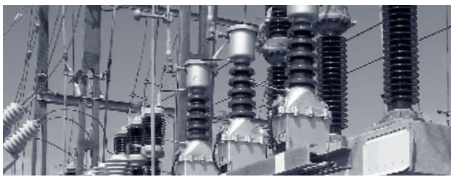
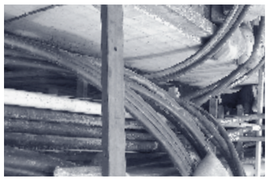
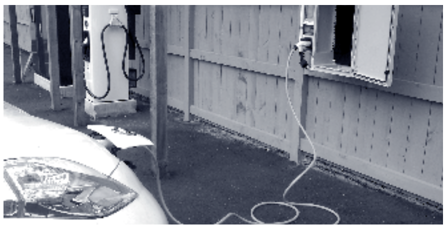
Asset Management Plan
2016 - 2026

March 2016







"safe, reliable, hassle free service"

Northpower

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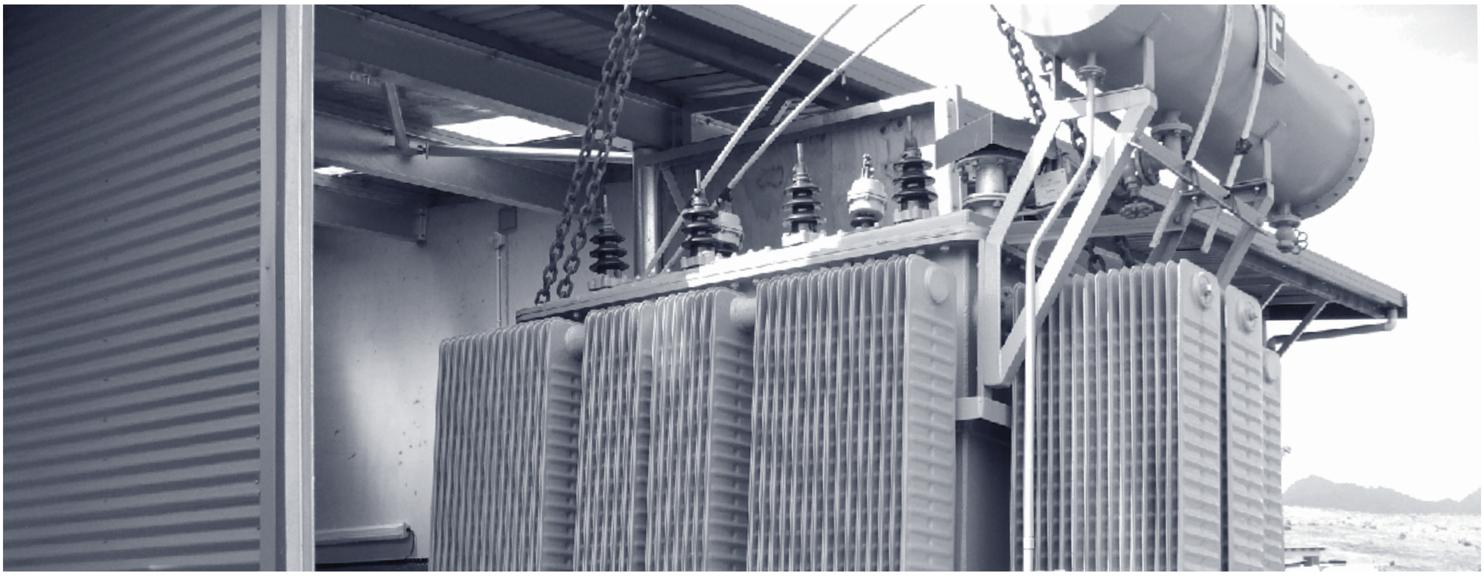
Section 1: Summary



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Summary

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Section 1: Summary

This Asset Management Plan is prepared in accordance with the Electricity Distribution Services Information Disclosure Determination 2012 (as consolidated in 2015) and covers the 10 year period 1 April 2016 to 31 March 2026. Northpower's Board of Directors approved the 2016 Asset Management Plan in February 2016.

The Asset Management Plan comprises of the following 7 sections and appendixes.

1.1 Background and Objectives

This section outlines the purpose of the AMP, describes Northpower's vision and focus and shows how the AMP is related to company strategy and the annual business planning process. Stakeholders and stakeholder interests are identified together with an explanation of how these interests are accommodated in the planning process. This section also describes accountability and responsibilities in terms of asset management governance and provides an overview of the systems and processes supporting the asset management function.

1.2 Assets Covered

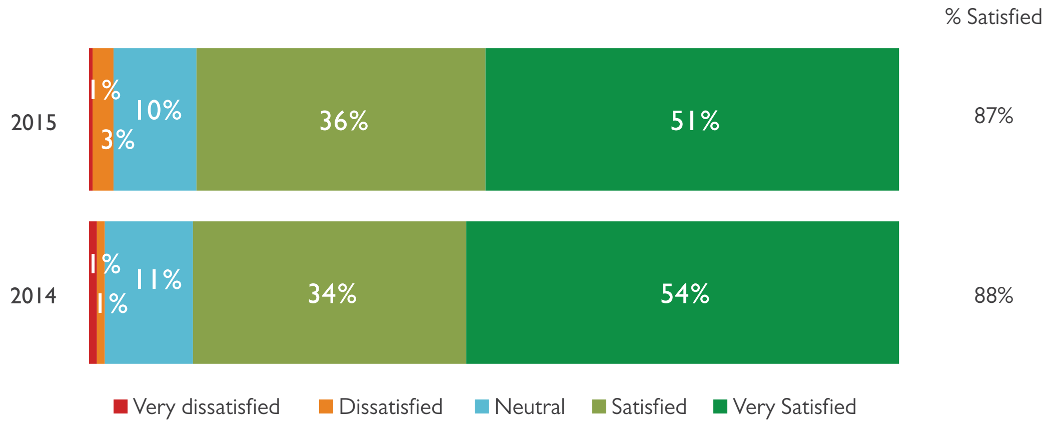
This section provides details of Northpower's network including area of supply, configuration and load characteristics. The network assets are described in terms of quantities, age and condition together with an explanation of the justification of existing assets as well as how the acquisition of new or replacement assets are justified.

Northpower geographical area of supply and major substations

1.3 Service Levels

This section describes Northpower's customer service performance targets and reviews the results of the 2015 externally conducted Customer Perceptions Survey. Other network performance indicators such as SAIDI, SAFI and CAIDI as well as number of faults per 100km of line are also discussed. The network's historical financial performance in terms of expenditure per customer connection and kilometre of line is presented together with a comparison with other EDB's in New Zealand.

Satisfaction with Northpower: Residential and Commercial combined(1)(2)



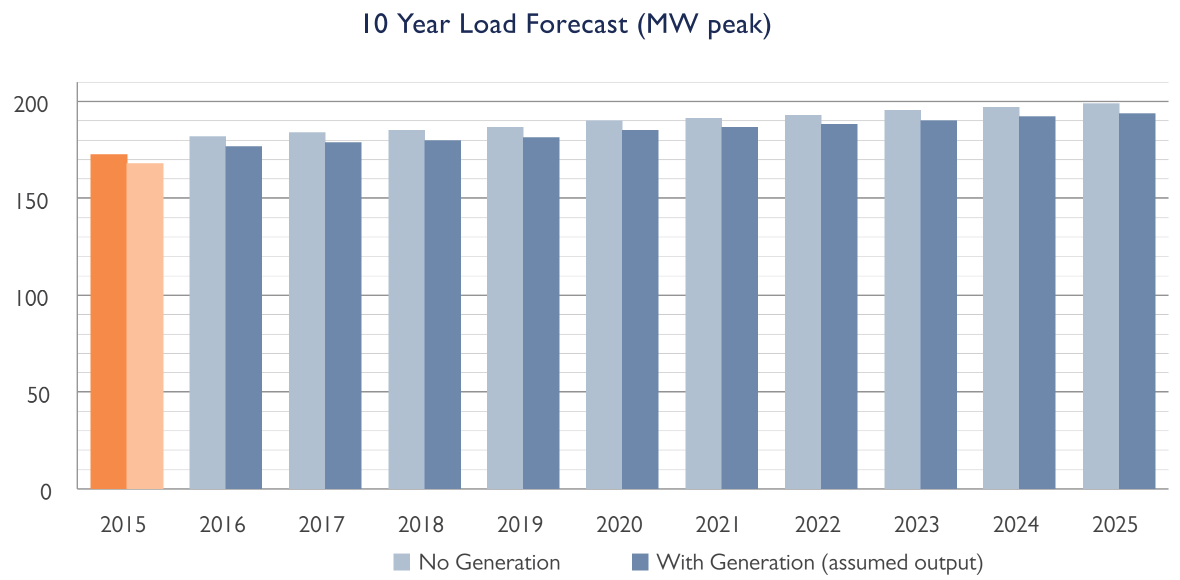
NOTES:
1. Sample: 2014 total n= 401, Commercial n=100, Residential n=301; 2015 Total n=400, Commercial n=100, Residential n=300
2. Which of the following best describes how satisfied you are with Northpower overall? Ordinal scale; Very satisfied, Satisfied, Neutral, Dissatisfied, Very Dissatisfied

Overall Satisfaction Residential and Commercial combined

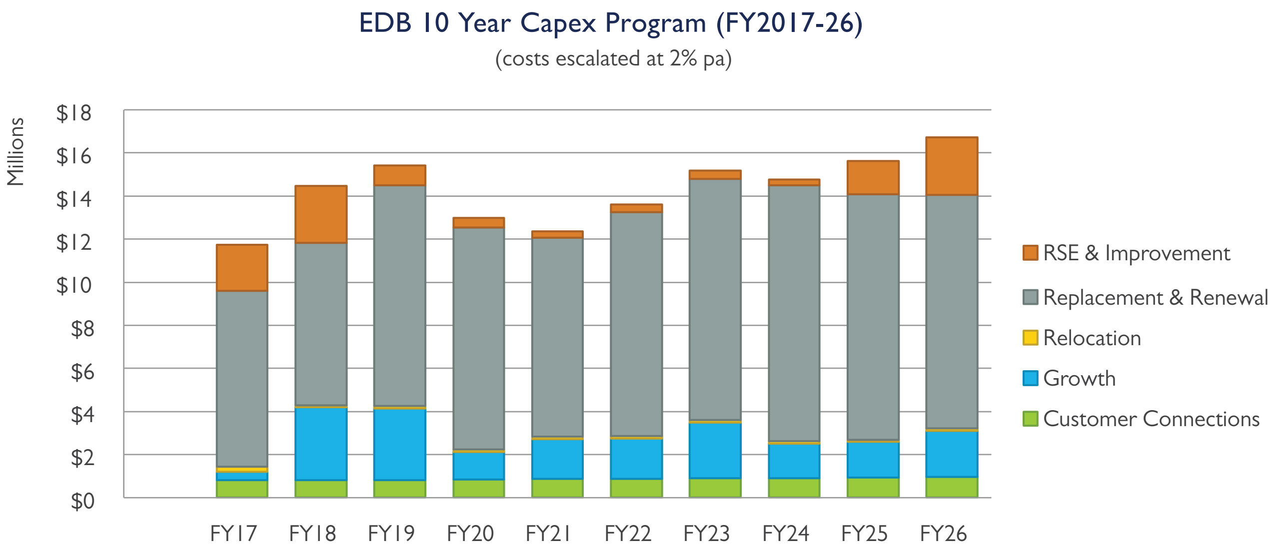
1.4 Network Development Plan

This section provides an overview of network planning criteria and network investment decision making and discusses network capacity, network work performance and quality of supply aspects.

The methodology used in load forecasting is described and a detailed 10 year load forecast is presented together with a review of anticipated network capacity constraints. Details of current zone substation loading and number of ICP's supplied are given for each zone substation together with a map showing the geographical layout of feeders emanating from the station and a summary of load growth expectations. This section also covers distributed generation, non-network solutions and other network development options. Details of the network development plan and proposed 10 year Capex program (FY2017-26) are provided together with a description of significant current and planned projects for the first year, a summary of significant projects planned for the next 4 years and a list of significant projects being considered for the remainder of the 10 year period.



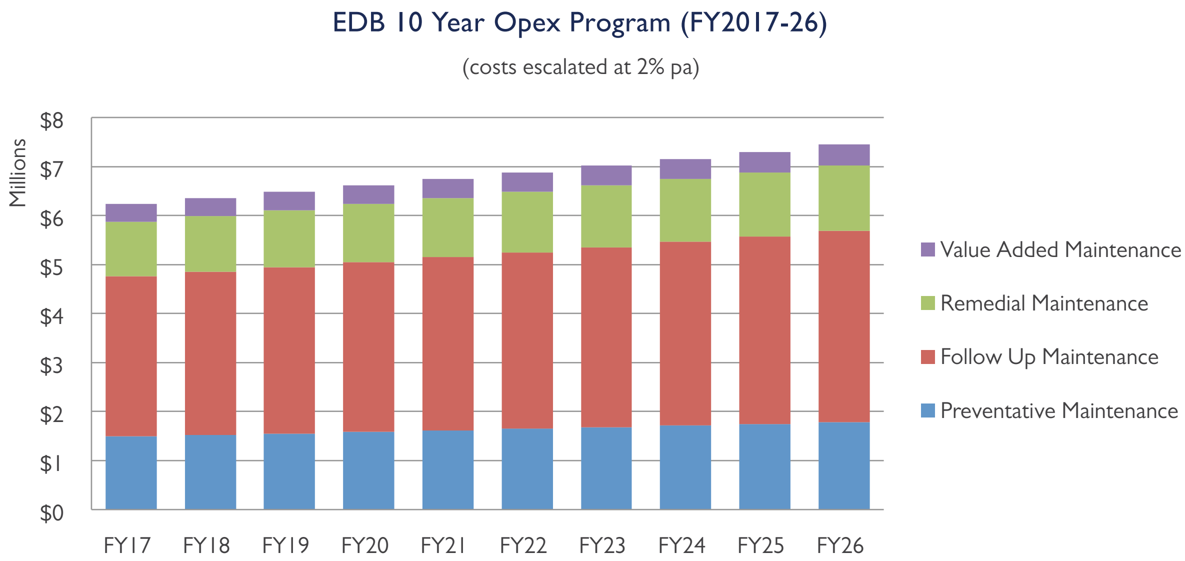
Network Load Forecast 2016-2025



Proposed 10 year Capex Program

1.5 Life Cycle asset Management Plan

This section covers asset maintenance planning criteria and assumptions as well as maintenance strategy and optimisation of expenditure over the categories of preventative maintenance, follow up maintenance and remedial maintenance. Asset inspection, condition monitoring and routine maintenance practices and processes are described as well as replacement and renewal policies. An overview of asset replacement and renewal by asset category is provided and non-network assets are also discussed. The asset maintenance 10 year (FY2017-26) plan Opex forecast is included at the end of the section.



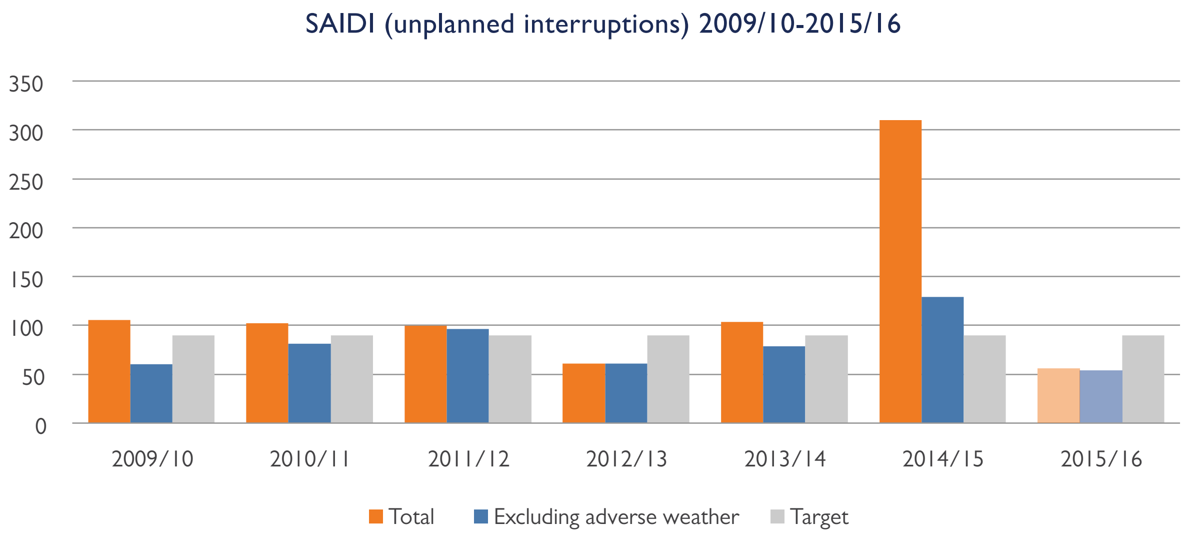
Proposed 10 year Opex Program

1.6 Risk Management

This section outlines Northpower's risk management policy and framework and describes the risk analysis governance and methodology. The risk management process, key business risks, asset risks and environmental risks are also described and emergency response and contingency plans are outlined.

1.7 Evaluation of Performance

This section reviews physical and financial performance against plans and budgets for the previous financial year for both Opex and Capex. Performance against service level targets and other key performance indicators is also compared. A gap analysis is provided and asset management improvement initiatives are discussed.



SAIDI (unplanned interruptions) 2009-2015

1.8 Appendixes

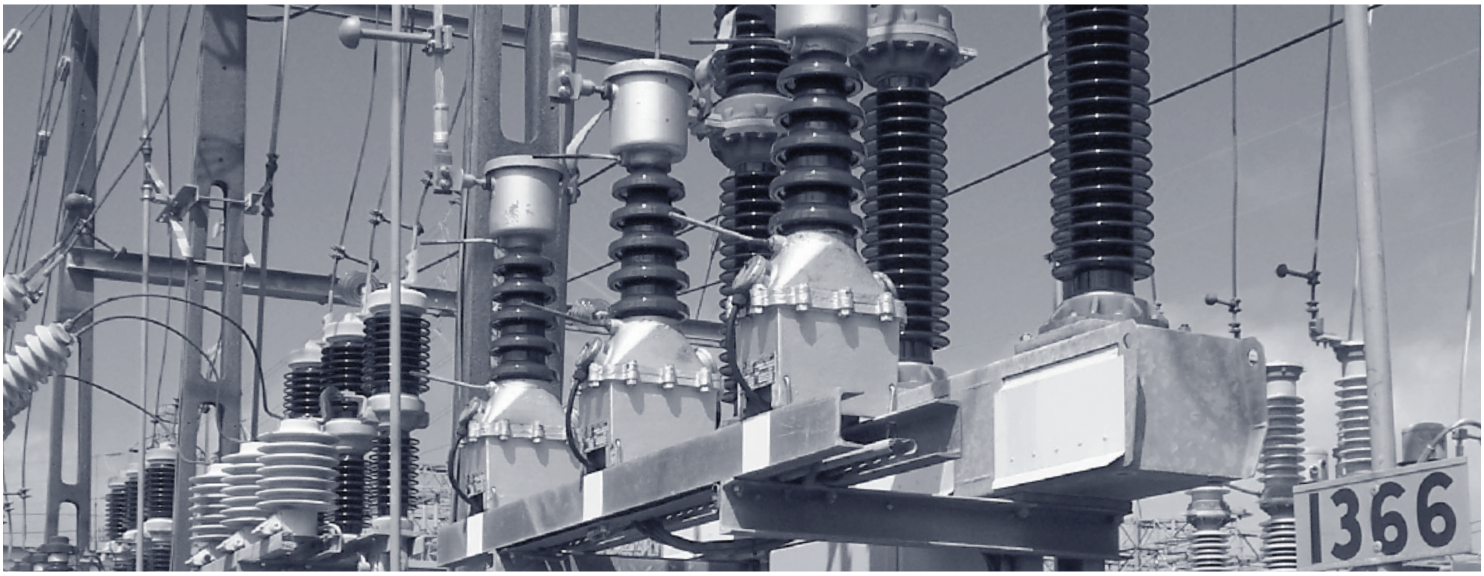
The appendixes include a glossary of terms used in the AMP, the 2016 year-beginning EDB Information Disclosure Schedules (Asset Management Plan and Forecast Information) and disclosure certification.

1.9 Stakeholder Feedback

Northpower encourages feedback on all aspects of the AMP to enable continued improvement in meeting the needs of consumers and stakeholders. Feedback should be addressed to:

Russell Watson,
Network Engineering Manager,
Northpower,
Private Bag 9018,
Whangarei Mail Centre,
Whangarei, 0148.
Email: russell.watson@northpower.com

Section 2:
Background and Objectives



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Background and Objectives

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Section 2: Background and Objectives

2.1 Purpose

2.1.1 Purpose of the Asset Management Plan (AMP)

The primary purpose of the AMP is to make visible Northpower's key objectives, network planning techniques and asset management practices to key stakeholders. The AMP addresses goals and objectives which relate to asset management by focusing on levels of service, life cycle asset-management planning and the resulting long term cash flow requirements. The AMP also establishes and evaluates performance benchmarks and demonstrates responsible ownership and management of assets to the wider community. Public comment and feedback is both welcomed and valued.

Northpower's Annual AMP is also published to satisfy the regulatory requirement, describing the methodology adopted to manage the assets in accordance with information disclosure requirements under Part 4 of the Commerce Act for EDB's.

Northpower's asset management philosophy is encapsulated in the vision of improving the prosperity and well-being of the people of Whangarei and Kaipara through our business activities, investment in profitable growth and distribution of profits to our shareholders.

The relationship between this philosophy, planning processes and company objectives collectively forms the Northpower concept of best practice asset management.

This is achieved by:

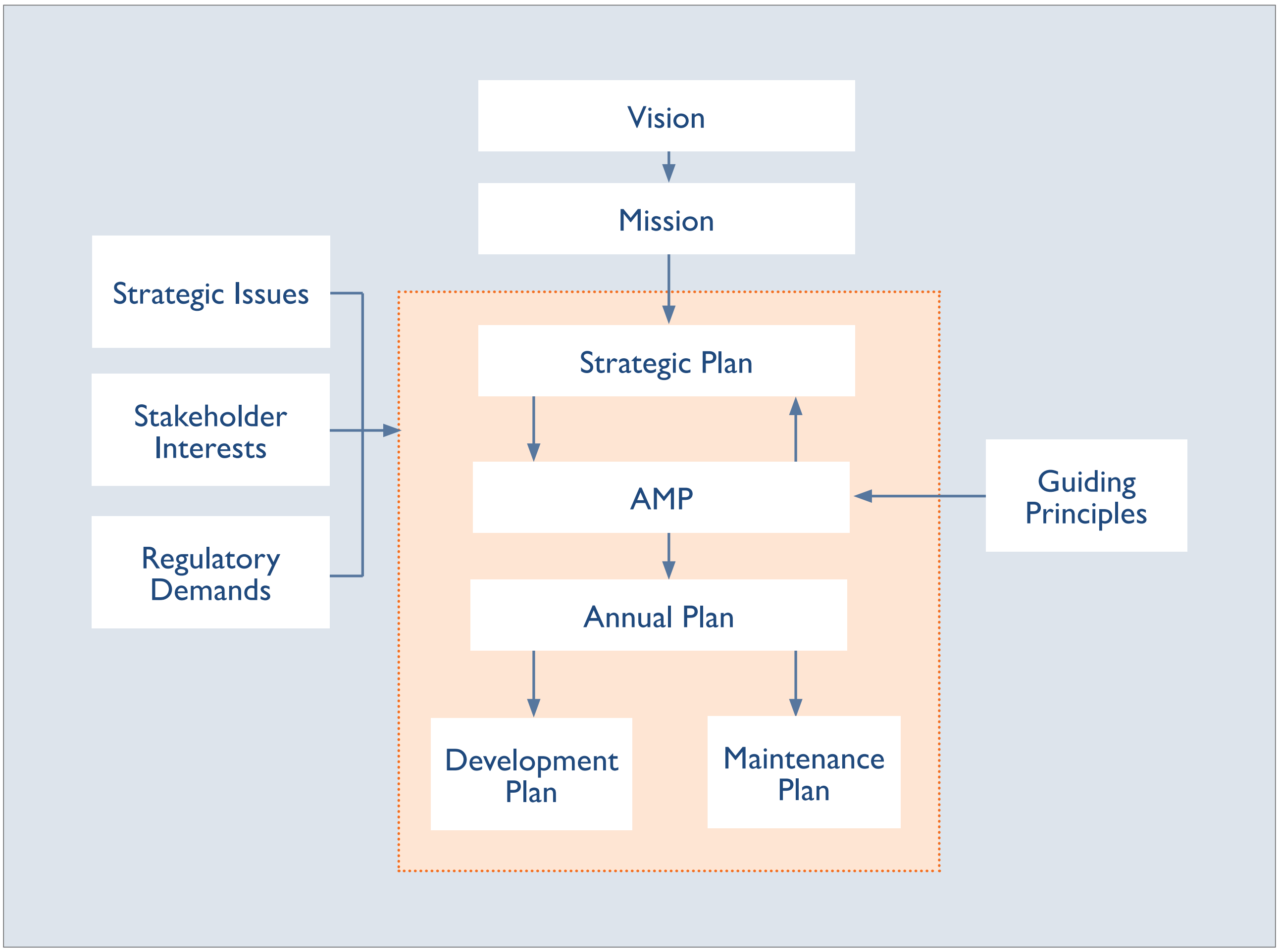
- Ensuring that the performance of the assets meets the needs of broad customer groups.
- Ensuring that the long term functionality and value of the assets is maintained.
- Being responsive to individual customer's needs and treating all customers with respect.
- Maintaining ongoing price stability.
- Focusing on operational efficiency and performance improvement.

2.1.2 Objectives of Asset Management Planning

From an internal perspective Northpower's AMP is a living document which undergoes continuous adjustment in response to environmental changes which may affect the lines business or the assets it manages.

The AMP along with the Development and Maintenance plans (which are based on future network capacity, asset replacement and performance requirements) and associated budgets and spend forecasts are updated quarterly and published annually.

Northpower has a continuous improvement philosophy and is a process driven organisation. The company is ISO9001 and ISO14001 certified and the network is certified to NZS7901. The asset management processes are aligned within these standardised frameworks. Planning is supported by the ongoing development and integration of core information systems together with the continuous improvement of the asset data (including type, volume, age and condition). Specialist asset management software is used to trigger, monitor and support maintenance management activities.



AMP Planning Process

2.2 Relationship with Other Business Plans and Goals

2.2.1 Our purpose

Northpower's purpose is to improve the prosperity of our shareholders, both in terms of providing a good commercial return (as articulated in the Statement of Corporate Intent), as well as improving the Kaipara and Whangarei communities through the services we provide.

We recognise power supply is an essential service and we look forward to continuing to prudently and efficiently deliver safe and reliable electricity to the communities we serve. Our direction and priorities strike the right balance of investments which we believe will support the safe and cost effective supply of electricity and address the current and future needs of the Kaipara and Whangarei communities as well as our contracting customers.

2.2.2 Who we are

Northpower has been serving the Kaipara and Whangarei districts for over 90 years with the safe and reliable supply of electricity.

As the region's electricity service provider, Northpower Network operates and manages electricity assets valued at $251m. We take a long term view to ensure we make the right decisions on investments which will best serve Northlanders for decades into the future.

Our business is about connecting residential and business customers to a safe and reliable electricity and fibre supply. Northpower Network key activities include:

- Maintaining the network's safety and reliability to meet the current and future network supply needs of our customers and delivering any investment in our infrastructure on an economic (cost effective) basis;
- Operating the networks on a day to day basis; and
- Connecting new customers to the network.

2.2.3 Our focus

Northpower is focused on creating long term value which extends beyond the services we deliver. It encompasses the wider benefits we bring to the region through the training, employment and career opportunities we create for Northlanders while also contributing positively to the spirit of the Northland community.

2.2.4 Our vision

Northpower's vision is to provide a safe, reliable and cost effective network infrastructure and to provide leadership for the introduction of new technology wherever possible for the long term benefit of the community.

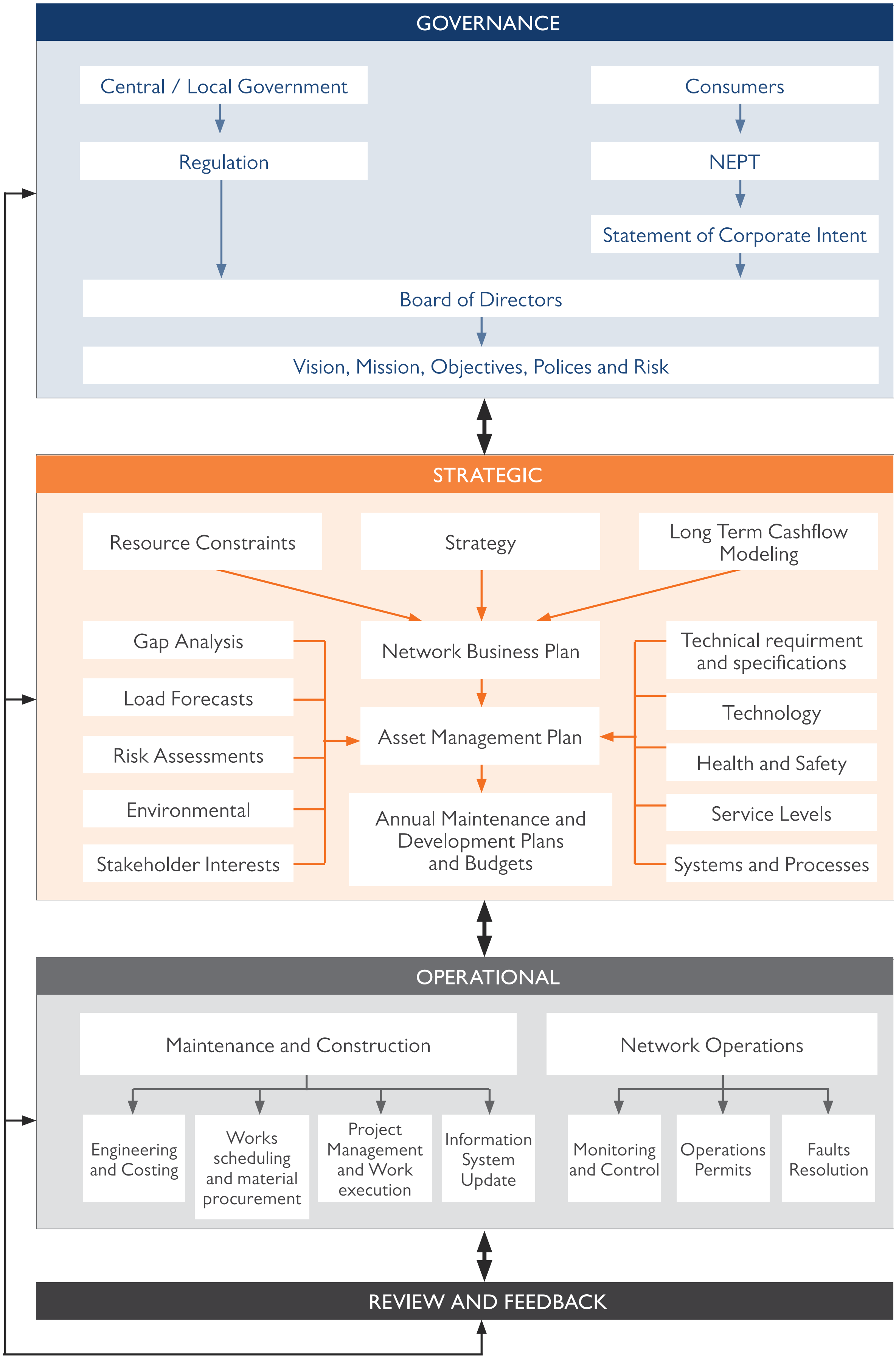
2.2.5 Documented Plans Produced in Annual Planning Process

The relevant documented plans that Northpower produces as part of the annual business planning process are:

Annual Planning Document	Description	Relationship with AMP
Statement of Corporate Intent (SCI)	Northpower's SCI is published annually and approved by the Northland Electric Power Trust on behalf of the consumers. The SCI sets out the goals and objectives for the business.	The AMP describes the way in which the goals and objectives embodied in the SCI will be achieved from an asset management perspective.
Strategic Plan	The Strategic Plan sets goals, objectives and key performance indicators for the business.	The forecasts in the AMP are based upon the forecasts approved annually by the Board of Directors.
Annual Network Management Plan (NMP)	The Network Asset Management Team annually produces the internal NMP which includes policies, standards and strategies.	The NMP informs Sections 5 and 6 of the AMP (network development and lifecycle asset management planning).
Company Risk Register	The Risk Register is a live database that is used to document key business risks. Risk mitigation strategies are reviewed annually.	Risks related to asset management within the Risk Register inform Section 7 of the AMP.

Annual Planning Process Plans

2.2.6 Relationships between Plans, Processes, Models and Stakeholders



Relationship between plans, process and stakeholders

2.3 Period Covered by the Plan

The planning period covered by this AMP is the 10 year period from 1 April 2016 to 31 March 2026. The 2016 AMP was approved by Northpower's Board of Directors in February 2016 and made available for public disclosure 31 March 2016.

Specific projects and activities included in this AMP represent Northpower's best estimates of optimal solutions based on projections of present day drivers, issues technologies and available network data. Given that drivers and network data will change over time, inclusion of specific activities and projects, particularly toward the far end of the planning horizon, does not represent a firm commitment by Northpower to proceed with those activities and projects. Rather it is to be recognised as a demonstration of a robust methodology for addressing long term capacity, reliability and security of supply requirements.

Network development plans and associated financial forecasts and budgets are essentially determined by load growth. Developments at subtransmission level tend to have more long term inertia and therefore tend to be less dynamic and more predictable than those at distribution level, with the result that projects relating to the former tend to have longer planning lead times and can normally be fairly accurately defined 5 years out. On the other hand, projects at distribution level are more closely linked to short term economic activity, with the result that confidence beyond the two to three year mark is difficult to achieve.

Network maintenance related activity is far more predictable than development needs, and plans can be developed with a fair degree of confidence as there is a direct relationship with historical expenditure and present network performance. However, to ensure optimal long term maintenance planning it is essential that a good asset knowledge base exists, together with appropriate maintenance regimes, and Northpower is busy increasing resources in this area.

2.4 Stakeholder Interests

2.4.1 Identification of Stakeholders

Stakeholders are persons, groups, organisations, or systems, who affect or can be affected by Northpower actions, activities and or performance.

Northpower's key principles listed below are derived from the fundamental values and business behaviours and apply to all actions and activities:

- Health and Safety.
- Financial Strength.
- Customer Satisfaction.
- People and Commitment.
- Environment and Communities.
- Operational Excellence.

Consideration of these key principles in relation to identities that interact with the company defines their level as a stakeholder. The following table identifies the major stakeholders in the electricity lines business and which series of the six key principles are applicable to the stakeholder.

Stakeholder	Health / Safety	Customer Satisfaction	Financial Strength	Environment / Communities	People and Commitment	Operational Excellence
Customers	✓	✓	✓	✓	✓	✓
Northpower Trust and Board	✓	✓	✓	✓	✓	✓
Energy retailers		✓	✓	✓		✓
Suppliers	✓	✓	✓			✓

Stakeholder	Health / Safety	Customer Satisfaction	Financial Strength	Environment / Communities	People and Commitment	Operational Excellence
Staff and Contractors	✓	✓	✓	✓	✓	✓
Public and Communities	✓	✓	✓	✓	✓	✓
Land owners	✓			✓		✓
Territorial Authority	✓		✓	✓		
Regional Authority	✓		✓	✓		
New Zealand Transport Agency	✓			✓	✓	✓
Teleco's	✓	✓		✓	✓	✓
Commerce Commission	✓	✓	✓	✓		✓
Electricity Authority		✓		✓		✓
Transpower – Grid owner		✓	✓	✓		✓
Transpower- systems operator	✓	✓			✓	✓
Regional/District Council	✓	✓		✓	✓	

Identification of Stakeholders Table

There is no single policy or documented process which fully captures every situation where stakeholders should be identified. Rather, the importance of stakeholders and their interests is entrenched within many processes for many activities across several disciplines. The underpinning principles are the same, in all projects and activities consideration of who and what will be affected and how is necessary. Any issues identified are to be addressed in a respectful and considerate manner.

The following table provides an overview of what each stakeholder's interest is and how the stakeholder's interests are identified.

Stakeholder	Key Interest	Method of Interest Identification
Consumers Includes: Domestic, Commercial, Lifeline groups, Large Consumers (Oil Refinery, Cement Works, Milk Production etc.)	Network reliability. Quality of supply. Speed of restoration. Hassle free service. Line charges. Reliability/price balance. Tariff options	Annual Northpower Customer Perceptions Monitor survey. Formal and informal feedback Dedicated Customer Advisor. Dedicated Communications Manager. Dedicated Network Commercial and Operations Manager. Trade shows. Direct line function service agreements with large industrial sites. Faults free phone directly to dispatch/ network system operators.

