the effects of material impurities in the moulding process on electrical stress degradation with time. There are very few XLPE cables this age.

A cable condition assessment program is under consideration, decisions on whether to outsource this to a third party to provide the service or to procure equipment and complete testing in-house, have yet to be made.

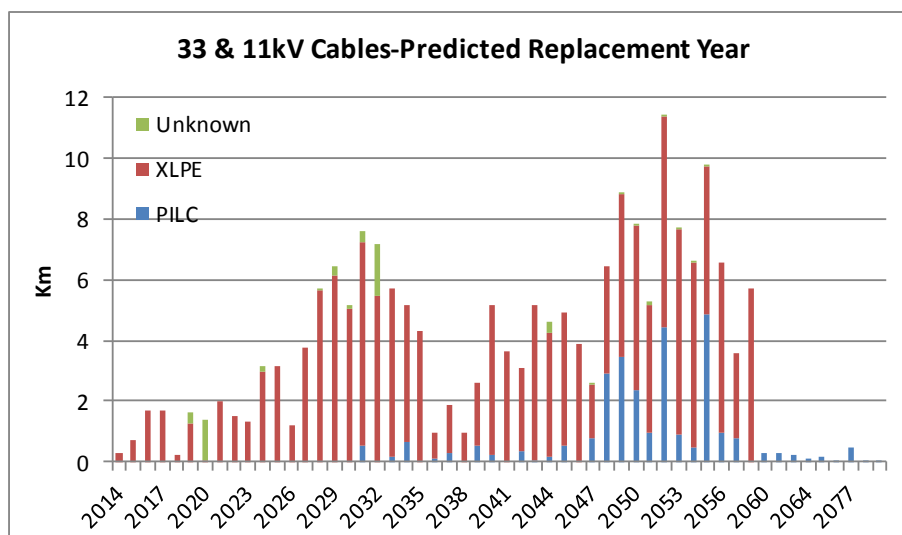
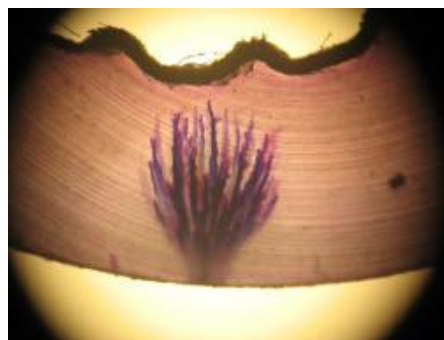


Figure 6.18 – 33kV and 11kV Cables Age Profile

The forward looking age replacement profile shows the probable future of 11kV and 33kV cable replacements. As with all asset replacements condition, load and reliability will be the primary drivers for replacement. Due to their generally lightly loaded condition, most cables are expected to exceed their standard life.

Faulty Cable Testing

A faulted 95sqmm XLPE 11kV feeder cable tested by Olex determined that the presence of large contaminants (0.7mm) in the insulation of the cable manufactured in 1971 was the likely cause of the cable failure. Pictures below show the fault location and a microscopic view of a vented tree in the XLPE insulation, but no electrical stress tree is present in the insulation. This cable failed following an extended period of overload during reinforcement.



Horizon Energy does not have a policy of testing every faulted cable, but following this failure a quantity of the same batch of cable was identified in service. Similar cable has failed in service in Kawerau in 2011 and 2013 so when these cables are identified they are assessed for consequence of failure and scheduled for replacement. A section of this type of cable on the Ohope feeder tie to Station Road was replaced in 2013 as a precautionary measure, along with various sections in Kawerau.

6.3.7 Low Voltage Systems

Whakatane and Opotiki urban low voltage reticulation systems are mostly configured to be able to provide sufficient reinforcement to enable the removal from service of any one 11kV transformer and allow the loads to be carried by adjacent transformers. The loads can be supplemented by the installation of generation if required.

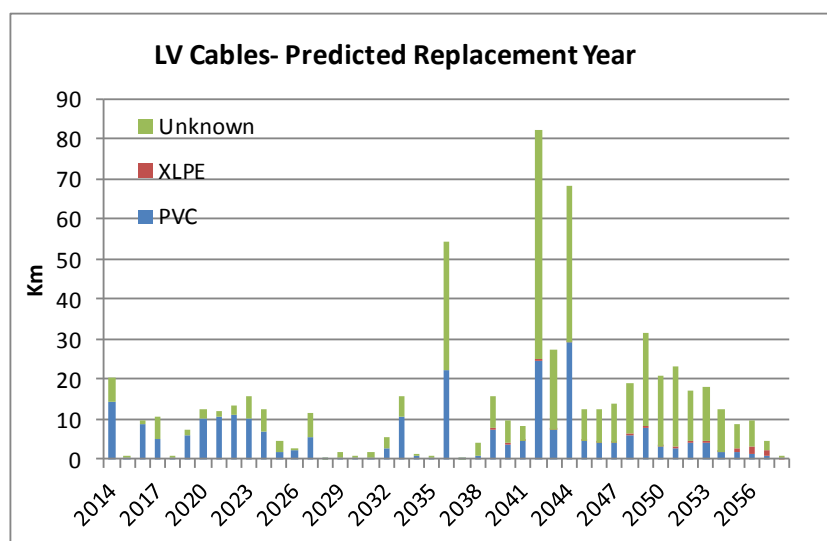
Load driven upgrades, over and above the requirements for reinforcement, will be implemented on a 'just in time' basis and will be driven by connection requests.

Horizon Energy has in place a long term undergrounding program for the urban areas of the network and other areas which are considered to have environmental or aesthetic value. Horizon Energy, the Eastern Bay Energy Trust, and the respective local District Councils jointly fund these works.

Effort is continuing in the interconnection of the LV system within the urban areas and in the production of LV schematics to assist in the operation of the network. In some cases augmentation of the LV assets has been required to address deficiency areas where load growth has caused stress to the existing network.

A multi-year safety driven project is scheduled to start in 2015 to install earthing at the ends of low voltage overhead lines neutral conductors.

The network has approximately 226km of low voltage overhead lines, and 165km of service lines, with approximately 264km of undergrounded low voltage network assets. There is 203km of streetlight assets, both overhead and underground.



LV cable is currently managed on a run-to-failure mode, and additional costs have been budgeted in the forward work plans from 2017 onward for low voltage cable replacements. The spikes shown on the chart are data reset dates within the asset databases.

Maintenance

Most low voltage maintenance work is reactive, or overhead circuits are repaired in conjunction with 11kV circuits when installed as an underbuilt structure.

During the asset inspection process it was determined that there is a compliance issue with earthing of the neutral conductor at the end of low tension conductor installations. To fully comply with MEN earthing requirements the neutral conductor should be earthed at the end of the conductor run, not just at the transformer supplying the low tension circuit. Special projects have been set up to remedy this issue.

Apart from defect or condition driven works there is no planned routine maintenance program for low voltage assets.

Life Cycle Management

Run-to-failure mode of operation means there is no planned end-of-life policy for low voltage assets. Ground mounted and overhead assets will be replaced on condition assessed, safety driven or failure basis.

Future budgets have made allowance for an increased expenditure on low voltage assets as the assets continue to age but no specific age based upgrades have been planned.

6.3.8 Load Control Plant

Description of Asset

A general overview of the ripple control transmitters is summarised in Table 6.12.

HORIZON ENERGY RIPPLE CONTROL TRANSMITTERS				
Location	Type	Date Commissioned	Injection	Frequency (Hz)
Galatea	Motor Generator	1969	11kV	750
Waiotahi	SFU-G/30	1992	11kV	317 and 750
Kawerau	SFU-G/60	1988	11kV	317
Plains	SFU-G/120	1999	33kV	317

Table 6.12 – Ripple Control Plant

- Demand side management strategy is to improve the efficiency of asset utilisation through minimising the magnitude of short duration peak loads;
- Four ripple injection plants positioned at key primary substations; and
- Load control has the capability to shed up to 3MW of interruptible load.

Operation Philosophy

A prime objective of the load management system is to minimise interconnection charges that apply at the various GXP's. The interconnection charge is based on the demand that is drawn at the GXP's that is coincident with the top 100 measured peaks for the lower North Island (LNI) Transpower demand region. A result of this operational philosophy is that if it is not an LNI peak, then no control is undertaken. The effect is that at many of the GXP's the demand at non LNI peak loads is allowed to reach levels that may stress the ability of the GXP assets sooner than they would have been had control been focused on the GXP demand.

Short term peaks are being incurred on the network particularly when controlled load is restored. This is common with a number of utilities and is caused by the tendency to over-control ripple plants to minimise peak transmission charges from Transpower. A modification to the algorithm of the load control system has been implemented so that network restraints are not created due to large levels of load swing being generated as the load control is returned to normal.

This is especially crucial on substations like Ohope that is already heavily loaded, where if all the load control system channels are returned to normal at the same time after an extended period of load control, the load can approach the full rated capacity of the zone substation transformer. Simple time delayed restoration for each of the ten load control channels will smooth out the restoration peaks.

The dispatch of control signals is automated through the SCADA master station that uses information published to the internet by Transpower for the indication of the LNI load profile.

Maintenance Schedules

Horizon Energy has a service contract with Landis + Gyr for backup support and spare parts holding for the ripple plants that includes an annual service inspection, 24 hour phone support, and stock holding of critical spares.

Lifecycle Management

Landis + Gyr recommend the replacement of a ripple plant after 20 years of service when the risk of component failure increases. Coupling cell components are regarded as highly stable, however the coupling capacitors are considered as having the greatest probability of failure. There are sufficient spare capacitors to replace one coupling cell held on contract in Auckland. New service parts are not manufactured for the SFU-G units and the number of critical spares maintained by Landis + Gyr is very limited.

The motor generator set that is used at Galatea is no longer supported by Landis + Gyr. Galatea operates at 750Hz and if replaced with a 317Hz unit would require replacement of all end-user receivers.

Replacement Assessment

- Load control is used for the reduction of Transpower interconnection charges that are treated as pass through costs. As such there is no opportunity for Horizon Energy to extract value from the assets that they provide and hence little incentive to replace the assets;
- There is benefit for retailers for cost reduction through the management of load away from times of high spot prices;
- Alternative options for demand management are summarised in Section 5.4.3 and form the basis for load management studies to consider options for replacing the ripple control system; and
- The continued operational function for the ripple control plants is under review and a run-to-fail with a no-replacement option is being considered.

Ripple Plant Replacement

Following a full study of the existing system in 2011, the following summary and recommendations were made from Landis + Gyr.

Study Conclusions

- SFU-G type converters and motor generators are not supported by Landis + Gyr and no spare parts are kept in stock. In the event of converter failure, a new SFU-K type converter will need to be freighted from Auckland and commissioned in place of the faulty converter. During this period of time, Horizon Energy run the risk of being out of Ripple control for a period of up to 24 hours;
- The existing Waiotahi Ripple Plant cannot be used if the network is upgraded to 33kV. The SFUG/30 converter rating is insufficient while the coupling cell is only rated for 11kV;
- Both the Galatea and Waiotahi regions have 750 Hz Ripple systems that are currently operational. Signal propagation at 750 Hz is poor and there is no guarantee of receiver operation; and
- Moving the Kawerau Ripple Plant away from the Transpower GXP will reduce its absorption and therefore allow a higher level of Ripple signal to spill into the Kawerau network. The DC bus of the Kawerau Ripple Plant could charge up resulting in converter damage if spillover occurred while the Plant was injecting. Excessive Ripple signal spillover can also result in Ripple telegram corruption thereby causing receiver mal-operation.

Recommendations from Landis + Gyr

- The Kawerau Ripple Plant is to be kept in its original location. Moving the Ripple Plant away from the GXP will impact the absorption of the Ripple Plant;
- Provisions to be made to upgrade the existing Ripple Plant (converter and coupling cell) at Waiotahi prior to the proposed 33kV network upgrade. It is also suggested that all 750 Hz receivers be migrated to 317 Hz prior to the network upgrade so that the new Ripple Plant is not

a dual frequency Plant. This is advantageous because the Plant would be cheaper and easier to manage;

- Provisions to be made to migrate the Galatea Ripple system (Ripple Plant and its receivers) to 317 Hz; and
- Horizon Energy to install redundant converters alongside the existing converters at Kawerau, Waiotahi and Edgecumbe. The redundant converters can be fitted with a manual changeover switch which will allow selection of the converter desired for operation. This would allow continuous service in the event of a converter fault. Alternatively a single redundant converter can be ordered and stored by Horizon Energy as a spare converter. In the event of a failure at Edgecumbe, Kawerau or Waiotahi the converter can be de-commissioned and the spare converter installed. Thereafter a Landis + Gyr Engineer may come on site to commission this converter.

High level (+/-30%) budgetary estimates (2011) to replace the load control plants are below:

Substation	Replacement Converter required	Budgetary price to replace converter	Budgetary price to replace entire Plant (2011)
Plains	SFU-K 403 (200 kVA)	\$120,000	\$300,000
Kawerau	SFU-K 203 (80 kVA)	\$75,000	\$200,000
Waiotahi	SFU-K 203 (80 kVA)	\$75,000	\$200,000
Galatea	SFU-K 103 (40 kVA)	\$60,000	\$160,000

These replacement projects have been included in the 10 year plan but implementation will be in consultation with retailers.

Smart metering technology is being investigated as an alternative to traditional Ripple Plant installations.

6.3.9 SCADA System

Description of Asset

Horizon Energy operates an IFIX HMI over a Foxboro SCADA system. The master station is located in the Horizon Energy control room in its main office at 52 Commerce Street in Whakatane.

The original SCADA was installed in 1992. The SCADA master station was replaced at the end of 2004 with a PC based Proficy IFIX system. The system has enhanced historian data storage and retrieval systems, alarm reporting and trending. It features remote terminal access for after-hours control staff, automatic fault and alarm calling and an escalating phone paging system.

Communications to each outstation is by fibre optic or radio communication. Outstation RTU's are located at each zone substation and communication repeater site, and at each pole top circuit breaker and controlled switch.

Outstations have components dating back to 1992 and these are being upgraded as substations are upgraded.

There is a project 2016 to replace the IFIX system with a Servalent SCADA system. The Servalent system has enhanced network automation packages, outage management, and improved system integration whilst being able to interface to the existing field equipment.

Maintenance Schedules

- Maintenance of the system is contracted to specialist SCADA providers, who maintain the master system and all software and upgrades;

- RTU remote stations maintenance is limited to visual inspections and battery bank maintenance; and
- There is an issue with firmware and hardware obsolescence within some of the RTU's and in the event of an outstation failure at a zone substation, there may be delays in restoring the service. A project was proposed to upgrade all stations to a common firmware level but this has been deferred and replaced with an upgrade project to convert the zone substations to a DNP3 protocol system over the next three years. This will see most of the old Foxboro RTU units either retired or upgraded.

Lifecycle Management

- A strategic upgrade to an IP based system is being implemented across all substations and field devices in the Edgecumbe region. The system will run dual protocols for three years as the existing Foxboro Conitel system is phased out and replaced with a DNP3 over IP system;
- IEC61850 communications protocol is under consideration for substations and has been implemented at the Galatea and Kope substations;
- SCADA master station servers are scheduled for replacement every five years;
- With progressive software and hardware upgrades the existing SCADA system is expected to have an indefinite life cycle, although this lifecycle is totally dependent on continued software, technical, and manufacturer support, plus the ability of the software to provide the functionality and integration required for future system automation and reporting requirements;
- Field equipment has a nominal life expectancy of 15 years. A number of existing field equipment components are approaching or have exceeded this age, but module replacement and the scheduled upgrade to IP based systems will reduce any risk of failure; and
- Invensys, the supplier of Foxboro equipment, in 2010 announced to all RTU users that the radio modem chip is no longer in production and that there are very limited spares stock available worldwide. With the migration of the communications system to an IP based radio system the modem will become redundant, but during the changeover period over the next three years, the system will be vulnerable to a modem failure. There is a functional work-around by using an external modem.
- The IFIX system will be retired in 2016-17

6.3.10 Communications System

The communications system provides voice communications, communications to pole-top circuit breakers and switches and high speed radio communications into the zone substations.

The system is configured with a high speed back-bone loop, with microwave radio from Plains zone substation, Pukehoko, Putauaki, and Commerce Street; and a leased fibre optic circuit completing the loop from Commerce Street, Kope, Station Road, Te Rahu, East Bank, and Plains substations.

Radial links exist to Galatea, Kaingaroa, Ohope, Waiotahi and Te Kaha, and a spur line VHF repeater is located at Cape Runaway to provide voice and data communication to the coast region north east of Te Kaha.

The system was installed between 2010 and 2012, with the substation spur lines scheduled between 2013-2016.

Each repeater site has a battery system that allows a minimum of 12 hours uptime should local supply be lost. The Cape Runaway site has a 36 hour battery capacity due to the remoteness and lack of vehicle access to the site.

The installation stages are:



2009-10	Installation of backbone repeaters at Commerce Street, Pukehoko, Putauaki and Cape Runaway	Complete
2010-11	Voice radio network including vehicle radios and pole top radio repeaters	Complete
2011-12	Pole top radios switched to E Band. All A band licences relinquished	Complete
2012-13	Completion of fibre optic link from Plains to Commerce Street, including East Bank, Station Road, Te Rahu, and Kope substations	Complete
2014-17	Progressive upgrade of substation infrastructure to Ohope, Galatea, Kaingaroa and Waiotahi	In progress
2015-16	Third Poletop repeater channel providing IP connectivity to field devices in the Edgumbe region	In Progress

Maintenance Schedules

- Annual check of repeater transmit and receive power levels, which is a mandated verification of performance;
- Battery condition; and
- Batteries are replaced on a routine five yearly basis.

Lifecycle Management

Upgrade of the complete system started in 2010 with the installation of the back-bone repeaters and new VHF systems. Links to the zone substations are scheduled to be upgraded over the next three years which will enable the retirement of the existing links and repeaters.

- Individual components installed in the new system have a life expectancy between 8 to 15 years;
- As a system, the ultimate system lifecycle is undefined as the technology is evolving at such a high rate;
- IP technology and digital radio developments are not expected to diminish in the foreseeable future and the technology behind the radios and the IP infrastructure will be supported well beyond the planning period;
- Direct connection to Transpower ICCP (Inter-Control Centre Protocol) system will remove the connection requirements at GXP sites (Edgumbe, Kawerau, Te Kaha, and Waiotahi);
- Communications with load control plant bypassed by the Transpower ICCP will be by VHF Poletop radios; and
- A third poletop repeater is scheduled to provide additional radio channels as the number of installed controlled field devices start to impact the available pole-top radio bandwidth within the Plains-Whakatane region.

6.3.11 Earth Banks

Earth banks are a critical safety component of the network and have a structured maintenance regime.

Regulations require that earth banks are tested at a frequency determined by the asset owner, at a period not exceeding 10 years. Horizon Energy has opted for a 10 year testing schedule. There are in excess of 5000 discrete earth banks in the network requiring 500 to be tested in any one year.

Earth Bank Management

- A recent analysis of a large number of earth bank test results has determined that a high percentage of the rural sites tested would fail to limit the step-touch potential rise to safe limits in a fault;
- IEC 60479-1 defines the step and touch voltage limits dependant on soil resistivity. There is different allowable step and touch voltages for each different geographical region, based on different soil resistivity;
- This data has been incorporated into an earthing compliance manual which defines earthing installation methods;
- An amount is budgeted within the operations budget each year for earth bank testing. Approximately 500 earth banks are required to be tested each year to complete the earth bank testing within the 10 year period;
- A separate sum is budgeted to complete any remedial works identified during testing;
- If a site is determined to have a higher than allowable earth bank resistance resulting in non-compliant step or touch voltages during a fault, the cost to reduce the voltage to acceptable levels is assessed against a probabilistic analysis of risk against cost. Risk assessment factors include the probability of a fault at the location, the likelihood of people being present at the time of the fault, and the profile of the people likely to be present as outlines in the EEA Guide to Power System Earthing Practice;
- The areas at highest risk of public harm are areas with overhead systems that are close to places where people congregate. These are priority areas for remedial works; schools, churches, maraes, beach resort areas etc. Mitigation works may include installing:
 - Larger earth banks;
 - Grading rings;
 - MEN bonding; and
 - Isolation of the risk from the site by the relocation of assets.
- The network region has four distinct areas of soil resistivity. Each area has its own different requirements for earthing to meet the touch potential limitation, and these are defined in the installation standards. These areas are shown in Figure 6.19.



Figure 6.19 – Soil Resistivity Chart

6.3.12 Substation DC Power Supplies

During 2011-12 there were a number of failed DC rectifier units in zone substations. Power supplies are redundant units so the failures have not caused any loss of service, but they are symptomatic of a

problem with ageing units. The DC units were all installed between 1992 and 1999 and direct replacement rectifiers are no longer available.

Reviews of modern equipment types and their supply voltages, demand loads, and the additional loads put upon substation systems has resulted in a decision to move the standard substation voltage to 48VDC, with battery banks designed for a 24 hour standby capacity. The substations DC supplies will progressively be upgraded as part of the substation communications and protection upgrade projects. DC-DC converters will provide legacy 24V and 12V supply requirements.

New substation equipment is being specified as 48VDC.

There is a single DC system for every substation except for Station Road. Station Road circuit breakers use 48V DC for circuit breaker closing, which introduces large spikes into the DC system. To mitigate this Station Road has a dedicated 48VDC supply dedicated to circuit breaker switching, with a second 48V bank for substation utilities. All other substation circuit breakers have spring charge systems which are supplied from the general DC supply for the substation.



DC Power Supplies Maintenance

- Batteries are sealed for life. Maintenance is limited to regular battery discharge testing, surface cleaning and visual inspection; and
- Modern controllers have full system monitoring, including controlled discharge testing, and fault alarming via Ethernet connection to SCADA and web browsers.

Lifecycle Management

- Batteries are scheduled for routine replacement every five years with annual testing to ensure the batteries still perform to their designed capacity;
- Rectifier and controller units have a 20 year life expectation. Due to the redundant installations these will be replaced on a failure mode basis; and
- Rectifier units replaced will be retained as spares.

6.3.13 Non-Network Assets

Non-network asset details are provided in accordance with subclause 1.4.3 of the Electricity Distribution Information Disclosure Determination 2012, being assets related to the provision of electricity line services but are not network assets. These assets include:

- Information and technology systems;
- Asset management systems;
- Office buildings and workshops;
- Office furniture and equipment;
- Motor vehicles;
- Tools, plant and machinery; and
- And other items treated as non-system fixed assets under GAAP.

The lifecycle management of non-network assets follows the estimated useful life as disclosed within the Company's accounting policies, most recently set out in the Annual Report. The estimated useful lives are as follows:

- Information and technology systems/Asset management systems:
 - Hardware 2 – 10 years

○ Software	5 – 10 years
• Office buildings and workshops	40 – 100 years
• Office furniture and equipment	10 years
• Motor Vehicles	5 – 10 years
• Tools, plant and machinery	2 – 10 years

The forecast capital expenditure on non-network assets as disclosed within Appendix A2 reflects this expenditure cycle.