Stakeholder	Key Interest	Method of Interest Identification
Northpower Trust	Fair commercial return on investment. Sustainability of business. Performance of Directors. Achievement against the Statement of Corporate Intent. Security of supply to region. Protection of shareholder's interests.	Pentennial ownership review. Triennial Trustee elections. AGM. Annual review with Directors. Six monthly meetings with Directors and Executive Team. Monthly meetings. Direct feedback from consumers.
Northpower Board of Directors	Performance of business operation. Long term business direction and outcomes. Performance of Chief Executive and Executive Management Team. Creation of shareholder value.	Annual review by Trust. Annual review with CEO. Annual business strategy sessions. Quarterly risk reviews. Quarterly field visits. Monthly meetings with Executive Team.
Electricity Retailers	Contractual relationship. Clear data to support billing. Accurate and timely billing. Minimisation of line losses. Risk mitigated network. Timely response to service and information requests.	Use of System Agreement. Annual relationship meetings. Direct consultation periodically throughout the year.
Suppliers	Network standards. Advance notice of Network requirements. Payment in accordance with the terms of trade. Partnership approach.	Regular relationship meetings with Logistics Manager. Supply agreements. Structured terms of trade. Survey feedback.
Staff	Risk mitigated network and work practices. Forward visibility of requirements. Involvement in company direction. Challenging work. Fair reward.	Biennial Best Places to Work survey. Annual strategic planning sessions. Open forums at biannual Safety Days. Monthly Safe Team meetings. Hazard ID and Near Miss process. Weekly team meetings. Regular relationship meetings with Union representatives. Annual employment contract negotiations.

Stakeholder	Key Interest	Method of Interest Identification
Contractors	Visibility of forward work load. Standards. Risk mitigated network. Return on investment. Partnership approach.	Biennial Contractor review process. Annual service level agreement* negotiation. Open forums at biannual Safety Days. Monthly Safe Team meetings. Monthly relationship meetings with major contractors. Regular relationship meetings with minor contractors.
Communities and Public	Risk mitigated network. Responsible corporate citizen.	Annual Northpower Customer Perceptions Monitor survey. Formal and informal feedback from interest groups. Dedicated Customer Advisor. Joint support of community sponsorship initiatives such as the Rescue Helicopter and Native Bird Recovery Centre. Public meetings.
Land owners	Protection of property values. Protection of areas with cultural or historical significance. Risk mitigated network.	Direct consultation with interest groups. Consultation with affected or potentially affected landowners. Dedicated lines inspectors and vegetation officers in the field.
District Councils	Capability of network to service growth. Forward visibility of significant Network additions/alterations. Environmental impact of the network is in accordance with district plans and is minimized.	Direct consultation between CEO's. District plan. Joint planning sessions.
Regional Council	Environmental impact of the network is in accordance with regional plans, the Resource Management Act and is minimized. Emergency response capability.	RMA. Growth strategy documentation. Direct consultation. Member of Northland Lifelines Group (Civil Defense and infrastructure disaster relief planning).
NZ Transport Agency	Risk mitigated asset. No harm to public from actions of Network contractors. Value added propositions.	Regulations. Direct consultation and co-operation.

Stakeholder	Key Interest	Method of Interest Identification
Telco's	Protection of their assets from electrical interference. Protection of their assets from physical interference. Synergies regarding access and asset placement.	Regulatory and legislative protection. Relationship meetings. Information sharing sessions.
Commerce Commission	Legislative and regulatory adherence. Information disclosure.	Legislation – laws and regulation. Disclosure documentation.
Electricity Authority	Legislative and regulatory adherence. Information disclosure.	Published rules. Electricity Commission updates published weekly.
Transpower - Grid Owner	Payment in accordance with commercial terms. Provision of connection assets.	Annual notification of prices. Relationship meetings. Price/quality trade off consultation.
Transpower - System Operator	Response to operating requests and conditions.	Relationship meetings. Annual plan. Monthly monitoring. Direct contact with local network System Operators.

*Stakeholder interests and method of interest identification *the Service Level Agreement details the requirements and expectations for the level of service provided by Northpower Contracting. The content is similar to the Service Level Agreements Northpower Contracting has with other Network companies throughout New Zealand.*

2.4.2 Accommodating the Interests of Stakeholders into Asset Management Planning

Northpower has a number of systems which assist with the accommodation of stakeholder interests; these are supported by satisfaction surveys and meetings with stakeholders.

These include plans, policies and procedures along with relevant standards, legislation and regulations. Of particular significance is the Northpower risk register (which details stakeholders and potential risks to sections of the business) and the interest's register (which details other interests that Northpower directors have, thus protecting against conflicting interests within decision making).

Northpower is ISO 9001 and ISO 14001 certified and Northpower's network is certified to ISO 7901. A gap analysis against international Asset Management standard PAS 55 (ISO 55000) has been completed and Work is currently underway to improve alignment with PAS 55 (ISO 55000) and obtain certification.

Northpower understands that good decision making processes and guides are required to support best practice asset management and ensure stakeholder needs are met. The guides in the table below are used to aid decision making.

Category	Description of guide	Type of decisions to be guided
Policies		
	Vision	All organisational decisions
	Mission	All organisational decisions
	Non-asset solutions	Whether non-asset solution should be used
	Distributed generation	Whether DG should be installed and on what terms and conditions
	Redeployment & upgrade of assets	Whether and how assets should be redeployed or upgraded
	Acquisition of new assets	Whether new assets should be acquired
	Adoption of new technology	Whether new technology should be adopted
	Disposal of assets	How assets should be disposed of
Plans		
	Statement of Corporate Intent	High level direction for the company
	Strategic Plan	High level corporate decisions such as growth and investment
	Asset management Plan	Asset investment, maintenance and operational decisions
	Risk management Plan	Whether the level of risk implicit in decision options is acceptable to Northpower
	Business Continuity Plan	Responses to defined events, allocation of resources in preparation for events
Procedures		
	Internal manuals and specifications	Operation and maintenance requirements
Standards		
	ISO 9001	Quality assurance decisions
	ISO 14001	Environmental decisions
	NZS 7901	Public safety
	AS/NZS 3931- Risk Application Guide	Risk assessment
	AS/NZS 4360 - Risk Management	Risk assessment
	Various technical standards (IEC, BS etc)	Operation and maintenance of network assets
	Various financial reporting standards	What information needs to be reported to various entities, and when
	ISO 55000/1/2	Asset management

Category	Description of guide	Type of decisions to be guided
Legislation		
	Commerce Act 1986	Disclosure of information, anti-competitive behavior, setting tariffs that comply with the price path thresholds, ensuring reliability does not materially decline
	Electricity Act 1992	Organisational and operational decisions
	Energy Companies Act 1992	Organisational and operational decisions
	Companies Act 1993	Requirement to file various returns
	Electricity Act 2010	Requirement to separate line and energy activities
	Electricity Industry Reform Amendment Act 2001	Organisational and operational decisions
	Health & Safety In Employment Act 1992	Organisational and operational decisions
	Resource Management Act 1992	Organisational and operational decisions
Regulations		
	Electricity Industry Participation Code	Distributed generation requirements
	Electricity Information Disclosure Determination 2012 – (consolidated in 2015)	What needs to be disclosed to the Commerce Commission and the public, and by when
	Electricity Governance Regulations	Metering and supply quality requirements
Codes		
	NZECP's	Guides to ensure compliance with regulations

Guides to aid sound decision making

2.4.3 Managing Conflicting interests

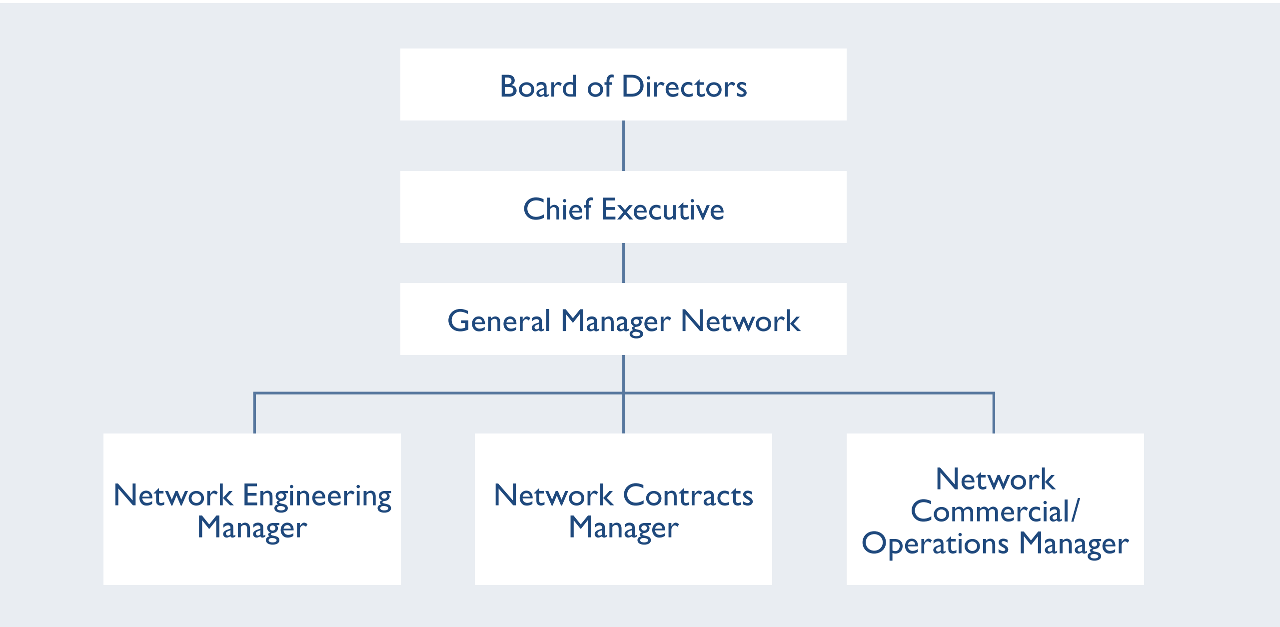
Northpower understands the importance of appropriate consultation of stakeholders in order to ensure proper planning coordination, dissemination of information and maintenance of good relationships. Conflict of interest is treated seriously at Northpower. Wherever possible, Northpower will endeavour to resolve conflict of interest in a responsible and amicable way.

In the event of a major conflict of interest, where an amicable solution cannot be found, Northpower is obliged to follow approved policy and process in order to discharge its responsibilities and obligations with regard to electricity supply.

In general when there is a conflict between the interests of stakeholders, Northpower will prioritise interests in the following way:

- Decisions and actions required to ensure safety take priority over other interests at all times.
- Electricity distribution is a core activity. Northpower is committed to delivering quality to consumers, therefore decisions and actions which protect supply quality are fundamental. Decisions taken to protect supply quality must be financially responsible and meet compliance requirements. These interests form the parameters around which supply quality is prioritised.
- Financial interests will be considered on their merits and outcomes will depend on overall best position for Northpower.
- Northpower is committed to 100% compliance with the law and relevant industry regulations. The only acceptable reason for a compliance breach is action necessary to ensure safety in unforeseen circumstances.

2.5 Accountabilities and Responsibilities



Responsibilities Structure

The responsibilities for asset management at Northpower are shown in the above diagram. Accountability of the positions is described below.

2.5.1 Governance of Asset Management

The Board of Directors is ultimately responsible for governance at Northpower. A significant proportion of the responsibility for governance and related decision making is delegated to the chief executive. However, board approval is required for:

High level plans including:

- 10 year AMP.
- Maintenance Plan.
- Development Plan.

Annual budgets including:

- Preventative maintenance.
- Follow up and remedial maintenance.
- Asset renewal.

Sanction for expenditure approval for significant individual projects and expenditure that exceeds budget. Board sign off is required for projects exceeding certain levels of expenditure or for those projects deemed to fall outside of 'normal' expenditure requirements. Examples include:

- Switchboard upgrades.
- Power transformer upgrades.
- New zone substations.
- New technologies.
- Research and development projects.
- Safety, reliability and security of supply initiatives.

The Chief Executive provides a business report to the Board Meeting each month. The report includes an outline of the Asset Management Division performance, business status and other significant issues. Specific examples include:

- Overall Network division financial position.
- Wairua power station (note that although not part of the lines business, Northpower network division is responsible for managing this asset).
- Network performance.
- Sub-divisional reports including:
  - Network Planning.
  - Commercial.
  - Operations
  - Contracts.
- Fibre network (note that although not part of the lines business, Northpower network division is responsible for managing this group of assets).
- Metering (note that although not part of the lines business, Northpower network division is responsible for managing this group of assets).

2.5.2 Northpower Asset Management Executive Team

The Network Assets division carries responsibility for the Asset Management functions at Northpower. Responsibilities within the division are as follows:

The **General Manager Network** is the principal point of day-to-day responsibility for the asset management function which includes improving and managing Northpower's image and relations with the Northpower Trust, community and other key stakeholders. The General Manager Network is accountable to the Chief Executive for meeting the network operational and financial targets.

The **Network Engineering Manager** (which encompasses Network Planning, Development and Information Analysis) is responsible for network policy, standards and asset management systems, together with the network development and maintenance plans (and associated annual budgets) which form part of the Asset Management Plan.

The **Network Commercial and Operations Manager** is responsible for the operation of the network and manages the interface between Northpower's network and the Transpower grid, Northpower's larger customers and the energy retailers. The Network Commercial and Operations Manager also manages the interface with the Electricity Authority and determines the network line charges.

2.5.3 Managing Field Operations

The **Network Contracts Manager** is the interface with the in-house field services division. This relationship is managed by way of a Service Level Agreement (SLA).

A significant function of this role is to monitor and audit key projects and required outcomes but, within the parameters of the Service Level Agreement.

Northpower Contracting is the primary contractor operating on the Northpower network. This is advantageous firstly because the values, standards and operating practice are aligned with Northpower's asset management practice; the two operations share the same governing factors. Secondly, a wide and mobile workforce is available if additional resources are necessary.

From time to time other contractors carry out work. These contractors are subject to the same safety and work criteria expected of Northpower Contracting. They are required to demonstrate this for approval to work on the Northpower network.

External contractors are also engaged to carry out services that are not available internally. Examples include civil engineering and construction services.

2.6 Asset Management Systems and Processes

2.6.1 Asset Management Systems

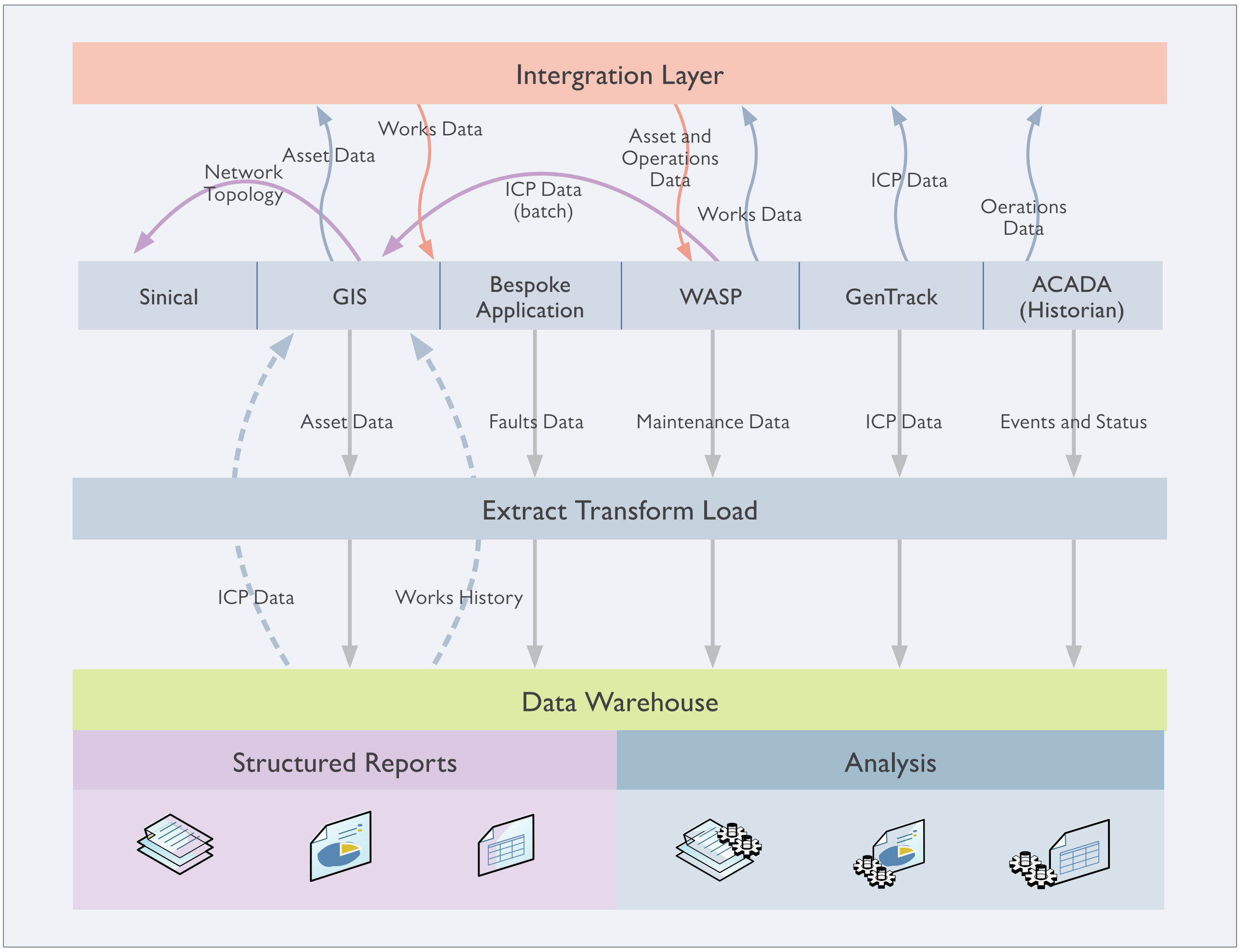
Network Data is managed in five core systems (OSISoft PI, Siemens SCADA, Intergraph GIS, EMS Works, Maintenance Management (WASP) and Gentrack Billing). These are supported by a number of MS SQL Server databases. Data from each of the above repositories is replicated to a data warehouse environment with analysis and operational visibility provided via structured reports and ad-hoc queries

The recent purchase and partial implementation of the JD Edwards ERP system, coupled with the end-of-life status of the WASP system, has led Northpower Network to consider the implementation of the JD Edwards Capital Asset Management system.

It is intended that this replacement system for the EMS WASP system be implemented during 2016, with its primary implementation objectives being to:

- Replace existing WASP maintenance management functionality
- Create and implement the planned maintenance schedule in JDE for all network assets
- Implement an agile and effective process and system for capturing reactive maintenance Northpower has adopted a 'de-coupled' integration philosophy based on Microsoft BizTalk Server, use of a 'service oriented architecture' (SOA) and industry standard tools and protocols. The net result is a configurable, reusable and scalable integration architecture that has lower cost of ownership. Leveraging this framework enables Northpower to continue with a 'best of breed' approach without compromising systems inter-operability.

The ongoing development of these systems particularly the GIS, together with related applications development, will continue to extend into the medium term.



Systems Integration Structure

A wide range of structured and ad-hoc reports are available via an Intranet portal to support asset management processes. Additionally specialised geospatial software is used to drive inspection regimes and provide analytical support for defect processing.

2.6.2 Document Management System

System	Purpose	Data Stored
Document Management (Sharepoint)	Repository for scanned records, currently held in paper archives. Offers enhanced search and retrieval, linking to GIS	Historic construction plans and connections records

In addition to providing an Intranet platform, Microsoft Sharepoint has been progressively integrated with business processes. Northpower has initiated a program to scan, catalog and archive paper records to this environment. Given the high volume of historic records, this work is expected take a number of years to complete but will deliver a number of benefits to the business. Cataloging and linking where possible to GIS will simplify the search and retrieval of historic records significantly.

2.6.2.1 Geospatial Information System (GIS)

System	Purpose	Data Stored
Geographic Information System (GIS)	Repository for Master Asset Data and Electrical Connectivity to support Records Management, Planning and Analysis.	Zone Substation assets, Sub Transmission, HV and LV Distribution Assets

The Geographic Information System (GIS) is of primary importance to Northpower as it acts as the master repository of asset data which provides the basis for asset planning. Northpower has invested heavily in upgrading the GIS and improving the data stored in the underlying database. GIS data now forms the basis of a number of downstream activities including planning, design, analysis and asset maintenance.

A web based GIS front end provides users with access to the underlying data through a wide range of search features.

Asset Data for distribution and most substation assets is mastered in GIS with a subset of this data replicated in the Maintenance Management System. This is essentially only that data which is required to support maintenance management activities. Assets mastered in GIS and interfaced to WASP include the following:

- Capacitors
- Distribution Switchgear & Reclosers
- Distribution Substations
- Distribution Transformers
- Regulating Substations
- Regulating Transformers
- Pillars
- Poles
- Distribution Earthing
- Circuit Breakers
- Current Transformers
- Tap Changers and Controllers
- Voltage Transformers
- Zone Transformers

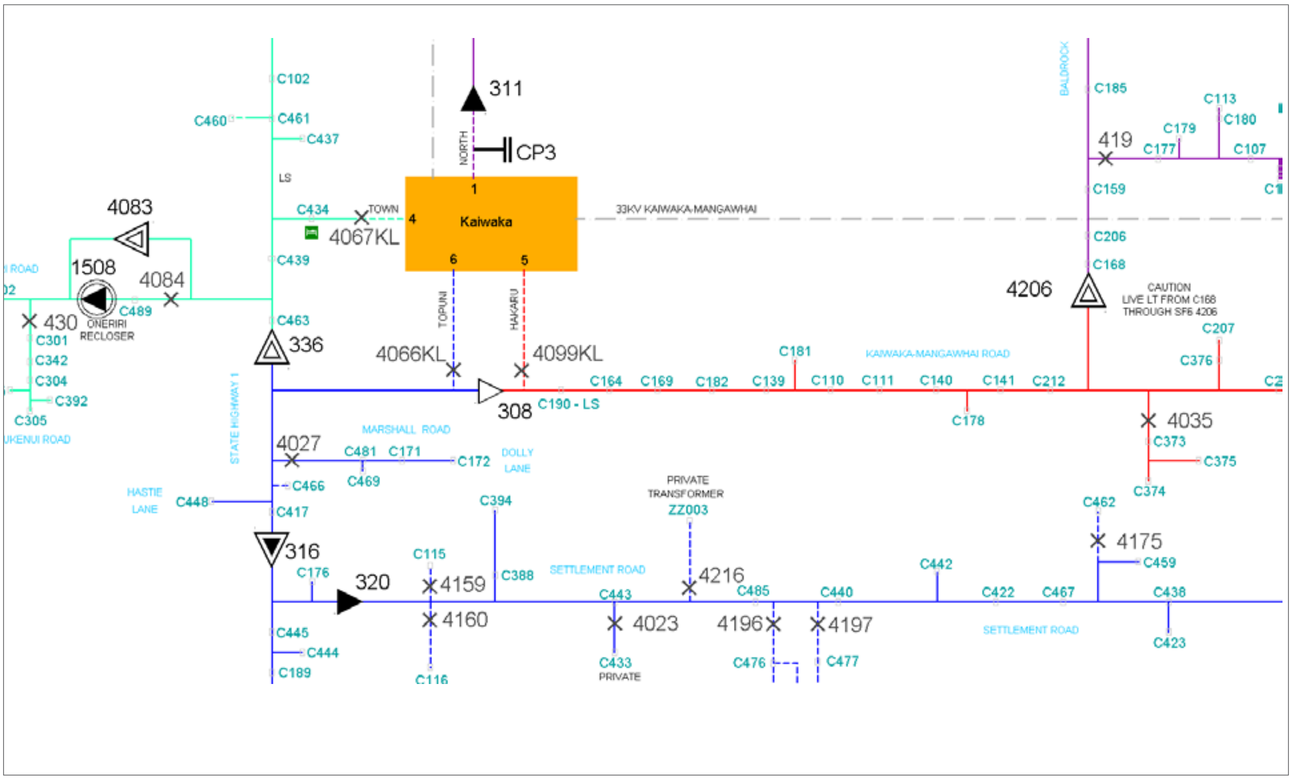
It is the intention to bring the balance into GIS and interface them to WASP as resources permit over the next two years

Network Representation

Asset data is maintained in the GIS database and two views are available – schematic (11kV only) and geographic (all voltages). Both are views of the same feature in GIS.

11kV Schematic

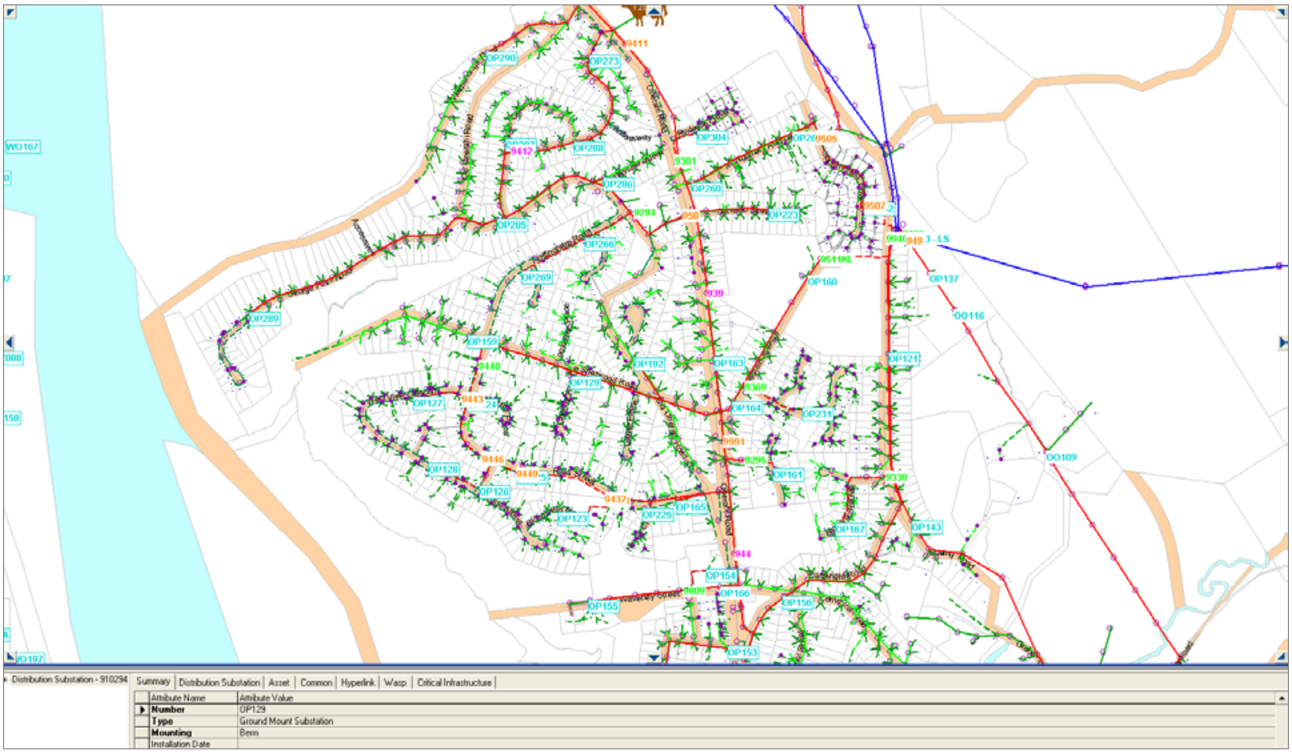
The 11kV schematic displays the source substation, circuit breaker, switching nodes, distribution substations, in-line links, critical sites and some basic location detail and is the primary source of information for control room operations.



11kV Schematic View

Geographic View

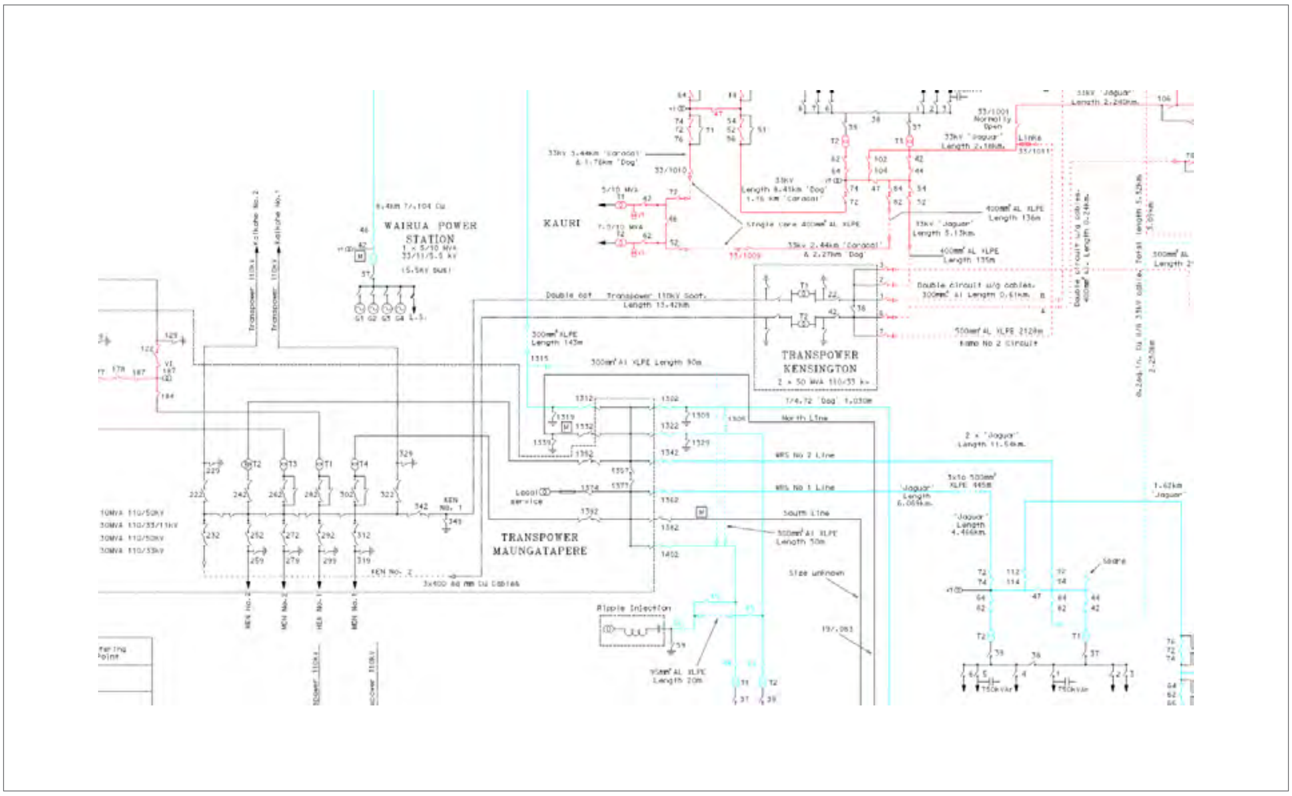
This displays the geographical location, electrical connectivity, and provides essential data for poles, conductor spans, cable sections, pillars, distribution substations, distribution transformers, switches, links, fuses and other network assets.



11kV Geographic View

33kV Schematic

The 33kV schematic is currently maintained in MicroStation and displays network interconnection, switching nodes and conductor circuit length details.



33kV Schematic

2.6.2.2 EMS WASP

The primary system used to support asset maintenance is EMS WASP (Works, Assets, Solutions, and People). This software is end-of-life and the functionality provided by this product will be replaced next year by JDE Capital Asset and Work Management modules

System	Purpose	Data Stored
EMS WASP	Asset Management	Assets and associated data required to drive maintenance. Condition data, test and inspection results. Maintenance/inspection regimes, triggers and tasks. Maintenance history. Capital projects

WASP has been configured to support the following functions:

- Storage of maintenance history for individual Network assets
- Forward planning of capital works programmes
- Automatic generation of regular tasks including preventative maintenance, inspections and testing tasks
- Recording test and inspection data
- Defect capture from asset inspections
- Task planning, packaging and scheduling using various criteria

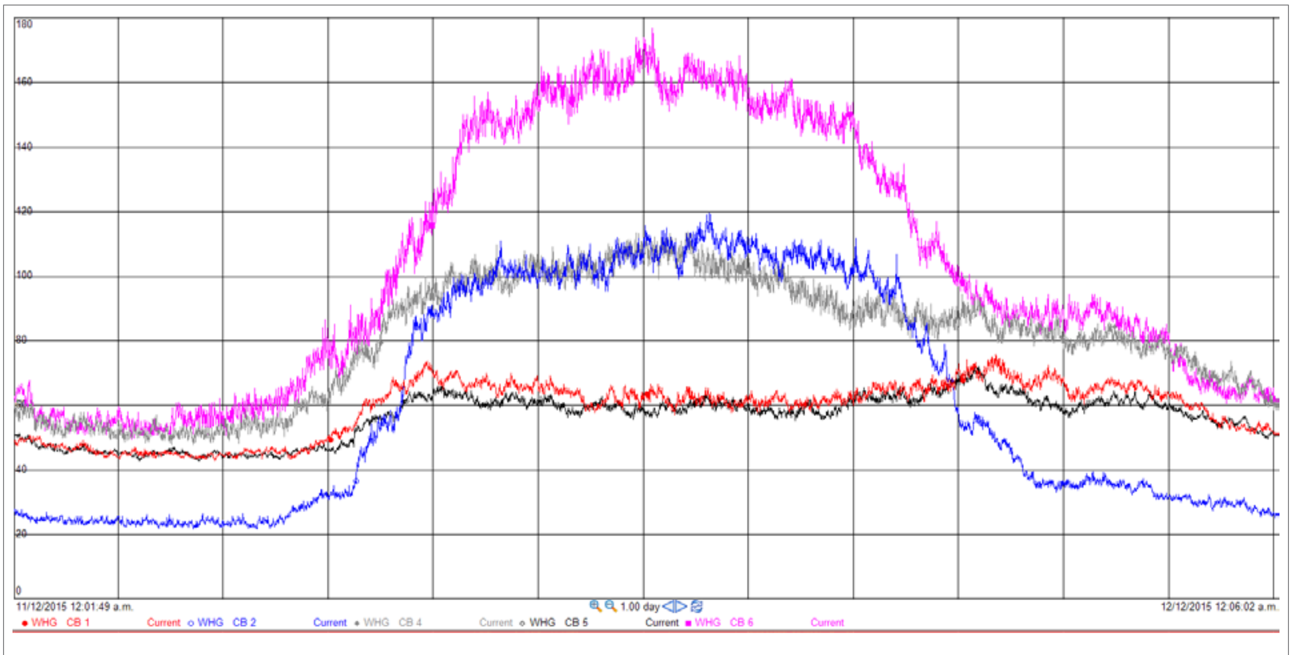
Data held in WASP includes condition data, test and inspection results as well as that required to drive maintenance management regimes, including manufacturer, type and model. Condition data from inspections is fed back into WASP and used to generate asset replacement and repair type tasks. Routine tests, inspection and maintenance regimes are held in relevant quality system documentation.

Earth test results are stored in WASP to ensure that regulatory and safety requirements for the operation of the Network are met. Where test results are not loaded directly into WASP, scanned copies of these records (together with consultant's reports and manufacturer certificate/test sheets) are linked to the asset record in WASP.

2.6.2.3 OSISoft PI Data Historian

System	Purpose	Data Stored
PI Server	Real time System Data Acquisition and Analysis.	System events, plant status and loading, busbar voltages

The PI system provides an improved Data Historian and analysis tool kit. Interfaces have been setup between the Siemens SCADA system, Communications Systems and other data repositories which provide an efficient historical capture of information. The information is mainly used for reporting and network planning/modelling purposes.

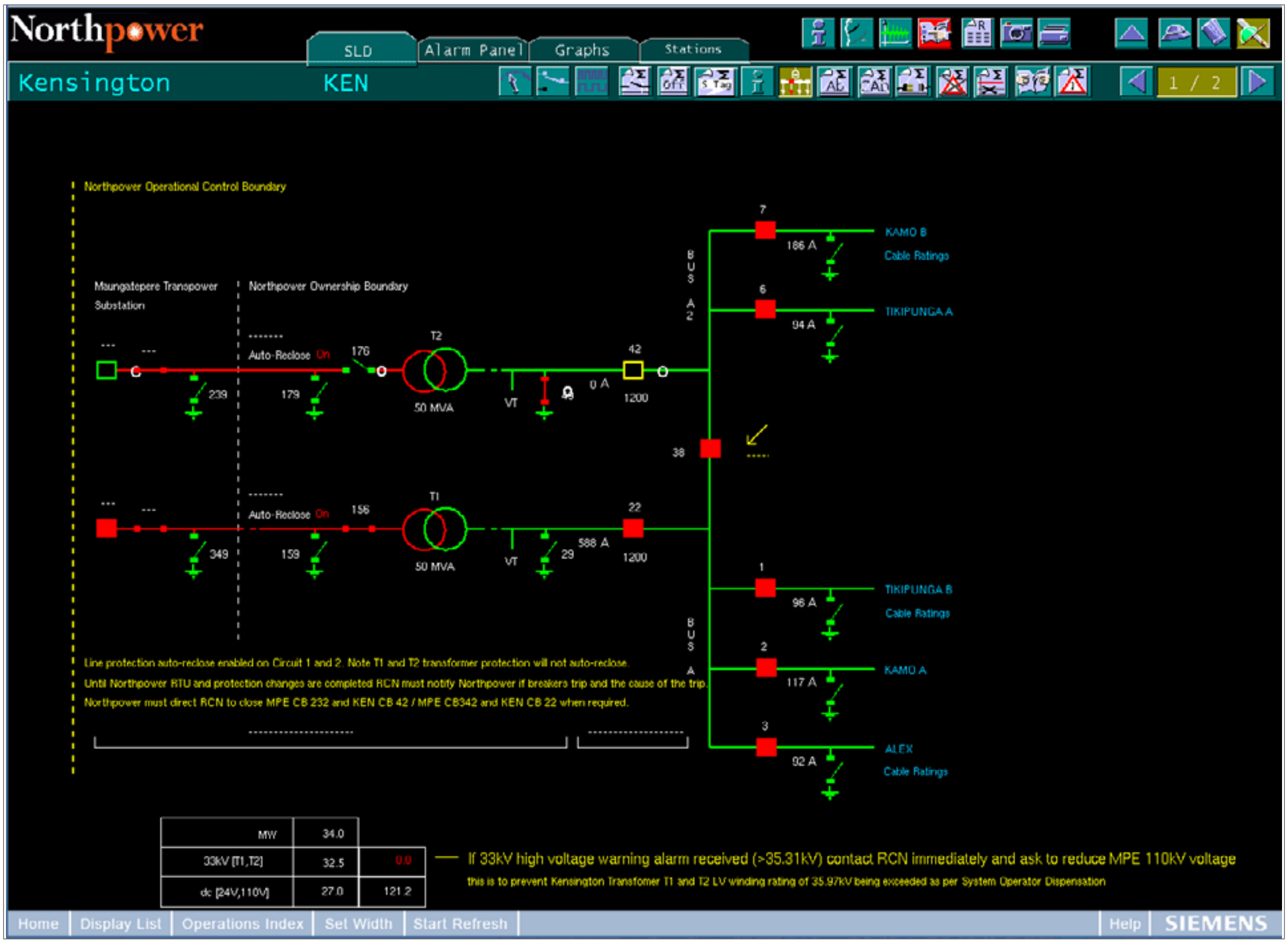


OSISoft PI Feeder Current Trace

2.6.2.4 Siemens PowerTG SCADA

System	Purpose	Data Stored
SCADA	Real time System Control & Data Acquisition	System events, plant status and loading, busbar voltages

The SCADA system records and stores time stamped event, status, loading and voltage data for the purpose of analysing system events (e.g. faults) and capturing network loading and voltage conditions for network modelling purposes.



SCADA Substation Screen

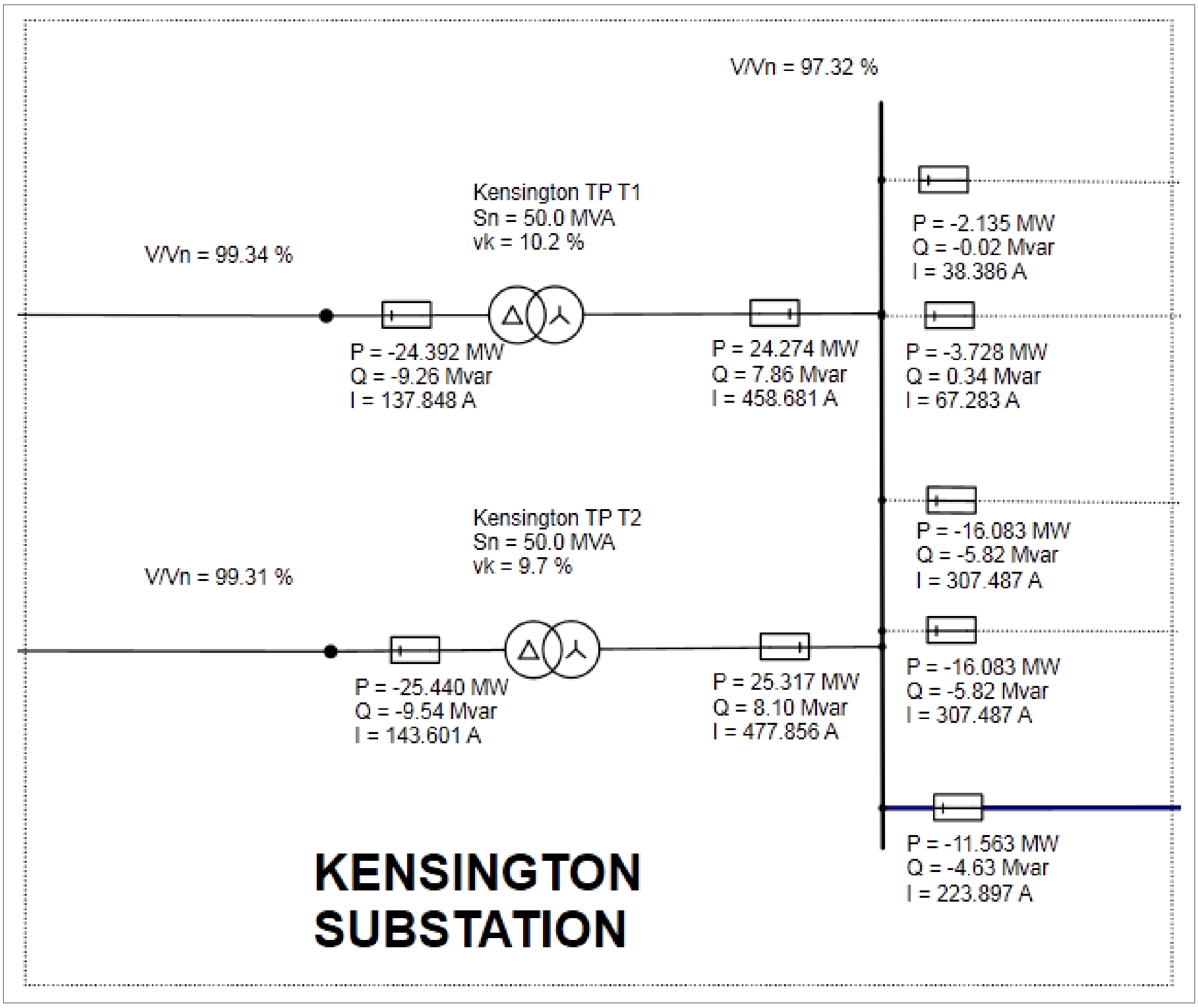
2.6.2.5 Power System Modelling and Analysis

System	Purpose	Data Stored
PSS/Sincal	Network load flow and fault level analysis	Network models and case studies

PSS/Sincal is a power system analysis software tool used to model the subtransmission and distribution networks. Network models are developed from GIS extracts and populated with rating and other data from equipment name plates and manufacturer's specifications. Loading data obtained from the SCADA system is then used to simulate actual network conditions to identify capacity constraints, calculate fault levels and determine optimum distribution transformer tap settings.

The software is also used to simulate future loading scenarios and network strengthening options in order to identify optimum solutions. The results of these studies ultimately determine the nature of the 10 year development plan. Many other applications such as motor starting, generation, backstopping capabilities, determination of available capacity for new customer connections, calculation of network losses and protection settings are also undertaken with this software.

Sincal is currently being extended to hold all the protection information and provide discrimination tools for coordinating protection across the network.



PSS/Sincal Load Flow Study SLD

2.6.2.6 Gentrack

System	Purpose	Data Stored
Gentrack	Network Billing	ICPs & Billing information

Gentrack maintains detailed ICP records for billing purposes and automatically synchronises its installation data with the national registry. Also, retailer's customer data for each ICP is received via the national registry to automatically notify customer and retailer changes (start dates and end dates). Retailers send a file of Northpower network ICPs for monthly billing which contains dates, tariffs, consumption (kWh units). Gentrack bills the retailer for daily fixed charges applicable to each tariff for the correct number of days (taking retailer switching and customer changes into account). Energy is charged according to consumption or demand notified by the retailer, and the rate applicable for each tariff. Gentrack also keeps a dated record of meter type and serial number at each installation, together with details of all relays deployed. The Northpower customer service team maintains a log for each ICP in Gentrack to record all requests for service, events and outcomes concerned with metering, connections and disconnections from the network.

2.6.2.7 Outage Recording

System	Purpose	Data Stored
HV & LV Faults Database (MS SQL Server)	Network Performance Data Capture	Fault records and outage imperials

Northpower currently measures and reports certain performance results for disclosure purposes on a routine basis. To do this, all planned and unplanned outages are entered into these databases

The HV Faults database produces network performance reports which include:

- SAIDI, SAIFI and CAIDI results for any selected time period
- The daily outage and incident report which is circulated to interested parties and key managers
- Outage causes sorted by various selected parameters

All unplanned outage causes are categorised as per the Electricity Industry Information Disclosure Regulations. Northpower's disclosure information and process is audited annually by PricewaterhouseCoopers for accuracy and consistency. The audit covers both planned and unplanned work.

2.6.2.8 Integration Services

System	Purpose	Data Stored
Systems Integration	Support the use of 'best of breed' approach to systems.	Business rules to ensure data integrity.

Systems Integration

Northpower's integration philosophy relies on a 'de-coupled' approach using a middleware layer for data exchange. This architecture is supported by the use of 'service oriented architecture' (SOA) and industry standard tools and protocols. The net result is a configurable, reusable and scalable integration architecture that has lower cost of ownership. Leveraging this framework enables Northpower to continue with a 'best of breed' approach without compromising systems interoperability.

2.6.2.9 Data Completeness and Accuracy

Ongoing data capture from BAU activities ensures data is captured in accordance with Northpower's data requirements. However data migrated from legacy systems is incomplete in some areas and work continues towards targets set in December 2007

The feeder by feeder data capture program, which stood at 70% complete in 2013, has now been completed. Overall data completeness has improved significantly as a result. All data has not yet been fully captured however and a second pass is underway in an effort to locate and migrate additional data from scanned construction plans and service sheets .

As part of the Service Level Agreement (SLA) with Northpower Contracting the payment for work undertaken is dependent on the accurate updating of network data into Northpower's core systems. This work includes data entry and the SLA stipulates targets for data completeness, accuracy and timeliness. An overhauled performance based contract with the service provider includes a set of KPI schedules which are designed to monitor the performance in each of these categories on a monthly basis. Data accuracy is monitored by random monthly audit, while data completeness and timeliness are monitored using a set of prepared scripts run on the database

Data quality from BAU activities has been improved further through the use of electronic field capture on tablets using applications designed to validate data at source and send it to backend databases, in most cases without further manual intervention. Data from distribution inspections and tests are handled in this way and this program will be rolled out to substations asset data capture in the next few years

As a result of these initiatives data quality has been improving steadily in recent years. Original targets for data accuracy and completeness are compared with the position in December 2015below

2.6.2.9.1 Subtransmission Lines and Cables

The target for data completeness and accuracy has been set at 100% and is currently sitting on 97%. This is due to the high value and strategic importance of these assets..

2.6.2.9.2 High Voltage Lines and Cables

The target for data completeness has been set at 98% with accuracy at 90%. As at December 2015 the percentage of conductors of known age had improved from 52% in 2013 to 74% in December 2015

2.6.2.9.3 Low Voltage Lines and Cables

The target for data completeness and accuracy have been set at 95% and 90% respectively

Ongoing retrospective data capture from archived plans has seen the age data improve from 40% to 64% since 2013. Other data attributes have also improved with over 90% of conductor types known

2.6.2.9.4 Subtransmission and Distribution Switchgear

Given the criticality of this group of assets, targets for data completeness and accuracy have been set at 100%. These efforts have been assisted by the total replacement of distribution air break switches with overhead enclosed switchgear, with the result that all switchgear data is almost fully complete

2.6.2.9.5 Distribution Substations and Transformers

As critical assets, the targets for data completeness and accuracy have been set at 100% for this group of assets. Critical data for these assets is now fully complete and almost all have been reliably aged.

2.6.2.9.6 Poles

Data completeness and accuracy targets reflect the voltage of conductors carried on the pole. Across all voltages however the target for completeness is 95%+ with accuracy at 90%.

Key pole data completeness and accuracy remains variable (and dependent on conductor voltage) however overall75% have been reliably aged (up from 60% in 2013).

2.6.2.9.7 Pillars

The target for this group of assets is 95% completeness with 90% accuracy.

Data for LV Link pillars in the CBD is good while for service pillars the completeness of key data also remains at a high level. Over 80% of distribution pillars have been reliably aged

2.6.2.9.8 Zone Substation Assets

A zone substation data capture project early in 2010 yielded a significant improvement in the quality of data for these assets. As a result, data completeness had improved across all zone substation assets to over 90%. Higher valued, strategic assets including circuit breakers and zone transformers now approach 100% data completeness and accuracy.

2.6.2.10 Data Quality Initiatives

To improve the efficiency and accuracy of data capture, in-field technology is preferred over traditional manual paper-based systems. To this end in-field data capture has been rolled out across the distribution network. Asset data retrieved from the field is validated against existing data and transferred directly to the relevant core system (GIS/WASP). Defects are transferred to the asset management system

The ongoing development and integration of information systems including GIS, Works Management and Network Billing in conjunction with a centralised data repository has greatly improved distribution of, and access to, asset data. Data is extracted from these core systems, aggregated in a data warehouse, and deployed via an intranet portal to a combination of structured and ad-hoc reports – with the result that users now access the "one version of the truth" often with no sense of data source. The success of these initiatives going forward will depend on the ongoing integration between core systems and reduced reliance on feral databases and islands of information.

2.6.2.11 Plans for improvement in information quality

The GIS database (and underlying data model) has provided the platform for a comprehensive data capture programme aimed at improving both completeness and accuracy. The overall goal of this project is to provide comprehensive and reliable data to support regulatory reporting and the Company needs for asset management. At December 2015 all assets had been visited by desktop investigation and data updated by a dedicated resource using historical records wherever possible. Unresolved data issues have been flagged and followed up by a combination of targeted and routine field inspection.

2.6.2.12 Network Communications

Due to the aging nature of the analogue based radio systems and copper based communications systems and the advent of modern communications technologies such as fibre/microwave Northpower has been upgrading the existing communications network infrastructure. The fibre/microwave systems extend Northpower's wide area network to remote sites providing geographic agility, reliability and speed improvements.

Some of the protection schemes employed by Northpower utilise fibre differential schemes to protect the important sub-transmission circuits. These fibre schemes provide greater reliablity than radio or copper based systems due to their resilience to interference and minimal attenuation during transmission.

2.6.2.13 Network Control

Network control is tasked with 24/7 monitoring of the electricity network. Northpower have focused on developing a fully equipped backup control room to provide a geographically separated control location in the event of failure of the main control room. This control room is fully equipped with corporate and SCADA network access, RT's and phones. This backup control room will leverage the PowerTG SCADA Schematic to provide a snapshot of the network configuration.

2.6.3 Business Processes

2.6.3.1 Managing routine asset inspections and network maintenance

Northpower uses specialist asset management software to support routine asset inspections and network maintenance management activities. The system, EMS WASP, automates repetitive manual tasks and ensures standardisation.

WASP is primarily driven by cyclical triggers which initiate work requirements. Event related data is also used to trigger work. The system captures and manages asset condition data and defect tasks. WASP operates as a slave to the GIS master data repository and generates event driven maintenance triggers based on data provided from the SCADA system. Note, in 2016 the functionality provided by WASP will be progressively replaced by the introduction of JDE Capital Asset Management. This module will offer tight integration with the JDE Financial system implemented by Northpower in 2015 and numerous other benefits

Section 6 of the Asset Management Plan specifically addresses the routines and related policy Northpower employs to manage network inspection and maintenance.

2.6.3.2 Planning and implementation of network development processes

Network development projects are grouped according to the following 4 main categories:

Growth (new customer connection and growth of existing load). The network load forecast is used to identify future capacity constraints and possible solutions are identified. Technical and financial analyses are carried out in order to identify the most suitable long term solution. Projects are then defined and planned.

Replacement and renewal (asset deterioration or obsolescence). Assets requiring upgrading or replacement due to end of life or condition (safety, performance, maintenance costs) are identified and their replacement planned.

Improvement (safety, reliability, environmental). Projects required to improve public and employee safety, network reliability and performance as well as reducing environmental impact where possible are identified, defined and planned.

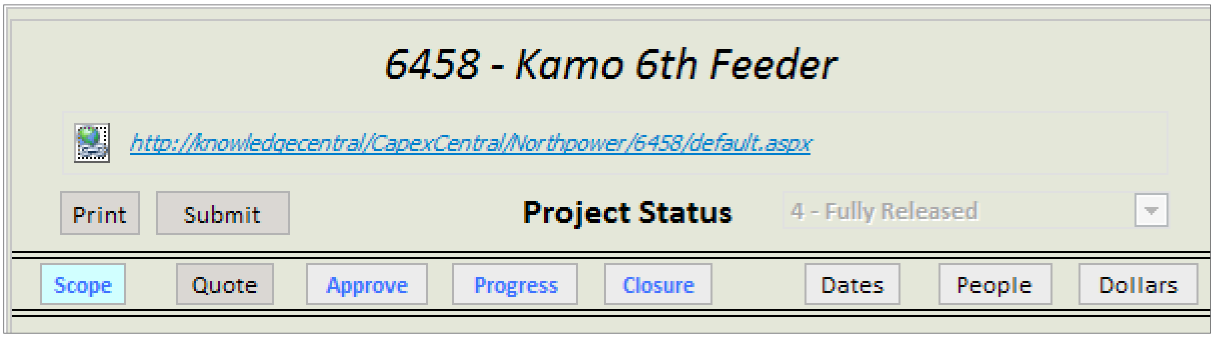
Relocation (relocation of existing assets). Assets required to be relocated for road works, property owner requests, network reconfiguration or safety reasons.

Optimum solutions are based on minimising capital outlay and life cycle costs without compromising safety, quality and performance.

A long term network development plan (10 years) comprising of planned projects is developed from these requirements with projects prioritised according to safety, performance and capacity requirements.

Individual projects (or groups of projects) are required to be justified in order to obtain sanction for expenditure (SFE) following which a project brief is generated. SFE approval is given at Board or executive management level depending on project value. Large projects with long lead times (detailed design, equipment procurement and construction) are required to be initiated well in advance.

Annual capital projects budgets are compiled from the development plan and the financial system tracks individual project expenditure against budget. Microsoft Sharepoint (Capex Central) is used to document the project scope of work and record cost quotations, approvals and project progress.



Capex Central Project Database

2.6.3.3 Measuring network performance (SAIDI, SAIFI) for disclosure purposes

Northpower currently measures and reports certain performance results for disclosure purposes on a routine basis. To do this, all planned and unplanned outages are entered into the Northpower "Faults Database".

The database produces network performance reports which include:

- SAIDI, SAIFI and CAIDI results for any selected time period
- The daily outage and incident report which is circulated to interested parties and key managers
- Outage causes sorted by various selected parameters

All unplanned outage causes are categorised as per the Electricity Industry Information Disclosure Regulations. Northpower's disclosure information and process is audited annually by Price Waterhouse Cooper for accuracy and consistency. The audit covers both planned and unplanned work.

Northpower is evaluating the use of an outage management system which will provide accurate SAIDI, SAIFI and CAIDI calculations on a per customer basis. This outage management system is budgeted for the next two years and will interface to the dispatch team and obtain information from the SCADA system and operations staff.

Section 3: Assets Covered

“safe, reliable, hassle free service”

Northpower

Assets Covered

3

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Section 3: Assets Covered

3.1 Distribution Area

3.1.1 Area Covered

As at 30 November 2015, Northpower supplies 55,901 connected customers spread over an area of some 5,700 square kilometres covered by the Whangarei and Kaipara Districts. This area includes Whangarei City and the towns of Dargaville, Hikurangi, Kaiwaka, Maungaturoto, Ruawai and Waipu. The main depot and head office for Northpower is located in Whangarei. Sub-depots are located in Dargaville and Maungaturoto. The map below shows the geographical area supplied by Northpower, the location of the three Transpower grid exit points (Bream Bay, Maungatapere and Maungaturoto) supplying Northpower's network and the two Northpower regional stations (Kensington and Dargaville) which are ex Transpower GXP's recently acquired by Northpower.

Northpower geographical area of supply and major substations

3.1.2 Northpower's Large Customers

Customers with high consumption (in terms of either maximum demand or energy or both) are defined as large industrial loads. These customers usually have special requirements with regard to security of supply (typically duplicate transformers and lines or cables) as their loads are too large to supply with emergency standby or backup generation. These loads are normally supplied directly from the sub-transmission system at 33kV or by one or more dedicated 11kV distribution feeders emanating from a nearby zone substation.

Northpower currently has five large industrial loads and together they consume approximately 50% of the electricity supplied via the Northpower network.

Key industries in the Northpower distribution area include:

- Oil refining
- Cement manufacture
- Wood processing
- Dairy processing

3.1.3 Load characteristics for different parts of the network

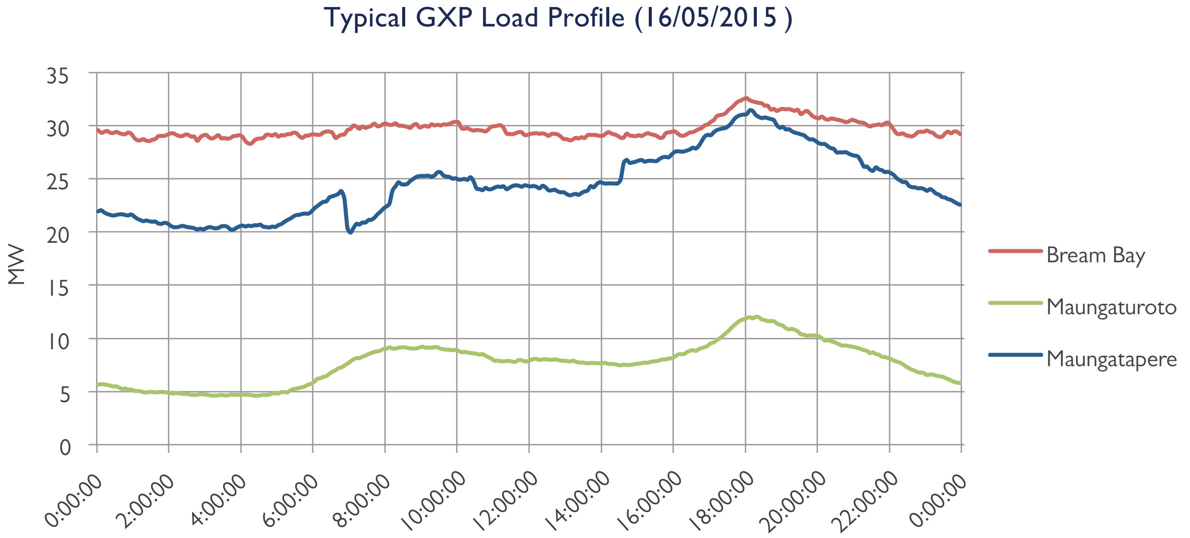
Major Station	Load Characteristics
Bream Bay (GXP)	Fairly constant load throughout the year Predominantly industrial load with some residential and commercial High reactive power component
Dargaville	Peak load in winter Predominantly rural dairy, residential and commercial load with some industrial Moderate reactive power component
Kensington	Peak load in winter Predominantly residential and commercial load but also significant industrial and some rural Low reactive component
Maungatapere (GXP)	Fairly constant load throughout the year Mixture of all load types with significant large industrial High reactive power component
Maungaturoto (GXP)	Peak load in spring Predominantly dairy and industrial load Increasing coastal settlement load Moderate reactive power component

Northpower's electricity network is predominately rural. Apart from the major industrial loads mentioned above, the major urban centre of Whangarei, and the smaller urban centres of Dargaville, Kaiwaka, Ruawai, Maungaturoto, Mangawhai, Ruakaka, Hikurangi and Waipu, the balance of the load is comprised mainly of dairy farming, small sawmills, townships and coastal settlements. Typically the load peaks in winter, usually late July or early August.

Generally, daily peaks for the network are cyclic and predictable. Residential and rural areas have highest demand during the mornings and evening hours while commercial areas and the central business districts demand are highest during the day.

Hikurangi Zone substation is also noteworthy as it has a significant amount of flood pumping connected. In periods of very wet weather this can place extra demand on the substation.

A typical daily profile is shown below and is a snapshot from the 16th May 2015.



Typical GXP Load Profile (16/05/2015)

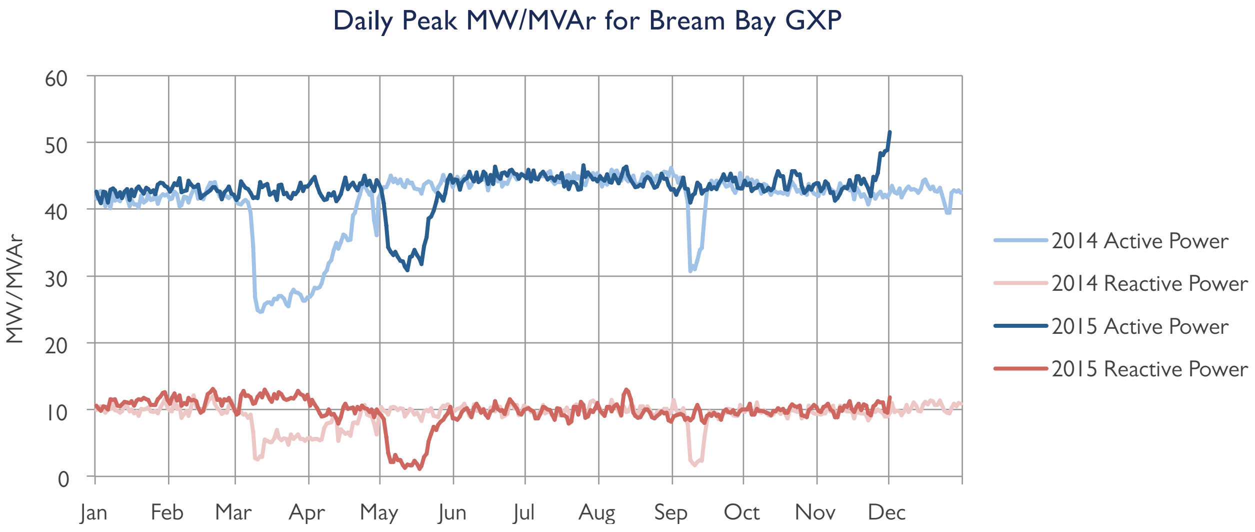
3.1.4 Peak demand and Total Electricity Delivered

3.1.4.1 Peak Demand

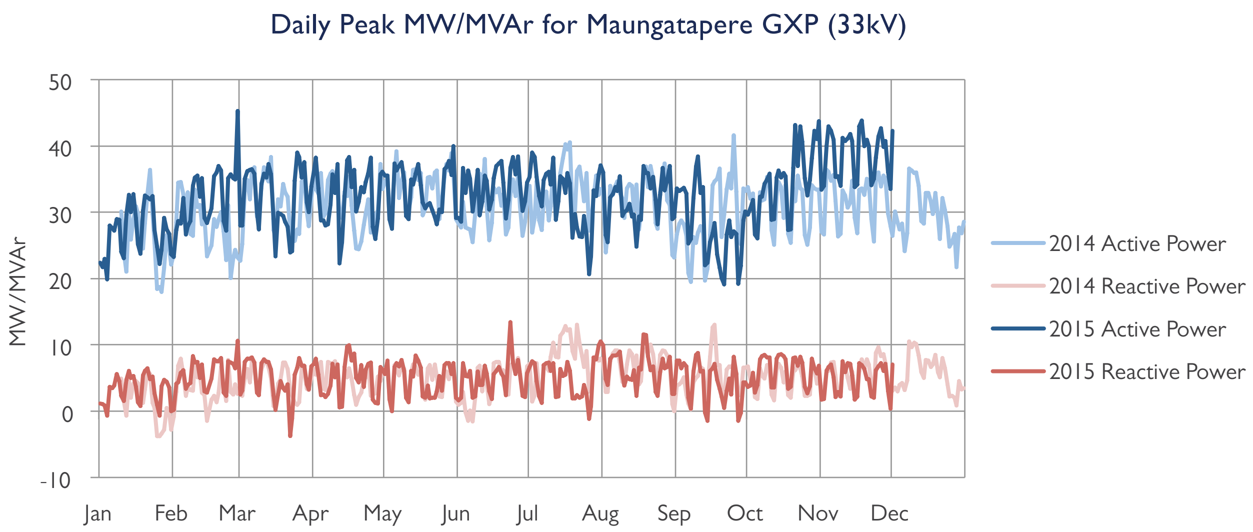
Peak demand on the network is due to coincident consumer activity. For example, demand will increase in residential areas in the mornings (as residents wake and switch on appliances) and evenings (as residents get home and prepare dinner). Residential demand is also highest in winter as consumers use more electricity to power heating devices. Peak demand is an important consideration when managing electricity assets because the electricity network must have the capacity to meet the peak demand to ensure uninterrupted delivery of electricity. Northpower employs ripple control systems to interrupt supply to hot water cylinders during peak load periods in order to reduce the peak load. This helps to reduce/defer investment in increased capacity of substations and lines /cables, which ultimately benefits the customers in the long term.

The peak demand on Northpower's network for 2015 was 173MW (which occurred on 18th Aug 2015 at 7:05pm) and the total energy delivered from April to December 2015 was 765GWh (total energy delivered in the financial year ended March 2015 was 993GWh).

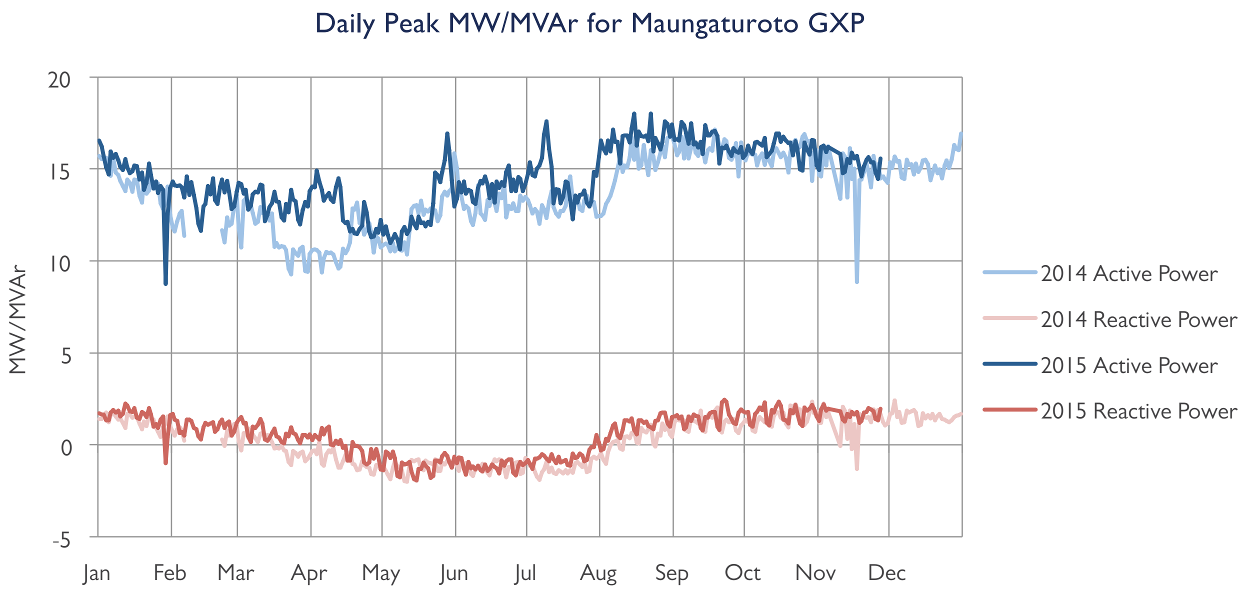
The following charts show the active (MW) and reactive (MVAr) daily peak demand profiles for Bream Bay GXP, Maungataturoto GXP and Maungatapere GXP (33kV only) for the 10 month period January 2015 to October 2015:



Daily Peak MW/MVAR for Bream Bay GXP



Daily Peak MW/MVAR for Mangatapere GXP(33kV)

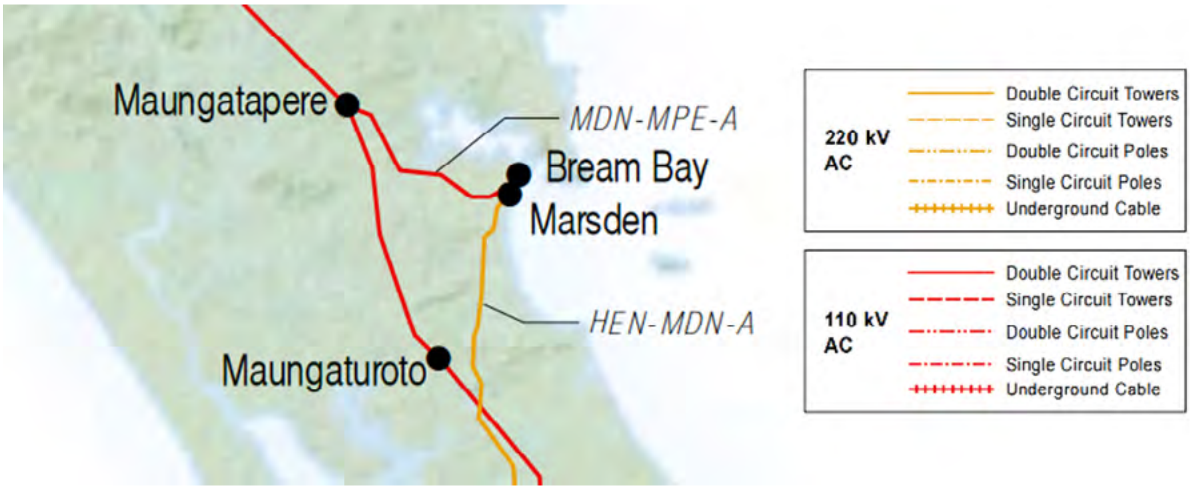


Daily Peak MW/MVAR for Maungaturoto GXP

3.2 Description of Network Assets

3.2.1 Grid Exit Points and Embedded Generation

Supply is taken from the national grid at 3 Transpower Grid Exit Points (GXP's), namely Bream Bay GXP (supply taken at 33kV), Maungatapere GXP (supply taken at 110kV) and Maungaturoto GXP (supply taken at 33kV). A map of Transpower's transmission network and 3 GXP's within Northpower's area of supply is shown below. There are 2 large generation stations connected to Northpower's network, namely Northpower's 5MW Wairua hydro power station and Trustpower's 9MW diesel powered peaker plant (Whangarei Hospital has an emergency backup diesel plant but this does not generate into Northpower's network). In addition to this approximately 280 small privately owned solar PV embedded generators (average installed capacity 4.7kW) are active across the network.



Transpower's Network Within Northpower's Area Of Supply

3.2.2 Subtransmission Network

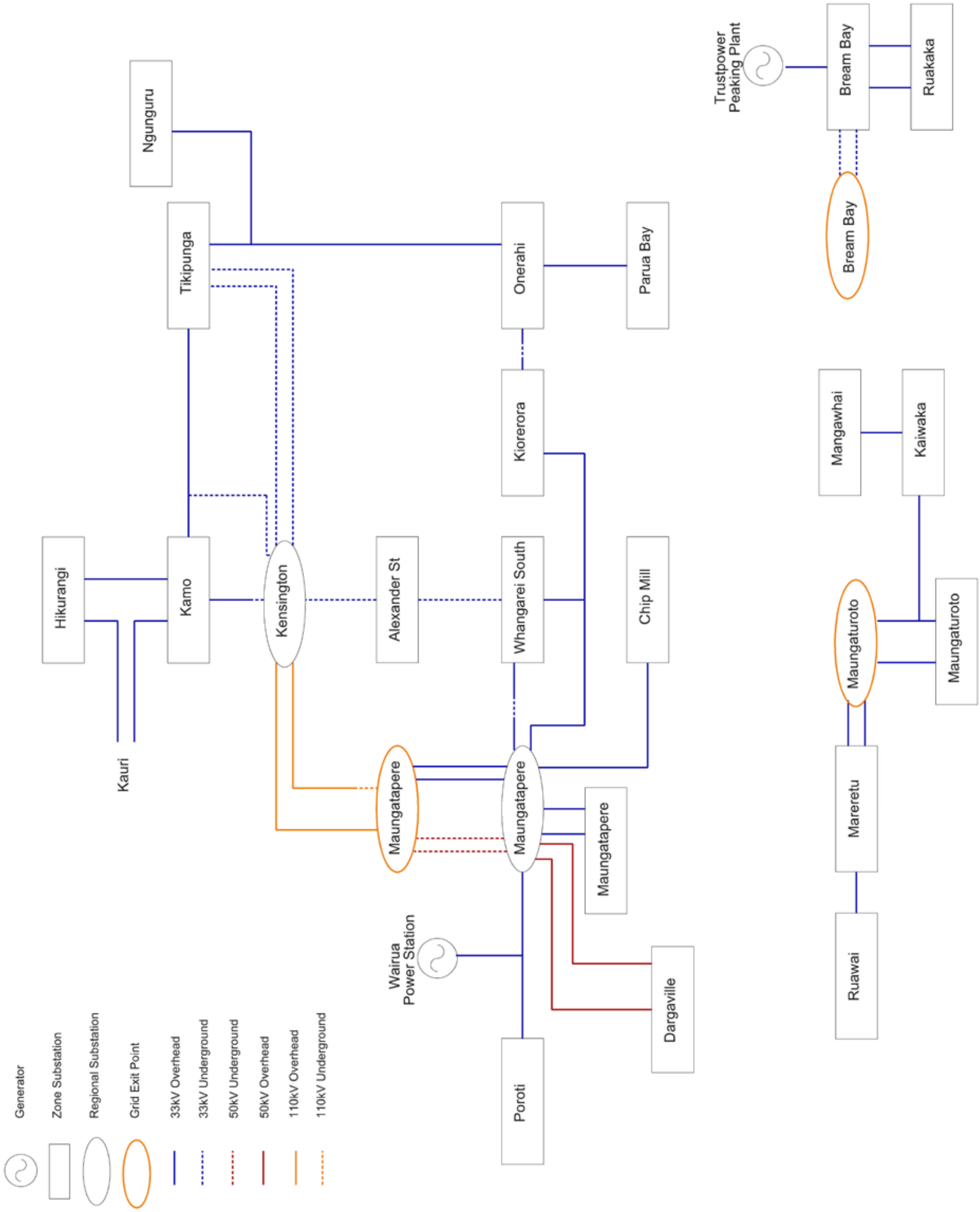
Northpower's Subtransmission network is shown schematically in the diagram below and comprises of regional substations and zone substations interconnected by110kV, 50kV and 33kV lines and cables.