Significant non-network projects planned or under development over the next five years include:

- Systems upgrade following the Electricity Distribution Information Disclosure Determination 2012;
- Asset management system and integration to GIS;
- ERP upgrade; and
- IT servers UPS system upgrade.

Horizon Energy owns two truck mounted 300KVA generator sets, purchased in the late 1990's and are approaching half-life. Full life retirement is scheduled for around 2025. Regular maintenance is scheduled in accordance with the engine manufacturer's recommendations. In 2012 the controllers on both generators were upgraded.

In 2013 the company took delivery of a containerised, transportable IMVA generator set and step up transformer. This unit is designed to be used for peak lopping, voltage support and fault restoration. The generator has full synchronising capability. It is planned that the units reside at Waiotahi to assist with the voltage support issues at Opotiki, but are available for re-location to other areas if required.

Maintenance schedules are defined by the equipment manufacturer. Policies around when the unit will be deployed on faults are not formalised, but due to the time required to mobilize relocating the units requiring cranes and heavy transporters, the generator will generally only be relocated for longer duration faults or planned outages.



Figure 6.20 – Generator Plant showing Generator, Transformer and Fuel tank

6.4 Network Systems Development Options

Network asset major projects and development alternatives are summarised in Table 6.13 below:

Area	Issue	Options	Preferred Solution	Justification	Year
LV Reticulation Upgrades	To provide adequate reinforcement to minimise outages	Network 1. Upgrades of identified reinforcement weak spots and high load zones in areas of the Whakatane urban area 2. Provision of generator connection points Non Network 1. Localised generation	Engineered on a case by case basis. Upgrade heavily loaded transformers and cables to provide sufficient capacity to reinforce neighbouring circuits	To minimise outages in areas of the Whakatane urban area. Based on a completed study	As required for LV upgrades
Undergrounding program	To improve the environmental or aesthetic value of the community by undergrounding the overhead lines	Network Long term undergrounding program for the urban areas of the network and other areas	Need clear value to Horizon Energy	Covered by a cost share agreement with each District Council and the Eastern Bay Energy Trust	Deferred for 2013-14 for all Councils
Load Control	Replacement of load control systems	Network Replace existing load control systems at Edgecumbe, Kawerau, Galatea and Waiotahi with optimal solution Non Network Investigations into smart metering and demand management Run-to-Failure with non-replacement	Still to be evaluated as part of the engineering study	The existing load control systems are beyond their economic life and require replacement. Replacement parts are no longer available for these units	in negotiations with local councils to remove load control from streetlight systems

Area	Issue	Options	Preferred Solution	Justification	Year
Poletop Circuit Breakers	To replace ageing circuit breakers	Network 1. Rolling programme based on replacement criteria Non Network 1. No options available	Based on replacement criteria of condition, test results the number of operations, the importance of the circuit breaker to the network, and the overall reliability of the feeder	Replacement parts are no longer available for these units	2009-2017
SCADA and Substation Automation	To upgrade to high speed communications systems	Network 1. Install high speed communications systems for each substation in conjunction with major planned works 2. Install high speed communications systems for remaining substations Kawerau, Plains and East Bank	Radio and fibre optic based communications systems for the SCADA system, using TCP/IP carriers and open protocols for substation data transfer	Enable each substation to provide improved metering and data collection, allow remote diagnostics of IED relays, sequence of event monitoring, intelligent or semi-automated switching schemes to be implemented,	From 2012 for remaining substations. 2017 for semi-automated/fully automated self-healing systems.
Feeders	Improve reliability	Implement smart system outage analysis and automated system recovery (after reliability projects completed)	Various options yet to be engineered	Provides self-healing system to meshed networks	2015-2017
11kV and 400V Overhead Distribution	To replace and upgrade end of life assets	Network Develop a planned replacement programme based on asset inspection process and load flow assessment Non Network No alternate options identified	Replace specific asset with modern equivalent based on weighted criteria that take into account condition, age, criticality to the network and previous history	To replace substandard or short life assets identified through the asset inspection process. Specific assets have poor functioning performance such as rotting poles, and rusting wires	Ongoing

Table 6.13 – Summary Network System Planned and Option Analysis

7 Risk Management

7.1 Introduction

Horizon Energy subscribes to the vision of 'Act Safe, Work Safe, Live Safe' and promotes it in its values as portrayed by the cultural behaviour program, SWITCH. Underpinning the vision, the following objectives drive and demonstrate success:

- We know, manage and understand our risk;
- Zero harm is a lifestyle at work and at home;
- We communicate even though there may not be bad news;
- We do the right thing even though nobody is watching; and
- We all participate to make a difference.

The objectives are supported by various strategies and deliverables to enhance the safety performance of the Group. Some of these strategies include:

- Implementation of a central database, Vault, to record all safety incidents, training and events;
- Establishment of the Company's risk register to review effective control measures and risk profiles for the tasks that are performed;
- Establishment of training needs analysis and training records that ensure competency of staff and systems;
- High emphasis on communication and the sharing of information;
- Participation in and alignment to industry benchmark performance measures;
- Proactive sub-contractor management.

Risk is managed through an on-going process of risk identification, safety by design, safety assessment, and the development of risk removal or mitigation strategies including routine inspections, maintenance and emergency response planning.

The risk assessment will reflect the potential impact on the business, including staff and public safety, the ability to maintain supply, environmental impact, legislative and financial exposures risk.

7.2 Risk Management Process and Methodology

7.2.1 Risk Process

Horizon Energy strives to manage risk to enable business objectives to be consistently met, whilst recognising the potential impacts of its activities on the environment (community within which the Company operates). The risk management process is linked to the strategic and business planning process.

The risk management process is designed to ensure that:

- All significant risks to the Company and community are identified and understood;
- The highest risks that should be addressed in the short to medium term are identified, eliminated, monitored and managed;
- Risk reduction treatments which best meet business needs are applied; and
- Responsibilities for managing risk are allocated to specific staff.

The risk management process adopted by Horizon Energy is consistent with Australian/New Zealand Standard AS/NZ ISO 31000:2009 (see Figure 7.1), which defines the generally accepted process for Risk Assessment and Management.

Areas of impact, reflecting the extent of the consequences assessed, are in the following broad areas:

- Regulatory risk;
- Business practice risk;

- Financial risk;
- Asset risk from physical events;
- Health and Safety risk to staff, contractors and the general public;
- Loss of information and intellectual risk; and
- Environmental impact risk.

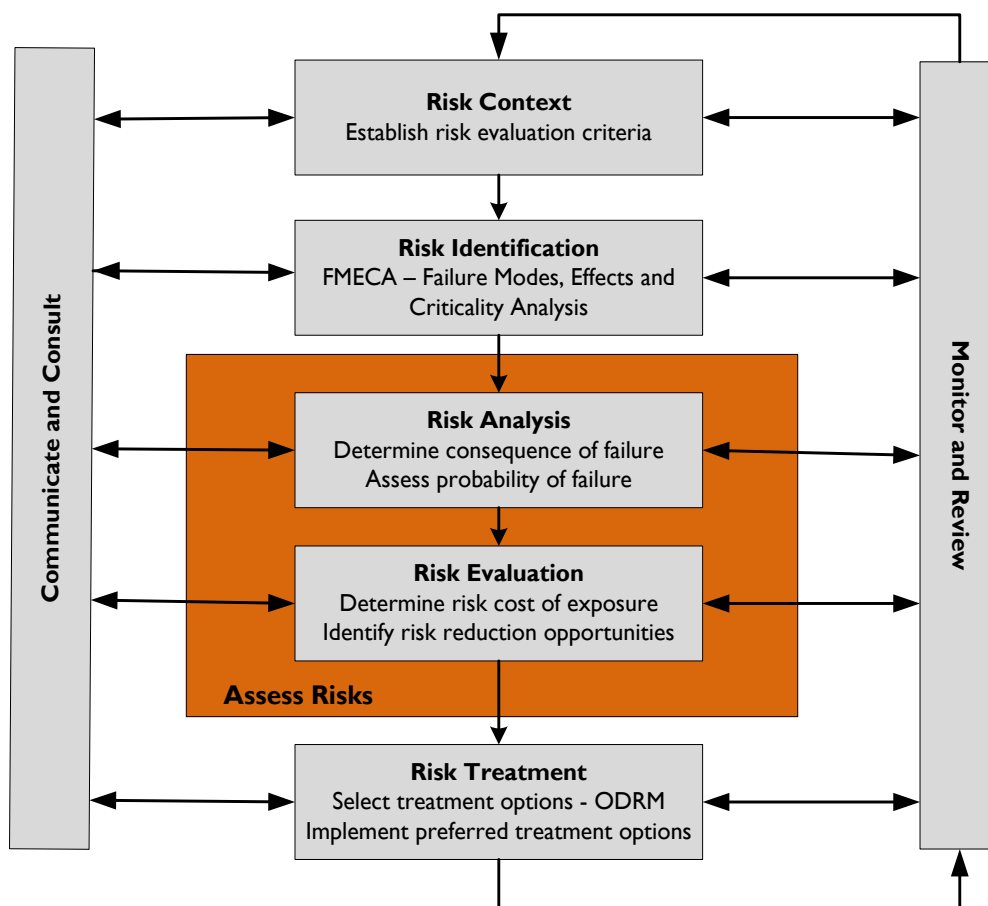


Figure 7.1 – Risk Management Process

The Risk Management Plan is part of the Company's Quality Management system.

The objective of this plan is to detail the processes that are required and the actions undertaken in the identification, assessment, review and management of risks that Horizon Energy is exposed to. The risk management plan seeks to:

- Identify risks to Horizon Energy;
- Assess the risks in accordance with consequence and likelihood;
- Monitor, treat, control and manage all risks; and
- Ensure that recovery plans are developed and implemented.

The Risk Management Plan has been developed by the Management team through group discussion, consideration of past incidents and an analysis of the Company's insurance assessments. The document details actions that can be undertaken to mitigate the impact of adverse events and the time and resource needed to undertake the correction.

7.2.2 Risk Assessment

The Management team have identified health and safety and business risks using the following methodology. Each hazard has been assessed against the likely consequence, frequency and probability scores before the controls have been applied. The hazards are subsequently reassessed after controls being applied to mitigate risk, resulting in most cases a residual risk.

Risk = Consequence x Frequency x Probability			
Risk Score	Risk	Initial Risk – without Controls	Residual Risk – with all Controls
<40	Acceptable	Hazard identification required	Proceed and monitor changes that could increase risk
40 to 200	Medium	Hazard ID required. “Significant Hazards” apply hierarchy of controls	Team Leader/Manager approval required
200 to 800	High	Hazard ID required. “Significant Hazards” apply hierarchy of controls	Manager approval required. Reassess using Root Cause Analysis or other quantitative risk assessment method
800+	Extreme	Hazard ID required. “Significant Hazards” apply hierarchy of controls	Proceed and monitor changes that could increase risk

Table 7.1 – Risk Severity Definitions

Consequence	
0.1	Negligible, superficial damage, nil or very low business interruption or financial exposure
5	First aid, property readily repaired in DIY form, minor business disruption or minor financial exposure
20	Medical treatment, property damage requires minor work, medium business disruption or medium financial exposure
40	Serious injury, hospitalisation, significant property damage, considerable business interruption, corporate image damaged or significant financial exposure
100	Catastrophic, fatality, total property destruction, major business interruption, significant loss in value and corporate image

Table 7.2 – Consequence definitions

Frequency	
1	Rarely
10	Yearly/seldom
12	Monthly/occasional
15	Weekly/frequent
20	Daily/continuous

Probability	
0.04	Improbable
0.2	Conceivable but unlikely to occur with exposure
0.4	Possible but not expected
0.8	Likely to occur with each exposure
1	Almost certain with every exposure

Table 7.3 – Likelihood definitions

7.2.3 Risk Register

The risk register is a database of all identified risks to the Company. The register is developed by the senior Management team and is reviewed regularly and twice by the Board during the year. The Company has identified all exposed risks in the broad areas detailed above.

The risk register is monitored monthly to identify changes in risk profiles.

7.2.4 Risk Treatment

When assessing the risk severity the impact of the controls that have been put in place for each identified risk is assessed using the following criteria:

- | | |
|---|------------------|
| 1 | Acceptable risk. |
| 2 | Medium risk. |
| 3 | High risk. |
| 4 | Extreme risk. |

These controls will either impact on the Consequence, the Likelihood or both. These controls are managed through the Audit Committee detailed in Section 7.3.1.

7.3 Risk Mitigation Measures

7.3.1 Responsibility and Governance

Part of Horizon Energy's risk management process and methodology is the allocation of responsibility for managing risk. Horizon Energy's Senior Management and Board members put a great emphasis on risk management and monitor the operational and financial risks of its activities on a regular basis. Risk management is part of the Board's monthly meeting agenda.

The Audit Committee consists of senior Management and Board members and meets on a bi-annual basis. The Company's risk exposure including legislative compliance is discussed along with internal controls such as delegated authorities and policies. The Risk Management Plan summarised in Section 7.2 are reported and approved by the Audit Committee at its annual risk management meeting.

7.3.2 Environmental Management

Environmental responsibility is part of Horizon Energy's vision and reflects the importance that the Company places on environmental management. Horizon Energy aims to achieve and maintain a high standard of environmental care as part of the Eastern Bay of Plenty business community. Complying with the Resource Management Act, specific resource consent conditions and the District Plan is a business risk for Horizon Energy.

All works contracted by Horizon Energy shall include consideration for environmental effects such as:

- Disturbance to domestic services such as water supply;
- Final clean up and reinstatement following construction or maintenance works to reinstate the area of works equivalent to the condition which existed prior to commencement of the operation or to such other conditions as may be required by the Environmental Controlling Authority;
- Operating noise – Contractors carrying out works for Horizon Energy shall not be permitted to use equipment which is unnecessarily noisy;
- Equipment or machinery that emits excessive or unnecessary fumes or pollution is not permitted on Horizon Energy's works sites; and
- On any site where there is a risk of oil or fuel contamination, steps shall be taken to minimise the effects of any spill. Oil spill response kits are available at all the zone substations.

7.3.3 Health and Safety

Horizon Energy is committed to providing a safe and healthy work environment – all practical steps are taken to see that our operations do not place our staff or the community at risk. Horizon Energy has achieved tertiary level ACC accreditation, is certified as compliant with AS/NZS 4801 Safety Management Standard and NZS 7901 Public Safety Standard.

Staff

- Safety committee comprising management and staff personnel;
- Monthly Health & Safety Committee meetings;
- Representatives from Management, contractors, and staff;
- Health and Safety Co-ordinator and a Group Safety Manager; and
- Staff competencies maintained through training and supervision.

Contractors

- Contractor job site audits undertaken by appropriate Horizon Energy staff;
- Engineering staff have a quota of inspections that must be undertaken each month and the results of these inspections are reported monthly to the Board; and
- Contractors that operate on the Horizon Energy network system undergo regular Health and Safety system audits. These audits are monitored by the Horizon Energy Health & Safety Coordinator.

Public

- Identified significant electrical hazards in the public arena are controlled through prudent selection of equipment and its positioning to reflect life cycle risks;
- Physical barriers and appropriate signage are used to restrict access to site works;
- Established safety protocols for all of its Zone Substations;
- Emergency hotline for public to call in faults;
- Pillar boxes are now being installed with hotline phone number on the box; and
- Priority for safety or hazard orientated defects.

7.3.4 Emergency Response and Contingency Plan Summary

Horizon Energy has a number of emergency plans in place to cover various emergency situations. All these plans are reviewed at least annually and updated as appropriate. The following are some of the plans:

- Maintains alliances with Civil Defence and Regional Council and takes part in civil defence exercises. The tactical response to civil defence risks is based on contingency plans summarised in Section 7.3.5;
- Pandemic – Horizon Energy has in place response preparedness plans should a pandemic occur. This plan is detailed in the Company's Business Continuity Plan;
- Emergency Preparedness – The identification of emergency situations that may arise in Horizon Energy's area of control and appropriate preparedness plans are part of the Company's Business Continuity Plan;
- Disaster Recovery – Summarised in Section 7.3.6 of this document;
- Injury Accidents – As part of the Health and Safety Manual the management of injuries is set out in Section 5.1: Accident and Incident Management, and Section 5.2: Serious Harm Accident; and

7.3.5 Network Contingency Plans

- A transportable IMVA generator plant has been purchased in 2013 to support network areas that are unable to be meshed. This supplements two 300KVA generators;
- An increased number of SCADA controlled switches provides for faster restoration of faulted areas in meshed networks than manual switching;
- Operational contingency plans are in place for major outages such as zone substations;
- Critical loads are also identified with contingency plans to ensure the effect of any outage is minimised; and
- A review of critical spares resulting in an identification of and procurement of critical spares.

7.3.6 Disaster Recovery

Horizon Energy has a long established Network Disaster Recovery Plan that describes recovery plans to restore supply following a disaster that may cause extensive loss of supply. The plan details the backup available and specifies the repair time. The plan assessed the major risks to the following asset groups:

- Zone substations;
- Major network components;
- SCADA system;
- VHF/UHF radio network;
- Office based systems;
- Warehouse;
- Mill Road archive store;
- Load control systems; and
- Commercial records.

The Network Disaster Recovery Plan operates in conjunction with the Company's Business Continuity Plan for managing the business following a major disruptive event which results in loss of business, resources or people.

Operational functionality is maintained in the event of the main control room having to be abandoned by the establishment of a remote SCADA access terminal located at Station Road substation.

7.3.7 Zone Substation Locations

As part of the disaster recovery or disaster management plan the GPS location of each large energy distribution site is recorded and is available to forward to emergency response services who may not necessarily know the actual location of each site. The sites are recorded in GIS, disaster recovery emergency response kits, and are repeated below:

Substation	Location
East Bank	1936826.11, 5789649.38
Galatea	1924758.64, 5739320.87
Kawerau	1926536.64, 5779170.47
Kaingaroa	1910076.73, 5742610.48
Kope	1949793.50, 5791094.42
Ohope	1955729.80, 5788860.00
Plains	1936423.27, 5788790.64
Station Road	1947690.89, 5788959.50
Te Kaha	2012948.71, 5812389.53
Waiotahi	1967977.38, 5783082.03
Waiohau	1936379.21, 5766053.53

Other Critical Sites	Location
Edgecumbe GXP	1936385.12, 5788735.98
Aniwhenua Power Station	1931617.64, 5754819.58
Snake Hill switching station	1933420.50, 5754030.65
Te Rahu substation	1947632.41, 5789052.75
Putauaki Radio site	1927467.98, 5775957.02
Pukehoko Radio Site	1953144.40, 5784167.33
Commerce St Control Room	1951115.94, 5791865.51

7.3.8 Engineering Lifelines

Horizon Energy is an active member of the Bay of Plenty Lifelines Advisory Group, (BOPLAG). The Civil Defence Emergency Management (CDEM) Act 2002 stipulates that Lifeline Utilities must:

- Plan for and be able to ensure continuity of service, particularly in support of critical functions;
- Be capable of managing its own response to emergencies;
- Develop plans cooperatively to coordinate across its sector and with other sectors; and
- Establish relationships with CDEM groups consistent across regions.

The BOPLAG currently has a regionally based project underway to understand risk areas common to different utilities with the lifelines group on a geographic basis, and to improve co-ordination between the groups to reduce or minimise risk.

7.3.9 Specific Development Projects to Mitigate Risk

Projects normally have multiple drivers. Those projects that have a high component of risk mitigation include;

- 1 MVA transportable generator;
- Plains TI replacement;
- Waiotahi circuit breakers replacements;
- CBD substation;
- Galatea 33kV bus upgrade;
- Kope 33kV indoor conversion;
- LV end of line neutral earthing
- 33kV sub-transmission dual circuit feeders reconfigure; and
- Various feeder cable overlays.

7.3.10 Specific Maintenance Programmes to Mitigate Risk

Maintenance response and routine inspections are a key part of the risk management philosophy. Particular maintenance programmes to manage risk are detailed in Section 6 and include:

- Pole testing regime;
- Vegetation control;
- Routine inspections of zone substations;
- Regular inspections of distribution switchgear;
- 33kV and 11kV lines inspections;
- Thermal imaging and partial discharge testing; and
- Earth bank testing.

8 Financial Summary

8.1 Introduction

The Electricity Distribution (Information Disclosure) Requirements 2012 issued by the Commerce Commission on 1 October 2012 require that financial forecasts developed as part of the asset management process be separated into the following components:

CAPITAL EXPENDITURE ON SYSTEM FIXED ASSETS

Disclosure Requirement	Horizon Job Coding
Customer Connection	Classification ID = 130
Capital Contribution	Classification ID = 130C
Infrastructure Development Cost	Classification ID = 130D
Vested Assets	Classification ID = 130V
System Growth	Classification ID = 140
Reliability, Quality Of Service	Classification ID = 151
Reliability , Legislative and Regulatory	Classification ID = 152
Reliability, Safety and Environment	Classification ID = 153
Asset Replacement and Renewal	Classification ID = 160
Asset Relocations	Classification ID = 170
Non-Network	Classification ID = 200

MAINTENANCE EXPENDITURE

Disclosure Requirement	Horizon Job Coding
Routine and Preventative Maintenance	Classification ID = 100
Refurbishment and Renewal Maintenance	Classification ID = 110
Fault and Emergency Maintenance	Classification ID = 120
Vegetation Management	Classification ID = 105

This AMP follows the requirements for all financial and project planning and reporting.

Where expenditure classification used in this report has been summarised by a number, the classification ID is as above.

8.2 Annual Budgets

Annual budgets are derived from projects included in the 10 year plan and the network operating budget for the planning year.

Some works contain both a capital and a maintenance cost component. An example of this is a line upgrade project where the conductor and poles are capitalised but crossarm replacements may be classed as maintenance. Where applicable, project budgets contain an estimate of the maintenance component of capital works, and operations budgets estimate the capital component of maintenance works to ensure adequate resources, plant and equipment is available..

The annual budget is developed and itemised by estimated capital materials, consumable materials, labour, labour type, cash flow, and project timing to assist contractors who will be involved in the undertaking of this work to complete their annual planning and operating budgets.

8.3 Projects

Most projects and tasks are estimated to a high level for long term budget forecasting, nominally $\pm 30\%$. As projects move into the planning phase, bottom up detailed estimates are completed to a more detailed task level using estimating tools, actual costs, and unit rate assemblies to give a high level of pricing confidence. At the completion of projects the actual to estimated cost is analysed and used in the future high level estimates.

Actual results often vary from forecast, as not all projects are fully scoped or have completed pre-feasibility studies prior to budget publication. Consequently, as projects evolve, their viability and priority is reassessed, and during a planning year some projects may be accelerated and some deferred or altered with similar projects.

Monthly reports are produced for Management and Directors summarising progress and adherence to annual budget targets.

The longer term planning goal is to achieve a greater lead time between design, procurement and implementation, to allow better project definition.

8.4 Maintenance

The maintenance, or operational, component of the budgets is made up of several different categories as follows:

Planned fixed and routine maintenance activities comprise:

- Zone substation maintenance; including routine inspections and periodic testing of switchgear, protection and transformers;
- Communication, SCADA and protective devices testing to meet regulatory guidelines;
- Thermal imaging of critical lines and equipment;
- Battery bank testing and scheduled battery replacement;
- Earth bank testing;
- Cable locates and close approach permits;
- Vegetation programme and asset inspections; and
- Standby fault support.

These activities are planned and budgeted ten years ahead based on recommended service intervals for equipment servicing, routine testing requirements and estimated lifetime replacement (e.g. batteries). Yearly adjustment may be made on the budgets and work plans following assessment of reliability and/or performance statistics.

Variable components of the maintenance budget include:

- Immediate fault response;
- Remedial works from faults;
- Defect work; and
- Safety or environmental works.

When defect remedial and fault work results in the replacement of a 'minimum asset unit' then a portion of this work is capitalised. This introduces a variable component into the capital budget that is difficult to predict on a year by year basis.

Within many projects there can be a component of both capital and maintenance expenditure. Annually, the capital component of maintenance works varies between 35-45%.

The increased use of live line work has resulted in the average cost of 11kV defect and AFS connection work to increase after 2010-11, but this cost increase is offset against a reduced number of planned network outages.

Minimum Assets

All assets are defined as to what constitutes a minimum asset for capitalisation purposes. Examples where expenditure on assets is classed as maintenance instead of being capitalised are

- Total cost < \$500;
- Cable replacement < 50 meters;
- Overhead line < 150m;
- Cross arms and insulators when not part of a pole replacement;
- Fuse links;
- Surge arrestor if not replaced as a set; and
- Asset removal where removal value < \$500.

Generally projects are arranged to maximise the amount of capitalisation but due to the minimum asset definitions there is usually a small maintenance component within most lines rebuild projects.

8.5 Replacement and Renewals expenditure

Replacement and renewal is the largest repeating capital spend category, in 2014 an external review⁸ was commissioned by Management to review Horizon Energy's planned replacement expenditure from the 2014-15 AMP against an asset condition replacement model. The model has recommended a 15% uplift in expenditure in this capital category from the last three years of the five year plan to fit with the ageing profile of the assets.

Figure 8.1 shows the planned expenditure against the recommended expenditure, with a recommendation that uplift on conductor replacement expenditure is required to maintain adequate replacement of the network. In all other respects Horizon Energy budgeted replacement expenditure forecasts were comparable to other EDB forecasts, whilst unit replacement costs appeared slightly higher, due in part to consolidation of other works into replacement project, and geographical distances.

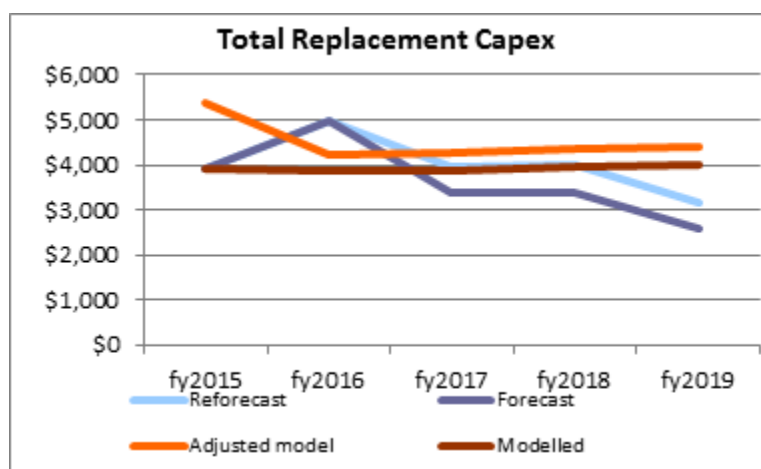


Figure 8.1 – Replacement Capex

The recommended replacement expenditure is over \$4M over the next 5 years, and this level of expenditure has been allowed for in the forward 10 year plan from 2015 onwards.

Figure 8.2 below is an Australian regulatory replacement expenditure model which uses Horizon Energy's asset age data to predict an annual replacement expenditure profile over the next 20 years. The predicted dollar values differ from Horizon Energy's due to the averaging of lump sum expenditure on zone substations and zone transformers, and different unit cost values – but the trend provides a good forecast of future liability for increased asset replacement starting later in the planning period.

⁸ Densem, T. (2014). Review of Horizon Energy Replacement Capex

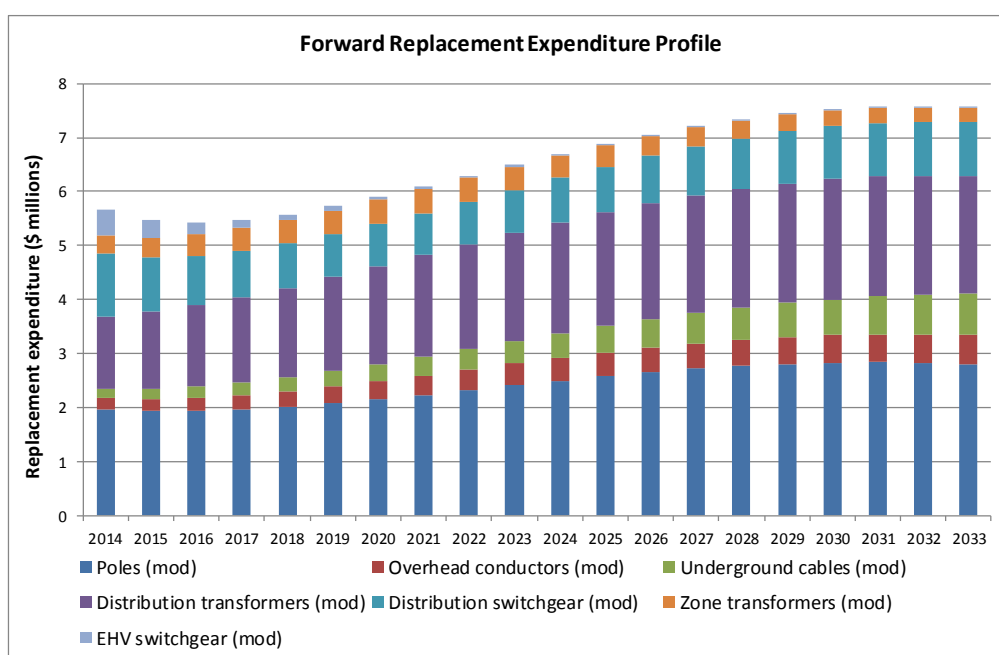


Figure 8.2 – Forward Replacement Capex Profile (Repex Model Profile)

The actual forward 10 year replacement and renewals budget compared to the Repex model⁹ is shown in Figure 8.3 below averages \$5.7M compared to the Repex average of \$5.8M over the 10 year period. Although presented as a reference point, absolute comparisons with the Repex model should be considered with caution as it is a very coarse model with a number of high level assumptions. The Horizon Energy expenditure includes values for capital growth, capital replacement and renewal, and maintenance refurbishment and renewal. The argument for including the maintenance component is that maintaining the asset extends its life, and a well maintained asset is likely to exceed its expected life. Likewise, expenditure on growth in a network that has limited physical growth is generally displacing existing assets. An example of this is the Opotiki substation development, which is replacing a quantity of the local distribution line assets, and will also displace Transpower Waiotahi GXP asset replacements when Waiotahi substation is eventually disestablished. As well as the above, quality of supply projects tends to have an asset replacement component when field switchgear is replaced.

The lower values for planned replacement expenditure, shown in green in Figure 8.3, during the years 2018-2021 are to level cash flow and resources in recognition of the additional expenditure planned for the Opotiki region over that period. The dip in 2022 is due to replacement capital being diverted to install a quality of supply project, a supporting substation on the Factory feeder at Hawaii, which will produce a backup supply for this radial feeder.

⁹ Model based on the AER's Electricity network service providers Replacement expenditure model Nov 2013

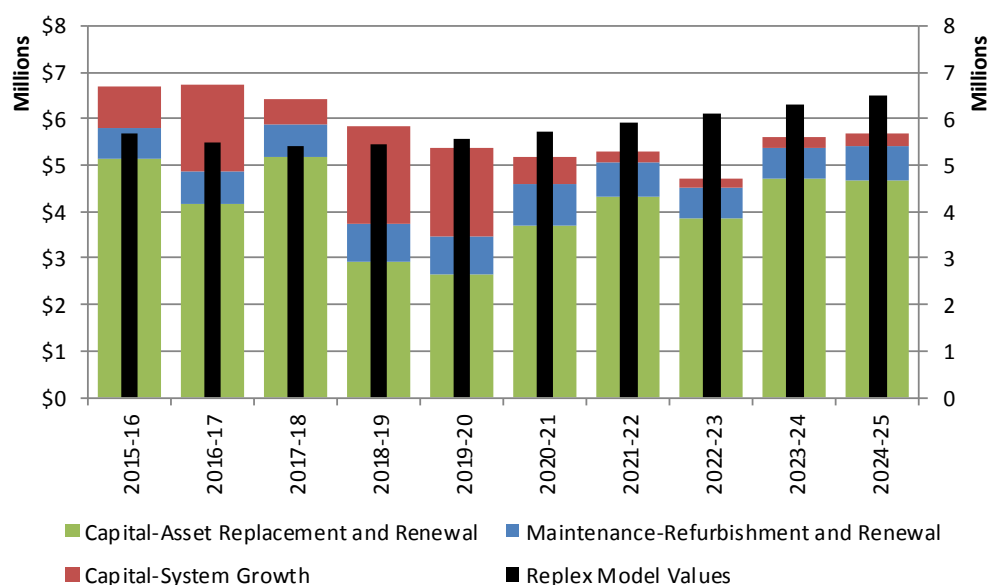


Figure 8.3 – Replacement Capex Profile Actual compared to repex model

Figure 8.4 below shows the REPEX predicted asset age profile by asset type across the complete asset range. The model currently projects the asset consumed life as greater than 50%. This indicates that the current level of replacement expenditure will need to be increased to return the network to the ideal of 50% of average life.

With the New Zealand Regulator currently focusing on reliability incentives, and incentives to reduce capital and operational spend, the trade-off between the benefits of expenditure for reliability driven projects and benefits of focusing on asset replacements, or on projects to extend asset lives, is becoming more complex.

Also unknown is the ultimate expected life of various asset types. Asset lives are currently a best estimate based on experiences of the relatively young worldwide electrical industry. The world has never been in a situation of having had electrical assets running through several life cycles to enable a comprehensive understanding of what the various influences and variability's that effect the average asset life. It is likely modern manufacturing techniques may well produce products today that have longer lives than their predecessors – conversely, some modern components may have shorter lives but have other benefits that make their use desirable. An example of this is XLPE insulated cable vs paper impregnated insulated cable (PILC). The industry recognises the extended life cycle of PILC cable over XLPE (70 years compared to 45 years), but for a number of mostly convenient reasons XLPE cable is still used more extensively worldwide than paper lead cable. Modern XLPE cables are expected to exceed the 45 year life but this will not be known until they have reached their designed lifespan..

Using Net Present Value (NPV) assessments, if run over the expected 70 year life of the PILC cable comes out strongly in favour of PILC, but with the higher procurement and installation costs of PILC a shorter NPV period used (typically 25 years) favours XLPE.

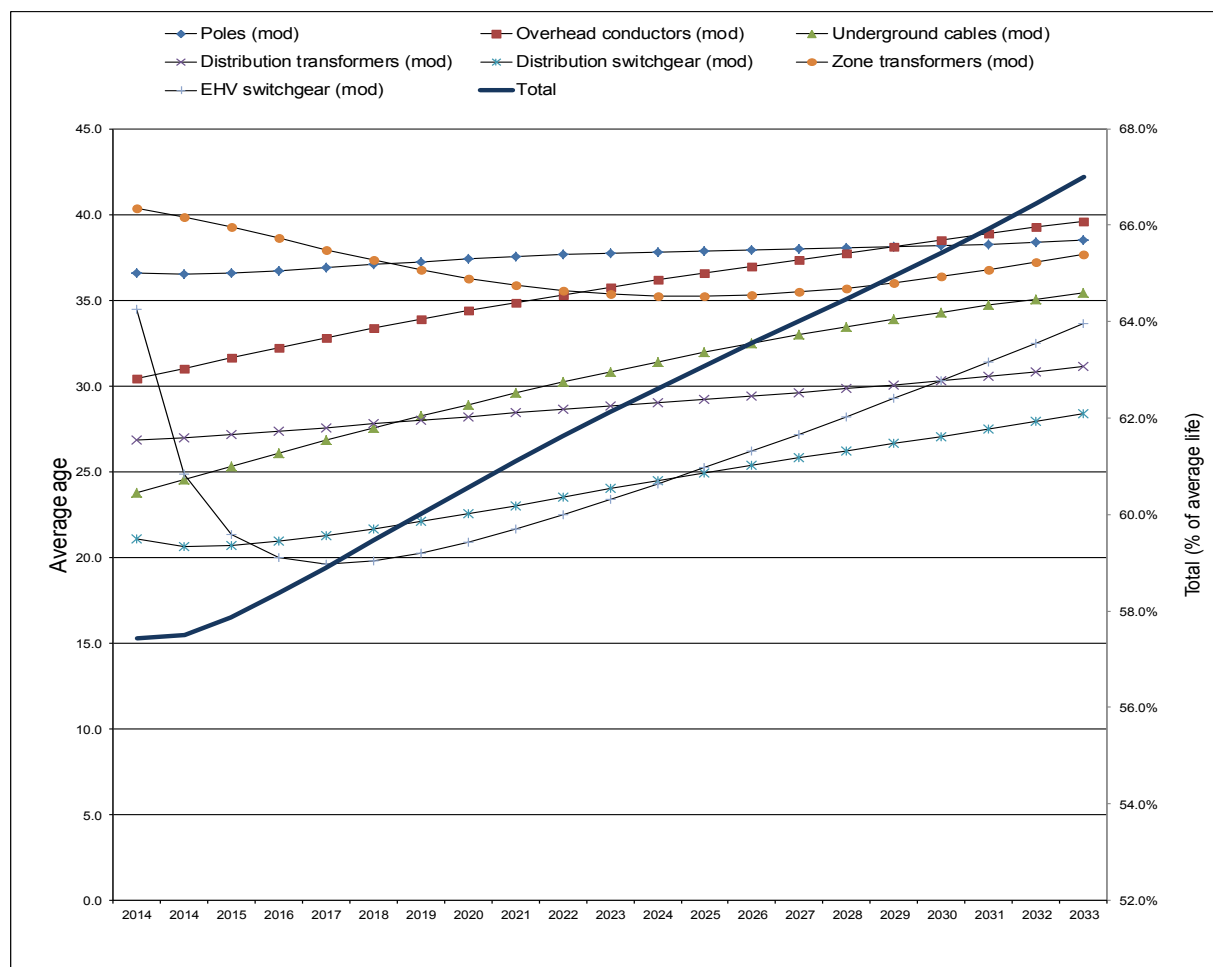


Figure 8.4 – Asset Average Age (Repex model profile)

8.6 Capital Projects

Major projects planned for the next ten years together with their drivers and justifications are described in Appendix C. There are over 320 individual projects identified over the next ten year period with a combined value close to \$65M.

Network areas with a high density of defects or assets nearing the end of their useful life have been grouped into projects. These projects have a component of both maintenance and capital expenditure as described above. This component alters depending on the work type; typically transformer replacement projects are 80% capital, 20% maintenance, line refurbishment projects average 70% capital, 30% maintenance.

Data from Statistics NZ predicts that the mean regional population increases are predicted to diminish over the next ten years, with some areas declining, and this is reflected in a constant amount budgeted for new customer connections.

Undergrounding projects are budgeted at the beginning of each financial year in consultation with the affected Local Authority and this program can be changed or deferred by Councils depending on the availability of Council funds.

Major projects greater than \$500,000 included in the ten year plan are summarised in Table 8.1 below:

Year Start	Project Name	Value(000)
2016	SCADA System upgrade	\$607
2016	Galatea 33kV bus upgrade plus line CB's	\$654
2016	Opotiki Substation Development-11kV Site Y1	\$1318
2017	Kope 33kV indoor Conversion	\$1295
2018	2nd 33kV line into Aniwhenua	\$1008
2018	Kope TI Replacement	\$1205
2018	Opotiki Substation Development -110kV line, Tx Y1	\$1894
2019	Station Road Replace T1	\$1359
2019	Opotiki Substation Development -110kV line, Tx Y2	\$1894
2020	WBMS 33kV Sub Transmission Capacity Upgrade	\$575
2020	HDBC/ Galv line replacement -Awakeri	\$650
2020	Station Road Replace T2	\$1359
2021	Replace GEC switchboard	\$879
2021	Ohope-11kV Indoor Conversion	\$1179
2022	HDBC/ Galv line replacement -Manawahe	\$609
2022	Hawai Zone Substation	\$623
2023	HDBC/ Galv line replacement -Te Teko Year 1	\$659
2024	Underground Harbour feeder Stage 2a	\$506
2024	HDBC/ Galv line replacement -Te Teko Year 2	\$659
2024	Lines replacements	\$1079
2025	Underground Harbour feeder Stage 2b	\$506
2025	HDBC/ Galv line replacement -Ruatoki Year 1	\$709
2025	Whakatane CBD Substation Y1	\$739
2025	Lines replacements	\$1079
2025	Express 33 kV Cable Gateway to CBD-4.25km	\$1169

Table 8.1 – Major Projects List

8.7 Evaluation of Performance

This Section evaluates Horizon Energy's performance against the previous AMP for the 2014/15 year. Commentary on the variance between actual and budget is provided where this information is available.

Progress against the 2014-15 AMP

The final financial performance to budget for the 2014-15 year as reported in the 2015 information disclosures is shown in Table 8.2.

		Forecast (\$000) ²	Actual (\$000)	% variance
9	7(ii): Expenditure on Assets			
10	Consumer connection	394	97	(75%)
11	System growth	492	222	(55%)
12	Asset replacement and renewal	3,977	4,278	8%
13	Asset relocations	20	8	(62%)
14	Reliability, safety and environment:			
15	Quality of supply	2,292	2,042	(11%)
16	Legislative and regulatory	77	150	95%
17	Other reliability, safety and environment	710	98	(86%)
18	Total reliability, safety and environment	3,078	2,290	(26%)
19	Expenditure on network assets	7,961	6,894	(13%)
20	Expenditure on non-network assets	1,669	475	(72%)
21	Expenditure on assets	9,629	7,369	(23%)
22	7(iii): Operational Expenditure			
23	Service interruptions and emergencies	564	820	46%
24	Vegetation management	482	440	(9%)
25	Routine and corrective maintenance and inspection	723	762	5%
26	Asset replacement and renewal	1,001	733	(27%)
27	Network opex	2,769	2,756	(0%)
28	System operations and network support	2,517	2,556	2%
29	Business support	2,741	2,668	(3%)
30	Non-network opex	5,258	5,224	(1%)
31	Operational expenditure	8,027	7,980	(1%)

Table 8.2 – Expenditure Comparison for the 2014-15 AMP

Significant differences are as follows:

- Customer connections actual shown net of capital contributions, IDC and vested assets;
- System growth project Opotiki substation deferred;
- Whakatane land purchase cancelled
- Asset Relocations are a very minor category making budget variations insignificant when considered over total forecast spend;
- The variability in operational expenditure is driven by how defects and remedial works are treated with the allocation of costs between replacement, renewal, and corrective works; and
- A number of assets were replaced and capitalised after the Easter storms.

8.8 Financial Forecasts 2016-2026

10 Year Financial Summaries

Figure 8.5 and Table 8.3 – 2016-2026 Network forward expenditure show the projected capital and maintenance budgets until 2025.