A key feature of the sub-transmission network is a 33kV ring between Maungatapere and Kensington regional stations which allows load to be transferred between the 110/33kV transformer banks at these stations.

Northpower has one 50/11kV zone substation, eighteen 33/11kV zone substations and one dedicated 33/11kV substation (Chip Mill) which supplies an industrial load. Zone substations comprise of HV and MV bus bars, one or two step down transformers with on load tap changers, HV and MV switchgear, associated protection and tap change relays and SCADA remote terminal units.

With the exception of a number of large customers who are supplied directly at 33kV, electricity is distributed to customers via ninety-three 11kV feeders emanating from the zone substations. Some customers are supplied directly at 11kV but the majority are supplied via 11,000/415V distribution transformers (either pole or ground mounted) ranging in size from 5kVA to 1,000kVA.

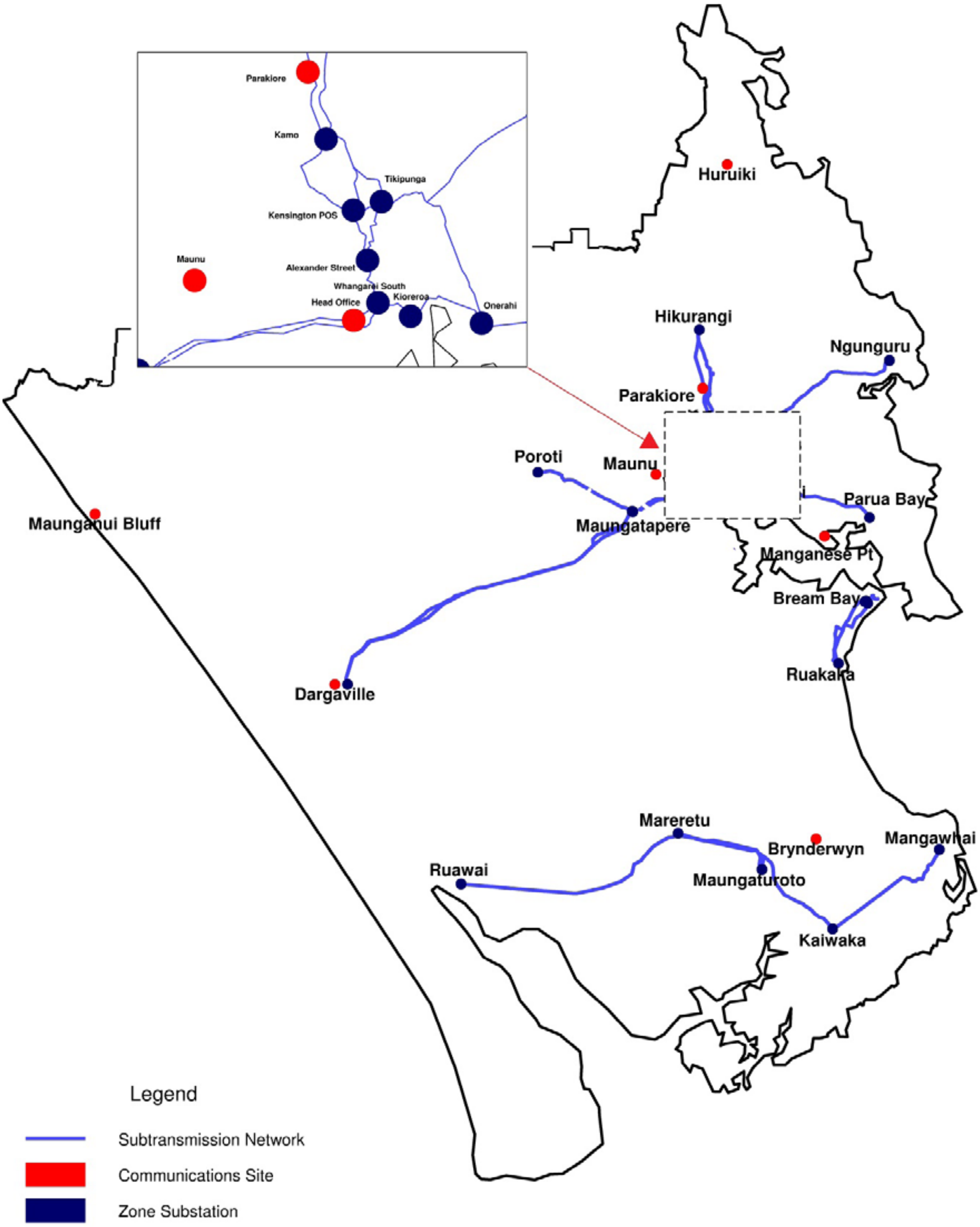
Detailed information on substation transformer capacity, loading and security of supply is provided in section 5.



Northpower Subtransmission Network Single Line Diagram

The map below shows the Northpower distribution area and geographical location of zone substations and communication sites. Section 5 contains maps showing the geographical areas serviced by each zone substations and its associated 11kV distribution feeders.

Most remote zone substations are fed by a single 33kV line with reasonable back-feeding capability on the 11kV network. Where back-feeding capacity is not adequate, mobile generation is used for voltage support and Northpower own a 500kVA purpose designed mobile generating system (including transformer) for this purpose.

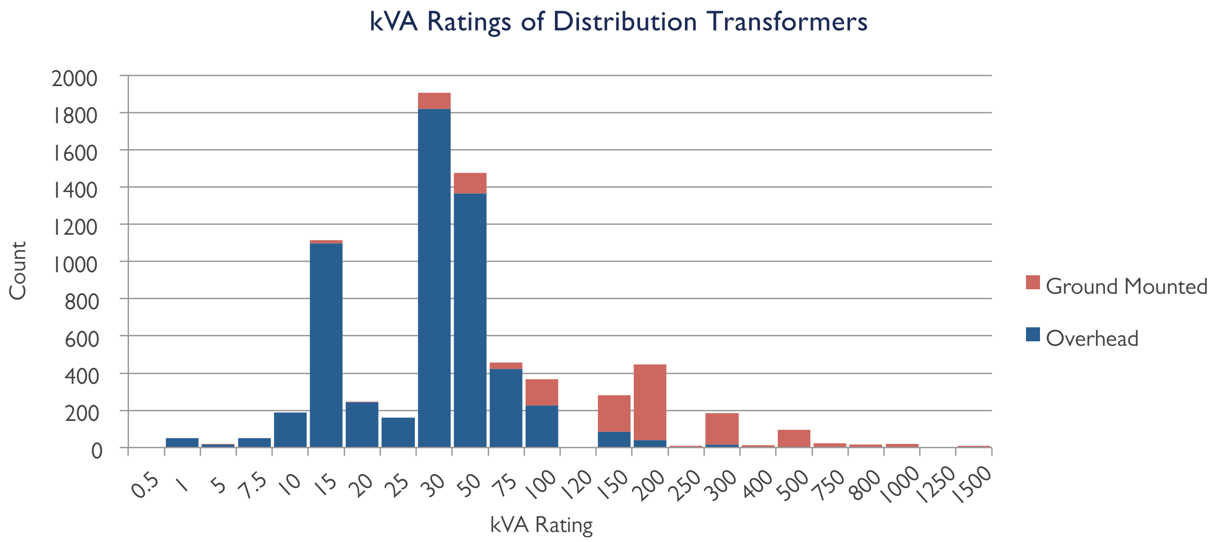


Northpower's Subtransmission Network Shown Geographically

3.2.3 Distribution Substations

Distribution substations comprise of an 11,000/415V transformer with an off-load tap changer, high and low voltage fuses, associated earth mats and in some cases high voltage surge arrestors. Fuses on the high voltage side of the transformer provide fault protection for the transformer. Fuses on the low voltage side provide both transformer overload and downstream fault protection for cables or lines.

Transformers with a rating exceeding 150kVA are normally ground mounted due to their weight and size. Transformers with a rating of 50kVA and below can be either 2 phase or 3 phase while those larger than 50kVA are all 3 phase. The number of customers supplied by a distribution substation typically range from 1 to 100. Shown below is Northpower's transformer's grouped by kVA rating and orientation. There are a large number of overhead 30/50kVA units in service due to the high proportion of overhead network.



kVA Ratings of Distribution Transformers

3.2.4 Low Voltage Network

The Northpower low voltage (LV) network is comprised of overhead lines and underground cables (feeders) operating at 400/230V. The LV feeders distribute power from distribution transformers connected to the 11kV network to consumers who are connected to the LV feeder via a service line or cable. In most cases this will be from poles or pillars near property boundaries. Each LV circuit is protected by fuses at the transformer and at (or as near as practical to) each customer point of supply (POS). Electricity meters and ripple relays or pilot control contactors (for control of water heating load) are generally located at the end of the service line or cable on the premises.

Where there are significant numbers of customers or where increased security of supply is required, the LV network is configured in a ring. Normally open links in the ring can be closed to allow an alternative supply should it be required. This type of arrangement is common in the central business district and residential areas.

The preference is for new network extensions to be underground in urban environments (this is a District Council policy requirement in the Whangarei urban area), however cost is a significant factor.

Description	Quantity (km)	Underground (km)	Overhead (km)
Low Voltage Lines 2015	1,837	637(34.7%)	1,200(65.3%)
Low Voltage Lines 2014	1,827	626 (34.3%)	1,201(65.7%)

Note: Northpower have been in the process of improving the data quality and correcting previous ownership issues. This explains the substantial changes to the quantities.

3.2.5 Secondary Assets

Metering equipment is located at strategic points to continuously measure, record and control (by way of ripple injection signals controlling hot water load relays) the Northpower network load on the Transpower transmission system.

Northpower's six ripple signal generation plants (located at Maungatapere, Tikipunga, Bream Bay, Maungaturoto, Dargaville and Ruakaka) transmit at 283Hz and inject into the 33kV network, except for 3 plants which inject into the 11kV network. Ripple control is used to manage GXP loadings by means of hot water and priority channel load control, street lighting, automatic load shedding and time of use metering.

The ripple system is also made available to the Northland Regional Council to use as a Tsunami warning system.

As Northpower is charged for reactive power demand which is supplied by Transpower, reactive power compensation (power factor correction) in the form of fixed capacitor banks are utilised. At present Northpower has 19 x 750kVAr, 5 x 150kVAr and 2 x 200kVAr (switched) capacitor banks (total 15.6MVAr) connected to the network and more will be installed in future as the load grows to manage the reactive power imported from the national grid.

Northpower owns a 500kVA mobile diesel generator (with associated 400/11,000V transformer) which is used to reduce the number of planned maintenance and fault shutdowns on the 11kV network. The purchase of larger 1MVA machines is being investigated for use at zone substations. Similarly, 400V generators are used on the low voltage network to maintain supply to customers where possible.

Northpower operates a supervisory control centre in Whangarei, which is attended 24 hours a day. A state of the art SCADA system continuously monitors load pulses, alarms and indication from equipment in the 33/11kV zone substations as well as reclosers, sectionalisers and switches on the network. This equipment, as well as street lighting and all load-shedding plant, are under direct supervisory control. In addition to this, load pulses, alarms and indication of the state of outgoing circuit breakers at the five GXP's are returned to the Control Centre via the SCADA system.

The communications network makes use of microwave, UHF and VHF radio links, as well as copper and optical fibre cable links.

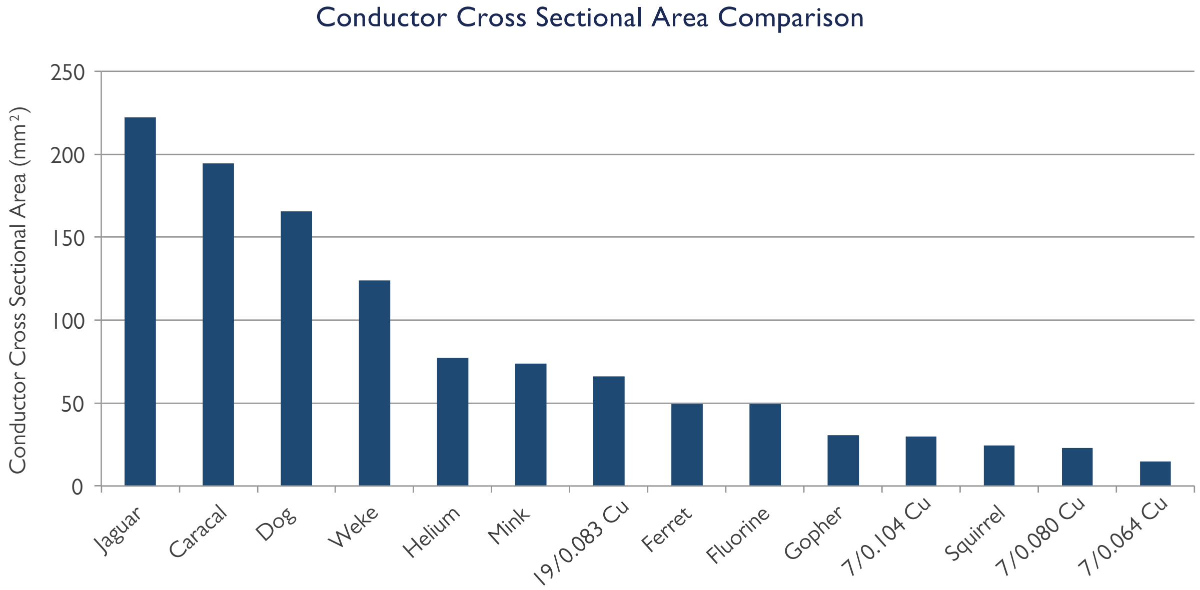
3.3 Network Assets

Notes: 1) Where the word 'fair' is used to describe the condition of an asset or group of assets, the term is used in the context of good, fair, poor (or new, mid-life, end of life)

2) Northpower has an ongoing data improvement program. When asset age data is invalid or nonexistent then associated assets are used to determine a possible age. If this technique fails then a default value is used and this is highlighted in associated graphs.

3.3.1 Sub Transmission Overhead Lines

The following chart details the conductor cross sectional areas for reference.



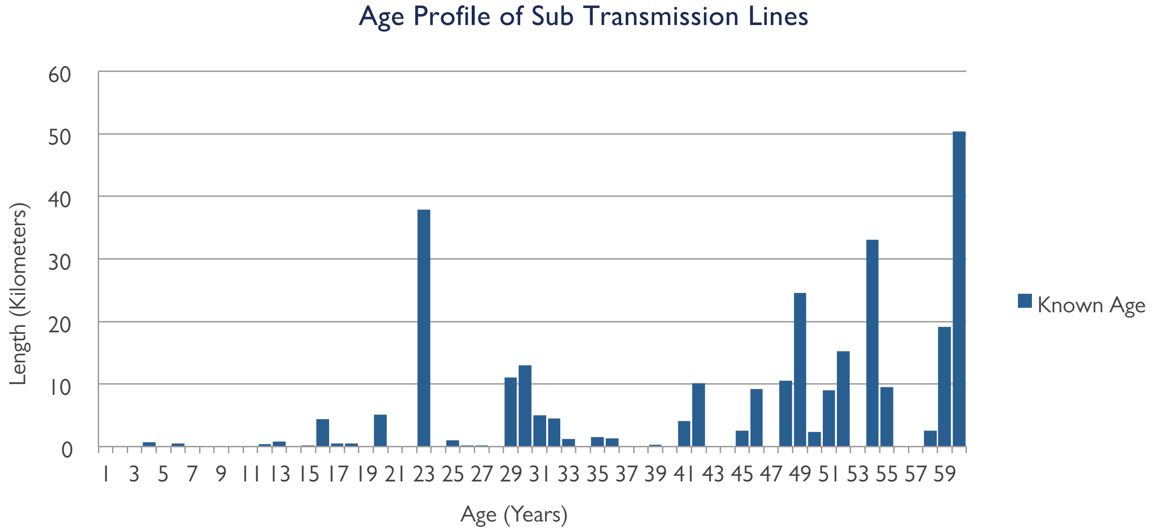
Conductor Size Comparison

3.3.1.1 Description of Asset

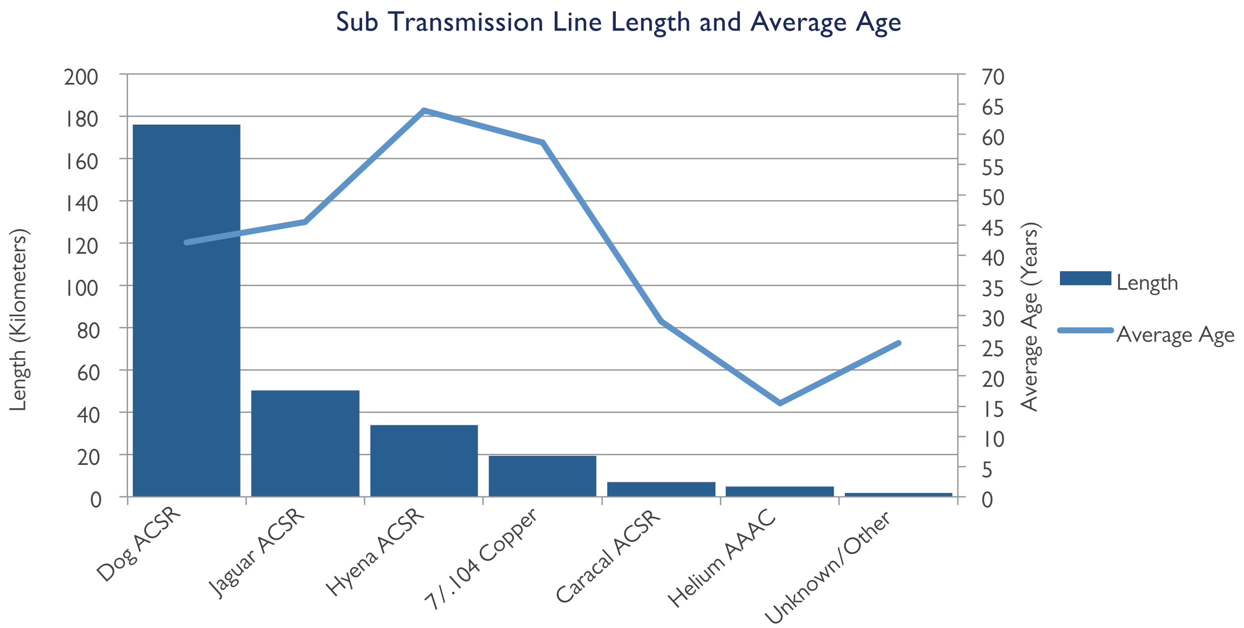
Description	Quantity (km) in 2015	Quantity (km) in 2014
Subtransmission lines	298	293

Electricity is transmitted at high voltages to reduce the energy lost in long distance transmission. The sub-transmission network connects the GXP's to the zone substations. Further interconnections may exist with sub-transmission lines or cables between zone substations. Northpower's sub-transmission network is operated at 110kV, 50kV and 33kV. The 298km of line is made up of three wires of conductor varying in size from Jaguar ACSR to Helium AAC.

3.3.1.2 Age Profile



Sub Transmission Lines Age Profile



Sub Transmission Lines Length/Age by Conductor Type

3.3.1.3 Condition

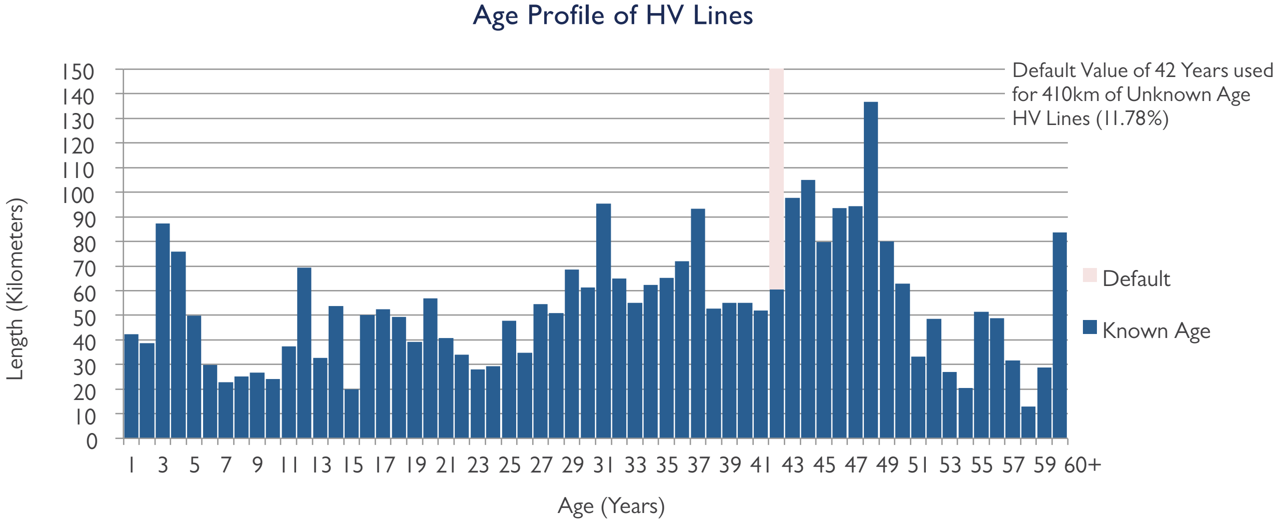
The condition of the sub-transmission network varies between fair to good. Regular preventative maintenance inspections which include a helicopter patrol of the lines provide regular condition assessments and follow up maintenance is carried out with some urgency given the strategic importance of this portion of the network.

3.3.2 HV Overhead Lines

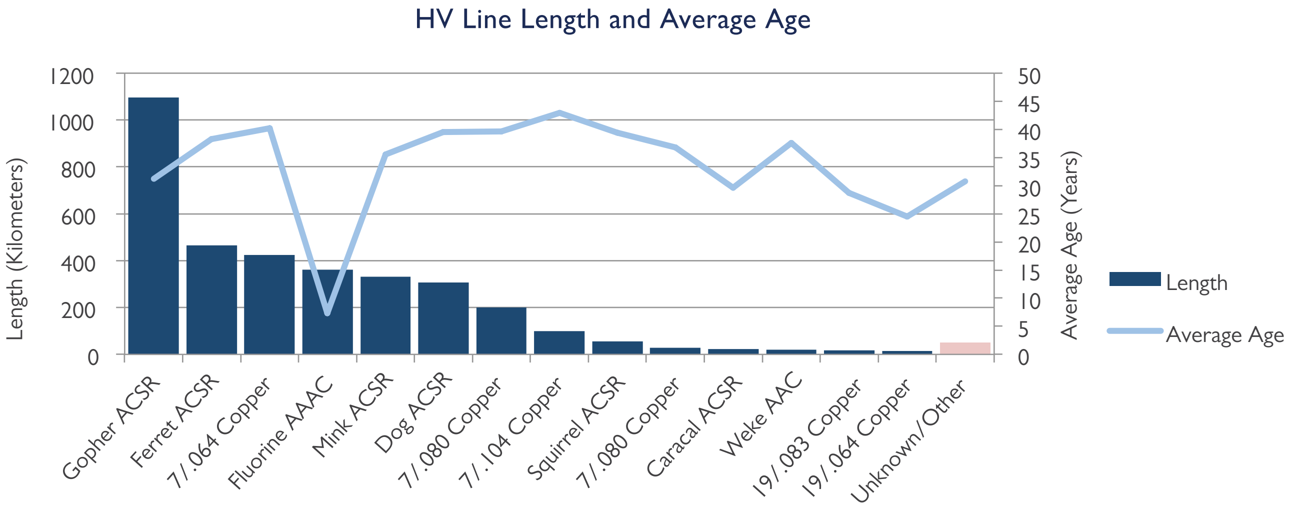
3.3.2.1 Description of Asset

Description	Quantity (km) in 2015	Quantity (km) in 2014
High Voltage Lines	3,497	3,500

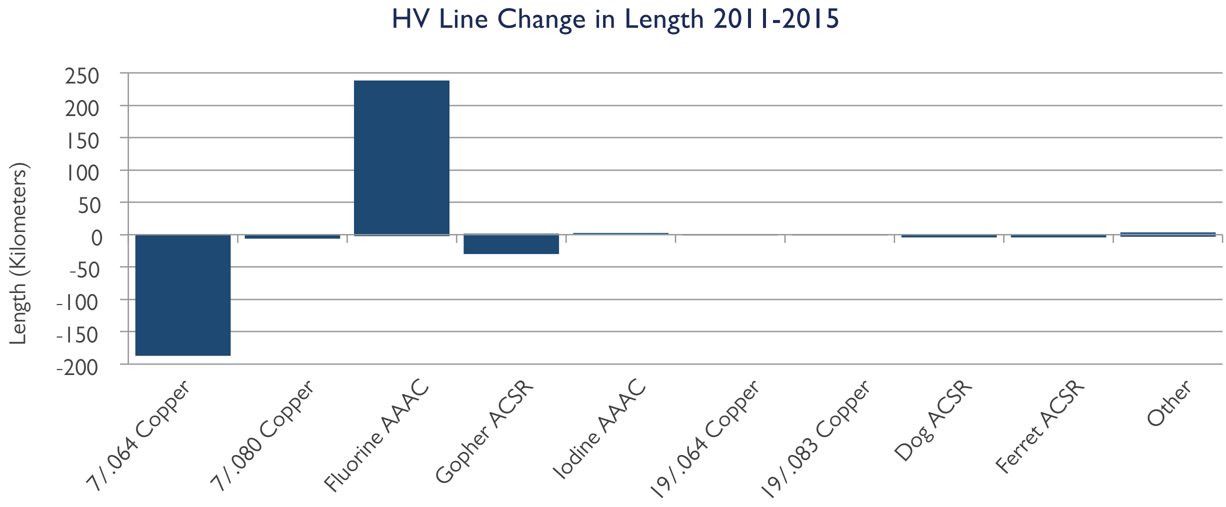
3.3.2.2 Age Profile



HV Lines Age Profile



HV Lines Length/Age by Conductor Type



HV Lines Change in Length 2014-15 by Conductor Type

The reduction in copper and ACSR conductor and increase in AAAC conductor is due to an ongoing conductor replacement program (replacement of 7/.064 copper and ACSR Gopher)

3.3.2.3 Condition

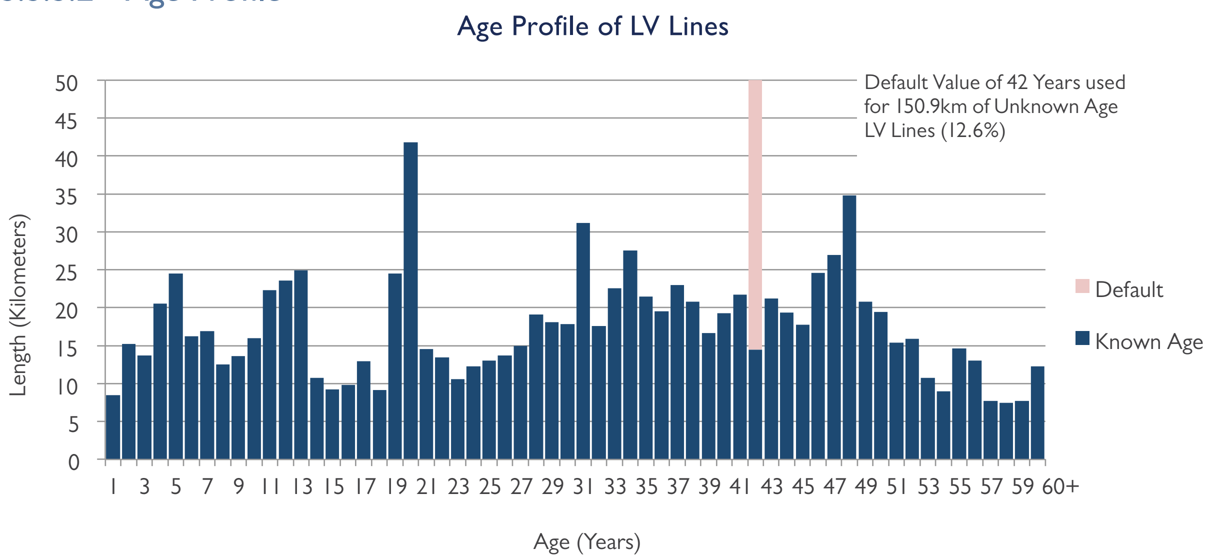
The average condition of these assets is fair

3.3.3 LV Overhead Lines

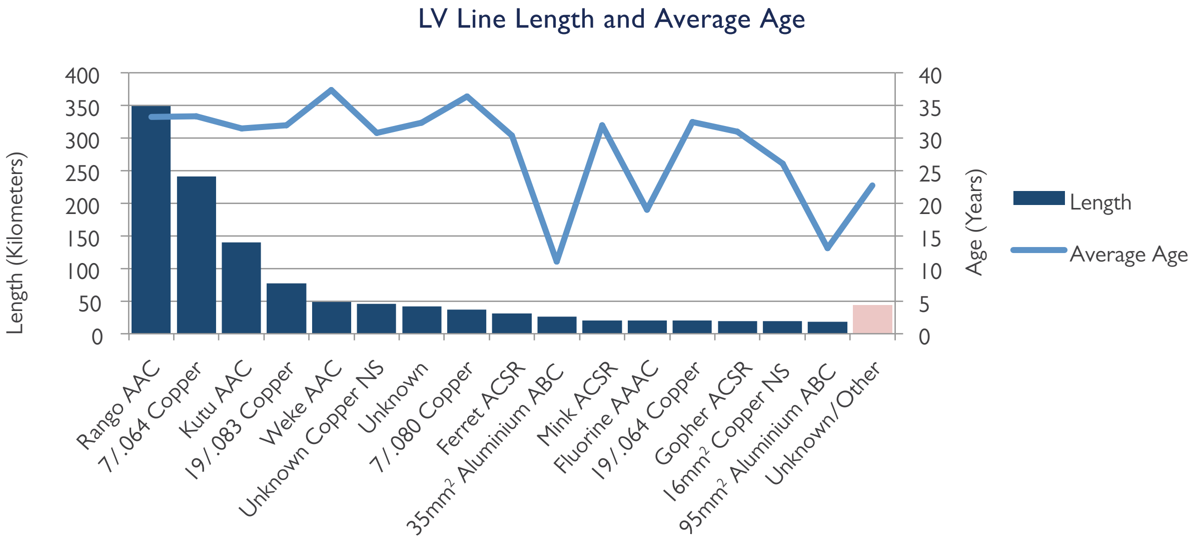
3.3.3.1 Description of Asset

Description	Quantity (km) in 2015	Quantity (km) in 2014
Low Voltage Lines	1,200	1,201

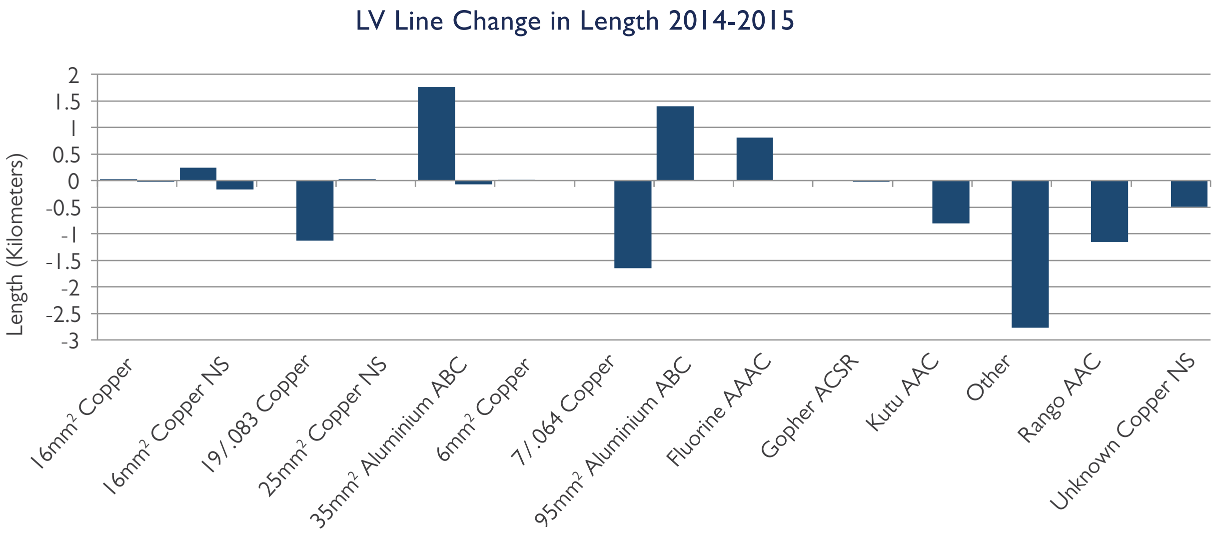
3.3.3.2 Age Profile



LV Lines Age Profile



LV Lines Length/Age by Conductor Type



LV Lines Change in Length 2014-15 by Conductor Type

3.3.3.3 Condition

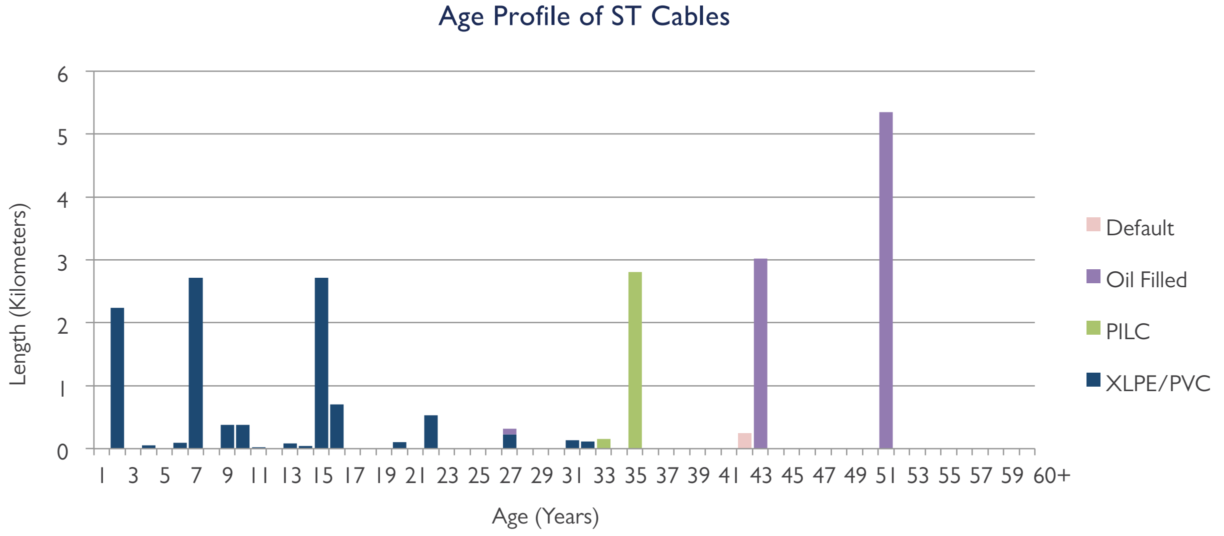
The LV network is in many places contiguous with the HV network. The age profile and condition therefore is very similar to that of the HV network, similar inspection and maintenance regimes are applied for corresponding improvements in performance. A program of works comparable to that of the HV network is to be undertaken on the LV network.

3.3.4 Underground Sub Transmission Cable

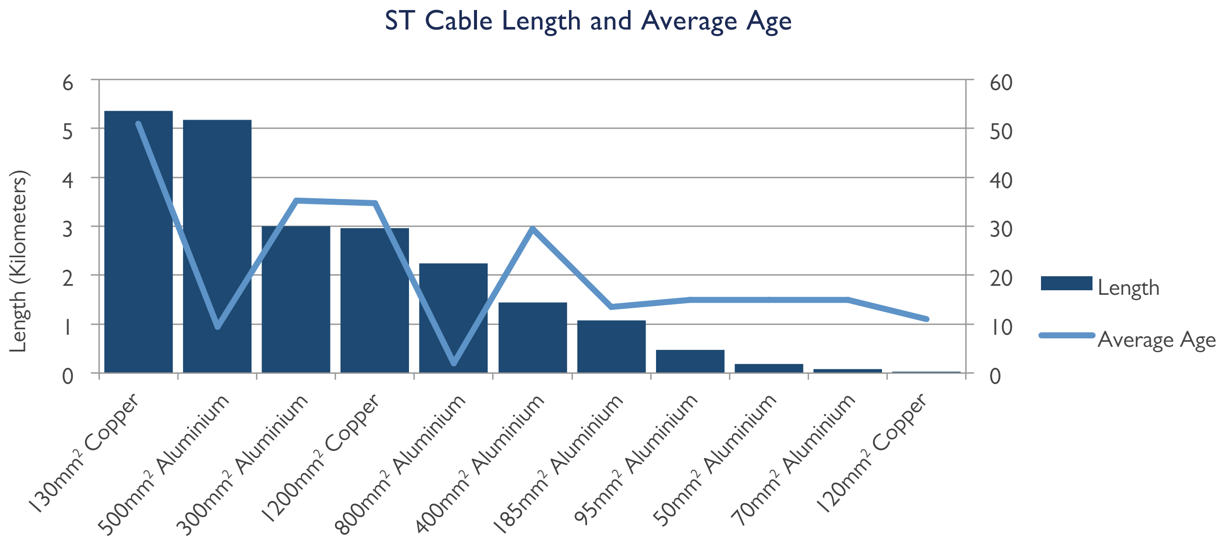
3.3.4.1 Description of Asset

Description	Quantity (km) in 2015	Quantity (km) in 2014
Subtransmission cables	22.2	19.9

3.3.4.2 Age Profile by Insulation Type



Sub Transmission Cables Age Profile



Sub Transmission Cable Length/Age by Conductor Type

3.3.4.3 Condition

The sub-transmission cable routes are also regularly patrolled and checked for any excavation or fill activity and to ensure access is maintained in the event of a cable fault. Sub-transmission cable condition has been assessed as good to fair. The cables are also tested on a 3 yearly cycle. Standard electrical testing is carried out by Northpower's contractors and PDC (Polarisation/Depolarisation and Partial Discharge) tests are carried out by a consultant engineer involving the use of specialist equipment. This ensures that the integrity or rating of the system has not been compromised.

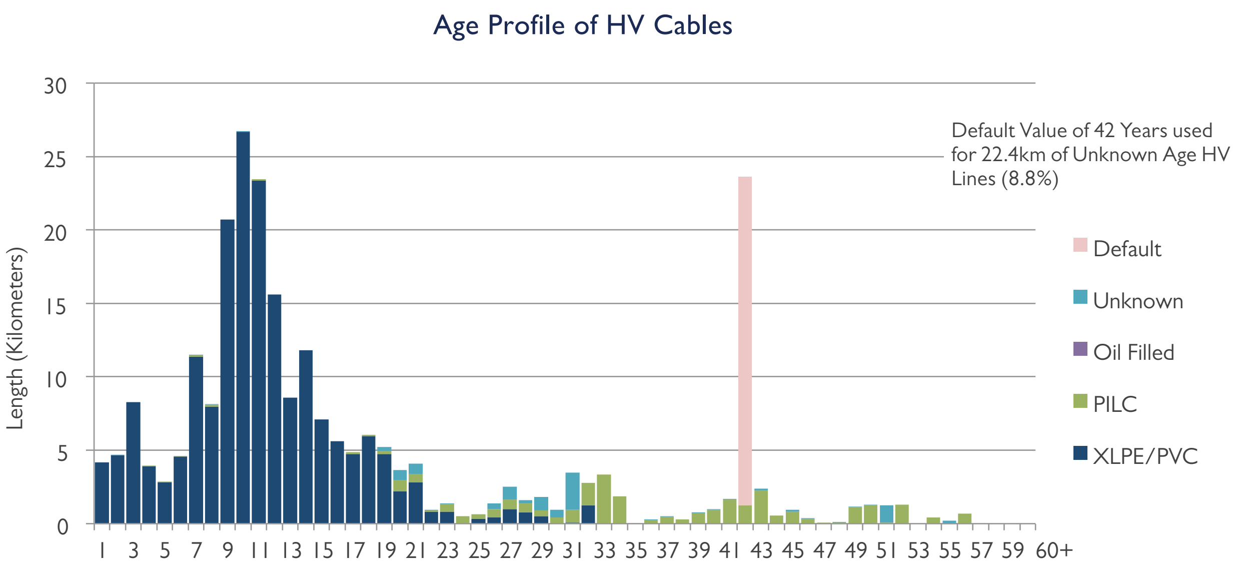
3.3.5 Underground HV cables

3.3.5.1 Description of Asset

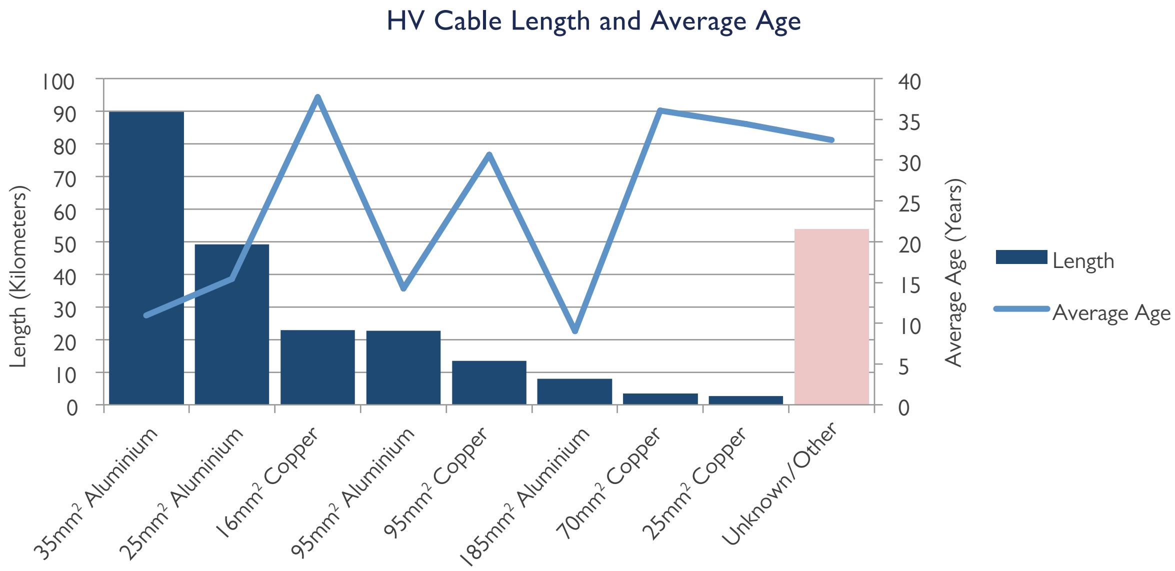
Description	Quantity (km) in 2015	Quantity (km) in 2014
High Voltage Cables	253	248

The type of underground cable used on Northpower's network has varied over time. Typically for HV cables it was common for paper insulated lead covered (PILC) multi-core with copper conductors to be installed. As gains were made in manufacturing technology, cross linked polyethylene (XLPE) cables became more prevalent. These cables were either single or multi-core and had copper or aluminium conductors.

3.3.5.2 Age Profile by Insulation Type



HV Cables Age Profile



HV Cable Length/Age by Conductor Type

3.3.5.3 Condition

The average condition of these assets varies from fair to good.

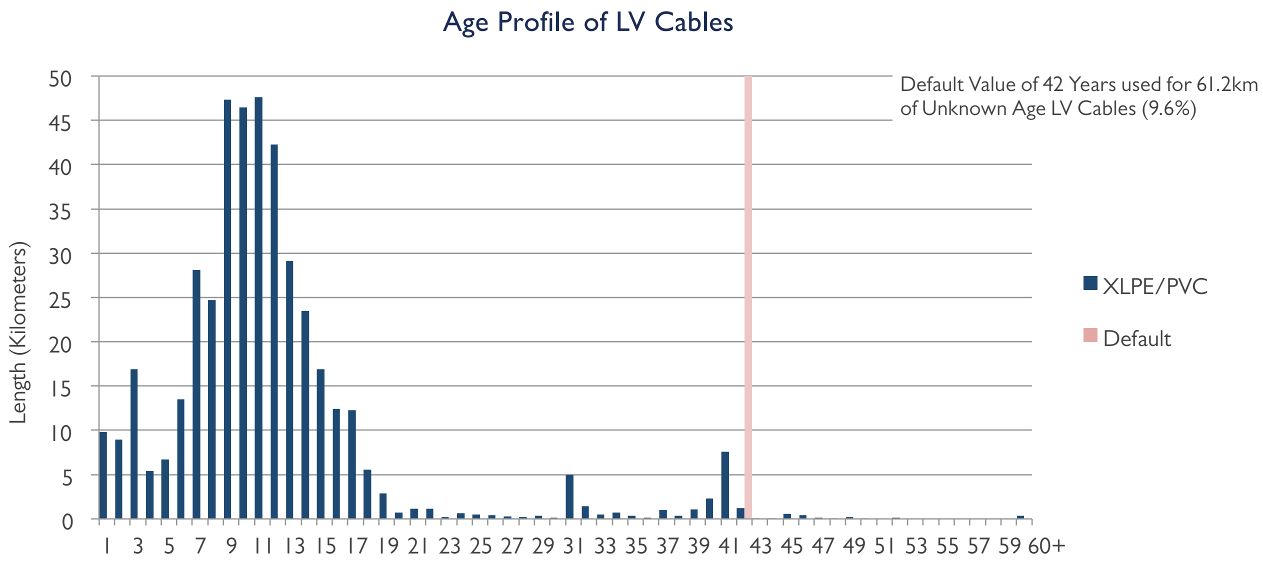
3.3.6 Underground LV cables

3.3.6.1 Description of Asset

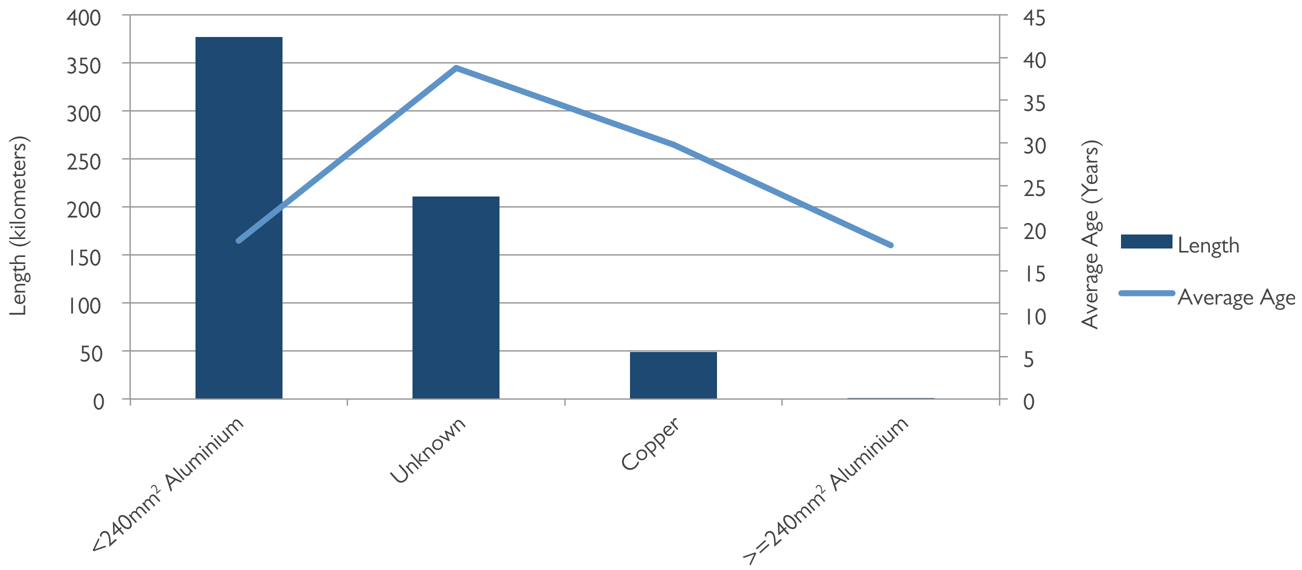
Cables on the LV network consist of single core PVC sheathed cables with either aluminium or copper conductors typically run inside a PVC duct. Latterly XLPE sheathed sector cables have been used. These cables typically have aluminium conductors.

Description	Quantity (km) in 2015	Quantity (units) in 2014
Low Voltage Cables	637	626

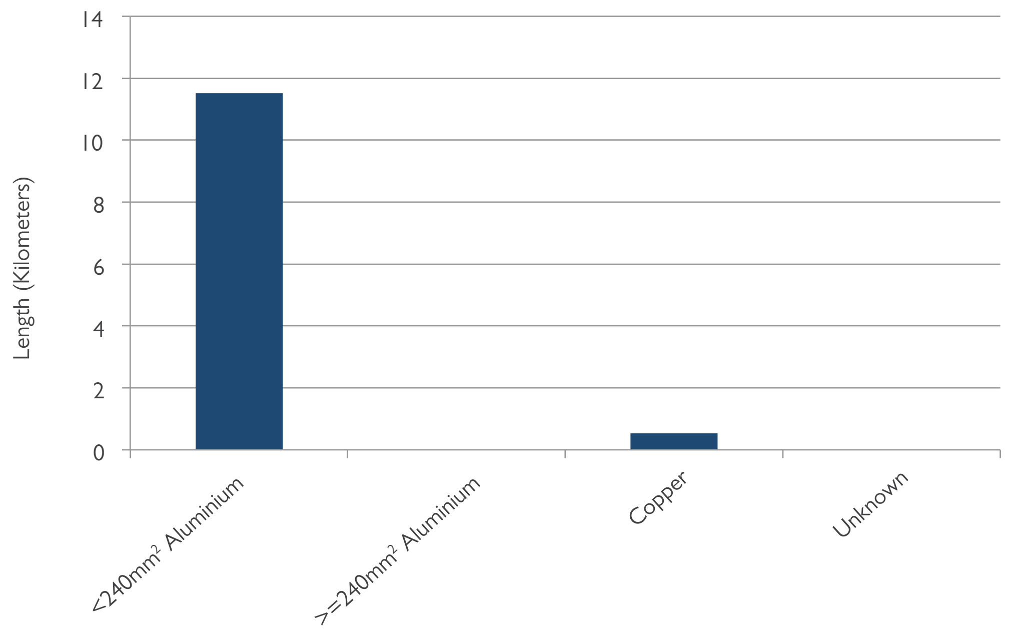
3.3.6.2 Age Profile by Insulation Type



LV Cables Age Profile



LV Cable Length/Age by Conductor Type



LV Cable Change in Length 2014-15 by Conductor Type

3.3.6.3 Condition

As with the 11kV cables, the 400V cables have proven to be very reliable. Failures, when they do occur tend to be at terminations or joints. The expected life of 45 years is applied to this asset category. Underground "tee" joints are showing an increasing incidence of failure due to an ingress of moisture through the epoxy joint; the volume of faults is however being closely monitored. There is nothing to suggest that it is a widespread issue and replacement occurs as a result of failure or in conjunction with other work on the asset.

Typically the life of older paper insulated lead cable can be extended if undisturbed. However cable risers, terminations and joints are more prone to failure than the cable itself.

3.3.7 Poles

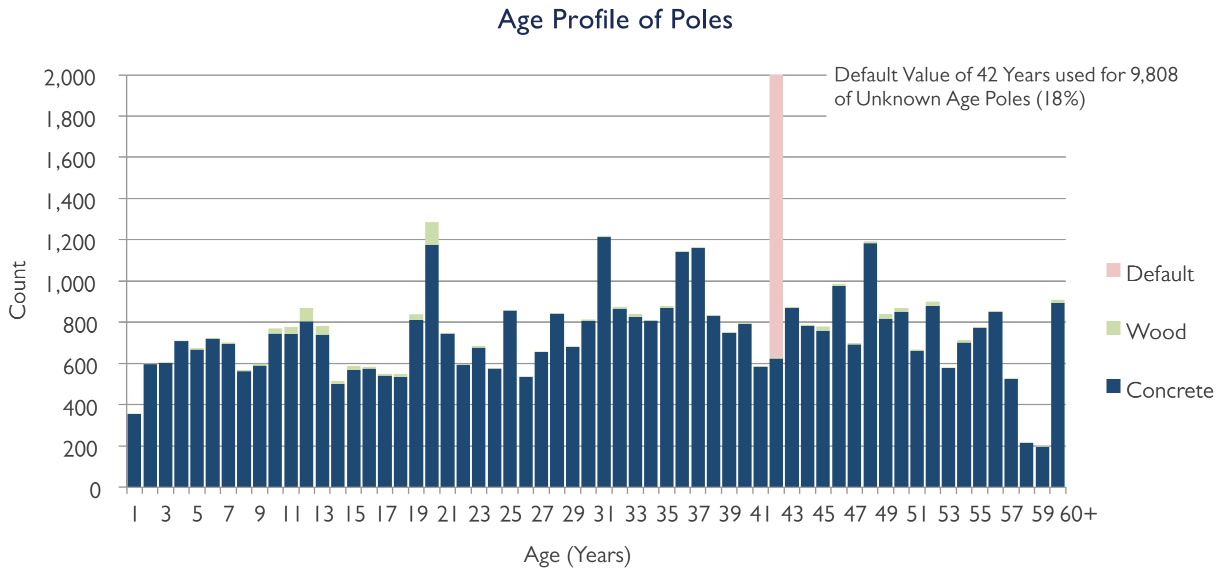
3.3.7.1 Description of Asset

Description	Quantity (Units) in 2015	Quantity (units) in 2014
Wood	1,602	1,640
Concrete	52,766	52,800
Steel	2	2

Northpower's distribution of overhead conductor is supported predominately by Concrete poles produced from Northpower's pole factory or latterly by BUSCK Industries. The wooden poles in use on the network are largely hardwood.

The crossarms used to separate and support the insulators/conductors are typically 100mm x 75mm hardwood on the HV network and 75 x 75mm hardwood on the LV network. The crossarms vary in length depending on the pole spacing to provide sufficient conductor spacing. Northpower is in the process of trialling a custom designed galvanised steel cross arm and intends introducing this as the standard HV crossarm on the Northpower Network with the goal of achieving a longer asset life together with more detectable modes of failure.

3.3.7.2 Age Profile



Poles Age Profile

3.3.7.3 Condition

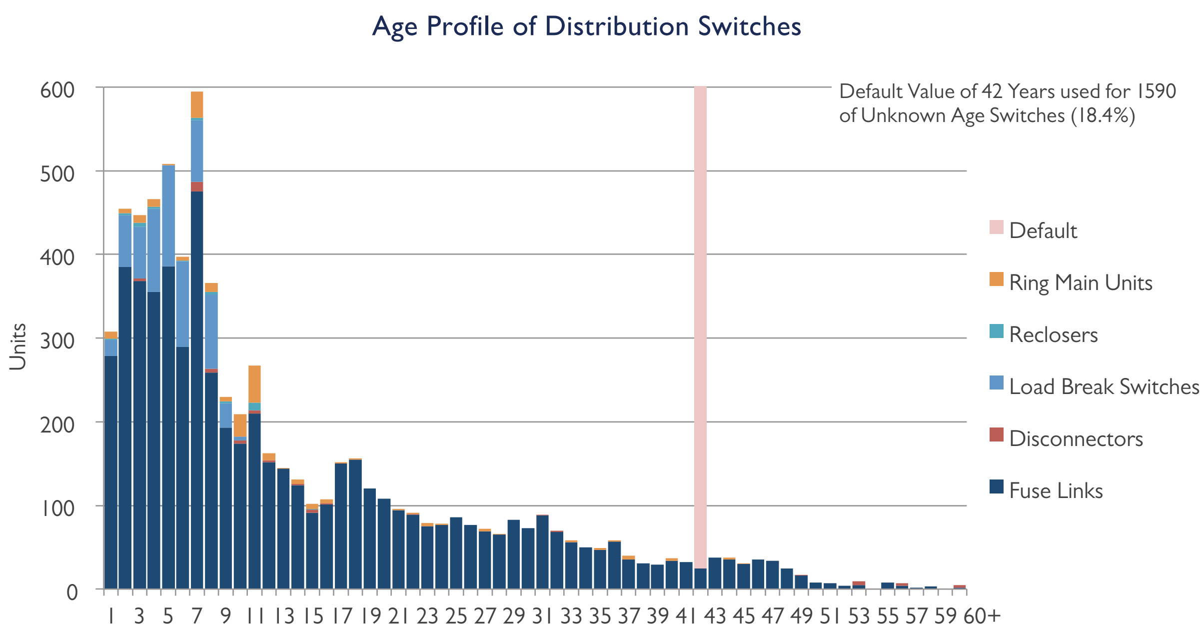
The average condition of these assets is fair but there are a large number of old poles which are in relatively poor condition

3.3.8 Distribution Switchgear

3.3.8.1 Description of Asset

Description	Quantity (units) in 2015	Quantity (units) in 2014
Disconnectors	203	214
Load Break Switches	662	648
Fuse links (sets)	7,553	7,507
Reclosers	29	27
Ring Main Units	216	208

3.3.8.2 Age Profile



Distribution Switches Age Profile

3.3.8.3 Condition

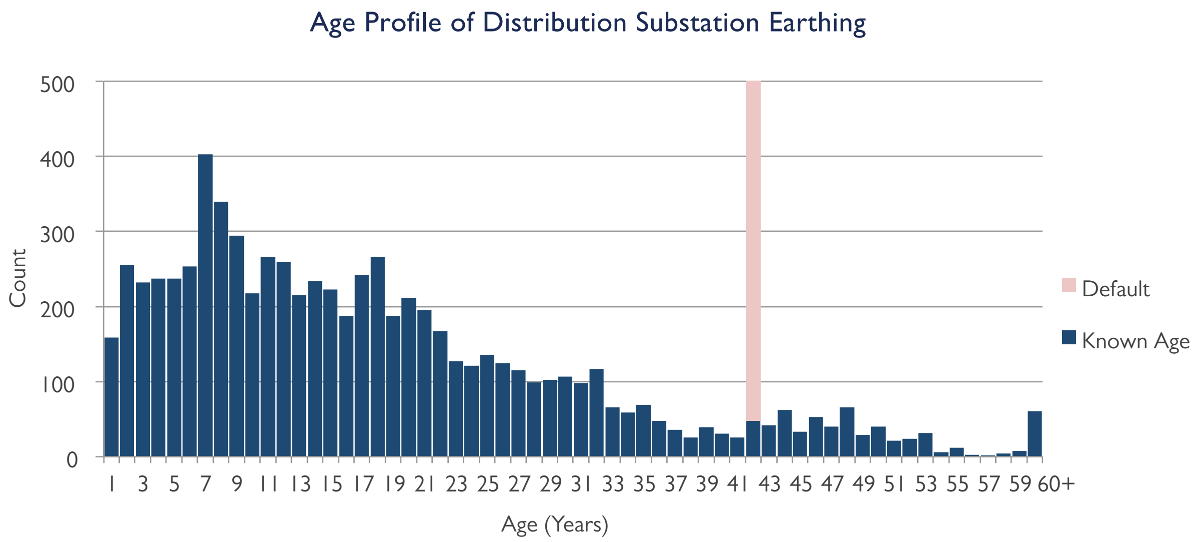
The average condition of these assets is fair to good but there is a significant number that have reached EOL and are in relatively poor condition

3.3.9 Distribution Earthing

3.3.9.1 Description of Asset

Description	Quantity (units) in 2012	Quantity (units) in 2011
Distribution earthing	8,897	8,731

3.3.9.2 Age Profile



Distribution Substation Earthing Age Profile

3.3.9.3 Condition

The average condition of these assets is fair to good but there are a significant number in poor condition

3.3.10 Voltage Regulators

3.3.10.1 Description of Asset

Description	Quantity (units) in 2015	Quantity (units) in 2014
Regulator Stations	4	4

An automatic voltage regulator is a tap changer equipped autotransformer that maintains the voltage level within a certain range, regardless of the load variations. The units in place on the network are typically on long, predominantly rural feeders that have a relatively high load characteristic.

As with other network hardware, there have been a number of different manufacturers who have supplied this type of equipment to Northpower. Units manufactured by McGraw Edison and Turnbull and Jones are currently in use.

3.3.10.2 Age Profile

Of the 4 regulator stations 1 is 11 years old, 1 is 16 years old and the other 2 are 44 years old.

3.3.10.3 Condition

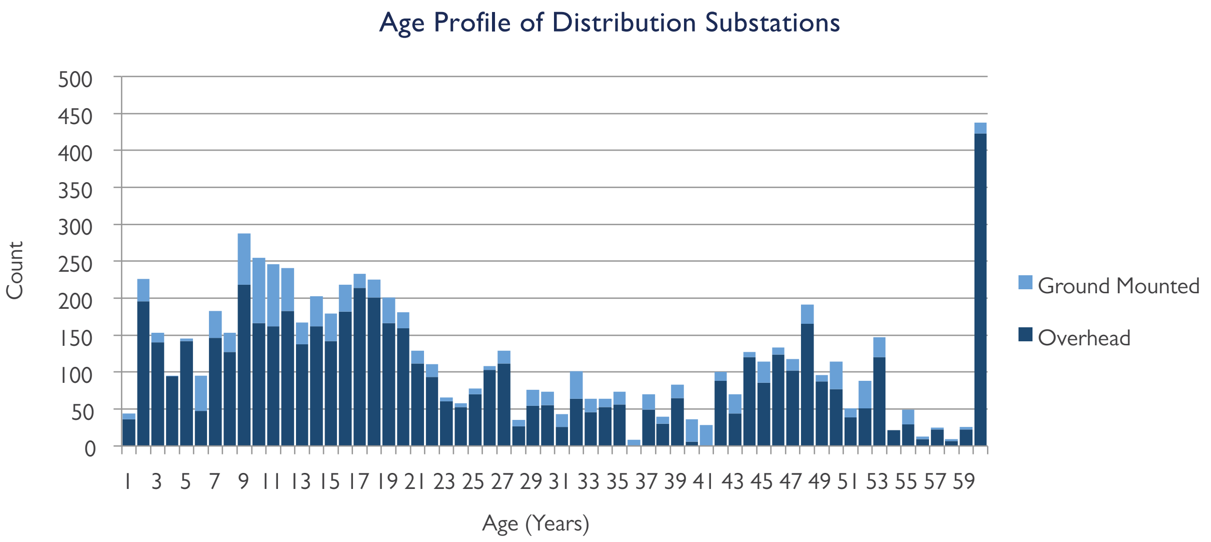
Given the low numbers of assets in this category, condition monitoring is uncomplicated. The overall condition of these units is considered to be good and the 55 year expected life should be achievable.

3.3.11 Distribution Substations/Transformers

3.3.11.1 Description of Asset

Description	Quantity (units) in 2012	Quantity (units) in 2011
Pole Mount	5,693	5,663
Ground Mount	1,307	1,296

3.3.11.2 Age Profile



Distribution Substations Age Profile

3.3.11.3 Condition

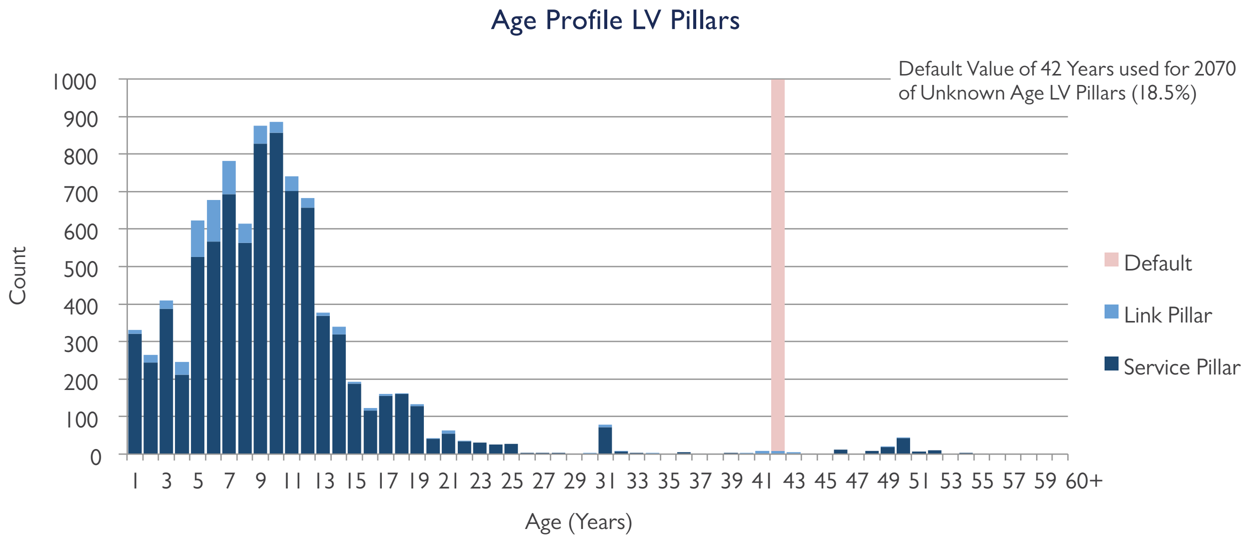
The average condition of these assets is fair but there are a significant number of old assets in relatively poor condition

3.3.12 Low Voltage Pillars

3.3.12.1 Description of Asset

Description	Quantity (units) in 2012	Quantity (units) in 2011
Link Pillar	525	761(659)*
Service Pillar	9,810	9,403 (12,759*)

3.3.12.2 Age Profile



LV PIllars Age Profile

3.3.12.3 Condition

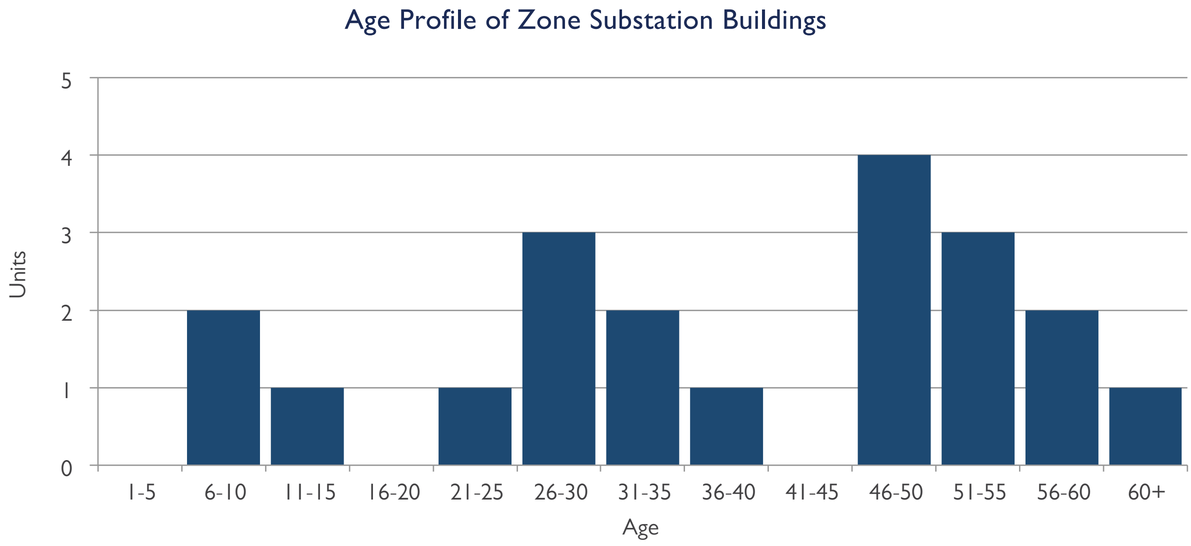
A visual inspection of all service pillars is undertaken on a biennial cycle and annually for the link pillars. The visual inspection identifies any safety issues which are remedied in a timely manner. Overall the condition of the pillars is fair. A number of the older concrete type pillars have been identified as having a potential safety issue due to moisture which can cause tracking and potentially liven the concrete. The steel plate and frame is unearthed and if physically damaged could become live.

3.3.13 Zone Substation Sites

3.3.13.1 Description of Asset

Description	Quantity (units) in 2012	Quantity (units) in 2011
Zone Substation Land	18	18
Zone Substation/GXP Buildings	22	22

3.3.13.2 Age Profile



Zone Substation Buildings Age Profile

3.3.13.3 Condition

Monthly inspections of the zone substation buildings and equipment ensure that they are maintained in an overall good condition. Although the standard life for buildings is assumed to be 50 years, buildings that are regularly maintained tend to last significantly longer than that. Given the construction techniques employed in the buildings, the preventative maintenance inspections and the follow up maintenance undertaken as a result of the inspections, it is anticipated that most of the zone substation buildings will remain serviceable longer than the standard lifespan (as evidenced by the number of buildings that are older than 50 years).

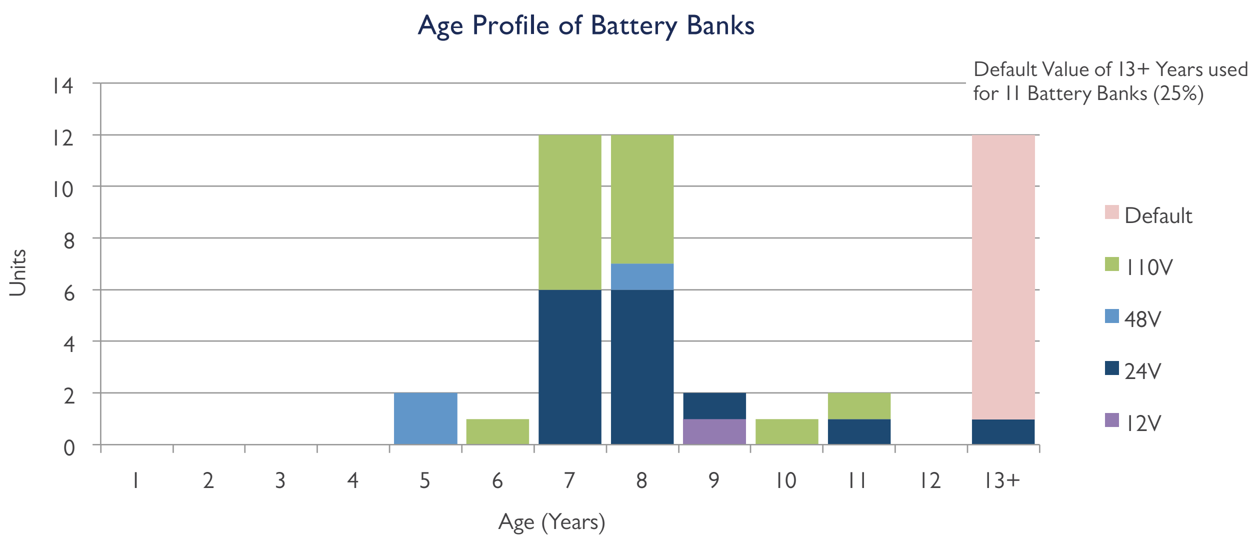
3.3.14 Zone Substation Battery Banks

3.3.14.1 Description of Asset

Description	Quantity (units) in 2015	Quantity (units) in 2014
110V Battery Bank	18	18
48V Battery Bank	6	6
24V Battery Bank	17	17
12V Battery Bank	3	3

All zone substations contain a series of 9 x 12V lead acid batteries providing an 110V DC supply. This supply is used to operate certain components of both the 33kV and 11kV circuit breakers such as closing coils, tripping coils and spring release charging motors as well as transformer tap changer motors.