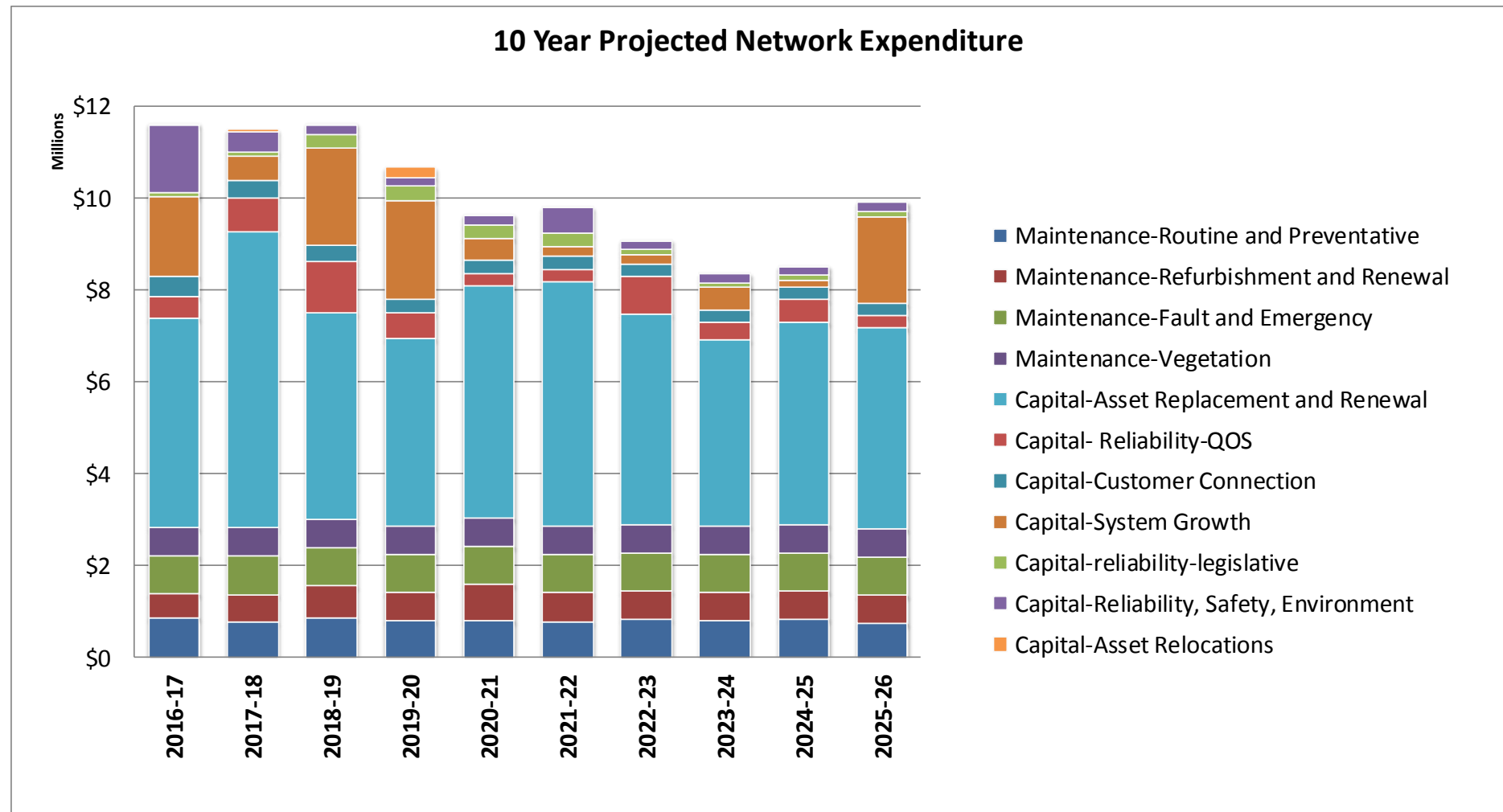


Figure 8.5 – 10 Year Projected Network Expenditure

Projected Expenditure	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Maintenance-Routine and Preventative	\$0.99	\$0.77	\$0.87	\$0.82	\$0.81	\$0.78	\$0.84	\$0.81	\$0.85	\$0.75
Maintenance-Refurbishment and Renewal	\$0.52	\$0.61	\$0.69	\$0.61	\$0.79	\$0.65	\$0.61	\$0.62	\$0.61	\$0.61
Maintenance-Fault and Emergency	\$0.83	\$0.83	\$0.83	\$0.83	\$0.83	\$0.83	\$0.83	\$0.83	\$0.83	\$0.83
Maintenance-Vegetation	\$0.61	\$0.61	\$0.61	\$0.61	\$0.61	\$0.61	\$0.61	\$0.61	\$0.61	\$0.61
Maintenance Total	\$2.95	\$2.83	\$3.01	\$2.87	\$3.04	\$2.87	\$2.89	\$2.87	\$2.90	\$2.80
Capital-Customer Connection	\$0.45	\$0.40	\$0.34	\$0.30	\$0.29	\$0.29	\$0.28	\$0.27	\$0.27	\$0.26
Capital-System Growth	\$1.72	\$0.52	\$2.14	\$2.16	\$0.47	\$0.21	\$0.21	\$0.49	\$0.16	\$1.91
Capital- Reliability-QOS	\$0.47	\$0.72	\$1.12	\$0.55	\$0.27	\$0.25	\$0.81	\$0.38	\$0.49	\$0.26
Capital-reliability-legislative	\$0.10	\$0.10	\$0.30	\$0.30	\$0.30	\$0.30	\$0.10	\$0.10	\$0.10	\$0.10
Capital-Reliability, Safety, Environment	\$1.47	\$0.44	\$0.20	\$0.20	\$0.20	\$0.55	\$0.20	\$0.20	\$0.20	\$0.20
Capital-Asset Replacement and Renewal	\$4.57	\$6.46	\$4.50	\$4.08	\$5.07	\$5.33	\$4.60	\$4.05	\$4.41	\$4.38
Capital-Asset Relocations	\$0.04	\$0.04	\$0.03	\$0.22	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03
Capital Total	\$8.82	\$8.68	\$8.64	\$7.82	\$6.63	\$6.95	\$6.22	\$5.52	\$5.65	\$7.14
Total (Millions)	\$11.76	\$11.51	\$11.64	\$10.69	\$9.67	\$9.82	\$9.12	\$8.39	\$8.55	\$9.94

Table 8.3 – 2016-2026 Network forward expenditure

Significant Factors in this Financial Forecast are:

Capital – Asset Relocations. There are no significant relocations of assets planned.

Capital – System Growth. Capital system growth budget increases significantly in 2016-20 due to the historic load growth development of Opotiki substation.

Capital Reliability, Quality of Supply. This category value is reduced compared to previous years as the initial implementation of rural feeder reliability projects is completed. Load driven asset replacement projects in the middle of the planning period replace the reliability expenditure to even out the cashflow and labour requirements.

Capital Asset Replacement and Renewal. An average of \$4.7M, up from \$4.15M last period, is budgeted per annum for renewals over the 10 year planning period, with expenditure slowly increasing annually throughout the period as ageing assets are scheduled for replacement.

Capital Customer Connection. No significant increase is expected in this category.

The basis for the financial forecasts is explained in the lifecycle management plan (Section 6). The following general assumptions have been made in preparing the 10 year expenditure forecast:

- The completion of the major infrastructure projects at Waiotahi zone substation and associated projects will ensure the network has minimal or no load constraint issues unless there is unforeseen population growth;
- An increase in replacement and maintenance expenditure due to asset ageing is expected and this has been included at a low level from 2016 onwards. Asset age charts in Section 6 show that significant increased expenditure is likely beyond 2021;
- Maintenance and renewal allocations have been based on preserving current levels of services; and
- Stated in Real 2016 dollars.

8.9 Forecast Uncertainty and Assumptions

There are a number of significant assumptions used in the determining of works and demand growth identified in this AMP that may affect the financial outcomes and forecasting. The reasoning behind the assumptions are generally covered in the body of the document but the likely effect of these uncertainties on the financial or work outputs are summarised as follows:

Issue	Basis for the assumption and the likely impact of this uncertainty
Load Growth	Load growth is based on historical growth trends. No step change loads are allowed for in the forecasts, unless these have been clearly identified with actual timing and the expected demand load.
Customer Growth	It has been assumed the annual quantity of new customer connections will continue to reduce; this prediction correlates well with Statistic NZ data. Any change in this trend is likely to be relatively insignificant on the network due to the small total quantity of connections. If a significant number of connections were to occur there is sufficient capacity within the network to accommodate significant additional domestic loads apart from at Opotiki. Increased commercial loads in Whakatane would have the effect of bringing forward capacity driven expenditure on the Strand North, Strand South, and Rex Morpeth feeders and/or the proposed CBD or Gateway substations.

Issue	Basis for the assumption and the likely impact of this uncertainty
Economic Activity	<p>The Eastern Bay of Plenty has minimal growth and is predicted to have negative population and economic growth over the next 20 years (Statistics NZ). This is unlikely to alter the planned asset refurbishment programs as the assets continue to age. The potential closure or down-sizing of major industry customers would result in either stranded assets or alternatively release assets that may be used to defer load driven asset replacements, depending on the area affected.</p> <p>It is highly probable that some major industries currently supplied will reduce demand during the planning period. This has been seen already with two major customers reducing demand over the past 4 years.</p>
Economic Activity Opotiki	<p>Opotiki already has load related issues. Any step change in load will seriously affect the ability of the network to deliver this load. A request for significant load to be connected 2015 has triggered the development of the planned Opotiki upgrade project. A generator procured in 2013 will be used for peak load lopping which will allow short term deferral of the Opotiki substation sub-transmission supplies.</p> <p>Increased demand has been connected at Opotiki due to the kiwifruit industry</p>
Network Priorities	<p>Network priorities are driven by both planned and unplanned events. Significant unplanned events (weather events, unanticipated customer requests, defect discovery, major faults) that impact the availability of labour or finances will prompt a re-prioritisation of projects. This may alter the financial spread of projects across the reporting categories. Historically, Horizon Energy has tended to defer larger strategic projects as long as practicable, but adherence to a priority matrix will ensure these projects retain their focus.</p>
Shareholder Expectations	<p>The Energy Trust expects a certain level of return on investment. Significant unplanned events that alter the annual cash flow requirements will force a review of expenditure in any period which may result in a re-prioritisation of projects to maintain annual budgets.</p>
Customer Expectations	<p>Surveys in 2014 indicated that customers will not tolerate a reduction in service or quality (outages, supply quality), nor will they accept an increase in charges to improve service. With this expectation in mind, future reliability projects will be used more and more as float projects and will be scheduled around strategic and load driven projects to balance cash and work flow. This approach will tend to slow down the implementation of reliability improvements on what are currently the more reliable feeders.</p>
Strategic Projects	<p>Strategic and load driven projects dominate the planning over the next five years. As the projects enter the detailed planning phase, complexities in the planning, design and delivery processes may impact the scheduled delivery and budgets of these projects. This is likely to result in some of the project expenditure being spread over different years to that originally planned.</p>
Work levelling	<p>Projects may be accelerated or deferred to level both labour requirements and/or cashflow. This will generally apply to non-urgent replacement projects where the risks of short term deferral are weighted against the need for cash flow and labour availability management</p>
Asset Refurbishments and Renewals	<p>Increased expenditure on assets due to age and condition is planned to increase over the next few years.</p>
Faults and Emergency	<p>Major weather events are the main cause of wide-spread and costly unplanned outages. These are impossible to predict. The result of a major event will be the likely delay of all works as resources are diverted into the fault restoration and remedial works. It is accepted by the network that a major weather event will be treated as an unbudgeted expense for that year.</p>

Issue	Basis for the assumption and the likely impact of this uncertainty
Initial Budgets	Initially, individual projects are budgeted at a high level only. As projects are further engineered, the budgets become more accurate. The budgeted amount each year for projects treats the total projects budget as a pool, so as budgets are confirmed additional projects are prioritised and are released into, or withdrawn from, the pool of projects for the year. This may significantly alter the expenditure by classification category
Cancelled or Deferred Works	During the year projects may be cancelled or deferred for any number of reasons. Funds from these projects will be released into the project budget pool for reallocation to other projects and the original project redesigned or rescheduled.
Unbudgeted Works	Occasionally works are identified that the network determines are beneficial to proceed with. A common example is customer initiated works where the customer contributes some or all of the costs. This is treated like an accelerated project and is elevated in priority, and a lower priority project may be delayed if resources are unavailable.
Resources	Resource availability has a direct effect on the ability to complete works. Shortage of engineering or construction staff will invariably result in either delays or increased costs. Experience has shown the use of contractors from outside the district can increase project costs.
Inflation	Forward budgets are at the current year's value with no inflation adjustment. As the projects are reviewed for the succeeding year the costs are re-assessed. It is accepted that any sustained high inflationary period will require a reassessment of the project plan as costs increase.

Budget Reporting and Monitoring Improvement Plan

The Microsoft Dynamics NAV financial reporting system is implemented to enable greater detailed control and accuracy of entry data, coupled with direct data input at source from stores and contracting. More regimented cost and budget category reporting is resulting in a better ability to estimate works. Planned system improvements are:

- Improved reporting templates;
- Automation of regulatory reporting;
- Increased contractor accountability;
- Project engineering completed earlier and ability to refresh prices as unit prices alter;
- Review of costs to actuals to improve project estimating;
- Develop unit rates for asset installation;
- Increasingly projects are being pre-engineered and to a greater level of accuracy prior to being submitted for budgetary approval;
- Tighter integration between the AMP 10 Year Plan and the Annual Plan;
- Increased number of maintenance renewal and condition works being managed as projects; and
- Benchmarking against other lines companies.

9 Improvement Plan

9.1 Asset Management Planning Framework

The process for developing and using this AMP is illustrated below in Figure 9.1.

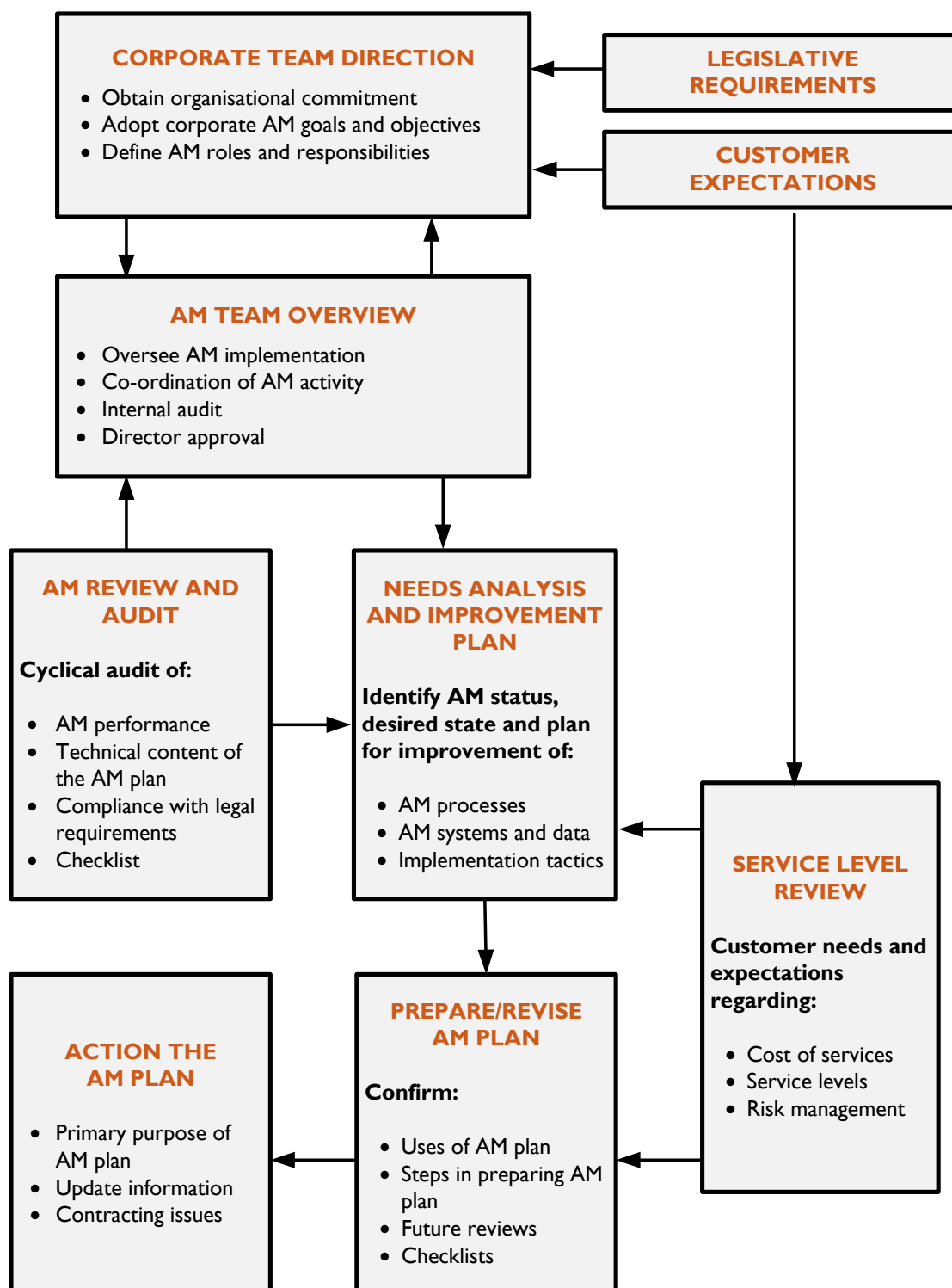


Figure 9.1 – Flow Chart for Developing and using AM Plans

9.2 Responsibilities

Responsibilities are allocated for the management of the various asset management functions. The activities involved and the position responsible is as follows:

Activity	Responsibility
Co-ordinate the preparation of programmes, estimates, project plans and performance measures for the improvement of asset management practices	General Manager Network with assistance from the Senior Planning Engineer
Periodically review the asset management improvement programme and specific improvement projects	General Manager Network, Asset Manager, Service Delivery Manager, Planning Engineer
Provide AMP budgets	Chief Executive
Identify internal/external peer reviews of asset management plan improvements	General Manager Network
Approve the Plan as being reflective of the emphasis that the Company places on its asset management function	Board of Directors
Engage consultants to assist with asset management improvements as required	General Manager Network
Monitor and report on all aspects of network projects	Service Delivery Manager

Table 9.1 – Activities and Responsibilities

9.3 Current Status of Asset Management

The document reflects the Company's structure as a dedicated lines business. The plan also reflects the staffing structure of the Company and the use of contracting staff (both internal and external) for the implementation of works.

The Company has a comprehensive Quality Manual system providing requirements for all activities that need to be undertaken. In particular, Part 4 of QM 4-2 Network Management and Planning, formulates activities for Asset Management. The components of the Quality Manual are periodically revised to ensure co-ordination with the existing Company structure. Staff members are able to effectively adapt the quality requirements in an appropriate manner.

9.4 Improvement Plan

In 2016 Horizon Energy intends to install an Asset Management System (AMS). Implementing an AMS represents a significant milestone in the strategic journey that HEDL has been on for the past 5 years by bringing together business insight from various sources such as SCADA, GIS, Financial Systems and staff in the field. The use of the system and changes to business process is expected to deliver operational efficiencies, better understanding and optimisation of the capital spend and improvements to the management of public safety.

The AMS solution will be aligned with ISO 55000. The system is expected to cost \$1.2M to install, which includes all project related internal costs and an amount set aside for further improvements post go-live. The AMS is expected to deliver substantial short term operational benefits as well as develop long term asset insights.

Other improvements that the network is working on include:

- Continual review and formal acceptance of design standards;
- Continual data gathering and data accuracy verification projects;
- Service level agreements and management of contractors and work flows; and
- Increase forward planning for planned works up to a year in advance.

Appendix AI – EDB AMP Information Disclosure Requirements Cross Reference List



No.	Disclosure requirements	Relevant AMP Section
3	The AMP must include the following-	
3.1	A summary that provides a brief overview of the contents and highlights information that the EDB considers significant	2.12– 1.10 8 pages
3.2	Details of the background and objectives of the EDB's asset management and planning processes	2.1-2.9 19 pages
3.3	A purpose statement which-	
3.3.1	Makes clear the purpose and status of the AMP in the EDB's asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes	2.4
3.3.2	States the corporate mission or vision as it relates to asset management	2.4
3.3.3	Identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB	2.13 fig 2.2
3.3.4	States how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management	2.13
3.3.5	Includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans	2.7, 2.13
3.4	Details of the AMP planning period , which must cover at least a projected period of 10 years commencing with the disclosure year following the date on which the AMP is disclosed	2.7
3.5	The date that it was approved by the Directors	2.8
3.6	A description of stakeholder interests (owners, consumers etc) which identifies important stakeholders and indicates-	2.10



3.6.1	How the interests of stakeholders are identified	2.10 Table 2.2
3.6.2	What these interests are	2.10 Table 2.2
3.6.3	How these interests are accommodated in asset management practices	2.10 Table 2.2
3.6.4	How conflicting interests are managed	2.10.3
3.7	A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	2.11
3.7.1	Governance—a description of the extent of Director approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to Directors	2.11
3.7.2	Executive—an indication of how the in-house asset management and planning organisation is structured	2.11.2
3.7.3	Field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used	2.11.3
3.8	All significant assumptions	8.8
3.8.1	Quantified where possible	8.8
3.8.2	Clearly identified in a manner that makes their significance understandable to interested persons, including	8.8
3.8.3	A description of changes proposed where the information is not based on the EDB's existing business	na
3.8.4	The sources of uncertainty and the potential effect of the uncertainty on the prospective information	2.12, 8.8



3.8.5	The price inflator assumptions used to prepare the financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b.	Na
3.9	Description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures	8.8
3.10	An overview of asset management strategy and delivery	2.3-2.4 11 pages
	<i>How the asset management strategy is consistent with the EDB's other strategy and policies;</i>	2.4
	<i>How the asset strategy takes into account the life cycle of the assets;</i>	2.4, 6
	<i>The link between the asset management strategy and the AMP;</i>	2.4
	<i>Processes that ensure costs, risks and system performance will be effectively controlled when the AMP is implemented.</i>	6.5,
3.11	An overview of systems and information management data	2.12
	<i>To support the AMMAT disclosure and assist interested persons to assess the maturity of systems and information management, the AMP should describe-</i>	
	<i>The processes used to identify asset management data requirements that cover the whole of life cycle of the assets;</i>	2.12., 5.2.4
	<i>The systems used to manage asset data and where the data is used, including an overview of the systems to record asset conditions and operation capacity and to monitor the performance of assets;</i>	2.12
	<i>The systems and controls to ensure the quality and accuracy of asset management information; and</i>	2.12
	<i>The extent to which these systems, processes and controls are integrated.</i>	2.13



3.12	A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data	2.12.1
	<i>Discussion of the limitations of asset management data is intended to enhance the transparency of the AMP and identify gaps in the asset management system.</i>	2.12.1
3.13	A description of the processes used within the EDB for-	
3.13.1	Managing routine asset inspections and network maintenance	Sect 6.1.3
3.13.2	Planning and implementing network development projects	Sect 5.3
3.13.3	Measuring network performance.	5.2.4, 5.2.5
3.14	An overview of asset management documentation, controls and review processes	2.12, 2.13, 2.13
	<i>To support the AMMAT disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should-</i>	
	<i>(i) identify the documentation that describes the key components of the asset management system and the links between the key components;</i>	
	<i>(ii) describe the processes developed around documentation, control and review of key components of the asset management system;</i>	
	<i>(iii) where the EDB outsources components of the asset management system, the processes and controls that the EDB uses to ensure efficient and cost effective delivery of its asset management strategy;</i>	6.5
	<i>(iv) where the EDB outsources components of the asset management system, the systems it uses to retain core asset knowledge in-house; and</i>	
	<i>(v) audit or review procedures undertaken in respect of the asset management system.</i>	Na



3.15	An overview of communication and participation processes	2.5
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	<i>To support the AMMAT disclosure and assist interested persons to assess the maturity of asset management documentation, controls and review processes, the AMP should-</i>	
	<i>(i) communicate asset management strategies, objectives, policies and plans to stakeholders involved in the delivery of the asset management requirements, including contractors and consultants;</i>	
	<i>(ii) demonstrate staff engagement in the efficient and cost effective delivery of the asset management requirements.</i>	
3.16	The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise;	8
3.17	The AMP must be structured and presented in a way that the EDB considers will support the purposes of AMP disclosure set out in clause 2.6.2 of the determination.	
	Assets covered	
4	The AMP must provide details of the assets covered, including-	
4.1	A high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including-	3.1
4.1.1	The region(s) covered	3.1
4.1.2	Identification of large consumers that have a significant impact on network operations or asset management priorities	3.4
4.1.3	Description of the load characteristics for different parts of the network	3.3
4.1.4	Peak demand and total energy delivered in the previous year, broken down by sub-network , if any.	5.4
4.2	A description of the network configuration, including-	5.5



4.2.1	Identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point;	5.5
4.2.2	A description of the subtransmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the subtransmission network(s) . The AMP must identify the supply security provided at individual zone substations , by describing the extent to which each has n-x subtransmission security or by providing alternative security class ratings;	3.2, 5.6
4.2.3	A description of the distribution system, including the extent to which it is underground;	3.8, 5, 6
4.2.4	A brief description of the network's distribution substation arrangements;	6.3.3
4.2.5	A description of the low voltage network including the extent to which it is underground; and	6.3.6
4.2.6	Injection systems, SCADA and telecommunications systems.	6.3.7, 6.3.8
4.3	If sub-networks exist, the network configuration information referred to in subclause 4.2 above must be disclosed for each sub-network .	Na
	Network assets by category	
4.4	The AMP must describe the network assets by providing the following information for each asset category-	
4.4.1	Voltage levels;	3,6
4.4.2	Description and quantity of assets;	3.8,6
4.4.3	Age profiles; and	6