3.3.14.2 Age Profile



Age Profile of Battery Banks

3.3.14.3 Condition

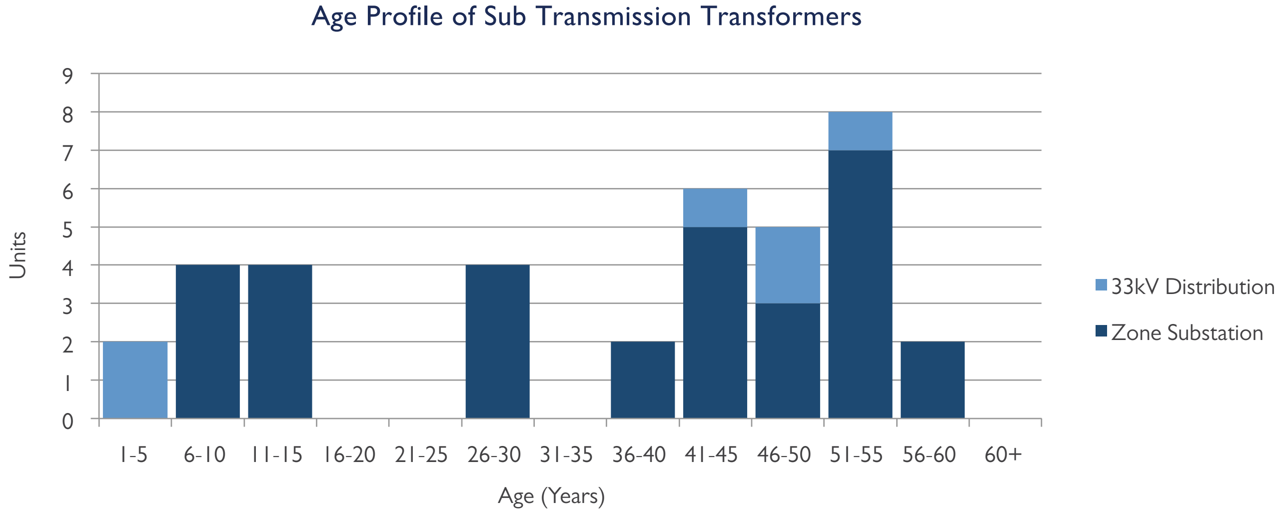
The average condition of these assets is fair to good

3.3.15 Zone Substation Transformers and Tap Changers

3.3.15.1 Description of Asset

Description	Quantity (units) in 2015	Quantity (units) in 2014
Transformers + OLTC	37	33

3.3.15.2 Age Profile



Sub Transmission Transformers Age Profile

3.3.15.3 Condition

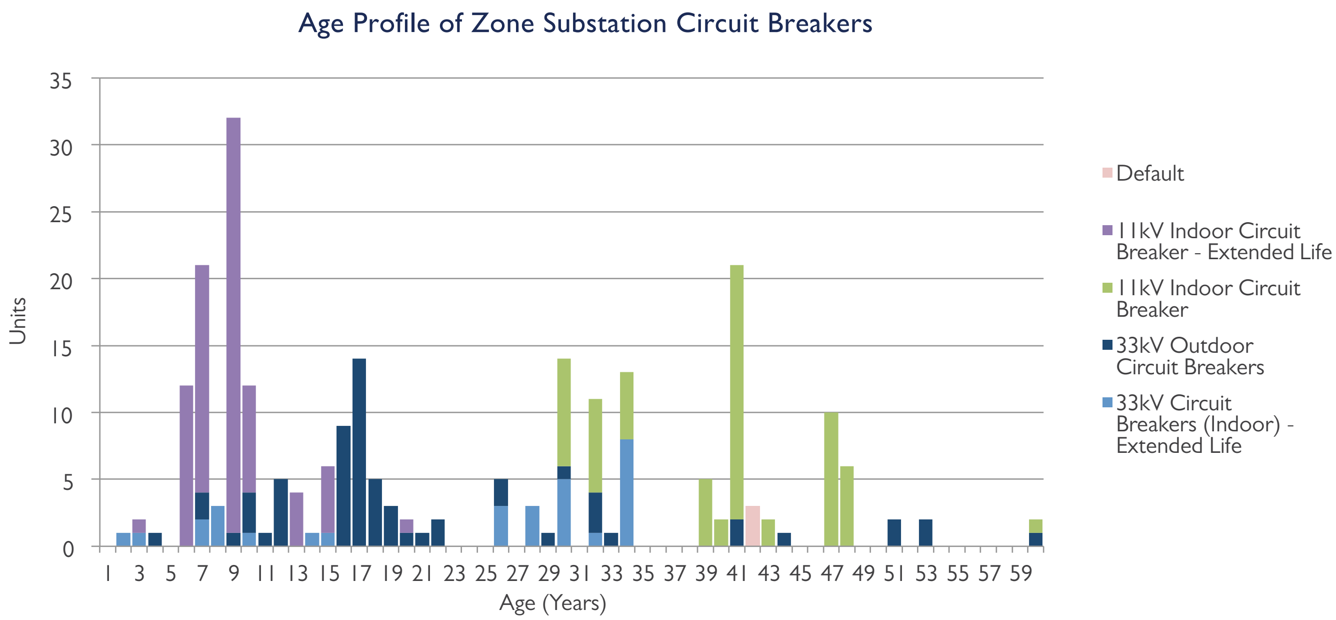
The average condition of these assets fair to good but there are a number of EOL units that are in a relatively poor condition

3.3.16 Circuit Breakers

3.3.16.1 Description of Asset

Description	Quantity (units) in 2015	Quantity (units) in 2014
Indoor circuit breakers	144	143
Outdoor circuit breakers	95	95
Isolators/switches	195	195

3.3.16.2 Age Profile



Circuit Breaker Age Profile

3.3.16.3 Condition

The average condition of these assets is fair to good although there are a number of EOL units which are scheduled for replacement

3.3.17 Zone Substation Earthing

3.3.17.1 Description of Asset

Description	Quantity (units) in 2015	Quantity (units) in 2014
Zone Substation Earthing	20	20

Age Profile

As the earth mat was installed at the time of the construction of the zone substation, the age profile is the same as that of the zone substation.

3.3.17.2 Condition

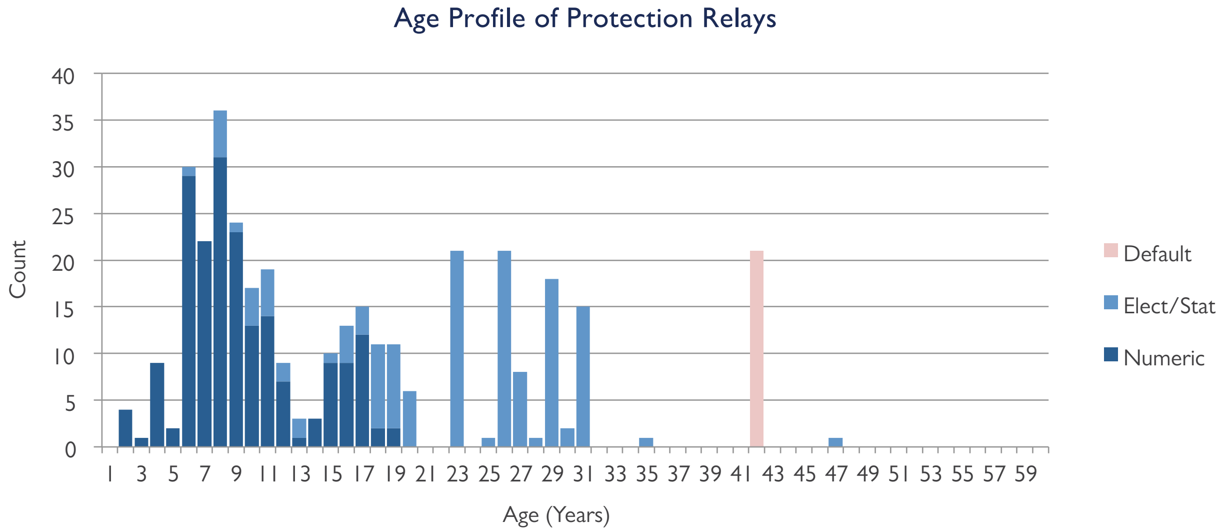
The preventative maintenance inspections and any follow up maintenance undertaken as a result of the inspections have maintained the condition of the zone substation earthing as good.

3.3.18 Protection Relays

3.3.18.1 Description of Asset

Description	Quantity (units) in 2015	Quantity (units) in 2014
Numeric Relays	198	194
Electric/Static Relays	157	157

3.3.18.2 Age Profile



Protection Relays Age Profile

3.3.18.3 Condition

The average condition of these assets is fair to good with older electro-mechanical relays gradually being replaced

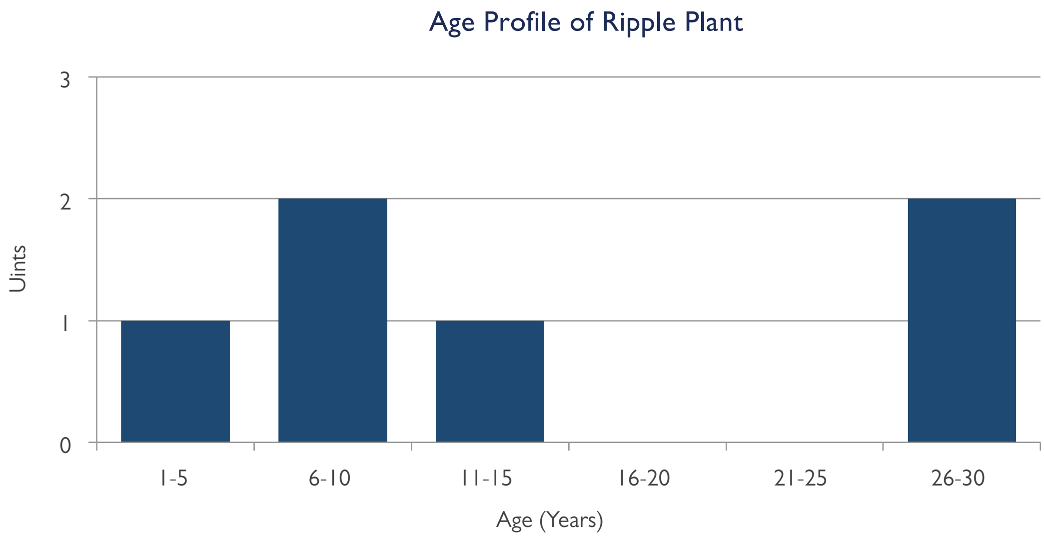
3.3.19 Ripple Plant

3.3.19.1 Description of Asset

Description	Quantity (units) in 2015	Quantity (units) in 2014
Ripple injection plants	6	6

Of the 6 plants 3 inject at 33kV (Maungaturoto, Tikipunga, Maungatapere zone substations) and 3 at 11kV (Dargaville, Ruakaka, and Bream Bay zone substations). All 6 ripple plants are static type using a 283Hz injection frequency. Each ripple plant consists of a coupling cell, transmitter and control system.

3.3.19.2 Age Profile



Age Profile of Ripple Plant

3.3.19.3 Condition

Ripple plant equipment is static so the average asset life can be fairly long. However end of life can be considered to be reached when the technology is no longer supported. One of the older plants is currently scheduled to be replaced.

3.3.20 SCADA and Communications

3.3.20.1 Description of Asset

Description	Quantity (units) in 2015	Quantity (units) in 2014
Zone Substation RTU's	26	26
Radio Stations	37	37

3.3.20.2 Age Profile

Due to the nature of the electronic hardware and changes in technology, the SCADA system together with the associated radio stations and remote terminal units have a wide spread of age profiles.

3.3.20.3 Condition

The condition of these assets is fair to good with an ongoing program to replace older assets currently underway

3.4 Supporting and Secondary Systems

3.4.1 Metering Systems

3.4.1.1 Power Quality Metering

Power quality metering is installed at key substations to monitor and record system waveform and voltage disturbances (sags, swells and other transient phenomena) as well as voltage and current harmonic distortion

3.4.1.2 Revenue Metering

Revenue metering (including check metering) is installed at Transpower GXP supply points to record energy delivered to the Northpower network from the national grid

3.4.2 Power Factor Correction Plant

Northpower currently has 18 x 750kVAr 11kV fixed capacitor banks installed at zone substations.

3.4.3 Mobile Substations and Generators

Northpower owns and maintains a 500kVA 400V mobile distribution substation with a 500kW generator. This unit is used to provide supply in the event of either an unplanned shutdown or planned shutdown. There are three modes of operation:

- Direct connection onto the LV network.
- In parallel with 11 kV network via transformer
- supplying an islanded 11 kV network via a transformer

3.4.4 Generation Plant

Northpower owns, operates and maintains a 5MW output hydro power station at Wairua. All generation plant has a preventative maintenance regime to ensure the most efficient use of the asset.

3.4.5 Backup Control Room

Northpower has a backup control room which has been setup in case of emergency situations. The backup control room is fully featured scaled down version of the primary control room and includes a SCADA workstation, communication equipment and basic amenities.

3.4.6 Fibre Network

With the development of the fibre network Northpower's communications and protection schemes have been migrated from older copper and wireless circuits where possible and cost effective. This has resulted in improved reliability and performance of these links.

3.5 Justification of Assets

Northpower owns and manages existing assets and acquires new assets in order to carry out the core business activity of electricity distribution. The following table categorises network assets which Northpower justifies on technical and economic grounds to meet the requirement to provide affordable electricity of sufficient capacity (allowing for reasonable load growth) and reliability to consumers.

Category of Asset	Justification
33kV switchgear within Transpower GXP's	Provide switching and fault interruption functionality at the source end of sub-transmission assets.
33kV sub-transmission lines and cables	Power transfer requirements are beyond that of distribution lines or cables.
Zone substations	Interface power transfer capability of the 33kV network with the flexibility and cost effectiveness of distribution network.
11kV distribution lines and cables*	Power transfer requirements are beyond that of 400V lines or cables, but the use of 33kV would present physical and cost constraints.
11kV distribution switches	Provide operational flexibility and supply security.
11kV distribution substations	Interface power transfer capability of the distribution network with the cost-effective delivery of 400V supply to low capacity (domestic) customers.
400V distribution network	Most cost-effective way of delivering 400V supply to low capacity (predominantly domestic) customers.

** As it is possible that the distribution system will be operated at both 11kV and 22kV in future, 22kV rated assets are technically justified.*

Ideally the total network assets should not exceed the minimum required to provide the levels of service mentioned above at least cost i.e. they should be optimum.

Northpower has some assets that exceed the theoretical optimum level. The value of these assets at replacement cost (2004) is shown in the table below which is an extract from the last Northpower ODV valuation carried out in 2004. The total replacement cost of Northpower system fixed assets at this date was $283million.

Northpower Limited Schedule of Optimisation	31 March 2004 ($000)
ASSET CLASS	**Optimisation Impact on RC**
Subtransmission	
33kV Lines - Heavy - Concrete	1,108
33kV Lines - Light - Concrete	704
33kV Cables - xlpe (<240mm2 Al)	26
Zone Substations	
Land	250
Distribution Lines & Cables	
11kV Lines - Heavy - Concrete	1
11kV Lines - Medium - Concrete	380
11kV Lines - Medium - Wooden	20
11kV Cables - Medium - xlpe	403
Distribution Transformers Normal Total Life	
Distribution Transformer - Single/Two Phase Unit - up to 15 kVA	489
Distribution Transformer - Single/Two Phase Unit - 30 kVA	340
Distribution Transformer - Single/Two Phase Unit - 50 kVA	21
Distribution Transformer - Single/Two Phase Unit - 100 kVA	3
Distribution Transformer - Pole Mounted - Three Phase Unit - 11kV - Up to and including 30 kVA	2,276
Distribution Transformer - Pole Mounted - Three Phase Unit - 11kV - 50 kVA	1,567
Distribution Transformer - Pole Mounted - Three Phase Unit - 11kV - 100 kVA	665
Distribution Transformer - Pole Mounted - Three Phase Unit -11kV - 200 kVA	214
Distribution Transformer - Pole Mounted - Three Phase Unit - 11kV - 300 kVA	21
Distribution Transformer - Pole Mounted - Three Phase Unit - 11kV - 500 kVA	8
Distribution Transformer - Ground Mounted - Three Phase Unit - 11kV - 100 kVA	183
Distribution Transformer - Ground Mounted - Three Phase Unit - 11kV - 200 kVA	701
Distribution Transformer - Ground Mounted - Three Phase Unit - 11kV - 300 kVA	138
Distribution Transformer - Ground Mounted - Three Phase Unit - 11kV - 500 kVA	94
Distribution Transformer - Ground Mounted - Three Phase Unit - 11kV - 750 kVA	18
Distribution Transformer - Ground Mounted - Three Phase Unit - 11kV - 1000 kVA	20
	9,649

The following are some reasons for the existence of these assets:

- The minimum rating available of some electrical equipment is significantly greater than the loads imposed, particularly in remote and rural areas.
- Some lines between existing zone substations and sites or areas identified as requiring a zone substation in the future were built to 33kV standard but are currently used at 11kV.
- One of the two 33kV circuits between Maungatapere GXP and Whangarei South zone substation was built as a single pole double circuit line (used currently as a single circuit line) for future capacity and security.
- The network grew incrementally over many decades. If the present-day network was being entirely constructed over a short period of time, it would probably look quite different as many assets would be optimised out. However, the present day network represents an accumulation of incremental investment decisions that were quite probably very efficient at the time they were made.
- A large part of the network was built in an era when investment criteria were different to those of today.

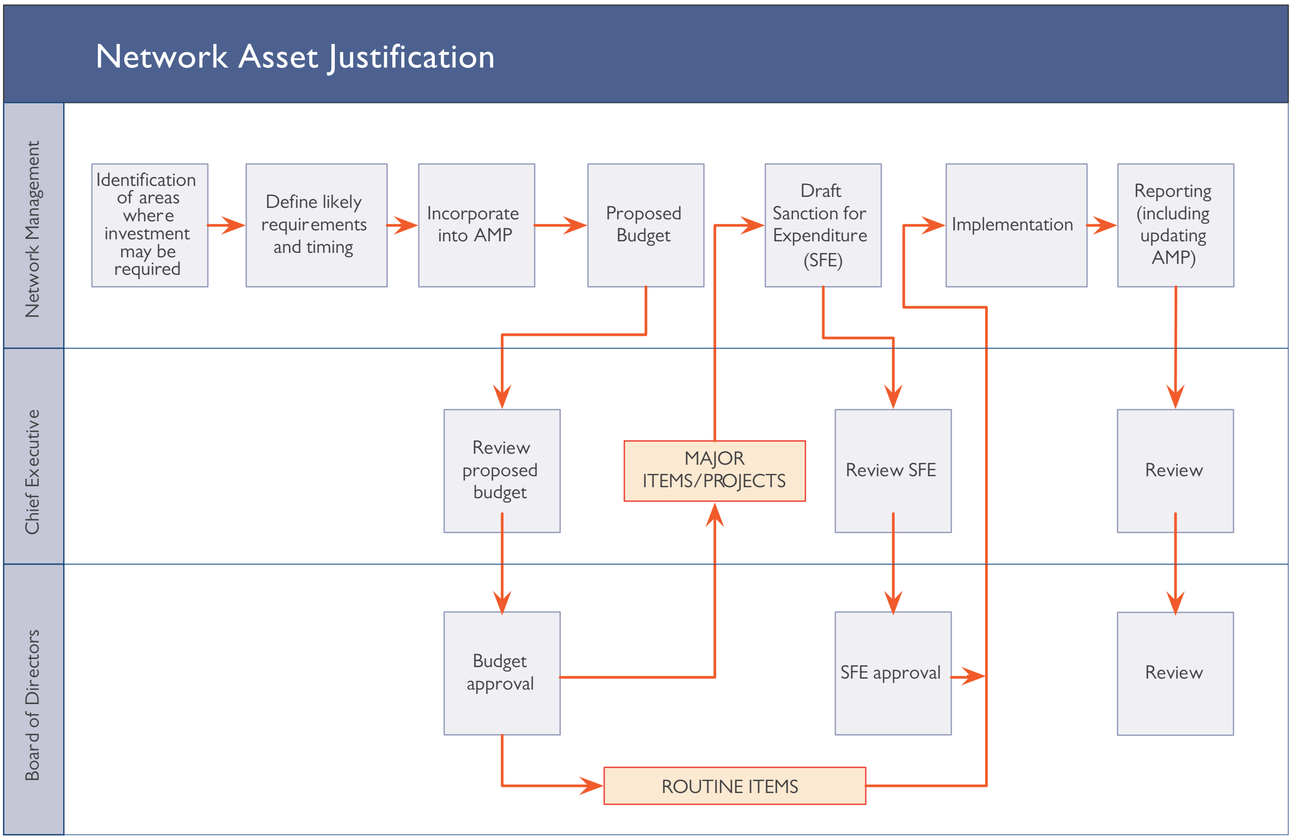
3.6 Justification process

Northpower has a rigorous justification and expenditure approval process which aims to optimise investment and prevent over-investment. The process involves approval at different levels and incorporates the 10 year development plan (AMP), the annual capex budget and individual project or program sanctions for expenditure (for extra-ordinary or large expenditure) which are approved by either the board of directors or the Chief Executive (within delegated authority limits) on their behalf, depending on the level of expenditure and strategic significance.

The following tools are used in combination within a Sanction for Expenditure (SFE) document to justify assets:

- Technical justification
- Fit with corporate goals and objectives
- Available technical solutions
- Risks to network assets
- Risk to overall Northpower business
- Financial impact (including measures such as NPV, IRR and impact on ODV)
- Legal and environmental requirements
- Safety requirements
- Life cycle cost analysis
- Customer requirements

The process for asset justification and inclusion in the Asset Management Plan is shown in the diagram below.



The reports and reviews that occur after the project has been justified and approved provide both performance indicators and data which is carefully considered and used for future asset justifications. This feedback loop is important to Northpower as the company uses learning to support the key principle of continual improvement.

Section 4: Service Levels

"safe, reliable, hassle free service"

Northpower

Service Levels

4

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Section 4: Service Levels

Northpower's vision is to be a high performing utility network by providing a safe, reliable, hassle free service. This aim is reflected in the service levels which are used to monitor performance. Targets have been classified into two principal groups; customer orientated and other related performance targets, with a number of levels within each group. Both groups include 'soft' or implicit service levels against which performance may be assessed, generally by surveys and 'hard' or technical service levels against which performance may be assessed by the analysis of data. The technical service levels also include statutory or regulatory service level requirements.

4.1 Purpose of Service Levels

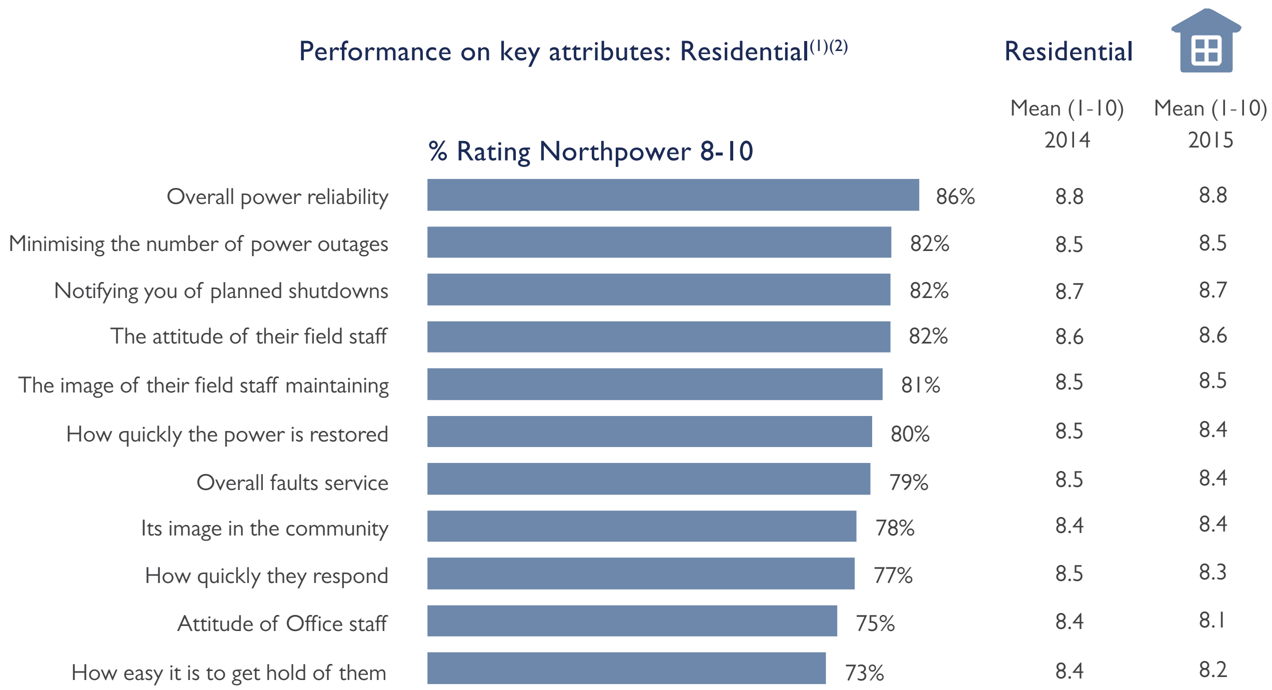
4.1.1 Customer Orientated Performance Targets

As Northpower's owners are also its end-use customers there is a strong linkage between the customers' performance targets (reliability, safety) and owner expectations (financial). Understanding the needs of customers/owners is achieved by way of regular customer surveys, market research, special interest/community groups as well as direct service feedback.

It is acknowledged that the success and stable operation of the business is dependent on customer satisfaction. This is a primary driver for setting performance targets.

Targets are set for the network as a whole (rather than different targets for different parts) based on the premise that all customers deserve quality performance and service. Northpower strives to meet these targets understanding that some areas may be more difficult to manage and may therefore require additional resources or effort.

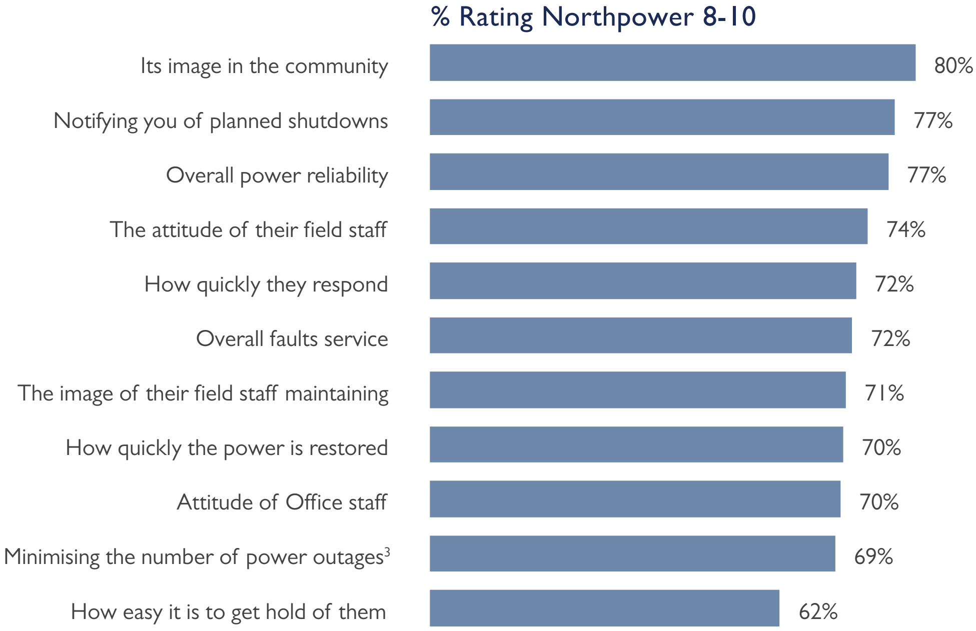
The following two graphs are based on the results of the 2015 Customer Perception Surveys and show residential and commercial customer ratings for Northpower's performance on key attributes. These results are valuable to Northpower in that they provide a good indication of where improvements need to be made.



NOTES:
1. Sample: 2014 total n= 401, Commercial n=100, Residential n=301; 2015 Total n=400, Commercial n=100, Residential n=300
2. Using a scale from 1 to 10, where 1 is extremely poor and 10 is excellent, how would you rate Northpower on… (1-10 scale where 1 means 'poor' and 10 means 'excellent')
3. This item was reformulated from the 2014 item: "The number of times the power goes off"

Performance on key attributes (Residential Customers)

Performance on key attributes: Commercial[(1)(2)]



Commercial

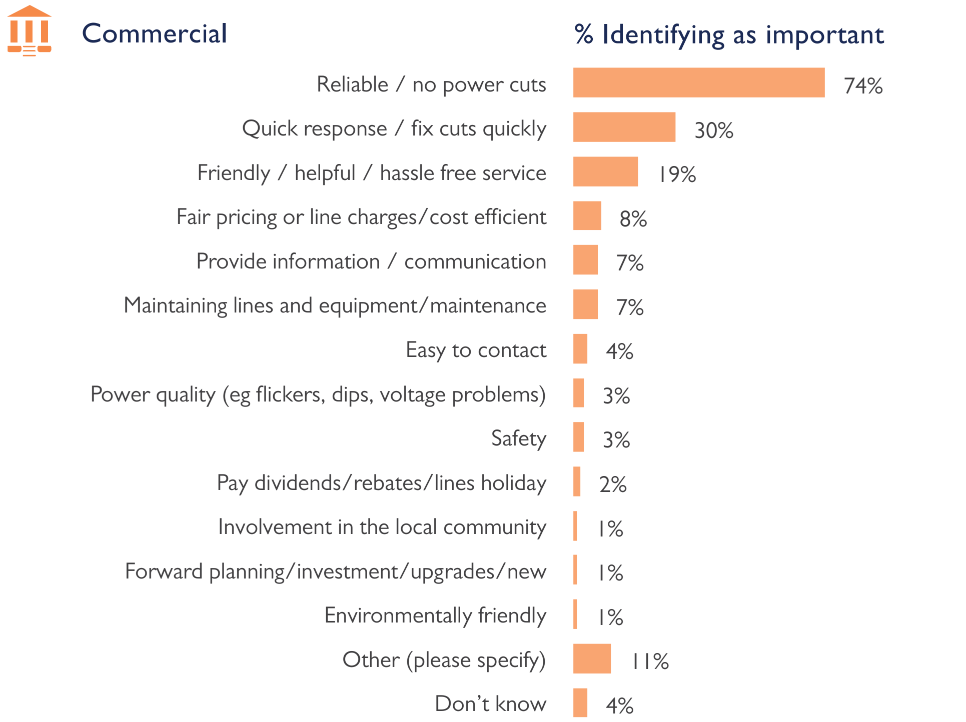
	Mean (1-10) 2014	Mean (1-10) 2015
Its image in the community	8.7	8.2
Notifying you of planned shutdowns	8.8	8.3
Overall power reliability	8.9	8.3
The attitude of their field staff	8.8	8.4
How quickly they respond	8.7	8.2
Overall faults service	8.7	8.2
The image of their field staff maintaining	8.7	8.2
How quickly the power is restored	8.7	8.0
Attitude of Office staff	8.7	8.0
Minimising the number of power outages[3]	8.8	8.0
How easy it is to get hold of them	8.7	7.8

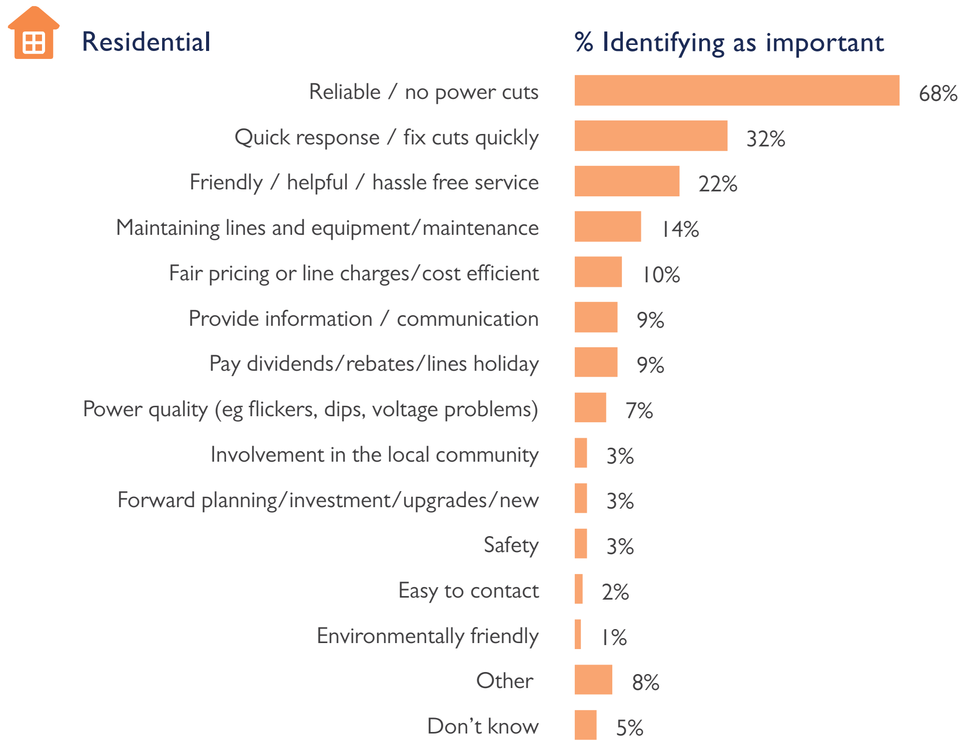
NOTES:
1. Sample: 2014 total n= 401, Commercial n=100, Residential n=301; 2015 Total n=400, Commercial n=100, Residential n=300
2. Using a scale from 1 to 10, where 1 is extremely poor and 10 is excellent, how would you rate Northpower on… (1-10 scale where 1 means 'poor' and 10 means 'excellent')
3. This item was reformulated from the 2014 item: "The number of times the power goes off"

Performance on key attributes (Commercial Customers)

The graphic below shows that Northpower customers (both residential and commercial) continue to rate reliability of supply and fault response as the two most important requirements. Northpower therefore continues to make these requirements a priority.

Importance (stated)





NOTES:

1. Sample: 2014 total n= 401, Commercial n=100, Residential n=301; 2015 Total n=400, Commercial n=100, Residential n=300
2. Remembering that Northpower is an electricity lines company and is not responsible for the bill, what are the most important things you look for in a lines company? … What else?

Commercial and Residential Customers ratings of the most important requirements

As discussed in the Lifecycle Asset Management Section, Northpower has adopted a more proactive approach to vegetation management to improve the reliability of supply through the reduction of interruptions to supply caused by vegetation contact. Ongoing monitoring is used to assess the impact of the philosophy.

In the area of improving fault response, two principal initiatives continue to be rolled out across the 11kV network. The installation of remote controlled switches and fault passage indicators at strategic locations on the network allows a more rapid isolation of the faulted section of line. Supply may also then be restored more rapidly to the balance of the sections of the network impacted by the original fault.

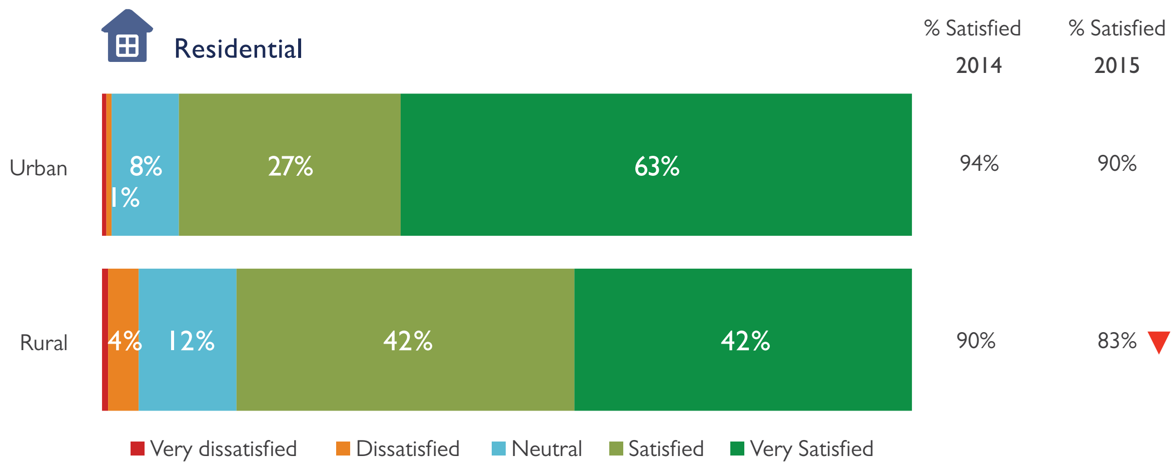
In addition, supply security is also carefully considered because the notion of security of supply is closely allied with reliability and fault response time in that higher levels of supply security enable supply to be restored via an alternative route or source while the fault is located and repaired.

4.1.1.1 Customer Service

4.1.1.1.1 Externally monitored domestic and commercial customer satisfaction

The target for this area is to achieve a combined overall customer satisfaction level of no less than 85%. The following charts show the 2015 levels of satisfaction compared with 2014.