4.4.4	A discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	6
4.5	The asset categories discussed in subclause 4.4 above should include at least the following-	6
4.5.1	Sub transmission	5.6
4.5.2	Zone substations	5
4.5.3	Distribution and LV lines	6
4.5.4	Distribution and LV cables	6
4.5.5	Distribution substations and transformers	6
4.5.6	Distribution switchgear	6
4.5.7	Other system fixed assets	6
4.5.8	Other assets;	6
4.5.9	assets owned by the EDB but installed at bulk electricity supply points owned by others;	Na
4.5.10	EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand; and	6.3.12
4.5.11	Other generation plant owned by the EDB .	6.3.12



	Service Levels	
5	The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period . The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period .	4.4
6	Performance indicators for which targets have been defined in clause 5 above must include SAIDI and SAIFI values for the next 5 disclosure years .	4.4.2
7	Performance indicators for which targets have been defined in clause 5 above should also include-	
7.1	Consumer oriented indicators that preferably differentiate between different consumer types;	4.4
7.2	Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	
8	The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	4.4.1
9	Targets should be compared to historic values where available to provide context and scale to the reader.	
10	Where forecast expenditure is expected to materially affect performance against a target defined in clause 5 above, the target should be consistent with the expected change in the level of performance.	8
	<i>Performance against target must be monitored for disclosure in the Evaluation of Performance section of each subsequent AMP.</i>	
	Network Development Planning	
11	AMPs must provide a detailed description of network development plans, including—	5.2



11.1	A description of the planning criteria and assumptions for network development;	5.2.1
11.2	Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	5, Appendix C
11.3	A description of strategies or processes (if any) used by the EDB that promote cost efficiency including through the use of standardised assets and designs;	5.2.2
11.4	The use of standardised designs may lead to improved cost efficiencies. This section should discuss-	
11.4.1	The categories of assets and designs that are standardised;	5.2.3
11.4.2	The approach used to identify standard designs.	5.2.3
11.5	A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network .	5.3.6
11.6	A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the network .	5.2
11.7	A description of the process and criteria used to prioritise network development projects and how these processes and criteria align with the overall corporate goals and vision.	5.3.3
11.8	Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand;	5.4
11.8.1	Explain the load forecasting methodology and indicate all the factors used in preparing the load estimates;	5.4.1
11.8.2	Provide separate forecasts to at least the zone substation level covering at least a minimum five year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts;	5.4



11.8.3	Identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period ; and	5.5 on
11.8.4	Discuss the impact on the load forecasts of any anticipated levels of distributed generation in a network , and the projected impact of any demand management initiatives.	
11.9	Analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including-	
11.9.1	The reasons for choosing a selected option for projects where decisions have been made;	Appendix C
11.9.2	The alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described;	Appendix C
11.9.3	Consideration of planned innovations that improve efficiencies within the network , such as improved utilisation, extended asset lives, and deferred investment.	Appendix C
11.10	A description and identification of the network development programme including distributed generation and non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include-	5.3.5 Appendix C
11.10.1	A detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months;	NA
11.10.2	A summary description of the programmes and projects planned for the following four years (where known); and	NA
11.10.3	An overview of the material projects being considered for the remainder of the AMP planning period .	Appendix F
11.11	A description of the EDB's policies on distributed generation , including the policies for connecting distributed generation . The impact of such generation on network development plans must also be stated.	3.5
11.12	A description of the EDB's policies on non-network solutions, including-	5.3.5
11.12.1	Economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation; and	5.3.5



11.12.2	The potential for non-network solutions to address network problems or constraints.	5.3.5, Appendix C
	Lifecycle Asset Management Planning (Maintenance and Renewal)	Section 6
12	The AMP must provide a detailed description of the lifecycle asset management processes, including—	
12.1	The key drivers for maintenance planning and assumptions;	Section 6
12.2	Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	Section 6
12.2.1	The approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done;	Section 6
12.2.2	Any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	Section 6
12.2.3	Budgets for maintenance activities broken down by asset category for the AMP planning period .	Section 8
12.3	Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	Section 6
12.3.1	The processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets;	6.3 by type
12.3.2	A description of innovations made that have deferred asset replacement;	Section 6
12.3.3	A description of the projects currently underway or planned for the next 12 months;	Appendix D
12.3.4	A summary of the projects planned for the following four years (where known); and	Appendix E



12.3.5	An overview of other work being considered for the remainder of the AMP planning period .	Appendix F
12.4	The asset categories discussed in subclauses 12.2 and 12.3 above should include at least the categories in subclause 4.5 above.	
	Non-Network Development, Maintenance and Renewal	6.3.12
13	AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including—	6.3.12
13.1	A description of non-network assets;	6.3.12
13.2	Development, maintenance and renewal policies that cover them;	6.3.12
13.3	A description of material capital expenditure projects (where known) planned for the next five years;	6.3.12
13.4	A description of material maintenance and renewal projects (where known) planned for the next five years.	6.3.12
	Risk Management	
14	AMPs must provide details of risk policies, assessment, and mitigation, including—	Section 7
14.1	Methods, details and conclusions of risk analysis;	7
14.2	Strategies used to identify areas of the network that are vulnerable to high impact low probability events and a description of the resilience of the network and asset management systems to such events;	7.3.8
14.3	A description of the policies to mitigate or manage the risks of events identified in subclause 16.2;	7
14.4	Details of emergency response and contingency plans.	7.3.4



	Evaluation of performance	
15	AMPs must provide details of performance measurement, evaluation, and improvement, including—	
15.1	A review of progress against plan, both physical and financial;	8.6
	<i>Referring to the most recent disclosures made under Section 2.6 of this determination, discussing any significant differences and highlighting reasons for substantial variances;</i>	8
	<i>Commenting on the progress of development projects against that planned in the previous AMP and provide reasons for substantial variances along with any significant construction or other problems experienced;</i>	8
	<i>Commenting on progress against maintenance initiatives and programmes and discuss the effectiveness of these programmes noted.</i>	6.1.3
15.2	An evaluation and comparison of actual service level performance against targeted performance;	Section 4.4
	<i>In particular, comparing the actual and target service level performance for all the targets discussed under the Service Levels section of the AMP in the previous AMP and explain any significant variances;</i>	
15.3	An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the EDB's asset management and planning processes.	Appendix A2
15.4	An analysis of gaps identified in subclauses 15.2 and 15.3 above. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	2.11
	Capability to deliver	
16	AMPs must describe the processes used by the EDB to ensure that-	
16.1	The AMP is realistic and the objectives set out in the plan can be achieved;	2.12.2



16.2	The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	2.10
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Appendix A2 – Information Disclosure Schedules 11-15

Schedule 11a: Report on Forecast Capital Expenditure

Company Name AMP Planning Period												Horizon Energy Distribution Limited 1 April 2016 – 31 March 2026	
SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE													
This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)													
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).													
This information is not part of audited disclosure information.													
sch ref													
7		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10	
8		for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
9	11a(i): Expenditure on Assets Forecast	\$000 (in nominal dollars)											
10	Consumer connection	121	449	407	355	320	317	317	314	313	313	312	
11	System growth	276	1,722	528	2,211	2,278	501	231	236	563	188	2,263	
12	Asset replacement and renewal	6,622	4,567	6,570	4,651	4,298	5,445	5,841	5,136	4,612	5,126	5,200	
13	Asset relocations	-	45	41	36	234	32	32	31	31	31	31	
14	Reliability, safety and environment:												
15	Quality of supply	472	469	729	1,163	578	292	269	906	430	571	306	
16	Legislative and regulatory	101	99	101	310	315	322	328	111	113	115	118	
17	Other reliability, safety and environment	227	1,467	452	205	209	213	601	221	226	230	235	
18	Total reliability, safety and environment	800	2,035	1,281	1,678	1,102	827	1,198	1,238	769	917	658	
19	Expenditure on network assets	7,820	8,818	8,826	8,932	8,232	7,121	7,619	6,954	6,289	6,575	8,466	
20	Expenditure on non-network assets	474	1,216	407	310	263	215	329	335	342	349	356	
21	Expenditure on assets	8,293	10,034	9,233	9,242	8,496	7,336	7,948	7,290	6,631	6,924	8,822	
22													
23	plus Cost of financing	102	115	115	116	107	93	99	90	82	85	110	
24	less Value of capital contributions	828	655	471	317	301	302	305	306	309	312	314	
25	plus Value of vested assets	350	405	392	235	210	207	207	204	204	203	203	
26													
27	Capital expenditure forecast	7,917	9,899	9,269	9,275	8,511	7,334	7,949	7,278	6,608	6,902	8,820	
28													
29	Assets commissioned	7,517	9,899	9,269	9,275	8,511	7,334	7,949	7,278	6,608	6,902	8,820	
30													
31		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10	
32		for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
33		\$000 (in constant prices)											
34	Consumer connection	121	449	400	344	304	295	289	281	275	269	263	
35	System growth	276	1,722	519	2,138	2,163	467	211	211	494	162	1,908	
36	Asset replacement and renewal	6,622	4,567	6,463	4,498	4,081	5,069	5,331	4,595	4,045	4,409	4,385	
37	Asset relocations	-	45	40	34	222	29	29	28	27	27	26	
38	Reliability, safety and environment:												
39	Quality of supply	472	469	717	1,125	549	272	246	810	378	491	258	
40	Legislative and regulatory	101	99	99	299	299	299	299	99	99	99	99	
41	Other reliability, safety and environment	227	1,467	444	198	198	198	548	198	198	198	198	
42	Total reliability, safety and environment	800	2,035	1,260	1,622	1,046	769	1,093	1,108	675	789	555	
43	Expenditure on network assets	7,820	8,818	8,683	8,636	7,816	6,629	6,953	6,222	5,517	5,655	7,138	
44	Expenditure on non-network assets	474	1,216	400	300	250	200	300	300	300	300	300	
45	Expenditure on assets	8,293	10,034	9,083	8,936	8,066	6,829	7,253	6,522	5,817	5,955	7,438	
46													
47	Subcomponents of expenditure on assets (where known)												
48	Energy efficiency and demand side management, reduction of energy losses												
49	Overhead to underground conversion	597	177	291	345	464	341	171	558	558	630	630	
50	Research and development												

Schedule 11a: Report on Forecast Capital Expenditure

Company Name

Horizon Energy Distribution Limited

AMP Planning Period

1 April 2016 – 31 March 2026

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

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Difference between nominal and constant price forecasts

Consumer connection

System growth

Asset replacement and renewal

Asset relocations

Reliability, safety and environment:

Quality of supply

Legislative and regulatory

Other reliability, safety and environment

Total reliability, safety and environment

Expenditure on network assets

Expenditure on non-network assets

Expenditure on assets

for year ended

31 Mar 16

31 Mar 17

31 Mar 18

31 Mar 19

31 Mar 20

31 Mar 21

31 Mar 22

31 Mar 23

31 Mar 24

31 Mar 25

31 Mar 26

\$000

-

-

7

12

16

22

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33

38

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-

-

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115

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69

26

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42

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56

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429

507

694

767

814

970

1,384

11a(ii): Consumer Connection

Consumer types defined by EDB*

General

[EDB consumer type]

[EDB consumer type]

[EDB consumer type]

[EDB consumer type]

*Include additional rows if needed

Consumer connection expenditure

less Capital contributions funding consumer connection

Consumer connection less capital contributions

for year ended

31 Mar 16

31 Mar 17

31 Mar 18

31 Mar 19

31 Mar 20

31 Mar 21

\$000 (in constant prices)

121

449

400

344

304

295

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Schedule 11a: Report on Forecast Capital Expenditure

Company Name

Horizon Energy Distribution Limited

AMP Planning Period

1 April 2016 – 31 March 2026

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
93	11a(iv): Asset Replacement and Renewal	\$000 (in constant prices)					
94	Subtransmission			415	237		
95	Zone substations	2,473	879	2,831	1,227	1,381	1,546
96	Distribution and LV lines	726	1,544	1,214	1,171	1,089	1,289
97	Distribution and LV cables	925	1,522	1,060	682	710	1,014
98	Distribution substations and transformers	550	478	389	391	570	745
99	Distribution switchgear	315	109	239	349	137	109
100	Other network assets	1,634	35	315	441	195	365
101	Asset replacement and renewal expenditure	6,622	4,567	6,463	4,498	4,081	5,069
102	less Capital contributions funding asset replacement and renewal						
103	Asset replacement and renewal less capital contributions	6,622	4,567	6,463	4,498	4,081	5,069

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
107	11a(v): Asset Relocations	\$000 (in constant prices)					
108	Project or programme*						
109	Transformer relocations driven by customer requests		45	40	34	222	29
110	(Description of material project or programme)						
111	(Description of material project or programme)						
112	(Description of material project or programme)						
113	(Description of material project or programme)						
114	*Include additional rows if needed						
115	All other project or programmes - asset relocations						
116	Asset relocations expenditure		45	40	34	222	29
117	less Capital contributions funding asset relocations						
118	Asset relocations less capital contributions		45	40	34	222	29

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
122	11a(vi): Quality of Supply	\$000 (in constant prices)					
123	Project or programme*						
124	Poletop digital rollout Y1		114				
125	11kV surge arrestors upgrade- Plains East bank stage 1		109				
126	Poletop digital rollout Y2			114			
	Hillcrest Cable upgrade 540m-2 RMU			178			
	Manawatu Voltage regulator			210			
	2nd 33kV line into Aniwhenua				1,008		
	Split West bank feeder off Rangitiki feeder					194	
127	Underground Plains-East bank high capacity tie feeder					294	
	Kope/SR/Gateway 11kV distribution tie points automation Y1						246
129	*Include additional rows if needed						
130	All other projects or programmes - quality of supply	472	246	215	116	61	26
131	Quality of supply expenditure	472	246	215	116	61	26
132	less Capital contributions funding quality of supply						
133	Quality of supply less capital contributions	472	246	215	116	61	26

Schedule 11a: Report on Forecast Capital Expenditure

Company Name

Horizon Energy Distribution Limited

AMP Planning Period

1 April 2016 – 31 March 2026

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions).
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
135							
136							
137	11a(vii): Legislative and Regulatory						
138	Project or programme*	5000 (in constant prices)					
139	LT end of run earthing project Y2				200		
140	LT end of run earthing project Y3					200	
141	LT end of run earthing project Y4						200
142	(Description of material project or programme)						
143	(Description of material project or programme)						
144	*Include additional rows if needed						
145	All other projects or programmes - legislative and regulatory	101	99	99	99	99	99
146	Legislative and regulatory expenditure	101	99	99	299	299	299
147	less Capital contributions funding legislative and regulatory						
148	Legislative and regulatory less capital contributions	101	99	99	299	299	299
149							
150							
151	11a(viii): Other Reliability, Safety and Environment						
152	Project or programme*	5000 (in constant prices)					
153	Galatea 33kV bus upgrade		938				
154	Relocate Galatea T2		183				
155	SCADA relocatable disaster recovery unit		66				
156	Zone Sub CB remote open-close project		60				
157	Te Rahu South /WBIM South Structures reconfigure			233			
158	*Include additional rows if needed						
159	All other projects or programmes - other reliability, safety and environment	227	221	211	198	198	198
160	Other reliability, safety and environment expenditure	227	1,467	444	198	198	198
161	less Capital contributions funding other reliability, safety and environment						
162	Other reliability, safety and environment less capital contributions	227	1,467	444	198	198	198
163							
164							
165							
166	11a(ix): Non-Network Assets						
167	Routine expenditure						
168	Project or programme*	5000 (in constant prices)					
169	Information and technology systems	154	109	110	110	110	110
170	Tools	11	18	10	10	10	10
171	Office buildings, depots, and workshops	5	-	25	25	25	25
172	Office furniture and equipment	2	-	15	15	15	15
173	Motor vehicles	31	200	40	40	40	40
174	*Include additional rows if needed						
175	All other projects or programmes - routine expenditure						
176	Routine expenditure	203	327	200	200	200	200
177	Atypical expenditure						
178	Project or programme*	5000 (in constant prices)					
179	Information and technology systems	271		50		50	
180	Information and technology systems		889	150	100		
181	(Description of material project or programme)						
182	(Description of material project or programme)						
183	(Description of material project or programme)						
184	*Include additional rows if needed						
185	All other projects or programmes - atypical expenditure						
186	Atypical expenditure	271	889	200	100	50	-
187							
188	Expenditure on non-network assets	474	1,216	400	300	250	200

Schedule 11b: Report on Forecast Operational Expenditure

Company Name

Horizon Energy Distribution Limited

AMP Planning Period

1 April 2016 – 31 March 2026

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.

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46

47

48

49

50

Current Year CY

CY+1

CY+2

CY+3

CY+4

CY+5

CY+6

CY+7

CY+8

CY+9

CY+10

for year ended

31 Mar 16

31 Mar 17

31 Mar 18

31 Mar 19

31 Mar 20

31 Mar 21

31 Mar 22

31 Mar 23

31 Mar 24

31 Mar 25

31 Mar 26

Operational Expenditure Forecast

\$000 (in nominal dollars)

Service interruptions and emergencies

Vegetation management

Routine and corrective maintenance and inspection

Asset replacement and renewal

Network Opex

System operations and network support

Business support

Non-network opex

Operational expenditure

828

826

842

855

868

881

898

916

935

953

972

423

612

620

629

639

648

661

674

688

702

716

1,117

992

781

896

851

855

844

926

912

970

878

728

517

621

712

640

833

698

672

696

695

712

3,095

2,947

2,864

3,092

2,997

3,217

3,102

3,188

3,230

3,320

3,278

2,288

1,970

1,996

2,026

2,056

2,087

2,129

2,171

2,214

2,259

2,304

3,400

3,596

3,546

3,599

3,653

3,707

3,782

3,857

3,934

4,013

4,093

5,688

5,566

5,541

5,624

5,709

5,794

5,910

6,028

6,149

6,272

6,397

8,783

8,513

8,405

8,716

8,706

9,011

9,012

9,217

9,379

9,592

9,676

Current Year CY

CY+1

CY+2

CY+3

CY+4

CY+5

CY+6

CY+7

CY+8

CY+9

CY+10

for year ended

31 Mar 16

31 Mar 17

31 Mar 18

31 Mar 19

31 Mar 20

31 Mar 21

31 Mar 22

31 Mar 23

31 Mar 24

31 Mar 25

31 Mar 26

\$000 (in constant prices)

Service interruptions and emergencies

Vegetation management

Routine and corrective maintenance and inspection

Asset replacement and renewal

Network Opex

System operations and network support

Business support

Non-network opex

Operational expenditure

828

826

831

831

831

831

831

831

831

831

831

423

612

612

612

612

612

612

612

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1,117

992

771

871

815

807

781

840

811

846

751

728

517

613

693

614

786

646

610

619

606

609

3,095

2,947

2,827

3,007

2,872

3,037

2,871

2,893

2,873

2,895

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5,470

8,783

8,513

8,297

8,477

8,342

8,507

8,341

8,363

8,343

8,365

8,273

Subcomponents of operational expenditure (where known)

Energy efficiency and demand side management, reduction of energy losses

Direct billing*

Research and Development

Insurance

</

Schedule 12a: Report on Asset Condition

Company Name **Horizon Energy Distribution Limited**
 AMP Planning Period **1 April 2016 – 31 March 2026**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref	Asset condition at start of planning period (percentage of units by grade)										
	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1-4)	% of asset forecast to be replaced in next 5 years
7											
8											
9											
10	All	Overhead Line	Concrete poles / steel structure	No.	-	0.19%	95.04%	4.77%		2	0.37%
11	All	Overhead Line	Wood poles	No.	-	10.58%	71.41%	18.00%		2	15.33%
12	All	Overhead Line	Other pole types	No.	5.56%	5.56%	72.22%	16.67%		2	33.33%
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	98.49%	1.51%		1	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-		-	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	77.50%	22.50%		4	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-		-	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-		-	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-		-	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-		-	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-		-	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-		-	-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-		-	-
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-		-	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	81.82%	18.18%		3	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-		2	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	100.00%		4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	62.50%	37.50%	-		2	62.50%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-		-	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	-	100.00%		1	-
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-		-	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-		-	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-		-	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	84.91%	15.09%		4	-
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	33.33%	-	66.67%		4	33.33%
35											

Schedule 12a: Report on Asset Condition

										Company Name	Horizon Energy Distribution Limited
										AMP Planning Period	1 April 2016 – 31 March 2026
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.											
Asset condition at start of planning period (percentage of units by grade)											
sch ref	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
35											
36											
37											
38											
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	61.11%	33.33%	5.56%		4	61.11%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	2.87%	92.98%	4.14%		3	3.09%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-		-	-
42	HV	Distribution Line	SWER conductor	km	-	-	95.48%	4.52%		3	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	0.32%	72.21%	27.47%		2	0.83%
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	96.47%	3.53%		2	-
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-		-	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	8.79%	91.21%		3	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-		-	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	9.16%	23.29%	49.50%	18.05%		1	35.46%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-		-	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	0.91%	1.82%	63.64%	33.64%		3	4.09%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.95%	7.13%	81.47%	10.45%		3	11.57%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	1.80%	4.65%	79.88%	13.66%		2	6.91%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	100.00%		4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	0.27%	5.25%	82.91%	11.57%		2	6.19%
55	LV	LV Line	LV OH Conductor	km	-	0.04%	98.26%	1.70%		2	0.04%
56	LV	LV Cable	LV UG Cable	km	-	0.01%	95.04%	4.95%		2	0.29%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	9.18%	89.14%	1.68%		2	11.73%
58	LV	Connections	OH/UG consumer service connections	No.	0.04%	10.42%	86.85%	2.68%		3	12.77%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	-	23.85%	76.15%		3	3.67%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	77.78%	22.22%	-		4	77.78%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	100.00%	-		4	-
62	All	Load Control	Centralised plant	Lot	25.00%	75.00%	-	-		4	100.00%
63	All	Load Control	Relays	No.	-	-	-	-		-	-
64	All	Civils	Cable Tunnels	km	-	-	-	-		-	-