Satisfaction with Northpower: Residential customers(1)(2)

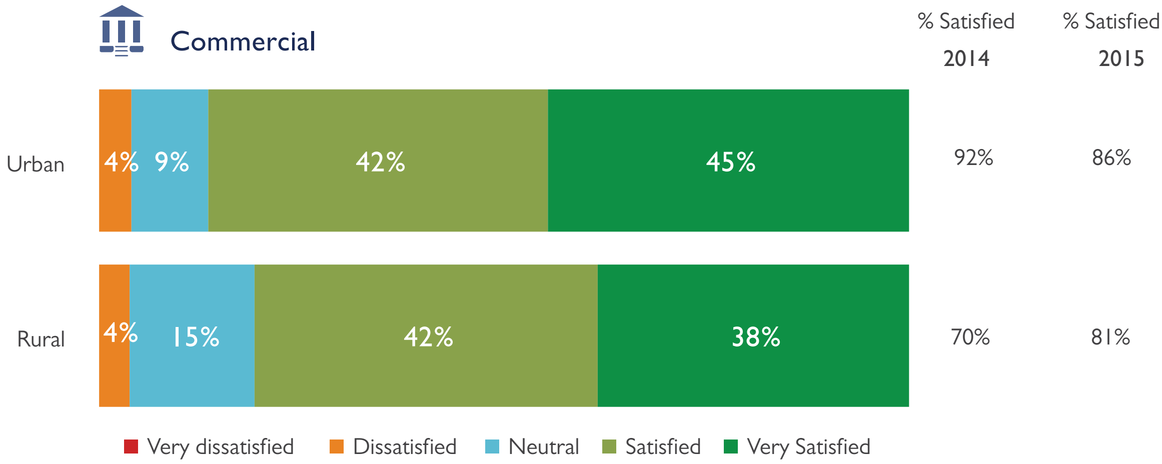


NOTES:
1. Sample: Total residential n= 300, Residential urban n=168, Residential rural n=132, Residential Whangarei n=165, Residential Kaipara n=135
2. Which of the following best describes how satisfied you are with Northpower overall? Ordinal scale; Very satisfied, Satisfied, Neutral, Dissatisfied, Very Dissatisfied

▼ Significantly lower than 2014

Overall Satisfaction Residential

Satisfaction with Northpower: Commercial customers[1][2]

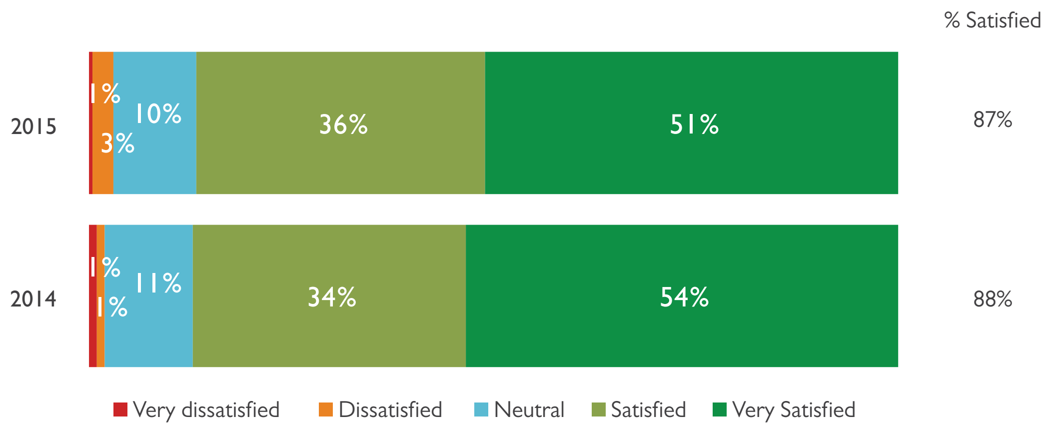


NOTES:
1. Sample: 2015 Total commercial n= 100, Urban n=74, Rural n=26
2. Which of the following best describes how satisfied you are with Northpower overall? Ordinal scale; Very satisfied, Satisfied, Neutral, Dissatisfied, Very Dissatisfied

Overall Satisfaction Commercial

Overall residential customer satisfaction has decreased from 92% in 2014 to 87% in 2015 and commercial customer satisfaction has decreased from 87% in 2014 to 85% in 2015. However customer satisfaction for both groups remains above the target of 85%. It is apparent that rural customer satisfaction is significantly lower than it is for urban customers and this is probably to be expected considering the difference in the networks supplying the two groups. However, Northpower is making a concerted effort to improve the performance of rural networks as evidenced by the projects currently underway and outlined in sections 5 and 6.

Satisfaction with Northpower: Residential and Commercial combined[1][2]



NOTES:
1. Sample: 2014 total n= 401, Commercial n=100, Residential n=301; 2015 Total n=400, Commercial n=100, Residential n=300
2. Which of the following best describes how satisfied you are with Northpower overall? Ordinal scale; Very satisfied, Satisfied, Neutral, Dissatisfied, Very Dissatisfied

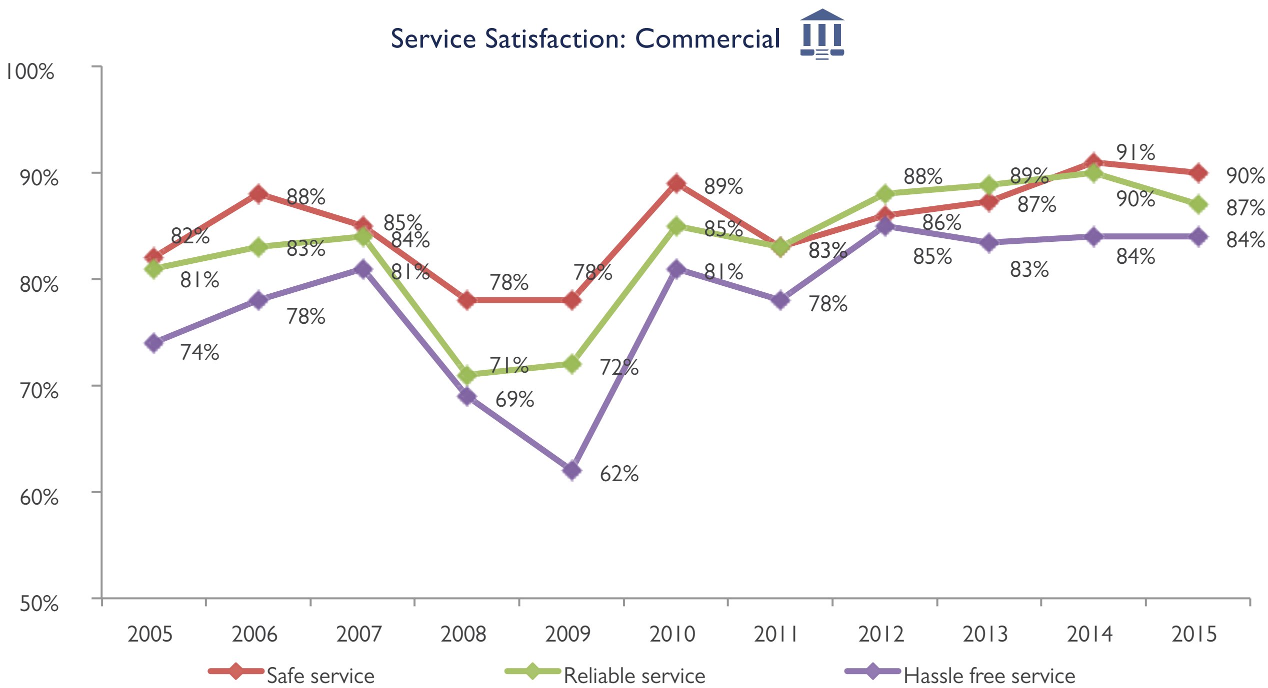
Overall Satisfaction Residential and Commercial combined

Overall customer satisfaction has decreased by one percent from 2014 to 2015 but remains above the target of 85%.

The following graphs show historical service satisfaction scores from 2005 to 2015 for residential and commercial customers. The service reliability score for residential customers has decreased in 2015 and both service reliability and service safety scores have decreased for commercial customers.

NOTES:
1. Sample: 2014 total n= 401, Commercial n=100, Residential n=301; 2015 Total n=400, Commercial n=100, Residential n=300
2. And using a similar scale, but this time 1 is strongly disagree and 10 is strongly agree, how strongly do you agree or disagree that Northpower offers a…
3. Based on those coded 'Agree' i.e. 8 - 10

Residential Service Satisfaction 2005 to 2015



NOTES:
1. Sample: 2014 total n= 401, Commercial n=100, Residential n=301; 2015 Total n=400, Commercial n=100, Residential n=300
2. And using a similar scale, but this time 1 is strongly disagree and 10 is strongly agree, how strongly do you agree or disagree that Northpower offers a…
3. Based on those coded 'Agree' i.e. 8 - 10

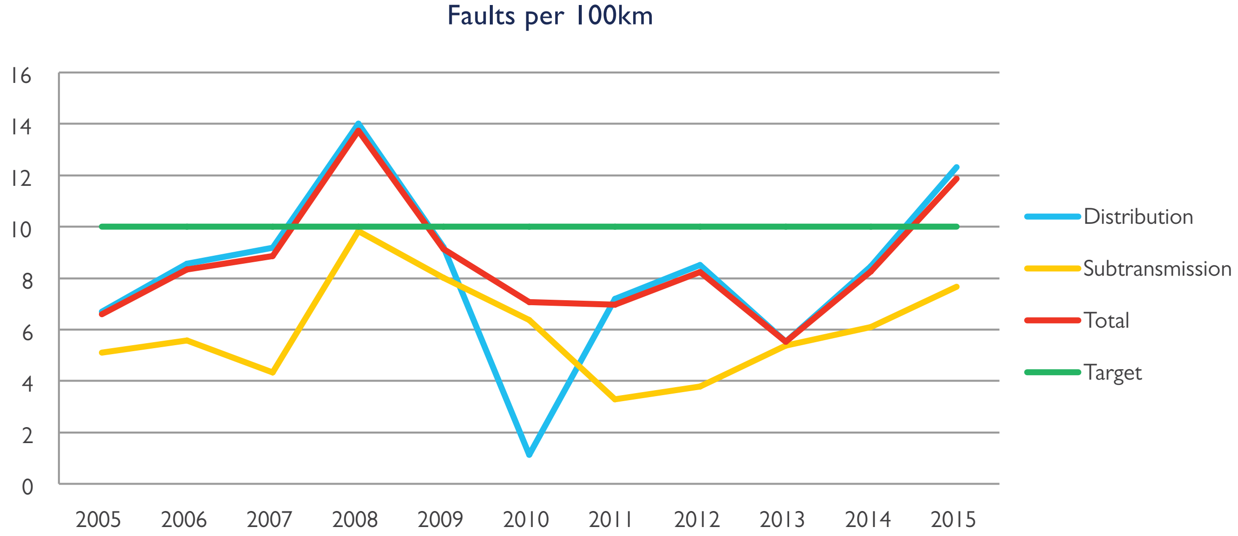
Commercial Service Satisfaction 2005 to 2015

4.1.1.1.2 Restoration Times for Advertised Shutdowns

Advertised or planned shutdowns not completed within 15 minutes of the advertised restoration time are deemed to have exceeded the time limit. The target is to have less than 50 shutdowns per annum that exceed the limit with a long term goal of having less than 30.

4.1.1.1.3 Number of Faults per 100km

A fault is classified by the Commerce Commission as a physical condition that causes a device, component or network element to fail to perform in the required manner'. This performance measure has been selected for its suitability to Northpower's network which has a high proportion of low density overhead network with long feeders. Northpower's current target for faults per 100km is less than 10 per year. As can be seen in the following graph, the average number of faults per km is higher on the distribution network than on the subtransmission network. During the last 10 years the target of less than 10 faults per 100km has been met in all years except 2008 and 2015 during which extreme weather conditions were experienced.



Faults per 100km 2006 to 2015

4.1.1.1.4 SAIDI, SAIFI and CAIDI Indices

Reliability of supply (frequency and duration of faults) is measured by Network performance indicators SAIDI, SAIFI and CAIDI. Northpower's current targets for SAIDI are as follows:

SAIDI (planned interruptions): less than 55 per year

SAIDI (unplanned interruptions): less than 90 per year

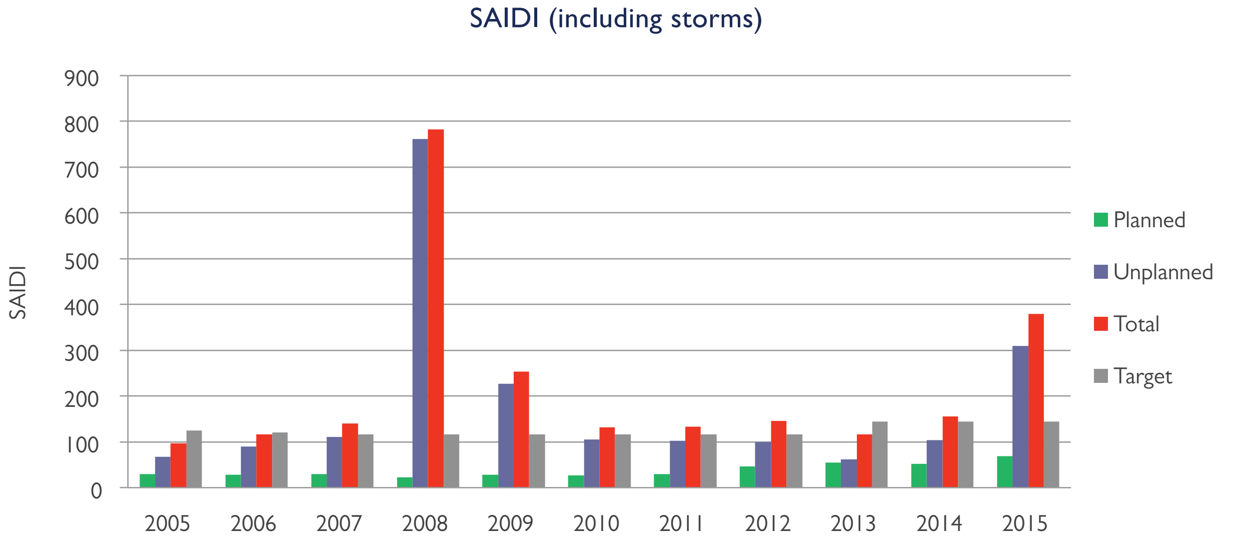
SAIDI (total interruptions): less than 145 per year

The following table provides a summary of performance (for unplanned interruptions) from 2005 to 2015 for the three indicators (the figures include the effect of major storms).

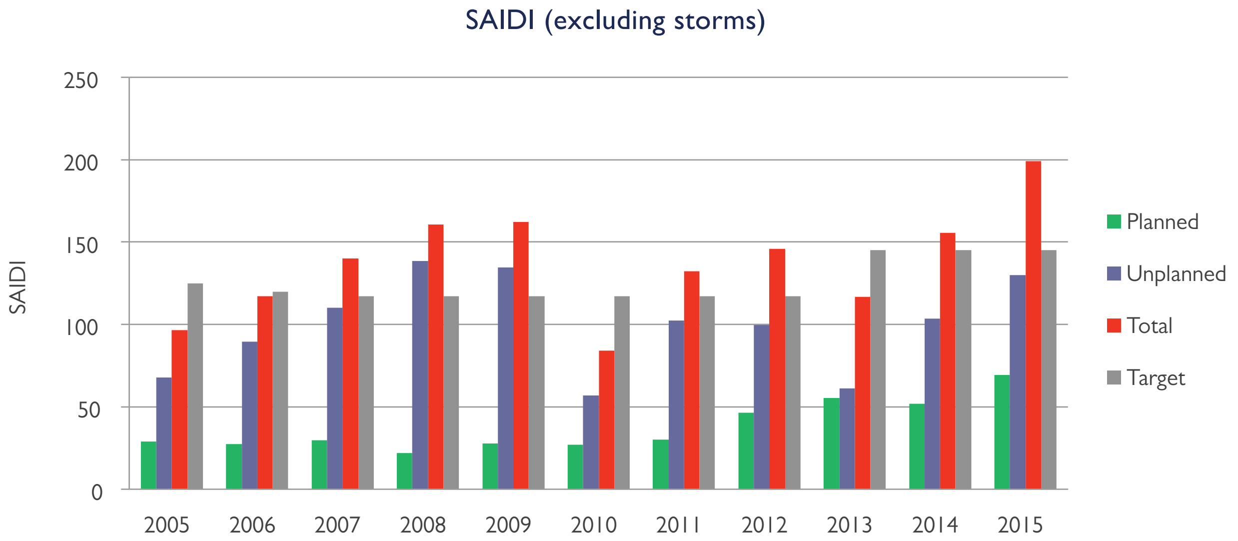
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
SAIDI	67.7	89.5	110.2	761.0	226.5	105.3	102.3	99.5	61.2	103.6	310.0
SAIFI	2.0	2.2	2.4	4.5	3.1	2.2	2.1	2.3	1.6	2.1	3.3
CAIDI	34.4	40.1	45.5	170.4	73.8	48.0	49.7	43.1	39.2	49.4	93.0

SAIDI, SAIFI and CAIDI trends (note these are financial reporting years i.e. April to March)

The following graphs show annual planned and unplanned SAIDI results with and without the effect of major storms.



SAIDI Including Storms



SAIDI Excluding Storms

If the impact due to storm damage is removed (second graph) it can be seen that total SAIDI has shown an increasing trend since 2010. This is partly due to an increase in the target from 2013 to make allowance for a greater number of planned shutdowns to accommodate switch upgrade and conductor replacement. SAIDI due to unplanned interruptions has remained relatively consistent except for a significant increase in 2015 due mainly to vegetation, defective equipment and third part interference. The statistics (which include adverse weather) are shown in the table below.

Analysis by Cause of Interruption

Cause of Interruption	No. of Interruptions		Impact of Duration		Impact of Frequency	
	No.	Proportion of Total	Customer Minutes	Proportion of Total	Customer Interruptions	Proportion of Total
Unknown/Other	108	12.5 %	2,193,762	10.3 %	63,723	31.6 %
Vegetation	59	6.8 %	1,598,631	7.5 %	20,152	10.0 %
Lightning	8	0.9 %	80,773	0.4 %	1,486	0.7 %
Defective Equipment	116	13.4 %	1,693,763	7.9 %	29,451	14.6 %
Adverse Weather	112	12.9 %	10,147,963	47.5 %	42,346	21.0 %
Adverse Environment	4	0.5 %	70,120	0.3 %	2,332	1.2 %
Human Error	4	0.5 %	51,153	0.2 %	3,106	1.5 %
Third Party Interference	33	3.8 %	1,011,901	4.7 %	11,501	5.7 %
Wildlife	25	2.9 %	598,867	2.8 %	13,401	6.6 %
Sub Total	**469**	**54.2 %**	**17,446,933**	**81.7 %**	**187,498**	**92.9 %**

Northpower has historically focused on SAIDI as the high level key performance indicator. The reasons for this are twofold. Firstly, SAIDI is affected by both outage frequency and duration and these reflect both network reliability and response time. Secondly, monitoring and reporting of SAIDI is a regulatory requirement.

In addition to SAIDI Northpower also uses other technical network performance indicators which it regularly measures and reports. These indicators are important to note as they not only indicate how the network is performing, but also when assessed together, suggest why the network is performing that way. This in turn indicates how network performance could best be improved.

Delivering on the customer's most important requirements demands a continuous focus on improving both the physical network and asset management practices. Northpower continues to make a concerted effort to improve reliability of supply and fault restoration times. Toward this end Northpower:

- Continues to focus on best practice asset management with a view to improving preventative maintenance routines because reliability of supply and fault response are outcomes of the quality of asset management
- Continues to review the formal Service Level Agreement (SLA) that Network management has with the internal service provider. The SLA provides an 'arm's length' style management tool to provide a framework for continual improvement of service delivery
- Continues to monitor improvements in technology and plan projects designed specifically to improve reliability (see sections 5 and 6)

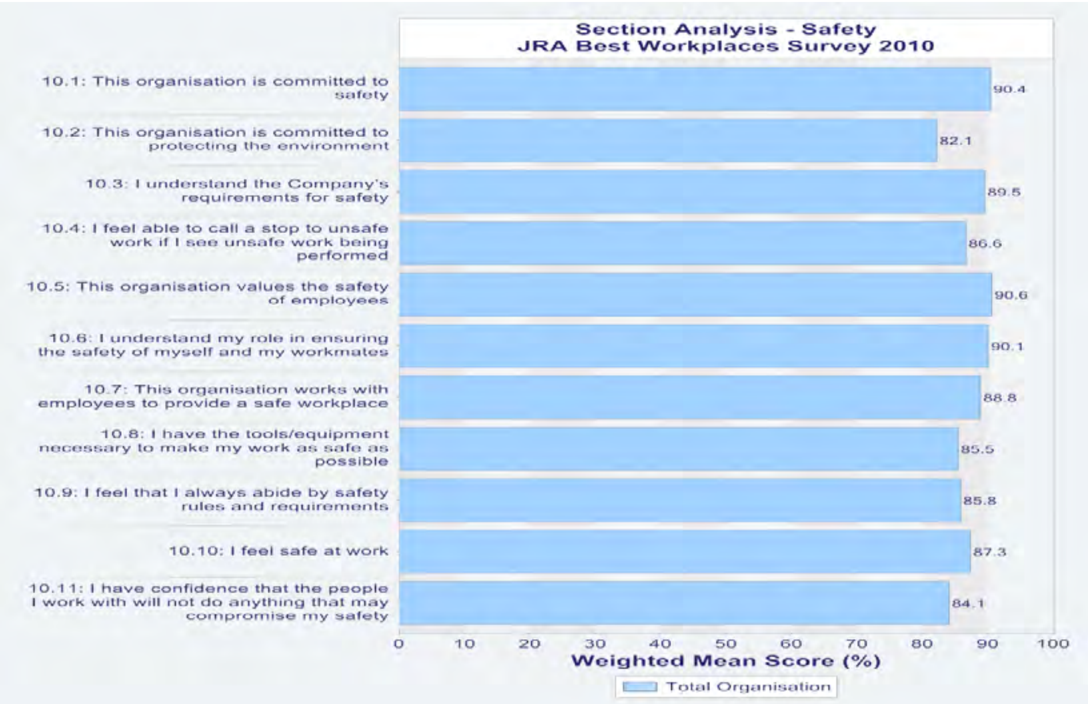
4.1.2 Other related performance targets

4.1.2.1 Safety

To ensure that Northpower's network does not present significant risk in terms of public safety and complies with the Electricity Safety Regulations 2010, Northpower has chosen to certificate to NZS 7901:2008 Electricity and Gas Industries – Safety Management Systems for Public Safety. Compliance with this safety standard requires an audit by an accredited auditor to be carried out at least once every 5 years.

Northpower is committed to keeping people safe around its electricity network, and has a number of safety programmes to protect customers, their children and work crews from the dangers of electricity. In addition, safety incidents are monitored and reviewed to ensure the best possible delivery of a safe service.

In the separate Safety section in the unlimited/JRA "Best Places to Work" biennial staff survey Northpower employees indicated that they have an excellent overall safety attitude and consider the company's focus on safety as being very important. The following graphic from the 'Best Places to Work Survey' illustrates the prominence of a good safety attitude within the organisation.



Safety – Best Places to Work Survey

4.1.2.2 Unsafe service lines

During the course of preventative maintenance inspections Northpower identifies and attends to unsafe service lines. However there are a large number of privately owned service lines which are not maintained by Northpower. Where an unsafe customer owned service line is identified, Northpower works with the owner and if necessary Energy Safety Services to reach a satisfactory outcome.

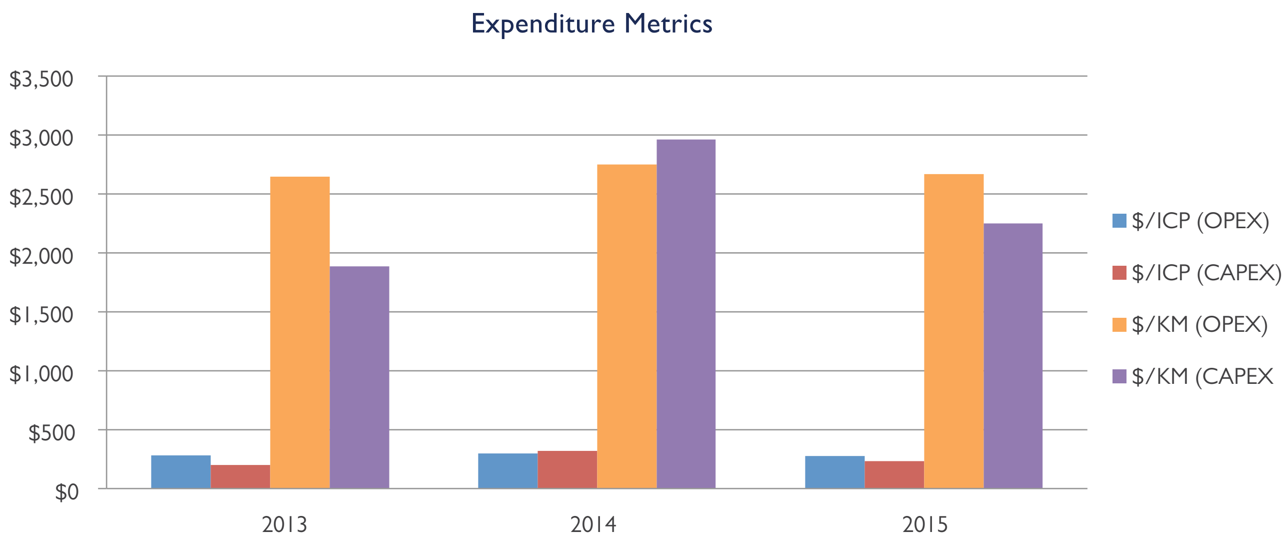
There appears to be a lack of understanding among the public that the line supplying low voltage electricity within their property is generally their responsibility. Northpower actively promotes this aspect through its website, customer newsletter and a dedicated Customer Advisor. In addition to this Northpower promotes public awareness of unsafe service lines at the Northland annual field days as well as through various media.

4.1.2.3 System Losses

System losses are monitored on an annual basis. The target is driven from optimizing the electrical performance of principally the distribution network. Feeder and transformer capacities and loadings are balanced with the capital expenditure necessary to drive the losses down. Both components of the loss cost versus the capital cost of improvement are ultimately funded by the end user so the cost benefit equation becomes the major consideration in establishing the target.

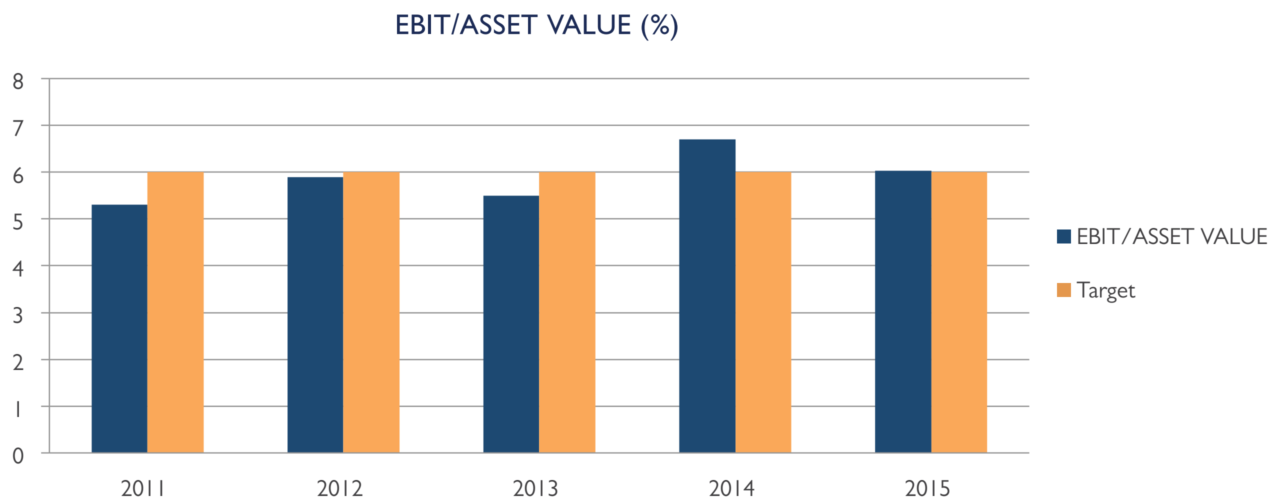
4.1.2.4 Financial

Northpower also monitors regulatory reporting indicators such as expenditure per kilometre circuit length and expenditure per customer connection point. The following graph shows Opex and Capex per connection point ($/ICP) and kilometre of line ($/km) for financial years 2013 to 2015. These metrics can be compared with those of other lines companies (see next section) to assess relative expenditure levels across the industry with respect to network performance levels achieved.



Network Expenditure Metrics

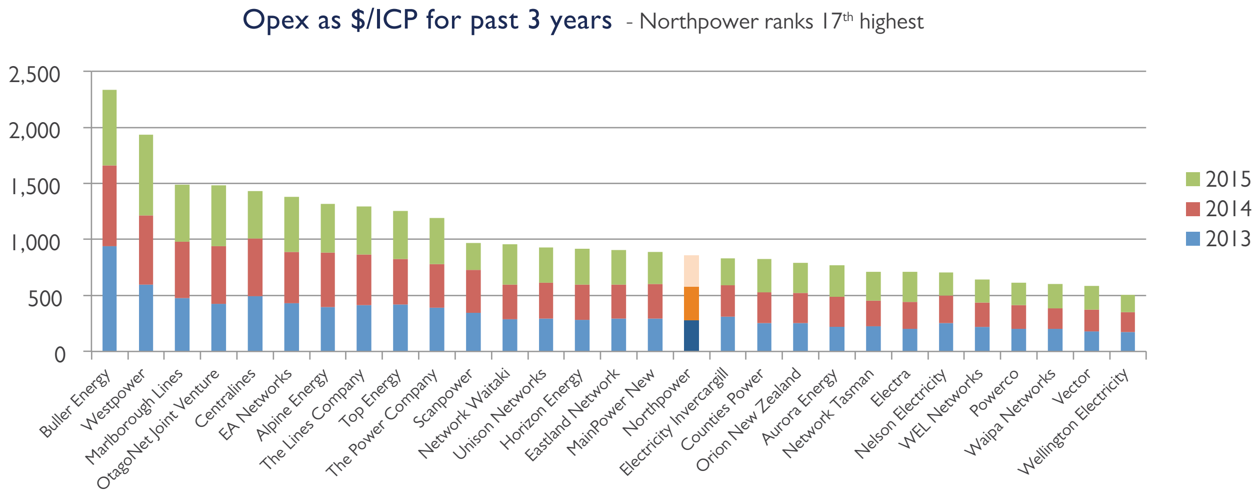
The following graph shows Northpower's return on investment performance for the last 5 years. Northpower's target for annual EBIT/Asset Value is 6%.



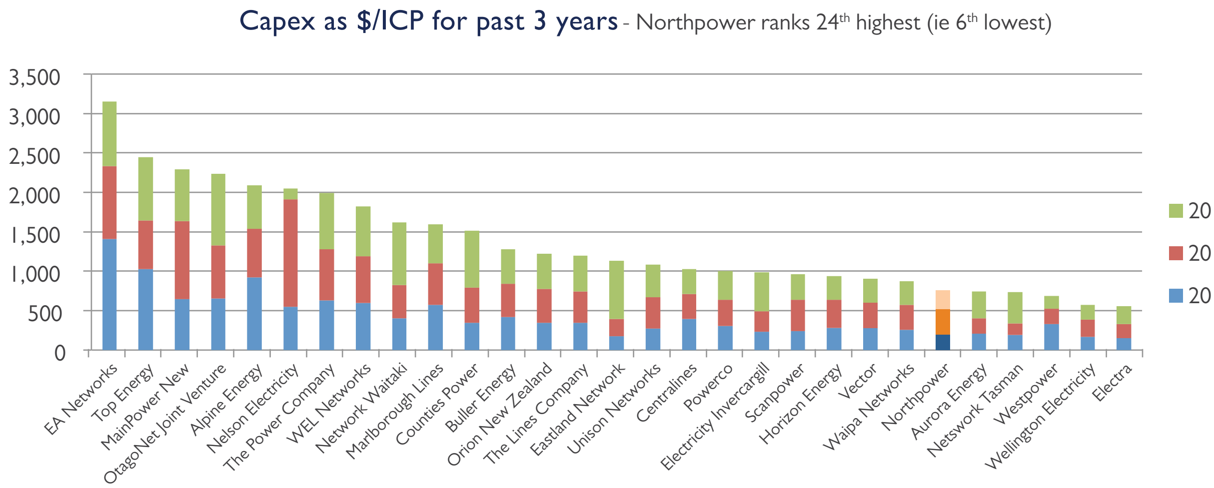
Return on investment

4.1.2.5 Comparisons with other EDB's

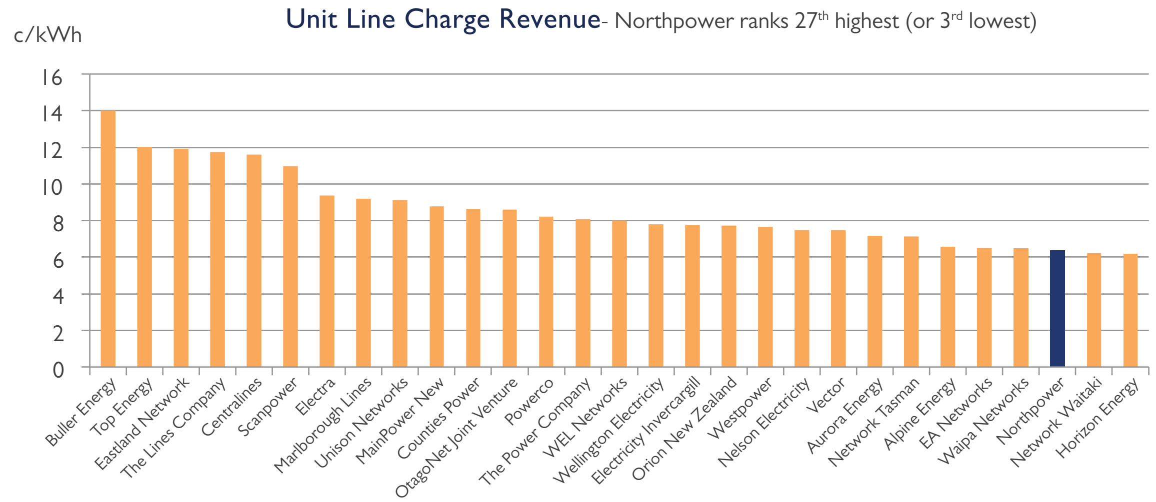
A comparison of Northpower's performance within the industry (insofar as it relates to overall customer service levels) is also important. Care needs to be taken in the comparison to make allowance for significant physical and geographic differences between the networks of different EDB's. The following graphics compare Northpower's 2015 performance with other EDB's for a number of different metrics.