Schedule 12b: Report on Forecast Capacity

								Company Name	Horizon Energy Distribution Limited
								AMP Planning Period	1 April 2016 – 31 March 2026
SCHEDULE 12b: REPORT ON FORECAST CAPACITY									
This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.									
sch ref									
7	12b(i): System Growth - Zone Substations								
8		Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)
9	<i>Existing Zone Substations</i>								
10	East Bank	6.7	-	N	20.0	-	-	-	No constraint within +5 years
11	Galatea	4.7	7.5	N-1	-	63%	8	63%	Switched security of supply from adjacent substations
12	Kaingaroa	2.7	5.3	N-1	-	50%	5	50%	None
13	Kawerau	18.2	25.0	N-1	2.0	73%	20	75%	No constraint within +5 years
14	Kopeopeo	15.6	13.3	N-1	12.0	118%	16	118%	Transpower
15	Ohope	4.6	-	N	4.0	-	-	-	Incoming 33kV cables thermal capacity limited
16	Plains	6.1	-	N	17.0	-	-	-	Subtransmission circuit
17	Station Road	10.2	10.0	N-1	18.0	102%	10	103%	Transformer
18	Te Kaha	1.6	-	N	-	-	-	-	Single phase tx with one installed spare
19	Waiotahi	9.7	10.0	N-1	2.0	97%	10	103%	Transformer
20						-			Transpower
21						-			Transpower GXP
22						-			Transpower GXP
23						-			
24						-			
25						-			
26						-			
27						-			
28						-			
29	¹ Extend forecast capacity table as necessary to disclose all capacity by each zone substation								

Schedule 12c: Report on Forecast Network Demand

Company Name

Horizon Energy Distribution Limited

AMP Planning Period

1 April 2016 – 31 March 2026

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

7

12c(i): Consumer Connections

8

Number of ICPs connected in year by consumer type

9

10

11

Consumer types defined by EDB*

12

All types

13

14

15

16

17

Connections total

18

*include additional rows if needed

19

Distributed generation

20

Number of connections

21

Capacity of distributed generation installed in year (MVA)

22

12c(ii) System Demand

23

24

Maximum coincident system demand (MW)

25

GXP demand

26

plus Distributed generation output at HV and above

27

Maximum coincident system demand

28

less Net transfers to (from) other EDBs at HV and above

29

Demand on system for supply to consumers' connection points

30

Electricity volumes carried (GWh)

31

Electricity supplied from GXPs

32

less Electricity exports to GXPs

33

plus Electricity supplied from distributed generation

34

less Net electricity supplied to (from) other EDBs

35

Electricity entering system for supply to ICPs

36

less Total energy delivered to ICPs

37

Losses

38

39

Load factor

40

Loss ratio

Schedule 12d: Report on Forecast Interruptions and Duration

		Company Name Horizon Energy Distribution Limited	
		AMP Planning Period 1 April 2016 – 31 March 2026	
		Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		Current Year CY 31 Mar 16	CY+1 31 Mar 17	CY+2 31 Mar 18	CY+3 31 Mar 19	CY+4 31 Mar 20	CY+5 31 Mar 21
8							
9							
10	SAIDI						
11	Class B (planned interruptions on the network)	20.0	20.0	20.0	20.0	20.0	20.0
12	Class C (unplanned interruptions on the network)	105.0	125.0	125.0	125.0	120.0	120.0
13	SAIFI						
14	Class B (planned interruptions on the network)	0.18	0.14	0.14	0.14	0.14	0.14
15	Class C (unplanned interruptions on the network)	1.25	1.60	1.60	1.60	1.50	1.50

Schedule 13: Report on Asset Management Maturity

						Company Name	Horizon Energy Distribution Limited	
						AMP Planning Period	1 April 2016 – 31 March 2026	
						Asset Management Standard Applied		
SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY								
This schedule requires information on the EDB's self-assessment of the maturity of its asset management practices .								
Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	3	Asset Management Policy in AMP Asset Management Policy on the intranet, authorised by the Board	The asset management policy has been documented, authorised by top management and communicated through the intranet.	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	Asset management Strategy derived from Company strategy and in support of stakeholder interests	The work done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders is fairly well advanced but still incomplete.	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 policies, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	Covered in Sections 5 and 6 of the Asset Management Plan		0 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	Covered in Sections 5 and 6 of the Asset Management Plan . Bottom-up forecasting of 10 yr plan	Analysis of the lifecycle of critical assets has been completed. The asset management plans for asset types has been established, documented, implemented and maintained to achieve the objectives across the life cycle of the asset types.	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).

Schedule 13: Report on Asset Management Maturity

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.



Schedule 13: Report on Asset Management Maturity

						Company Name	Horizon Energy Distribution Limited	
						AMP Planning Period	1 April 2016 – 31 March 2026	
						Asset Management Standard Applied		
SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)								
Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document 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	Works packs for projects. Maintenance: Navision The prioritised "Defects Plan". Maintenance: Weekly contractor meetings. Asset management plan.	The project and maintenance plans are communicated to most of those responsible for delivery as required. There were weaknesses identified in the interviews with incomplete communication. The organization recognizes improvement is needed as is working towards resolution.	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	Asset Management Plan Job descriptions Assignment of Project Managers	Asset management plan(s) have documented the responsibilities for the delivery actions and the detail is enough to deliver the actions. The designated responsibility and authority for achievement of asset plan actions is considered appropriate.	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	Combination of internal resources plus ability to use external resources Plan is resource levelled to avoid shocks to internal resources	Horizon Energy ensures the implementation of asset management plans are efficient and cost effective and address resources and timescales required by forward planning. The board and the financial team understand the requirement for this. Functional policies, standards, processes and the asset management information systems enable this forward planning.	It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	Incident management procedure Critical spares list Risk registers Various documents including: Business Continuity Plan Disaster Recovery Security of Supply ICT Recovery Plan Risk Register	Appropriate emergency planning and procedures are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Some training and external agency alignment is in place (see question 34). Emergency preparedness and response plan(s) and procedure(s) are periodically tested and the lessons learnt are consistently captured and fed into the review process.	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.

Schedule 13: Report on Asset Management Maturity

				Company Name AMP Planning Period Asset Management Standard Applied			
				Horizon Energy Distribution Limited			
				1 April 2016 – 31 March 2026			
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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					Company Name	Horizon Energy Distribution Limited		
					AMP Planning Period	1 April 2016 – 31 March 2026		
					Asset Management Standard Applied			
SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)								
Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document 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	Appointment of an Asset Manager supported by an Asset Management team	Very recently an asset manger has been appointed to have full responsibility for ensuring that Horizon Energy's assets deliver the requirements of the asset management strategy, objectives and plans. Further to this other members of the management team understand and are competent with rolling out asset management. They have been given the authority to achieve	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?	3	Historical achievement, resource forward plan, competency framework	Resources that are required are determined for AM activities and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	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	Support for this project. Asset Management Plan concerns are formally communicated in management meetings. Financial approvals in Navision. Network meetings, Contractor interface meetings, toolbox talks.	CEO communicates the importance of meeting asset management requirements to relevant parts of both Horizon Energy and Horizon Services.	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 walkabouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3	Tender documents have a clear scope for design of facilities and controls are in place as per industry standards. All contracts are ensured to be in line with the Strategic plan, asset management policy and Strategy. Financial controls and service levels applied to contracts.	Outsourced activities are controlled to provide for the compliant delivery of the strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	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 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 person 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 organisation's 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 organisation's 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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				Company Name AMP Planning Period Asset Management Standard Applied		Horizon Energy Distribution Limited 1 April 2016 – 31 March 2026		
SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)								
Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/document 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)?	3	Training / competency matrix Position descriptions Horizon Energy training database Succession Plan	The staff in the field (Horizon Services) has a comprehensive plan to match competencies and capabilities to the asset management work they do. The management team ensure they are competent by attending industry conferences and seminars. Administration staff do not have a comprehensive training for AM systems, this is ad hoc.	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?				Widely used AM standards require that organisations 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	Training / competency matrix Professional development plan in line with job description.	The staff in the field (Horizon Services) has a comprehensive plan to match competencies and capabilities to the asset management work they do.	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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					Company Name AMP Planning Period Asset Management Standard Applied			
SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)					Horizon Energy Distribution Limited 1 April 2016 – 31 March 2026			
Question No.	Function	Question	Score	Evidence – Summary	User Guidance	Why	Who	Record/document 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	As built Defect forms Asset Management Plan Surveys GIS - G Technology	Asset management information flows via the control centre, technical standards, AMP on the website, mailouts for outages, major stakeholder meetings, radio advertisements, shared with external parties through GIS and other databases that they are provided. Other information is collected through defect forms, as built, surveys, through the energy trust, and customer complaints via the EGCC. Customers can understand who	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	Flow chart of the business processes Asset Management Plan	Horizon Energy is in the process of documenting its asset management system and has documentation in place.	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	System review project Maintenance policies Review of an Asset Management System GIS systems implemented	Horizon has developed a process to determine what its AM system should contain in order to support its business and has commenced implementation of the process. At this time it has been highlighted that the CMMS (maintenance history) is lacking and required.	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	Asset inspection project, including GPS location and photos As built Asset update sheets Standards for data	Horizon has effective controls in place that ensure data held is of the requisite quality and accuracy and is consistent. The controls are reviewed and improved where necessary.	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.

Schedule 13: Report on Asset Management Maturity

				Company Name AMP Planning Period Asset Management Standard Applied		Horizon Energy Distribution Limited 1 April 2016 – 31 March 2026		
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	Network construction and Maintenance Outsourcing Policy As built - commissioning Financial controls within the systems Tender documentation for design and construction. Tree Database, DIS, Call Care, (fault call centre) AMS under Review	Processes and procedures are in place to manage and control the implementation of asset management plans during activities related to asset creation, and enhancement.	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	Zone Substations site and buildings Substation miscellaneous equipment, and other documents Hazard assessment forms As built Risk Register	Horizon Energy and Services has in place processes and procedures to manage and control the implementation of asset management plans. They are being reviewed this year.	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?	3	Thermal imaging Oil testing reports Visual inspections of above ground assets Partial discharge testing	Thermal imaging, oil testing, earth testing, visual inspections of above ground assets, level checks, IP performance monitoring, partial discharge testing, performance modelling on site measurements and trending through control centre (performance). They are done regularly and data collected and stored.	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	Fault procedure for failures Incident register Corrective action register Health and Safety function Regulatory function		0 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 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)							
Question No.	Function	Question	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.

Schedule 13: Report on Asset Management Maturity

				Company Name AMP Planning Period Asset Management Standard Applied		Horizon Energy Distribution Limited 1 April 2016 – 31 March 2026		
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	Network construction and Maintenance Outsourcing Policy As built - commissioning. Financial controls within the systems Tender documentation for design and construction Board Approval of Projects>\$250K	Processes and procedures are in place to manage and control the implementation of asset management plans during activities related to asset creation, and enhancement.	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	Regular audits Service level targets Asset inspection Corrective action register	Horizon Energy and Services has in place processes and procedures to manage and control the implementation of asset management plans. They are being reviewed this year.	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	Thermal imaging Oil testing reports Visual inspections of above ground assets Partial discharge testing Asset inspection Service Levels	Thermal imaging, oil testing, earth testing, visual inspections of above ground assets, level checks, IP performance monitoring, partial discharge testing, performance modelling on site measurements and trending through control centre (performance). They are done regularly and data collected and stored.	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	Fault procedure for failures Incident register Corrective action register Non-conformance Policy Audits		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.

Schedule 13: Report on Asset Management Maturity

<div> <div>Company Name</div> <div>AMP Planning Period</div> <div>Asset Management Standard Applied</div> </div> <div> <div>Horizon Energy Distribution Limited</div> <div>1 April 2016 – 31 March 2026</div> </div>							
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
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 conformance 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.

Schedule 13: Report on Asset Management Maturity

				Company Name AMP Planning Period Asset Management Standard Applied		Horizon Energy Distribution Limited 1 April 2016 – 31 March 2026		
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	NZS7901, ISO9001 auditing process. Previous IIMM and PAS55 audits Risk Review	Horizon can demonstrate that its audit procedures cover appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and are consistently managed.	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	Defect management process 10 years works programme Tender documentation As built Audits Corrective action register	Investigation conducted after issue identified through defect, routine maintenance, M&S, risk register and modelling, load growth predictions, then when job identified it is tendered of O&M NAV job raised, contractor responds, asbuilt delivered, captured in GIS with new asset records. This is the process of instigation of preventive and corrective actions of non compliance / incidents identified by investigations, compliance evaluation and audits.	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?	3	Asset management plan Maintenance free equipment Life cycle analysis report External reviews Asset inspection Service levels	If new practices are heard from the people. Continuous improvement, including consideration of cost risk, performance and condition for assets managed across the asset life cycle are applied.	Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing action to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather than reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
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	Conferences Newsletters Industry news Training Industry magazines	Horizon Energy engages both internally and externally with AM practitioners, professional bodies and conferences. Investigates and evaluates new practices and improves AM activities.	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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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
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 investigate 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 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.

Appendix A2 – Schedule 14a Mandatory Explanatory Notes on Forecast Information

Company Name	<u>Horizon Energy Distribution Limited</u>
For Year Ended	<u>31 March 2017</u>

Schedule 14a Mandatory Explanatory Notes on Forecast Information

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.
2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

3. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

Difference between nominal and constant price capital expenditure forecasts are due to forecast indexation applied. For the forecast to 2026 this is based on an updated capital goods price index from NZIER through to 2020, and then an annualised average forecast indexation using capital goods price index estimates of 2.0%.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

Difference between nominal and constant price operational expenditure forecasts are due to forecast indexation applied. For the forecast to 2026 this is based on annualised average forecast consumer price index estimates of 1.3% for 2017, 1.5% up to 2020 and then 2.0% for the remainder of the forecast period up to 2026.

Appendix A2 – Schedule I5 Voluntary Explanatory Notes

Company Name	<u>Horizon Energy Distribution Limited</u>
For Year Ended	<u>31 March 2017</u>

Schedule I5 Voluntary Explanatory Notes

1. This schedule enables EDBs to provide, should they wish to-
 - 1.1 additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1 and 2.5.2;
 - 1.2 information on any substantial changes to information disclosed in relation to a prior disclosure year, as a result of final wash-ups.
2. Information in this schedule is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.
3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

1. All forecast capital expenditure provided for in schedule 11a is intended to be included in the value of assets commissioned relating to the RAB.

Appendix B – Glossary of Terms

AAAC	All Aluminium Alloy Conductor
AAC	All Aluminium Conductor
ABS	Air Break Switch
AC	Alternating Current
ACC	Accident Compensation Corporation
ACSR	Aluminium Conductor Steel Reinforced Cable
AL	Aluminium Conductor
AMP	Asset Management Plan
BCP	Business Continuity Planning
BOPLAG	Bay of Plenty Lifelines Advisory Group
CAIDI	Customer Average Interruption Duration Index – SAIDI/SAIFI
CAPEX	Capital Expenditure
CB	Circuit Breaker
CDEM	Civil Defence Emergency Management
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CT	Current Transformer
CU	Copper conductor
DC	Direct Current
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DRC	Depreciated Replacement Cost
EEA	Electricity Engineers Association
EDB	Electricity Distribution Business
ELB	Electricity Lines Business
EO	Engineering Officer
GIS	Geographic Information System
GPS	Global Positioning System
GWh	Giga Watts per hour (10^6 Watts)
GXP	Transpower Grid Exit Point
H&S	Health and Safety
HDBC	Hard Drawn Bare Copper conductor
HEIL	Horizon Energy Investments Limited
Horizon	Horizon Investments Contracting
Horizon Energy	Horizon Energy Distribution Limited
HV	High Voltage
Hz	Hertz
ICP	Installation Control Point
ICCP	Inter-Control Centre Protocol, a Transpower communications system
IFRS	International Financial Reporting Standards
kV	Kilo Volts (10^3 Volts)
kW	Kilo Watt
kWh	Kilo Watt per hour

LCP	Legislative Compliance Programme
LV	Low Voltage
MEN	Multiple Earthed Neutral system
MD	Maximum Demand
MIND	Mineral Insulated Non Draining insulated cable
MV	Medium Voltage, 11kV and 33kV
MVA	Mega Volt-Amps
MVAR	Mega Volt-Amps reactive
MW	Megawatt
MWh	Megawatt per hour
NEDeRS	UK based ENA National Equipment Defect Reporting Scheme
N security	Peak load may only be supplied without curtailment or interruption if all zone substation transformers are operating
N-1 security	Peak load may be supplied without curtailment or interruption including if the largest zone substation transformer is not operating
N-2	Peak load may be supplied without curtailment or interruption including if the largest 2 zone substation transformers are not operating
N-1 switched	Peak load may be supplied following a brief interruption during which switching is carried out to re-establish supply following an unexpected outage of the largest zone substation transformer
NPV	Net Present Value
ODRC	Optimised Deprival Replacement Cost
ODV	Optimised Deprival Value
OH or O/H	Overhead
ONAN	Natural oil flow and natural air flow cooling for transformers
ONAF	Natural oil flow and forced air flow cooling for transformers
OFAF	Pumped oil flow and forced air flow cooling for transformers
OPEX	Operational Expenditure
PD	Partial Discharge (Voltage leakage)
PILC	Paper Insulated, Lead Covered cable
PAS55	British Standard specification for the optimized management of physical assets
PLC	Programmable Logic Controller
POS	Point of Supply
PVC	Polyvinyl Chloride
RAB	Regulatory Asset Base; value of assets according to a regulated valuation model
RMS	11kV Ring Main Switch
rms	Root Mean Square
RMU	Ring Main Unit
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index (minutes) Sum of customer interruption duration / total number of customers
SAIFI	System Average Interruption Frequency Index Number of customer interruptions / total number of customers
SCADA	Supervisory Control and Data Acquisition



SCS	SCADA Controlled Switch
SF6	Sulphur Hexafluoride gas
SLT	Service Level Target
SWER	Single Wire Earth Return
UG or U/G	Underground
UHF	Ultra High Frequency
VA	Volt-Amps
VAR	Volt-Amps Reactive
VHF	Very High Frequency
VLf	Very Low Frequency
VT	Voltage Transformer
XPfE	Cross Linked Polyethylene insulation
ZS	Zone Substation

Appendix C– Major Projects List

The following sections summarise the significant projects planned and includes discussion on the main driver for the projects, options considered, and the preferred outcome.

All projects in the AMP are subject to continual review, managerial and Board approval on an individual basis, and the final outcome of any particular project is dependent on meeting the needs analysis and priority assessment for that project against the requirements of all projects and the needs of the organisation.

Ref Numbers/ Name:	
785 - Te Rahu South 33kV Sub-transmission Capacity Upgrade 75 - WBM South 33kV Sub-transmission Capacity Upgrade	
Description:	
Increase the capacity of Te Rahu South and WBM South 33kV feeders	
Constraint:	
<p>33kV feeders Te Rahu South and WBM South are a smaller conductor size than the parallel conductors Te Rahu North, Te Rahu Central, and WBM North feeders which supply Te Rahu and the future Gateway substations. This conductor limits the load carrying capacity of the conductors to 17MVA compared to the parallel feeders rating of 24MVA.</p> <p>When required to operate in reinforcement role, in case of the loss of one of the parallel circuits, the overall circuit capacity is limited to that of the small conductor. Under existing load conditions this is not a problem, and will not become a problem until the network load increases beyond 40MVA.</p> <p>In normal operation there is uneven load distribution across the parallel feeders. This is not an issue at present but will become more of an issue as total load increases.</p>	
Network Options:	
Increase the conductor size to match the size of the other parallel feeders	Balances all loads to provide full redundancy. Pole spacing and physical line layout is mostly adequate for this.
Increase the conductor size to be greater than the parallel feeders	Requires a new line design. Moves the constraint onto the opposite parallel circuit. Provides for future capacity. Uses non-standard network conductor. Reduces line losses.
Non-Network Options:	
Thermally re-rate the lines from the designed rating of 55 deg. C to 75 deg. C	Does nothing to correct line resistance, line losses, or volt drop. Existing loss when loaded to 19MVA is 2MVA which provides a delivery capacity of only 17MVA. Losses increase at re-rated full capacity and volt drop becomes the limiting factor. Lines require re-sagging and tensioning. Low cost option.
Implement summer/winter protection settings	Does not address the full load line losses. Low cost option.
Do nothing	With the Te Rahu and proposed Gateway substations operating properly in a parallel configuration the existing full load utilisation factors for the five lines in parallel is around 47%. Loss of one circuit, leaving four circuits, has about 60% utilisation. This will provide adequate system resilience until beyond 2040 unless there is a step change in loads.
Preferred Option:	
Detailed feasibility study yet to be completed. Completion of Gateway 33kV substation will provide good resilience to the network and these projects may be deferred indefinitely.	
Estimated Cost/Accuracy: 785 - Te Rahu South: \$500k, +- 30% 75 - WBM South: \$500k, +- 30%	
Projected Implementation Year: Deferred pending Gateway substation development	

Ref Numbers/ Name:	
I4 - Gateway 33kV Switching Station	
Description:	
Install a 33kV substation at Mill Road Whakatane and supply from feeders WBM North, WBM South, and Poroporo feeders.	
Constraint:	
Gateway 33kV sub station was always planned to support the Te Rahu 33kV substation. The existing system supplying Whakatane Mill Limited is load restricted when on a single feeder, and Te Rahu substation is restricted when on a single feeder. Gateway operating in a live bus arrangement with Te Rahu provides the required any time n-1 level of support between both substations. This substation will supply 33kV for the proposed CBD substation.	
Network Options:	
Develop an indoor 33kV substation at Mill Road for integrating three 33kV feeders and provide a tie link to Te Rahu Road	More costly option but provides a robust industry standard solution.
Install a series of poletop circuit breakers to perform the same function	Shorter lifecycle than indoor switchgear. Lower cost. More exposure to weather or wildlife impact. No benefit to WML. Visual impact.
Site location under review. Cost of getting circuits into and out of proposed Mill Road site is high. Possible integration with Whakatane Mill Ltd	WML site option is closer to the load sources and allows full underground integration with WML transformers and retirement of aged WML equipment.
Install new feeders to remove constraints	Existing assets have sufficient capacity if used as planned. Cost of new feeders out of Edgecumbe more costly and visually less appealing. Resource consenting issues for new feeders.
Non-Network Options:	
Do nothing	Te Rahu and WML 33kV overload risks are not reduced.
Encourage load saving initiatives	Benefits of these options are discussed in section 5.3.5.
Preferred Option:	
Develop 33kV substation on WML site and integrate to WML and Te Rahu substations. Deferred – not supported by customer	
Estimated Cost/Accuracy: \$2.1M +/-10%	
Projected Implementation Year: Deferred pending load demand	

Ref Numbers/ Name:	
15 - Gateway 11kV Development	
Description:	
Build a new zone substation located adjacent to the Gateway industrial zone. The scope of this project is for the 11kV infrastructure only.	
Constraint:	
A substation is required to take load off Kope and Station Road substations, to provide 11kV support between the two substations, and support load in the Piripai-Coastlands area. Estimate initial load is up to 6MVA.	
Network Options:	
Build a new zone substation to support load in the Gateway/ Piripai area adjacent to Coastlands	Estimated growth in the Piripai-Coastlands area 500 dwellings by 2050 (WDC, 2011) is an additional demand of 1.5MVA. No land identified. Allows support to CBD by cable under river.
Build a substation at Gateway 33kV substation	Close to existing loads and infrastructure. Allows integration with WML for support. 33kV infrastructure from Gateway 33kV bus.
Build a substation in the Whakatane CBD load area to support Kope and the CBD loads	Provides better overall support to CBD than a substation located at Gateway or Coastlands. Can distribute more load into three existing 11kV feeders.
Non-Network Options:	
Utilise spare 11kV capacity from Whakatane Mill Ltd	While being a viable option for support, both parties are uncomfortable with this as a permanent solution due to security of supply concerns.
Do nothing	The long term concept plan to off load Kope substation is to share load between Gateway, Station Road, and a future CBD substation. This substation is a crucial part of this plan. Do nothing is not considered a viable alternative.
Preferred Option:	
Deferred beyond 2023 or until area load growth drives development Deferred – not supported by customer	
Estimated Cost/Accuracy: \$1.2M, +-30%	
Projected Implementation Year: 2029	

Ref Numbers/ Name:	
45 - Express 33kV Cable Gateway to CBD-4.25km	
Description:	
Install a 33kV insulated cable from Gateway substation, or extend Poroporo Feeder, to a central location in the Whakatane CBD. Cable will use an existing duct along the river stop bank.	
Constraint:	
As the CBD grows there is limited capacity available from the Kope substation to support this growth, both from capacity and available cable routes and sizes out of Kope.	
Network Options:	
Install cable as described	Duct already installed along a large portion of the length.
Run cable /overhead along Keepa Road and thrust under river	Thrusting risk with rocks embedded in river. No comparative costs obtained so no cost benefit yet established.
Install larger feeder cables and transformers at Kope	Kope substation needs upgraded 33kV supplies, transformers, and 11kV distribution. Currently there is limited means of supporting Kope for a full outage in other than low load periods. Kope 11kV incomer circuit breakers rated at 15.2MVA.
Non-Network Options:	
Do nothing	Significant load growth in the Whakatane CBD will force a load demand strategy to support this load. Other options have been considered including a substation at Mokorua and larger capacity at Kope.
Local generation	This is not regarded as an economic long term solution due to the flat load profile of commercial loads.
Preferred Option:	
A new CBD zone substation is the preferred long term solution. Support at 11kV from a remote substation is an interim measure. Whether this is Gateway substation, a CBD substation, or a substation at Piripai or Mokorua will be determined once final site location decisions are made. There is a valid argument to progress this substation as a single transformer 12/16MVA site ahead of Gateway 11kV. Any development will be driven by a load needs basis.	
Estimated Cost/Accuracy: \$1.2M, +-30%	
Projected Implementation Year: Earliest 2025 unless driven earlier by CBD substation development	

Ref Numbers/ Name:

59 - Ohope-33kV Transformer T1 replacement

Description:

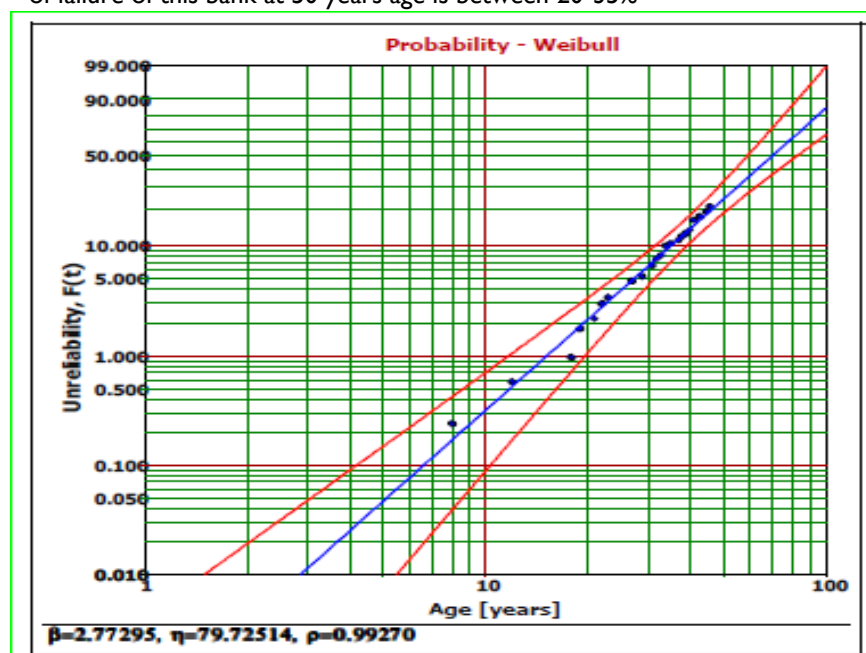
Install new transformer at Ohope zone substation.

Constraint:

Ohope Zone substation peak load is approaching the available 5MVA transformer bank capacity and was previously predicted to overload by 2014 during peak periods. The existing bank is a bank of three single phase transformers manufactured in 1966.

The implementation of enhanced load control and limited peak load growth has reduced the constraint previously identified.

- A Transformer probability of failure chart for similar sized transformers is below which shows the probability of failure of this bank at 50 years age is between 20-35%

**Network Options:**

Replace transformer with larger transformer 7.5/15 MVA	Same size as East Bank. A larger size may be considered to maintain a standard transformer across the network. Galatea transformers would also be a good fit at Ohope.
Install a dual transformer bank at Ohope	More costly but provides a higher level of security albeit with only a single 33kV feeder line.
Relocate Kope T1 transformer	

Non-Network Options:

Allow the transformer bank run in overload condition through peaks	Ohope peaks are very short duration so allowing the transformer to overload (130%) for up to two hours is technically acceptable – this could be used to defer the replacement by up to 10 years.
Manage peak loads	Peaks are primarily caused by load control restoration spikes. Load management to correct this will reduce the peaks allowing for a delay in the scheduled transformer replacement.
Load displacement	Dynamically displace peak loads to an adjacent substation. Feasible if automated switching is installed between

	Pohutukawa feeder and Mokorua feeder. This could provide a solution for up to 10-15 years.
Peak load cropping generation	Good option to manage peak loads as well as providing some back up security of supply. Could be used to defer transformer replacement.
Preferred Option:	
Relocate Kope TI to Ohope following Kope TI replacement in 2018.	
The lack of redundancy issue is a separate consideration that is discussed separately.	
Estimated Cost/Accuracy: \$1.1M, +-20%	
Projected Implementation Year: 2019 unless driven by condition	

Ref Numbers/ Name:	
741, 781 – Ohope T2, Ohope 2nd 33kV line	
Description:	
Ohope Reinforcement	
Constraint:	
Ohope Zone substation lack of 33kV reinforcement. Ohope is a single bank transformer supplied from a single 33kV line. Reinforcement is via 11kV from Station Road. As Ohope load increases the ability to provide reinforcement at 11kV becomes more constrained.	
Network Options:	
Continue to supply reinforcement at 11kV from Station Road Mokorua feeder	This feeder was upgraded to provide more capacity in 2009. It can physically supply Ohope but there are voltage quality issues at the end of Harbour feeder with this reinforcement route.
Install a substation at Mokorua to support Ohope from Pohutukawa feeder	Would not be considered viable unless load demand in the Mokorua region warrants additional capacity.
Insert a second transformer at Ohope	Provides a high level of 11kV security. Does nothing to remedy the single 33kV feeder line issue.
Convert the existing 33kV circuit to dual circuit	This does not provide the level of security a separate circuit would provide. Should be easier to consent than a new line. Less cost than a separate line. Issues maintaining supply during construction.
Install 2 nd 33kV circuit	Very costly option with resource consenting difficulties. Difficult line route.
Install 110kV line off the Waiotahi 110kV supply	This option has not been investigated in detail but is feasible in the longer term. Phase shift would need to be considered. Load at Ohope is insufficient at this stage to make this option a realistic alternative.
Connect supply from Waiotahi by thrusting a cable under the harbour	Phase shift between Waiotahi and Ohope. Expensive. May not be compatible with Opotiki development plans.
Non-Network Options:	
Install voltage support regulator/s	A voltage regulator at the tie point to Pohutukawa feeder would regulate the voltage into the Ohope region under reinforcement. This would be unused except during load reinforcement. Any regulator would need to be >5MVA to supply the full load of Ohope.
Install capacitor bank	Initial modelling results indicate that capacitive support would have limited benefit for voltage support during reinforcement. This would need to be centralised to enable automated switching to remove the capacitors when on normal supply from Ohope. Assets would be un-used under normal configuration.
Demand load management	Options discussed in section 5.3.5 could be applied as interim measures to manage peak demand load.
Support from Waiotahi at 11kV	There is a phase shift between Waiotahi and Ohope that

	requires break before make switching. Also the distribution feeders from Waiotahi are generally smaller conductors so voltage support becomes an issue. Capacitor banks and /or regulators would assist this.
Embedded generation	Peak load >4MVA would require 6MVA generation. 1MVA generation for voltage support in conjunction with 11kV reinforcement from Station Road substation would be a short term viable option during peak load periods.
Preferred Option:	
The preferred option at this stage is to not install a second feeder and to continue to support Ohope at 11kV until the load at this voltage becomes unsustainable, then support with generation during peak periods.	
Estimated Cost/Accuracy:	
There are a number of projects that apply to this constraint. Detailed engineering is yet to be complete to determine the best solution in the long term.	
Projected Implementation Year:	
>2026	

Ref Numbers/ Name:	
379 - 33kV-2nd 33kV line into Aniwhenua	
Description:	
Install a second 33kV circuit into Aniwhenua power station and connect to Kopuriki feeder.	
Constraint:	
Galatea and Kaingaroa combined loads are approaching the limits of the capacity of the Snake Hill 33kV feeder from Edgecumbe due to line voltage drop causing the transformer regulators at Galatea and Kaingaroa to saturate.	
Network Options:	
Upgrade the Snake Hill conductor size	Snake Hill feeder is connected at Edgecumbe. This feeder is 37km long and runs through rugged terrain. Estimated cost to re conductor this feeder exceeds the cost of installing a new line into Aniwhenua and does nothing to enhance the reliability for Galatea.
Install a new line into Aniwhenua	This would provide full redundancy for Galatea, and additional security is provided by the Aniwhenua connection to the 110kV. Two potential line routes are available.
Install new transformers with larger tap ranges	The existing transformers have extended range tap changers already. All four transformers are not yet due for replacement and there is no load constraint to force replacement.
Voltage regulator and/or capacitive support for the Snake Hill feeder	These devices will correct for the line losses to enable the Galatea and Kaingaroa transformer voltage regulators to work within their ranges. Estimated costs are similar to a new line build without the benefits of reduced line losses and reliability.
Non-Network Options:	
Demand Management	This is a short term alternative. Peak load is in summer due to irrigation, which is normally run at night so load demand management will have minimal effectiveness.
Generation support	Good alternative. Capital and running costs are high. Portable generation could be located in Galatea for the four months of the peak load period. There would be a high annual cost for standby generation.
Preferred Option:	
A full study is yet to be completed but at present the new 33kV line option is preferred.	
Estimated Cost/Accuracy: \$1,000,000 +-30%	
Projected Implementation Year: 2018 unless step load change forces acceleration	

Ref Numbers/ Name:	
384,385 - Kope 33kV Feeder Cables thermal upgrade	
Description:	
Upgrade thermal rating for Kope 33kV cables.	
Constraint:	
33kV cables are de-rated to below transformer full load capacity due to high soil thermal resistivity.	
Network Options:	
Replace cables	XLPE cable manufactured 1986. Project to coincide with Kope 33kV indoor conversion.
Non-Network Options:	
Do nothing	Conductor thermal loading can be managed with load management. Not a problem as long as cables are run in parallel. Switchboard loading limited by 800 amp incomer circuit breakers (15.2MVA).
Develop support substation 33kV ring feeders	Completion of planned satellite substations Gateway and/or CBD along with ring feed 33kV sub-transmission would provide alternative 33kV parallel supplies that would reduce the load on the Kope feeders. Would require sophisticated protection systems to prevent undesirable fault response trips.
Improve thermal conductivity of ducting by installing thermal mix into ducts	Gain in capacity is estimated at <5% so not regarded as a viable alternative.
Install thermal fill around cable ducts	Very costly option. Easy to do now due to good access to route. Potential future area development is likely to restrict access.
Install thermal sensors onto cables	Use to manage heat loading. Requires new cables
Preferred Option:	
Not yet defined.	
Estimated Cost/Accuracy: \$400K +/- 30%	
Projected Implementation Year: 2017 aligned to Kope 33kV indoor project	

Ref Numbers/ Name:	
380 - Whakatane CBD zone substation	
Description:	
Build a 33/11kV zone substation to support the Whakatane CBD loads.	
Constraint:	
<p>Supplies into the Whakatane CBD from Kope zone substation are restricted by the 33kV supply into Kope, the Kope transformer size, and the 11kV distribution out of Kope. Kope is 1.8km away from the CBD load centre and is located in the middle of a commercial and residential area.</p> <p>A CBD located single transformer zone substation will support Kope as well as supplying the CBD loads, and will be supported by Kope using the existing feeders.</p>	
Network Options:	
Build a 33/11kV substation adjacent to the CBD	Substation is close to load. Losses reduce and distribution into loads is easier from a more centralised substation.
Upgrade Kope substation and distribution cables	<p>This option is more costly and provides fewer benefits when compared to a separate substation.</p> <p>Would require extensive feeder 11kV cable overlays.</p>
Non-Network Options:	
Demand load management	Options discussed in section 5.3.5 could be applied as interim measures to manage peak demand load but not regarded as a permanent solution.
Alter the mix of domestic to commercial loads on the Kope substation	Limited opportunities to achieve this. As the domestic/commercial dual zoned areas close to the CBD are gradually converted to commercial use the load is taking on a more commercial profile, with a daytime peak.
Preferred Option:	
<p>33/11kV substation; Initial studies show that a 16MVA transformer would support Kope during a full outage if used in conjunction with Station Road and Gateway for the next 30 years.</p> <p>A full CDR study is yet to be completed to verify this preference.</p> <p>Any substation constructed in the CBD area would need to be constructed as a fully indoor solution to reduce visual impact. Indoor solutions are commonly used in other network companies in urban environments.</p>	
Estimated Cost/Accuracy: \$3.1M, +-20%	
Projected Implementation Year: 2025 will be a load driven development	

Ref Numbers/ Name:	
Various - Kope Zone Substation off-loading projects	
Description:	
Install high capacity distribution feeders between Kope, Station Road, Gateway, and the CBD zone substations.	
Constraint:	
The load management plan for the heavily loaded Kope substation is to re-distribute the loads between the adjacent substations, by providing high capacity tie feeders between the substations to provide inter-substation support. This allows single transformer substations to be constructed that are supported by adjoining substations at 11kV.	
Network Options:	
Upgrade various 11kV feeders	Feeders are existing. Certain sections require upgrading to enable additional load to be carried for cross supporting substations.
Construct all new substations as dual transformer substations	This creates a number of physically large substation sites, with redundant assets solely for back up purposes.
Install express feeders between substations	This is an ideal solution to maximise load transfer between substations and will be used when new feeders are able to be run. For existing feeders it is more economical to use the existing cables and accept the distribution of load along the feeder.
Non-Network Options:	
Install feeder automaton to enable dynamic load switching	A good option that allows loads to be dynamically switched as required balancing substation peak loads, especially providing an ability to mix commercial and domestic loads. This is described in more detail in section 5.12.9.
Share loading between adjacent substations	This is the preferred option and is actively being implemented.
Preferred Option:	
Continue the option of installing high capacity feeders between substations to dynamically share loads with adjacent substations.	
Estimated Cost/Accuracy:	
Various	
Projected Implementation Year: Ongoing	

Ref Numbers/ Name:	
928 - Kope 33kV indoor conversion	
Description:	
Extend the existing 11kV switchroom and install indoor 33kV switchboard	
Project:	
<ul style="list-style-type: none"> - Replace aged outdoor 33kV gear in an urban environment - Year of manufacture 1967 - Includes additional circuit breakers for a 33kV ring system to supply future CBD and/or Gateway substations - Converts Kope to an total indoor substation except for the transformers - Eliminate existing minimum approach distance safety hazard with the overhead 33kV bus - Clears site for replacement T1 transformer 	
Network Options:	
Do nothing or delay	CB's are 49 year old minimum oil devices. Safety issues have been identified with minimum approach distances to the existing 33kV overhead bus arrangement.
Rebuild outdoor system	Although a cheaper option, this is not a preferred option in an urban environment for both visual and safety reasons.
Install indoor option	Extend existing 11kV building. Re-route 33kV cables to new location. Allows the substation site to be reduced and allows room for a green belt to help disguise the substation.
Non-Network Options:	
None	
Preferred Option:	
Indoor installation	
Estimated Cost/Accuracy:	
\$1.2M +-20%	
Projected Implementation Year: 2017	

Ref Numbers/ Name:	
63 - Ohope 11kV indoor conversion	
Description:	
Install indoor 11kV circuit breakers for Ohope. Increase substation to four feeders.	
Constraint:	
<p>Ohope currently has two feeders. Both feeders have a significant number of ICP's and consequently accrue a significant level of SAIDI impact during faults. Some work is being completed to add more backup reinforcement to Harbour feeder. Once the Harbour loop cabling is complete this will be split into a third feeder, with a fourth feeder being the Cheddar Valley rural feeder.</p> <p>Due to reliability issues with the existing circuit breakers these were replaced in 2013 with Nova pole top circuit breakers. Whilst a good solution for the existing system configuration, replacing the transformer will introduce a requirement for more sophisticated transformer differential protection and reverse flow protection schemes, and the additional benefits of more feeders justifies an 11kV expansion.</p> <p>The preferred option for this is the prefabricated solution installed as installed in Galatea.</p>	
Network Options:	
Install an indoor 11kV switchroom using the Galatea pattern	Repeat design.
Install outdoor CB's	Area is coastal and equipment suffers corrosion issues. Outdoor CB's require an extensive bus structure system.
Non-Network Options:	
Do nothing	Does not address the large number of customers per feeder.
Preferred Option:	
Prefabricated indoor substation solution to coincide with T1 replacement.	
Estimated Cost/Accuracy:	
\$1.1M +/-20%	
Projected Implementation Year: 2021	

Ref Numbers/ Name:	
768 –Kope T1 replacement	
Description:	
Install new transformer at Kope, relocate Kope T1 to Ohope	
Constraint:	
Kope T1 and Kope T2 have dis-similar transformer impedances and full load power, meaning that the transformers are not load balanced. 10/13MVA T1 was manufactured in 1986 so is suitable for re-deployment at another substation site.	
Network Options:	
Replace T1 with transformer identical to T2	<p>Allows balanced load sharing.</p> <p>T1 available for re-location to alternative service and would be considered for Ohope, Plains, or CBD substations development.</p>
Non-Network Options:	
Do Nothing	<p>Mismatched transformers create high internal circulating currents that reduce the overall capacity of the transformer pair, as well as causing un-necessary heating of the transformers. This can be managed to some degree by the tap change controllers.</p> <p>Total substation output is determined by the rating of the lowest rated transformer.</p>
Other Considerations	
<p>Kope T1 has no oil containment system. Also the transformer is within 10 metres of the control room and fails to comply with the fire risk provisions of AS2067, Substations and High Voltage Installations Exceeding 1kV AC.</p> <p>Project is required as a predecessor for Kope 33kV bus replacement project</p>	
Preferred Option:	
Replace with a transformer matched to T2. Relocate Kope T1 to Ohope substation.	
Estimated Cost/Accuracy:	
\$1.1M +/-20%	
Projected Implementation Year: 2018	

Ref Numbers/ Name:	
766 - Galatea Load Control Plant replacement	
Description:	
Retire obsolete load control plant and implement non-ripple control methods to control street lighting	
Constraint:	
Ripple plant is rotating plant 750hz 40 years old. There is no economic justification for replacing the plant to control the small number of consumers in the Galatea region.	
Network Options:	
Replace load control plant with 317 Hz plant	Requires replacement of all control relays.
Load control spill from Edgecumbe at 33kV	Load is not always connected to Edgecumbe
Relocate plant from Kawerau or Waiohahi once these are replaced	A viable option that uses redundant plant. Kawerau and Waiohahi plants would provide sufficient spares to keep the plant running for a reasonable time.
Non-Network Options:	
Install smart meters	Requires replacement of all relays. Technically complex. Requires extensive communications infrastructure. Additional benefits include point of use metering and remote disconnect-reconnect. Has to be driven by retailers.
Do Nothing	Allow the plant to run to failure and not replace. Requires a method of controlling street lighting to be implemented.
Preferred Option:	
Feasibility study 2013 considers the amount of switchable load does not justify the capital required to replace the ripple plant and load control relays, so the preferred option is to run the ripple plant to failure. A consequential project is to install local daylight sensors on the street lighting to remove the streetlight control from the ripple control plant then allow the ripple plant to run to failure. Using redundant plant is also an option once these plants are replaced.	
Estimated Cost/Accuracy: \$100,000 +/-20%	
Projected Implementation Year: Deferred. Run to failure mode initially	

Ref Numbers/ Name:	
466 - Waiotahi Substation Feeders	
Description:	
Replace aged feeder KFE circuit breakers	
Constraint:	
CB's are at end of life and are not rated to the full close in fault current	
Network Options:	
Replace with new pole top circuit breakers	Difficult to do and maintain supplies. Requires larger footprint. Lower cost than preferred option. Shorter life than indoor switchgear.
Install pole-top CB's outside the substation and bypass the CB's inside the substation yard	Allows staged installation. Low cost alternative and easy implementation. Communications via pole-top VHF radio is simple and proven. Low cost option that reduces the investment loss if Waiotahi substation is eventually stranded by the development of a substation at Opotiki. CB's can be re-deployed if made redundant
Install ground mount switchgear in transportable building	Same design as Galatea. \$1.2M cost. Allows assets to be re-deployed if made redundant.
Non-Network Options:	
Extend Transpower Bus	Viable alternative. Costs passed on as interconnection charges, or charges may be reduced with capital contribution. More costly than network option but technically integrating into the existing bus and building is a technically more elegant solution with lower overall lifecycle costs. Would leave stranded assets if Waiotahi substation is made redundant by an Opotiki development.
Do Nothing	Viable alternative only if Opotiki substation is built at 110kV at Opotiki, and Waiotahi substation abandoned or down scaled. Would still require a circuit breaker to supply Waimana feeder .
Preferred Option:	
Still being assessed. Technical preference is to extend Transpower bus. Project to be considered along with Opotiki development plan and possible long term dis-establishment or down-scaling of Waiotahi substation.	
Estimated Cost/Accuracy:	
\$1.3M +/- 15%. \$350K if completed as Transpower project.	
Projected Implementation Year: 2017-18	


Ref Numbers/ Name:	
785 - Waiotahi and Opotiki Development	
Description:	
Build a new zone substation at Opotiki.	
Constraint:	
Opotiki area load growth is constrained by the capacity of the existing feeders supplying Opotiki from Waiotahi. Losses and volt drop are excessive and the three 11kV feeders exceed 50% capacity at peak loads, which reduces their ability to provide N-1 security during these times. Voltage support levels are out of tolerance under certain load conditions especially during reinforcement without interventions. There is limited ability to provide for step change load requests at Opotiki.	
Network Options:	
Increase the conductor size from Waiotahi to Opotiki	Costly option and would only provide a short term solution due to the transmission distance. Voltage regulators and reactive capacitors could compensate for some of the losses but this option has high losses, high capital cost, and a relatively short utilisation time.
Extend the Waiotahi 110kV line from Waiotahi to Opotiki and develop a 110/11kV substation at Opotiki	Upgrade the existing Transpower 50kV Te Kaha line route to 110kV and build a 110/11kV substation at Opotiki. This would leave Transpower with stranded assets at Waiotahi. Only one substation site would need to be developed, at Opotiki. Requires high capital investment to get the required level of security. Site could be developed by Transpower. Eliminates the 33kV to 11kV transformation step which saves on the cost of 33kV transformers and infrastructure. Would require step up transformers to supply Te Kaha out of Opotiki.
Convert 50kV line to 33kV, Convert Opotiki feeder to 33kV, Convert Waiotahi GXP to 110/33kV Build 33kV/11kV substation at Opotiki	Most costly option. Provides a fully redundant solution that can be developed in stages. Would require a third 33kV line within 15-30 years. Some duplication of assets between Waiotahi and Opotiki. Allows the possibility of a 33kV feed to support Ohope out of Waiotahi. Allows for future sub-transmission at 33kV around Opotiki and to supply Te Kaha. N security only from Edgecumbe to Opotiki.
Non-Network Options:	
Implement load management options	Short term solution only.
Supplement with generation	Not viable as a long term solution.
Implement summer/winter protection settings for the distribution feeders and thermally re-rate lines	Does not address the full load 11kV line I ² R losses and volt drop issues. Low cost option provides temporary relief. Would need voltage regulators to compensate for increased line losses.
Load balance 11kV feeders	Currently at peak loads the Waiotahi to Opotiki distribution system is approaching the ability of the system

	to provide N-1 security. This option is currently being done seasonally now. Very limited life cycle.
	There is merit in developing a 11kV substation and bus the 11kV feeders. This approach provides 2-3 years of grace prior to needing a high voltage sub transmission solution.
Preferred Option:	
Several studies have been completed on this project. A firm decision on the 33kV option vs the 110kV option has not yet been made and is also dependant on negotiations with Transpower.	
Estimated Cost/Accuracy:	
\$9M +/- 30%	
Projected Implementation Year: 2016 to 2019	

Ref Numbers/ Name:	
933 - 4th Poletop repeater	
Description:	
Install 4 th pole top repeater to provide additional coverage in Plains area	
Constraint:	
The number of installed pole top devices is predicted to reach the bandwidth limits of the existing repeater covering the Plains region by 2016.	
Network Options:	
Install repeater at existing sites either Mt Putauaki or Plains substation	Economic to do as infrastructure exists for connection to existing IP network. Part of an existing ring communications circuit.
Install repeater at Manawahe to provide improved coverage to the network beyond Manawahe ranges as well as plains area	Expensive as two radio links are required- one to connect to the ring loop, another for the poletop repeater. Would need to lease a site at Manawahe. Not on ring loop unless three radio links are installed. Limited number of devices in the Manawahe region.
Option of VHF vs high frequency VHF or UHF repeater	Changing the repeater frequency will require different radios than currently employed in Poletop applications. Digital radios at higher frequencies provides capability of IP connectivity to poletop devices. UHF requires line of sight to repeaters so will likely have more black areas.
Non-Network Options:	
Reduce the poletop devices data polling interval	Introduces more time lag delays into the information gathering required for smart network implementation.
Preferred Option:	
Digital UHF.	
Estimated Cost/Accuracy:	
\$90,000 -\$250,000	
Projected Implementation Year: 2016-17	

Ref Numbers/ Name:
53 – Scada system upgrade
Description:
Replace SCADA system
Constraint:
The existing system was installed initially in 1993 with an HMI upgrade in 2003. The proposed new system improves functionality by incorporating a connectivity model, an outage management system as well as feeder automation.
Network Options:
<ul style="list-style-type: none"> - Modify existing system using system integrators to provide interconnection capability - Procure new system with functionality already available
Non-Network Options:
Contract SCADA and operations management systems to a third party Do nothing
Benefits
Full integration with existing and proposed IT systems. Network upgrades in recent years have been driven towards a full IP interconnected system.
Preferred Option:
Replace SCADA system entirely
Estimated Cost/Accuracy:
\$600k +/-20%
Projected Implementation Year: 2016

Ref Numbers/ Name:	
502 - Manawahe, Herepuru Road and Pikowai Road Tie	
Description:	
Install tie line Manawahe, Herepuru Road and Pikowai Road Tie	
Constraint:	
Manawahe feeder is a long spur line without any reinforcement connections	
Network Options:	
Install new tie line 5.2km	Enables meshing of 10km of rural feeder. Somewhat rugged terrain. Some existing plantation forestry but due to be cleared soon.
Non-Network Options:	
Install Generation	Good alternative for planned maintenance but unless installed permanently not viable for quick restoration during faults.
Do Nothing	
Preferred Option:	
Yet to be engineered	
Estimated Cost/Accuracy:	
\$220,000 +- 30%	
Projected Implementation Year: 2023	

Ref Numbers/ Name:	
I043- Replace Station Road GEC switchboard	
Description:	
Replace 11kV 9 panel switchboard	
Constraint:	
<p>Switchboard is under consideration for risk mitigation over a number of safety issues;</p> <ul style="list-style-type: none"> • Bus fault withstand rating is too low for the 11kV bus fault current; (there is ambiguous data concerning the fault withstand rating); • No arc containment or flash protection from the front of the switchboard for operators; • Instances recorded in the UK with early failure of boards manufactured between 1980-1990 circuit breaker resin housing failing, with rapid degradation if potential discharge starts occurring; • Control box needs to be replaced if any protection is replaced or arc flash detection equipment is installed 	
	
Picture showing failure of a UK switchboard	
Network Options:	
Replace switchboard	Replace with modern switchboard
Upgrade circuit breakers to IEC90439 200	Replace circuit breakers only, re-using busbars
Protection upgrades	Install arc flash and high speed protection, and remote operation switches
Non-Network Options:	
Do Nothing	Full assessment of risk vs benefits to be completed.
Preferred Option:	
Yet to be engineered	
Estimated Cost/Accuracy:	
\$880,000 +/-30%	
Projected Implementation Year: 2021 earliest	

Ref Numbers/ Name:	
778, 779 Replace Station Road T1 and T2	
Description:	
Replacement transformers 16MVA	
Constraint:	
Transformers manufactured in 1966 will be 53 years old by the scheduled replacement date. Peak loads are exceeding the firm capacity of the substation.	
Network Options:	
Replace transformers	Transformrrs 16 to 20 MVA are appropriate size Option to reduce to one transformer and strengthen ties to Kope and proposed CBD./Gateway substations to provide load back-up
Non-Network Options:	
Delay	Transformer replacement can be deferred to fit labour or cash flow requirements as there are no immediate conditions requiring urgent action
Preferred Option:	
Yet to be engineered	
Estimated Cost/Accuracy:	
\$1.2M +/- 20% each bank	
Projected Implementation Year: 2019, 2020	

Appendix D – Current Year Projects 2016-17

project Number	Project Name	Project Cost (000)
I056	Opotiki Substation Development-11kV Site Y1	\$1318
	Opotiki-Otara Rd to Waioeka Rd- 2*900m cables	\$404
	Opotiki-RMU CCCC Otara rd-Waioeka rd	\$66
I367	Cable Replacement-RMC108-RMC4 -373m	\$84
I382	Fonterra Protection Systems Arc Flash &sync Scheme enable	\$26
I417	SS DDO replacement program Y4	\$57
I488	SCADA System upgrade	\$607
I504	Galatea 33kV bus upgrade	\$938
(blank)	Metrix Metering of large transformers Y1	\$26
	Configure FDIR for Kawerau network	\$21
	FDIR/OMS GIS import and training	\$15
	Relocate Galatea T2	\$183
I589	RWBSRS-Stage 1- New Cabling	\$49
I590	RWBSRS-Stage 2- Replace 28M058	\$77
I626	Poletop digital rollout Y1	\$114
I627	DCIU retirement Project	\$145
I641	Transpower Kawerau 11kV bus replacement Y1	\$278
I628	Ruatoki Feeder-Downard rd to Reid Rd 11kV re-build	\$249
I629	Te Rahu South ABS at Te rahu	\$23
I631	HDBC/ Galv line replacement Thornton	\$163
I632	HDBC/ Galv line replacement Awaitei Y1	\$487
I642	Rationalise SCADA IP Comms systems documentation	\$11
I639	Kope 33kV indoor-engineering	\$86
I618	23B024 Murupara- replace 2 pole structure Ngatimanawa Rd	\$59
I633	SCADA relocatable disaster recovery unit	\$66
I613	Waiotahi Factory feeder-Gabriels Gulley and tableands rd	\$96
I609	Onslow St Refurbishment	\$80
I610	Tunui Place Undergrounding	\$62
I611	Te Kaha Lines 2016	\$96
I640	Beach St Whakatane Undergrounding	\$121
I612	SCADA computer hardware replacement- Servers	\$32
I619	Generator connection sites Y2	\$54
I637	Herepuru Road upgrade to 3 phase stage 1	\$109
I638	11kV surge arrestors upgrade- Plains East bank stage 1	\$109

I608	Cable Replacement-RMC4-28M083 : Rex	\$121
I614	MAG 3KIT 22S067 Replacement	\$84
I616	RMC17 and 28M066 replacement	\$84
I617	RTE 28M087 Replacement	\$102
I634	Zone Sub CB remote open-close project	\$60
I622	33O009-Otara Rd replace with ground mount 100KVA	\$51
I624	22S065 replace Transformer + RMC53	\$85
I625	Cable Upgrade Kope RMC10 to 27M112-. Replace RTE 27M112 -307m	\$154
I651	ABS 484 Piripai Upgrade to Sectos	\$12
I654	ABS 867 Factory Upgrade to Sectos	\$12
I655	ABS 970 Te Kaha Upgrade to Sectos	\$12
I657	ABS 538 Waihou Bay Upgrade to Sectos	\$12
I666	ABS 585 Piripai Upgrade to Sectos	\$12
I671	ABS 511 Waimana Upgrade to Sectos	\$12
I672	ABS 972 Waimana Upgrade to Sectos	\$12
I673	ABS 902 Waimana Upgrade to Sectos	\$12
I675	ABS 925 Waimana Upgrade to Sectos	\$12

Appendix E –Planned Projects 2017-2020

Year Start	Project Name	Project Cost (000)
2017	23P049-NS Ponds-Transformer- transformer refurbish and bunding	\$25
	33kV cable-St Joesphs Thermal upgrade to Kope (462m)	\$193
	33kV Tuhoe cable-Thermal upgrade to Kope (462m)	\$222
	33kV-2nd line into Aniwhenua-Engineering design	\$32
	Generator connection sites Y3	\$121
	Kawerau ZS- Kawerau feeder cable fault level compliance 145m	\$36
	Kawerau-Load Control Plant Upgrade	\$266
	Kope 33kV indoor Conversion	\$1295
	MAG 3KIT 22S062 Replacement	\$84
	Manawahe Voltage ragulator	\$210
	Opotiki undergrounding 2017	\$44
	Plains Load Control Plant Upgrade	\$272
	Porcelain Fuse Holder Upgrades Y2	\$64
	RMC46 SDAF3 Replacement	\$66
	RTE 28M085 Replacement	\$102
	SS DDO replacement program Y5	\$57
	Te Kaha Lines 2017	\$96
	Te Rahu South /WBM South Structures reconfigure	\$287
	Waiotahi Factory feeder lines maintenance upgrade 2017	\$96
	Waiotahi- Load control Plant upgrade	\$266
	Waiotahi- Replace Substation circuit breakers Y1	\$309
	Poletop digital rollout Y2	\$114
	Opotiki Substation Development -Consenting & 110 line design	\$216
	Opotiki- Sub Factory rd to Waioeka 700m	\$173
	Opotiki-Otara Rd to Wellington St-600m cable	\$98
	HDBC/ Galv line replacement Awaiti Y2	\$487
	HDBC/ Galv line replacement -Galatea	\$29
	HDBC/ Galv line replacement -Jolly Road	\$10
	HDBC/ Galv line replacement -Mokorua	\$57
	Kawerau Lines refurbishments 2017	\$161
	Replace cable RMC53 to RMC210 Fenton Mill-Kirk Cr 285m	\$64
	Transpower Kawerau 11kV bus replacement Y2	\$278
	RWBSRS-Stage 3- Replace RMC76 and 28M062	\$130
	RWBSRS-Stage 4- Replace 28M033	\$71
	Hillcrest Cable upgrade 540m -2 RMU	\$178
	Ohope- Install 2 * 33kV Circuit breakers and bus section	\$319
	Poroporo to Tuhoe tie feeder	\$45

	22S053 replace polemount	\$73
	Manawahe Rd to Herepuru Rd refurbishment	\$151
	Herepuru Road upgrade to 3 phase stage 2	\$109
	RMC1 Automate	\$45
	Kaingaroa upgrade 11kV protection	\$82
	ABS 531 Te Teko Upgrade to Sectos	\$12
	ABS 406 Awaiti Upgrade to Sectos	\$12
	ABS 400 Manawahe Upgrade to Sectos	\$12
	ABS 1410 Piripai Upgrade to Sectos	\$12
	ABS 978 Waihou Bay Upgrade to Sectos	\$12
	ABS 612 Minginui Upgrade to Sectos	\$12
	ABS 613 Minginui Upgrade to Sectos	\$12
	ABS 822 Waimana Upgrade to Sectos	\$12
	ABS 339 Hospital Upgrade to Sectos	\$12
	Ferry Road, Whakatane	\$132
	Metrix Metering of large transformers Y2	\$26
2018	22S052 replace Transformer + RMU	\$81
	23H003-Minginui replace with ground mount 100KVA	\$32
	24P010-Te Teko replace with ground mount 100KVA	\$32
	2nd 33kV line into Aniwhenua	\$1008
	Cable upgrade Garaway st RMC7 to RMC32 301m	\$72
	GEC RMU DDFD RMC66-SB1	\$35
	James St East King to Hinemoa (LT)	\$193
	Lines upgrades	\$197
	LT end of run earthing project Y2	\$247
	MAG 1KIT 22S069 Replacement	\$84
	Opotiki 833 Tie CCC automated switch	\$90
	Opotiki undergrounding 2018	\$44
	Porcelain Fuse Holder Upgrades Y3	\$64
	RTE 28M102 Replacement	\$102
	SS DDO replacement program Y6	\$57
	Te Kaha Lines 2018	\$96
	Te Rahu Central and Te Rahu North Structure Re-configuration & Maintenance	\$331
	Waiotahi Factory feeder lines maintenance upgrade 2018	\$96
	Opotiki Substation Development -110kV line, Tx Y1	\$1894
	Opotiki- 33kV overbuild Otara Rd to Te Kaha 2000m	\$244
	23S018 Replace poletopm tx	\$58
	HDBC/ Galv line replacement Piripai	\$159
	HDBC/ Galv line replacement Waimana	\$254
	HDBC/ Galv line replacement -Minginui	\$19
	HDBC/ Galv line replacement -Murupara	\$195
	Kawerau Lines refurbishments 2018	\$161
	RWBSRS-Stage 5- Replace RMC16/28M064 and RMC20/28M112	\$141

	RWBSRS-Stage 6- Replace RMC8	\$70
	Kope T1 Replacement	\$1205
	ABS 744 Onepu Upgrade to Sectos	\$12
	ABS 722 Onepu Upgrade to Sectos	\$12
	ABS 748 Ruatoki Upgrade to Sectos	\$12
	ABS 1441 Ruatoki Upgrade to Sectos	\$12
	ABS 342 King Street Upgrade to Sectos	\$12
	ABS 358 Harbour Upgrade to Sectos	\$12
	ABS 1520 Minginui Upgrade to Sectos	\$12
	ABS 1521 Harbour Upgrade to Sectos	\$12
	ABS 493 Mokorua Upgrade to Sectos	\$12
	Metrix Metering of large transformers Y3	\$26
2019	28M089 Upgrade to 300KVA	\$86
	Cable Replacement-RMC6-RMC127 : Strand South - STADIUM	\$28
	Distribution Transformer Replacements	\$416
	Lines upgrades	\$214
	LT end of run earthing project Y3	\$247
	Ohope-33kV Transformer T1 replacement	\$192
	Opotiki undergrounding 2019	\$44
	Porcelain Fuse Holder Upgrades Y4	\$64
	RTE 28M080 Replacement	\$103
	SDAF3 RMC55 replace	\$44
	Split West bank feeder off Rangeteiki feeder	\$194
	SS DDO replacement program Y7	\$57
	Station Road Replace T1	\$1359
	Te Kaha Lines 2019	\$96
	Underground Plains-East bank high capacity tie feeder	\$294
	Waiotahi Factory feeder lines maintenance upgrade 2019	\$96
	Opotiki Substation Development -110kV line, Tx Y2	\$1894
	Opotiki-Tie at Paereta Ridge Rd	\$35
	HDBC/ Galv line replacement -Kawerau Fdr	\$46
	HDBC/ Galv line replacement Onepu	\$44
	HDBC/ Galv line replacement Plateau	\$16
	HDBC/ Galv line replacement -West Bank	\$420
	Kawerau Lines refurbishments 2019	\$161
	ABS 596 Piripai Upgrade to Sectos	\$12
	ABS 942 Opotiki Upgrade to Sectos	\$12
	ABS 297 Jolly Road Upgrade to Sectos	\$12
	ABS 483 Jolly Road Upgrade to Sectos	\$12
	ABS 738 Golf Upgrade to Sectos	\$12
	ABS 664 Murupara Upgrade to Sectos	\$12
	ABS 566 Murupara Upgrade to Sectos	\$12
	ABS 743 Golf Upgrade to Sectos	\$12

2020	Whakatane CBD Substation Land Purchase & prelim engr	\$270
	Metrix Metering of large transformers Y4	\$26
	24O008-Te Teko replace with ground mount 50KVA	\$21
	25M053-Edgecumbe replace with ground mount 200KVA	\$37
	28M025-Valley Rd replace with ground mount 200KVA	\$37
	ABS replacements	\$109
	Distribution Transformer Replacements	\$416
	Hillcrest 16mm Cable Upgrade 492m	\$258
	Kawerau- River Road-RMC77 to Pole- Cable replacement- 190m	\$42
	Kawerau-Fenton Mill-RMC153-RMC62 XLPE cable replace-330m	\$40
	Lines upgrades	\$214
	LT end of run earthing project Y4	\$247
	MAG 2KIT 22S073 Replacement	\$84
	MAG 2KIT 28M018 Replacement	\$84
	Opotiki undergrounding 2020	\$44
	Opotiki undergrounding 2021	\$44
	Porcelain Fuse Holder Upgrades Y5	\$64
	Reconductor to Dog 8km Gatalea feeder Te Teko Road Y1	\$102
	Replace SEL 351 relays (9)	\$165
	RTE 28M084 Replacement	\$102
	SS DDO replacement program Y8	\$57
	Station Road Replace T2	\$1359
	Te Kaha Lines 2020	\$96
	Waiotahi Factory feeder lines maintenance upgrade 2020	\$96
	WBMS 33kV Sub Transmission Capacity Upgrade	\$575
	HDBC/ Galv line replacement -Awakeri	\$650
	Kope/SR/Gateway 11kV distribution tie points automation Y1	\$246
	Kawerau Lines refurbishments 2020	\$161
	Kawerau Lines refurbishments 2021	\$161
	Metrix Metering of large transformers Y5	\$26

Appendix F – Proposed Major Projects 2021-2026

Year Start	Project Name	Project Cost (000)
2021	Distribution Transformer Replacements	\$416
	LV cable replacements	\$395
	Ohope-11kV Indoor Conversion	\$1179
	Fonterra YSF6 CB replacement project	\$350
	HDBC/ Galv line replacement -Factory	\$308
	Replace GEC switchboard	\$879
2022	Distribution Transformer Replacements	\$416
	Hawai Zone Substation	\$623
	Kaingaroa- Upgrade 11kV bus	\$263
	LV cable replacements	\$395
	Replace SEL 351A relays (7)	\$291
	Underground Harbour feeder Stage 1a	\$427
	HDBC/ Galv line replacement -Manawahe	\$609
2023	Distribution Transformer Replacements	\$416
	LV cable replacements	\$395
	Upgrade Popoporo feeder Dog sections- 3.4km	\$283
	Underground Harbour feeder Stage 1b	\$427
	HDBC/ Galv line replacement -Te Teko Year 1	\$659
2024	Distribution Transformer Replacements	\$416
	Lines replacements	\$1079
	LV cable replacements	\$395
	Underground Harbour feeder Stage 2a	\$506
	HDBC/ Galv line replacement -Te Teko Year 2	\$659
2025	Distribution Transformer Replacements	\$416
	Express 33 kV Cable Gateway to CBD-4.25km	\$1169
	Lines replacements	\$1079
	LV cable replacements	\$395
	Whakatane CBD Substation Y1	\$739
	Underground Harbour feeder Stage 2b	\$506
	HDBC/ Galv line replacement -Ruatoki Year 1	\$709
2026	Distribution Transformer Replacements	\$416
	Ground Fault Neutraliser-Galatea	\$370
	Lines replacements	\$1079
	LV cable replacements	\$395
	Whakatane CBD Substation Y2	\$2201
	Underground Harbour feeder Stage 3a	\$389
	HDBC/ Galv line replacement -Ruatoki Year 2	\$709

Appendix G - Certificate for Asset Management Plan

Certification for Year-beginning Disclosure – Asset Management Plan

Clause 2.9.1

We, ROBERT TAIT and CHRISTOPHER BOYLE, being directors of HORIZON ENERGY DISTRIBUTION LIMITED certify that, having made all reasonable enquiry, to the best of our knowledge -

- a) the following attached information of HORIZON ENERGY DISTRIBUTION LIMITED prepared for the purposes of clauses 2.6.1, 2.6.6, and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.
- b) the prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.
- c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both aligns with HORIZON ENERGY DISTRIBUTION LIMITED's corporate vision and strategy and are documented in retained records.

Dated: 11 day of March 2016



ROBERT TAIT



CHRISTOPHER BOYLE