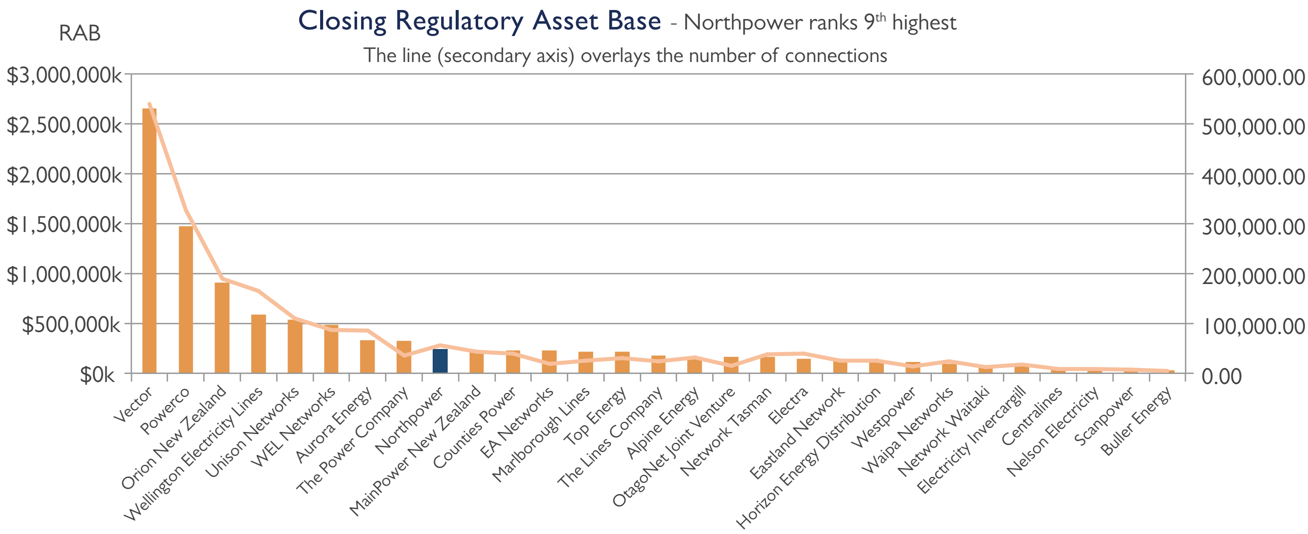
Industry OPEX as $/ICP for Past 3 Years (Source: PWC ELB Information Disclosure Compendium 2015)



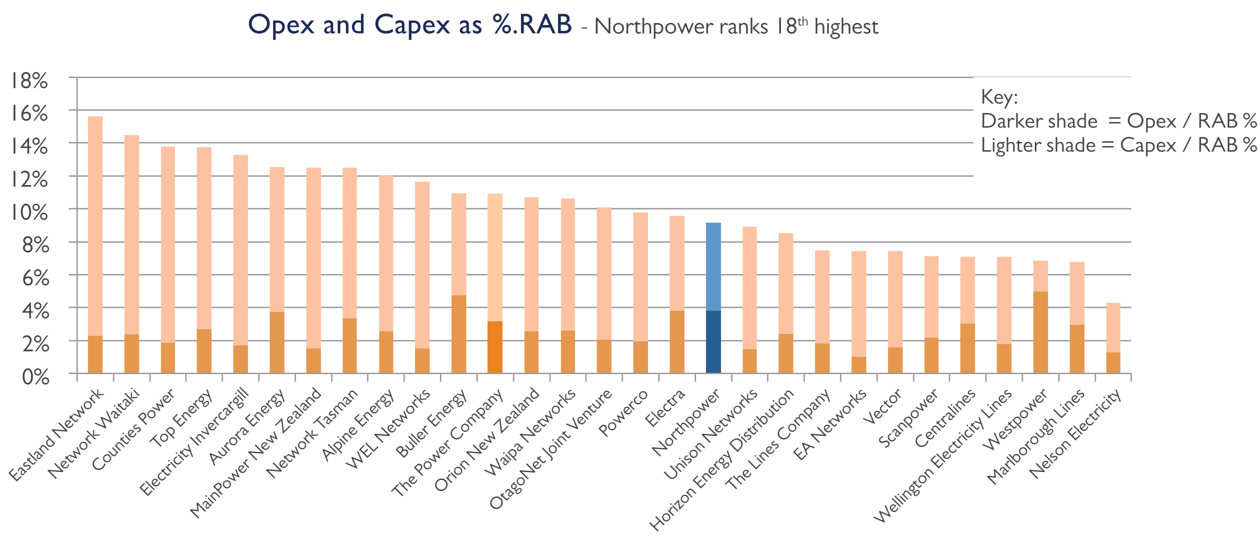
Industry CAPEX as $/ICP for Past 3 Years (Source: PWC ELB Information Disclosure Compendium 2015)



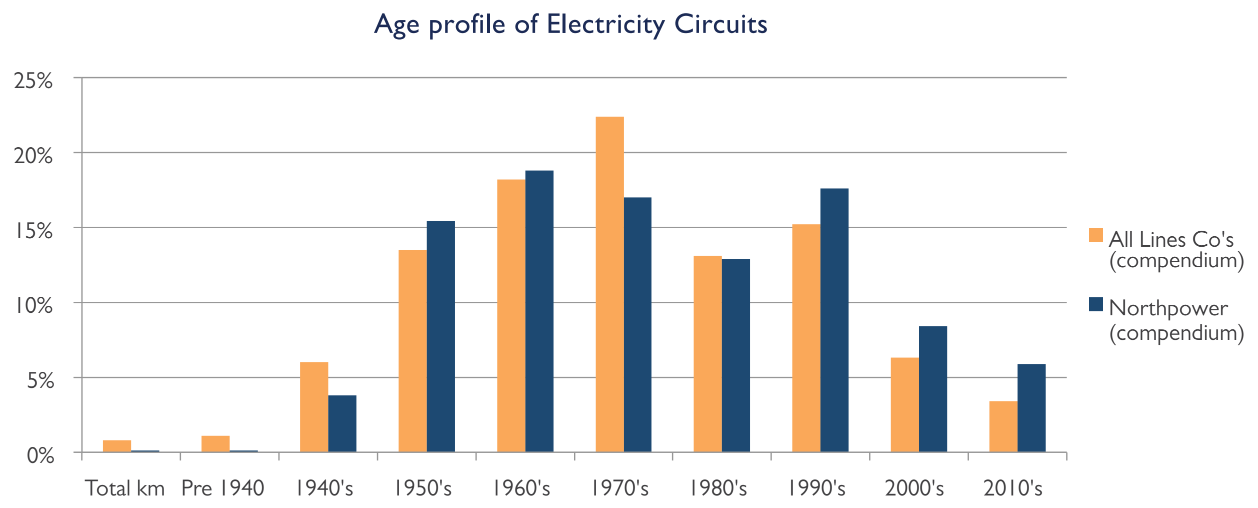
Comparison of Industry Unit Line Charges for 2015 (Source: PWC ELB Information Disclosure Compendium 2015)



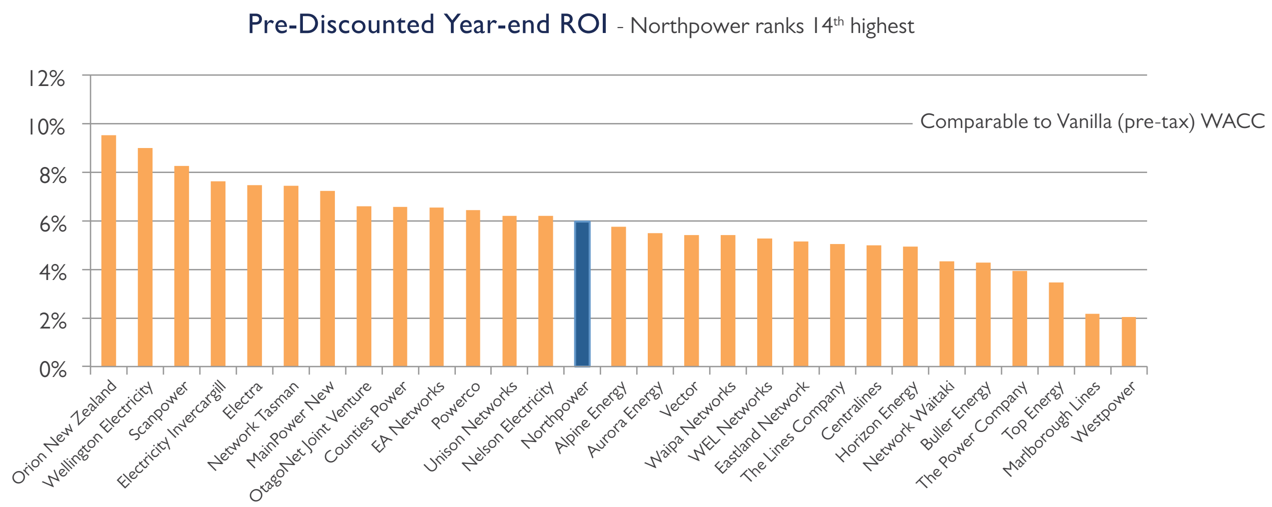
Comparison of Industry Regulatory Asset Base for 2015 (Source: PWC ELB Information Disclosure Compendium 2015)



Comparison of Industry OPEX and CAPEX as percentage of RAB for 2015 (Source: PWC ELB Information Disclosure Compendium 2015)



Northpower's Asset Age Profile compared with that of the Industry (Source: PWC ELB Information Disclosure Compendium 2015)



Comparison of Industry ROI for 2015 (Source: PWC ELB Information Disclosure Compendium 2015)

4.2 Justification for Target Levels of Service

4.2.1 Customer Oriented Performance Targets

4.2.1.1 Customer Service

4.2.1.1.1 Externally monitored domestic and commercial customer satisfaction

A key objective of asset management planning is to ensure the level of service provided matches the expectations of customers and stakeholders. This is consistent with Northpower's vision and organisational objectives and goals as outlined in Section 2 of this plan.

To ensure that Northpower is providing a service in line with customer expectations, Northpower consults with customer, both residential and commercial, through the annual customer perceptions survey. Northpower undertakes an annual survey to gauge customer satisfaction across a number of areas including the following core areas:

- Overall satisfaction and satisfaction with service attributes
- Key attributes driving satisfaction/dissatisfaction
- Comparison with other companies
- Image attributes
- Satisfaction with communications
- Awareness and appropriateness of sponsorship
- Satisfaction with service
- Attitudes to trade-off between increased charges and increased service levels

4.2.1.2 Restoration Times for Advertised Shutdowns

Northpower advises customers of planned shutdowns for maintenance or other work by way of shutdown notification mail outs which provide the reason for the shutdown as well as the planned start and finish times. As customers plan around these times the restoration of power on or close to the advertised time is very important. Planned shutdowns not completed within 15 minutes of the advertised restoration time are deemed to have failed to meet customer requirements. The target is to have less than 50 shutdowns per annum that exceed the limit with a long term goal of reducing the number to 30.

4.2.1.2.1 Reliability measures SAIDI, SAIFI and CAIDI

The justification for setting target levels of reliability is complex. An idealistic approach would be to set a target level for SAIDI of zero minutes, but there are obviously cost and other practical considerations which make this unrealistic.

The target is made up of a planned outage component and an unplanned outage component based on historical data and what is realistically achievable given the network architecture (largely rural overhead) and its susceptibility to the variances of weather and vegetation. Northpower customers have indicated through surveys that they are largely not prepared to fund an increase in performance through an increase in price. Based on these factors it would be imprudent for Northpower to focus on driving down the reliability targets with an associated increase in charges. The focus instead is to drive consistency of performance across the network through the philosophy of continuous improvement.

The justification for targets set for reliability measures (SAIDI, SAIFI and CAIDI) is based on what is expected to be achievable with the present network assets and the level of funding available. It also assumes no extreme weather events and that customer satisfaction with historic levels of reliability remain unchanged.

4.2.1.3 Number of Faults per 100km

Future targets are similar to or the same as current targets, largely due to feedback from our customers who have indicated that the current level of service for the price paid is acceptable. This feedback validates the selection of reliability and performance targets equal to or trending slightly downwards from current levels.

4.2.2 Other Related Performance Targets

4.2.2.1 Safety

4.2.2.1.1 Public harm events, Unsfafe Service Lines and LTI Rate

As a responsible corporate citizen and employer, Northpower is committed to zero harm targets. Targets like this have become the accepted industry norm and no other justification is required.

4.2.2.2 Network Efficiency

4.2.2.2.1 System losses

Historical data is used to review prior performance and highlight any trends. The system losses target is based on this historical performance data. There will be an equilibrium point where the cost of the capital investment necessary to reduce the losses is on a par with the cost of the losses themselves.

4.2.2.3 Financial Performance

4.2.2.3.1 Annual EBIT/Asset Value

The statement of corporate intent is a requirement of the Energy Companies Act 1992 and reflects the objectives for the company as required by legislation and the owners. One of these objectives is the required return on investment by the owners and Northpower's current SCI specifies an EBIT/Asset Value of 6% per annum.

4.2.2.3.2 Costs per kilometre and per ICP

Minimisation of cost increases is an important performance attribute. The line charge component of customer's power bills contains a direct and an indirect cost component. To deliver on the customer requirement for price/cost control, it is necessary for these costs to be well managed.

4.2.2.3.3 Comparisons with other EDB's

Benchmarking is a valuable tool to gauge relative performance within the industry. It is justified as a level of service measurement to ensure that as an organisation Northpower's performance aligns with industry norms and customers/shareholders are receiving an appropriate return on investment.

Section 5:
Network Development Plan

"safe, reliable, hassle free service"

Northpower

Network Development Plan

5

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Section 5 - Network Development Plan

5.1 Planning Criteria and Assumptions

Current and planned network assets are required to ensure customer requirements and expectations with respect to capacity, reliability and security of supply are met at an affordable cost. Northpower has adopted various engineering standards and policies to ensure that it can satisfy customer requirements in line with the following guiding principles:

- Minimisation of over-investment
- Optimisation of operational efficiency and flexibility
- Minimisation of long-term stranding risks
- Maximisation of return on investment (life-cycle cost analysis)
- Compliance with legal, regulatory, environmental and safety requirements

Northpower's network comprises of the following key components:

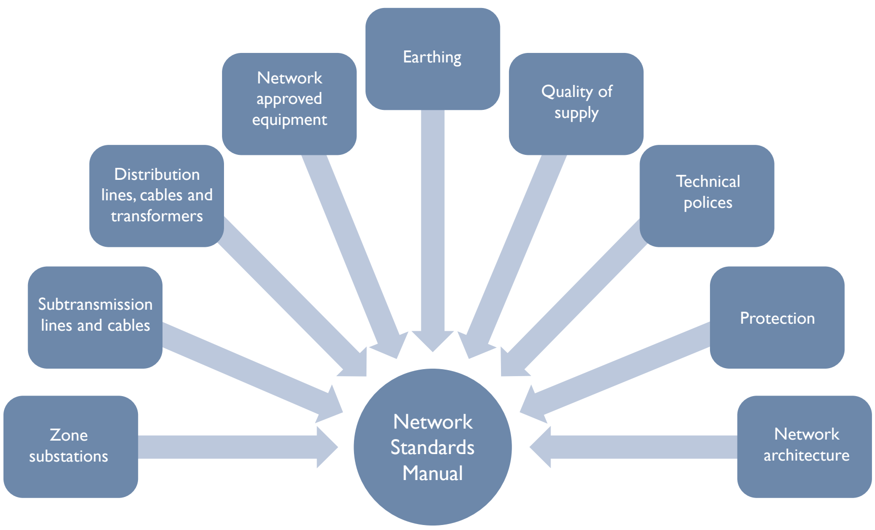
- 33kV subtransmission (lines, cables and switches)
- 33/11kV zone substations (power transformers and circuit breakers)
- 11kV distribution (lines, cables, switches, reclosers, regulators and capacitors)
- 11kV/400V distribution substations (distribution transformers)
- 400V distribution (lines, cables and pillars)

Northpower recognises that ongoing and exclusive investment in long term traditional network assets only makes sense if there is an adequate supply of low cost grid generation. The rapid evolution of technologies such as solar panels, wind turbines and fuel cells could reduce the demand on traditional electricity networks.

To this end, Northpower recognises the importance of monitoring technological developments and the ability to rapidly respond to the implementation of new or alternative technologies in order to minimise the risk of stranded assets or changing load patterns in the long term. Examples of technologies that Northpower is currently actively monitoring are photo-voltaic generation, electric vehicles, LED (light-emiting doide) lighting and hot water heat pumps.

For this reason, all planned major new network investment needs to be carefully scrutinised to ensure best practice investment. Similarly, Northpower needs to be aware of possible changes in the regulatory environment which could require a different approach to investment decisions.

Planning and design parameters as well as equipment rating criteria are set out in Northpower's Network Standards Manual and include the following aspects:



Network Standards Manual Sources of Information

5.1.1 Capacity Determination

Capacity and rating of new equipment is generally determined by the magnitude of the load to be supplied and the prevailing fault level, whereas reliability and security of supply aspects are based on the number of customers, the nature of the load, susceptibility of the network to faults in the particular area and affordability.

Technical specifications for the range of equipment used on Northpower's network are detailed in the Network Approved Equipment section of the Network Standards Manual.

Examples of planning and design guidelines for switchgear are shown below:

Nominal Voltage	11 kV		22 kV		33 kV	
	Standard capacity	*High capacity*	*Standard capacity*	*High Capacity*	*Standard capacity*	*High capacity*
Current (A) - Feeder	630	630	630	630	630	800
Current (A) - Incomer	630	1,250	630	630 see note 5	630	1,250 / 1,600
Current (A) – Bus & BC	630	1,250	630	1,250	630	1,250 / 1,600
Fault Current (kA)	*Light Fault Level*	*Heavy Fault Level*	*Light Fault Level*	*Heavy Fault Level*	*Light Fault Level*	*Heavy Fault Level*
See notes 7, 8, and 9	16 (3 sec) see note 2	25 (3 sec) see note 6	12.5 (3 sec) see note 5	16 (3 sec) see note 5	16 (3 sec) see note 2	25 (3 sec)
Rated Voltage kV	12		24		36	
BIL (kV)	75		125		170	

Planning and Design Guidelines

Notes to the table:

1. These are typically minimum specifications. Higher rated equipment will be given preference when priced at similar levels.
2. 12.5kA rating may be used if the long term fault level is likely to remain light.
3. Light fault level is where the long term fault level is not expected to be greater than 6 kA for fixed switchgear. For movable switchgear e.g. recloser, then "light" rating can be regarded as less than 8kA.
4. GXP should be treated as "heavy" fault levels.
5. Use 11 kV requirements if 22 kV network is to be initially run at 11 kV.
6. Some equipment is manufactured to 20 kA rating rather than 25 kA. Generally we will specify the 25kA rating; however we will consider the 20 kA rating on a case by case basis.
7. The 3 or 1 second rating is based on the fault clearance time of the protection. Traditionally the fault clearance time of the larger zone substation is slightly over the 1 second therefore we have traditionally used a 3 second rating. The 3 second rating required maybe reduced on a case by case basis.
8. Fault current rating means both 'rated short circuit breaking current' and 'rated short time withstand current'. The time (usually 3 seconds) refers to the 'rated short time with stand current'.
9. High fault is when the long term prospective fault level is greater than 50% of the 'standard' fault capacity.

Examples of planning and design specifications for zone substation transformers are shown below:

Specification	Standard
Primary Voltage	33,000 V
Secondary Voltage	22,000 / 11,000 V - see note 1
Rating ONAN)	Typical sizes 5, 7.5, 10, 15 & 20 MVA
Forced Cooling	Where applicable - see note 2

Specification	Standard
OLTC range	20 % (+4% to -16%, +5% to -15%, +6 to -14%)
No of Taps / step size	11 or 17 (2% or 1.25%)
Impedance	Not specifically specified usually in the range 7 to 9% - see note 3
Oil	Mineral oil to BS 148, bladder conservator preferred.
BIL	170 kV HV side, 125/75 kV LV side
Fault Rating	25 kA 1 sec

Zone Substation Transformer Specifications

Notes to the table:

1. Consideration should be given to dual Voltage secondary winding i.e. 22,000 V / 11,000 V when purchasing new transformers for future upgrading of the distribution network to 22 kV.
2. Forced cooling should be considered if practical, as it does provide increased capacity for contingency events without unduly increasing the fault level. Generally forced cooling will increase the rating by 25% or 100% depending on whether air fans or air fans and oil pumping are used.
3. There may be cases where a specific impedance or minimum impedance is specified. Typically this would be to reduce the fault level on the LV switchboard and downstream distribution network.

5.1.2 Performance and Quality of Supply

Northpower has a range of criteria that represent planning rules for different categories of fixed assets, refer to the table below:

Category of asset	Capacity criteria	Reliability criteria (worst case)	Security of supply criteria
400V distribution network	Statutory voltage level	Supply restoration within repair time or within switching time where 400V link pillars present	(n) security of supply for standard residential or commercial connection (n-1) where link pillars present and backstop capacity available
11kV/400V distribution substation	Transformer continuous rating	Supply restoration within fuse or transformer replacement time or within switching time where 400V link pillars present	(n) security to most urban distribution networks (n-1) where link pillars present and backstop capacity available
11kV distribution network	Maximum operating load 80% of lowest segment rating	Supply restoration of 80% within switching time	(n-1) security except for spurs
11kV distribution equipment	Regulator rating RMU rating Cable rating	Supply restoration within switching time	(n-1) security except for spurs

Category of asset	Capacity criteria	Reliability criteria (worst case)	Security of supply criteria
33/11kV zone substation	80% of firm maximum load relative to firm capacity	100% load restored within 30 min for >5MVA , 80% within 1 hr for <5MVA	(n-1) >5MVA (n) <5MVA
33kV sub-transmission network	110% of overhead line rating 80% of cable thermal rating	100% load restored within 30 min for >5MVA , 80% within 1 hr for <5MVA	(n-1) for dual circuits (n) for single circuits
33kV assets within Transpower GXP	CB load and fault level rating	Supply restoration within switching time	(n-1) >5MVA (n) <5MVA

Planning Rules

Actions to change the parameters of individual assets within these categories to ensure compliance with the planning rules can take the following forms:

- Construct new distribution assets that will move (generally increase) an asset's capacity to a level at which the planning rule is not contravened. An example would be to replace a 300kVA transformer with a 500kVA transformer so that the 100% MD criteria is not exceeded. Other examples would be installing a voltage regulator on a feeder to ensure that statutory voltage levels are maintained or upgrading switchgear to meet increased fault level requirements.
- Modify distribution assets so that the asset's attributes will move to a level that no longer contravenes a planning rule. This is essentially a sub-set of the above approach, but will generally involve less expenditure. An example would be installing forced cooling on a 33/11kV transformer to allow a greater maximum demand at a lower cost than installing a larger transformer that might be under-utilised most of the time.
- Retrofitting high-technology devices that can exploit the features of existing assets. For example replacing air break switches with enclosed switches. Other examples might include SCADA monitoring of transformer core temperatures to enable higher cyclic loadings instead of installing a higher rated transformer or using remotely controlled switches to improve reliability.
- Operational activities, in particular switching on the 11kV network (reconfiguration) to shift load from heavily-loaded to lightly-loaded zone substations to avoid new investment. The downside to this approach is that it may increase line losses, reduce security of supply or compromise protection settings.
- Feeder reconfiguration to mix different load categories e.g. urban and domestic load, so as to obtain the benefit of load diversity.
- Construct or contribute to the development of distributed generation so that associated distribution asset performance is restored to compliance with the planning rules. Distributed generation would be particularly useful where additional distribution assets could eventually be stranded or where primary energy is going to waste, e.g. waste steam from a process.
- Influence customers to alter their consumption patterns so that assets perform at levels which comply with the planning rules. Examples might be to shift demand to different time zones, negotiate interruptible tariffs with certain customers so that overloaded assets can be relieved or assist a customer to adopt a substitute energy source or encourage energy conservation initiatives to avoid new capacity (the required separation of lines and energy functions does, however, make demand management more difficult).
- In identifying solutions for meeting future demands for capacity, reliability and security of supply, Northpower considers options that cover the above range of categories. The benefit-cost ratio (including capitalised electrical losses and estimates of the benefits of environmental compliance and public safety) of each option is considered and the option yielding the most cost effective outcome in the longer term is adopted.

5.2 Prioritisation Methodology

5.2.1 Network Investment Framework

Network development projects are grouped according to the following 3 main categories:

- **Growth** – these projects relate to network capacity and are driven by new customer connections and growth of existing load.
- **Replacement and renewal** – these projects are driven by asset condition due to deterioration or end of life impacting on safety, performance and maintenance costs.
- **Improvement** – these projects are driven by the need to maintain or improve reliability, public and employee safety and environmental impact.

The prioritisation of projects has to take into account the following constraints:

- Availability of funds and the need to smooth annual capital expenditure.
- Availability of design, construction and other resources.
- Acquisition of resource consents and permissions.
- Equipment lead-times.

The methodology employed to prioritise or rank projects across the network is based on the analysis of risk as it pertains to Northpower's obligations in terms of the following aspects:

- Safety.
- Regulatory compliance and environmental impact.
- Network capacity, reliability and security of supply.
- Cost-benefit analysis.

An example of a project risk assessment matrix is shown below.

Risk	Probability	Severity	Risk Factor
Safety	2	3	6
Environmental impact	1	1	1
Regulatory compliance	1	2	2
Capacity	1	1	1
Security	2	2	4
Reliability	1	2	2
Score			16

Project Risk Assessment Matix

Probability and severity ratings:

Low – 1
Medium – 2
High – 3

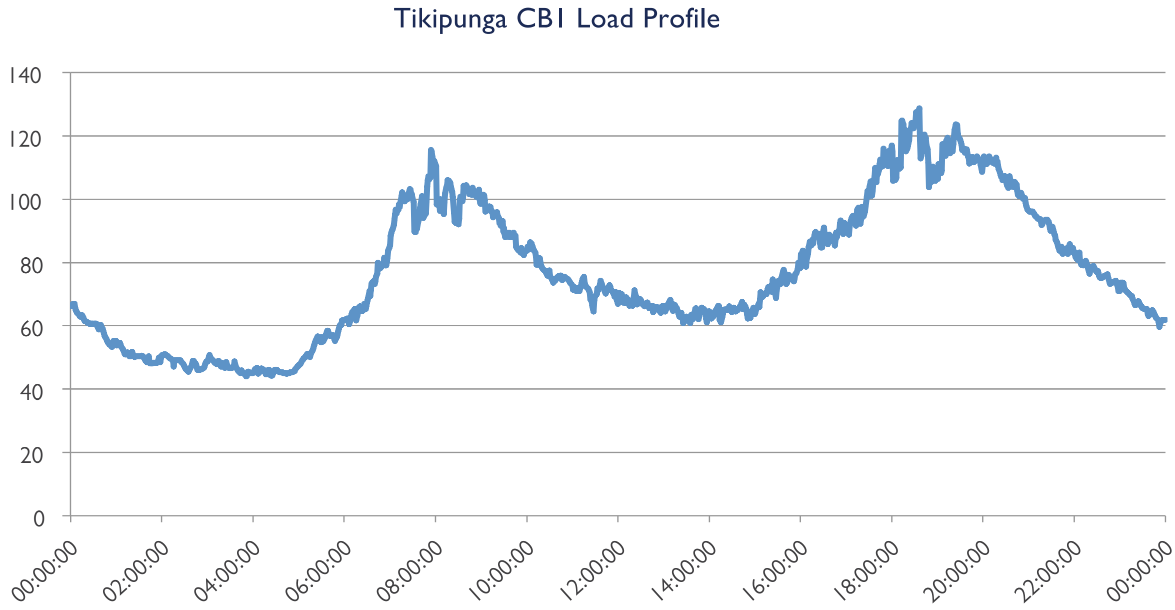
Where necessary (usually undertaken for larger high value projects), a cost-benefit comparison of projects can also be carried out using net present value (NPV) and internal rate of return (IRR) techniques to assist with project ranking decisions.

5.3 Demand Forecast and Capacity Constraints

5.3.1 Network Capacity

Network components such as circuit breakers, isolators, transformers, cables and lines are required to have sufficient capacity to ensure overloading does not occur during peak load periods. In addition to this, allowance needs to be made for contingencies that may arise during peak load periods due to equipment failure. This additional capacity is termed N-1 which expresses the ability of the network to lose a component without causing an overload failure elsewhere on the network. This usually takes the form of duplicate powerlines and transformers. Northpower's network only has full N-1 capacity in certain strategic areas such as high density urban areas, supplies to critical loads or where a customer has requested and paid for it.

A typical 48 hour residential feeder load profile is shown below. The 'spiky' nature of the load peaks is due to the operation of hot water load control which has suppressed the natural peak.



Typical Feeder Load Profile

There is a large demand for energy in the morning and again in the evening. Similarly this demand will vary during the year. In Northpower's case the highest demand occurs in winter. Unless some form of load control is in place to manage the peak demand (either supply side or demand side) all network components supplying the load are required to have sufficient capacity to meet the highest peak demand.

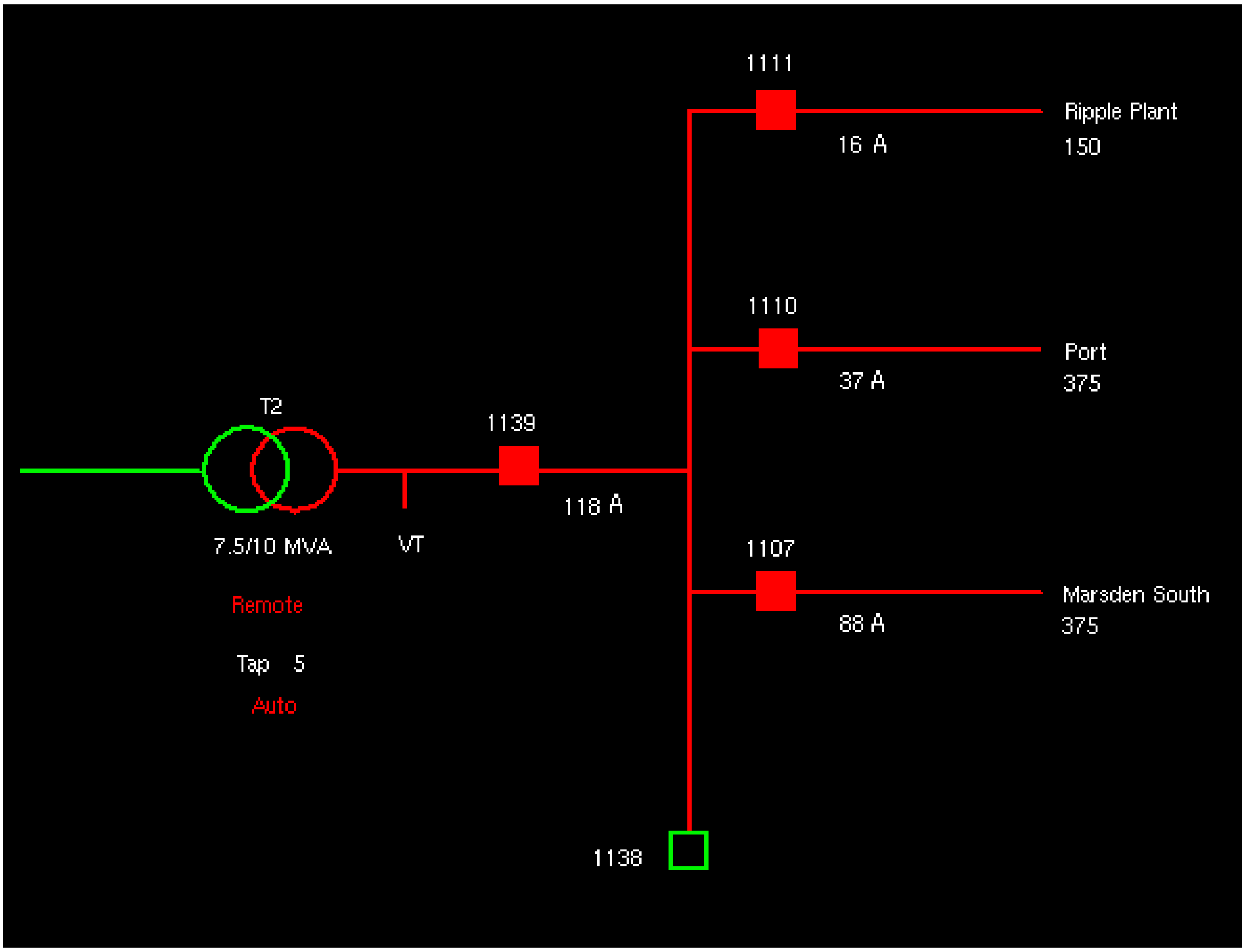
As equipment ratings are generally related to heat dissipation, there is an advantage in having loads peaking in the winter months. Northpower's ripple injection load control equipment (controlling hot-water load) is currently used to manage peak demand at GXP level. It is therefore not possible at present to manage peak loadings at a specific zone substation or feeder although for most parts of the network the peakload at the various levels is approximately coincidental. Restoration of controlled load can result in a higher peak load occurring if not managed carefully

5.3.2 Recording and Analysing Network Loading

Northpower records network loading via the SCADA system in terms of current and power at the following levels:

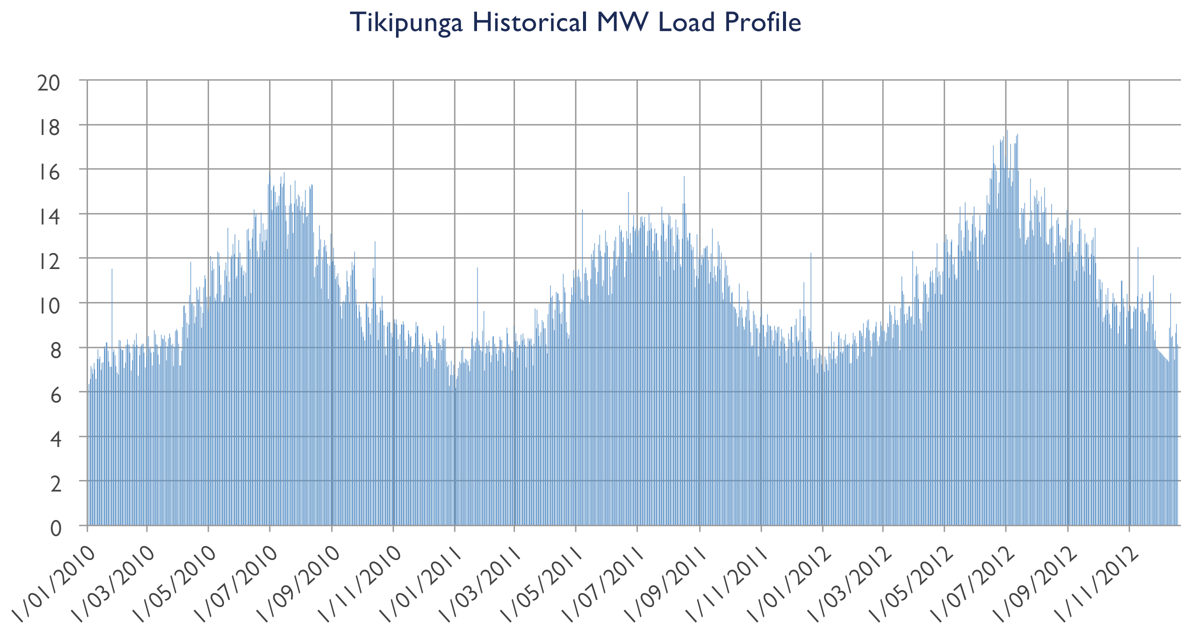
- GXP
- Subtransmission feeder
- Zone substation transformer
- Zone substation feeder

A typical SCADA screen view displaying substation real time data is shown below:



Typical SCADA Schematic

An example of historical loading data for a zone substation is shown below:



Historical Loading Data for Zone Substation Analysis

Loading data is also available from tariff metering associated with large customer loads. At the distribution transformer and LV feeder level, selected large transformers (200kVA and above) in the Whangarei City area are equipped with maximum demand indication to capture peak loading. For all other distribution transformers and LV feeders, peak loading is estimated based on summated premise kWh data as well as the number of connections where the load is predominantly residential or rural.

When analysing current or historical network demand data for the purpose of establishing trends, there are a number of factors which can distort the data, such as:

- Seasonal effects e.g. wet/dry summer, cold/warm winter.
- The system may have been configured differently for a shutdown, fault event or permanent change to the normal supply configuration.
- The use of load control on switching off and restoration of controlled load.
- Economic cycles slowing or accelerating demand.

5.3.3 Load Forecasting Methodology

Northpower has traditionally relied heavily on the following aspects to generate the load forecast:

- Historical growth trends.
- Knowledge of the area.
- Degree of growth saturation of developed areas.
- Notification of reasonably definite potential new load.
- Notified planned increases in existing commercial and industrial load.
- Information obtained from district council plans.
- Future economic outlook.

Northpower recognises the need to develop and employ a more sophisticated load forecasting methodology which also takes cognisance of the following mix of potential future developments:

- Availability and affordability of grid power.
- Electric vehicles.
- Distributed generation.
- Demand side management (including SMART metering and punitive tariffs).
- Climate control systems.
- New major commercial and industrial loads.

Assumptions made with regard to the aspects mentioned above (and applied in the development of the 10 year load forecast below) are set out in section 9.

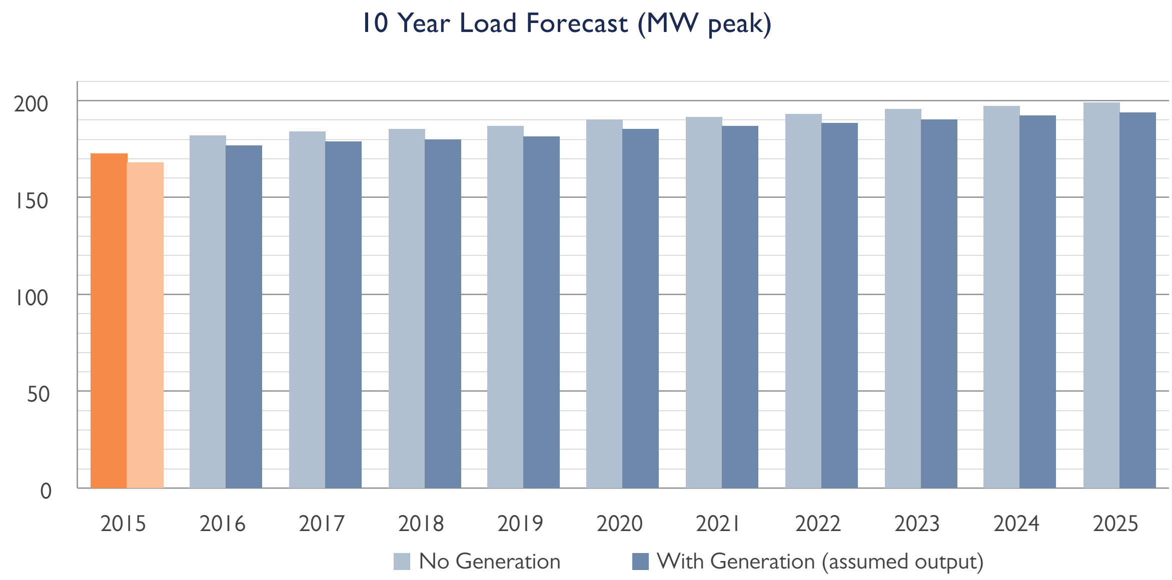
5.3.4 Network Load Forecast

Northpower's current demand growth comprises relatively low growth in domestic and commercial connections overlaid by some new industrial projects, as well as plant upgrade projects by existing large commercial and industrial consumers.

The demand growth averaged across the entire network is expected to be approximately 1.4% per annum for the 10 year forecast period. This figure, however, disguises the extremes of growth expected at local levels which can range from nil (or even negative) up to about 5% per annum in high growth areas. These estimated annual growth rates are based both on historical trends and examination of present and expected future activity at feeder and zone substation level and include anticipated step-load increases.

Northpower's network peak load forecast (with and without the embedded generation at Wairua and Bream Bay) is shown in the graph below and assumes continued use of water heating load control plant. Without load control the magnitude of the load would be approximately 10MW to 15MW higher. The peak demand (with generation) on the network is expected to increase from the present 168MW to around 194MW during the next 10 years, barring any developments with respect to major new loads or embedded generation. Peak demand on the network at present occurs in winter but peak demand in summer is increasing due mainly to the emergence of increasing climate control and refrigeration load.

Section 9 in this document contains high level assumptions regarding future load growth expectations in general.



Network Load Forecast 2016-2025

The detailed load forecast at GXP and zone substation level is set out in the table below. This forecast is supported in the following section which summarises present loading and expected growth activity at zone substation level. Some other considerations are given in the notes to the table below.

10 YEAR LOAD FORECAST	-1	0	1	2	3	4	5	6	7	8	9	10	Notes
STATION (MW PEAK)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
Kensington	65.1	65.2	65.9	67.3	67.0	67.7	70.0	70.7	71.5	72.2	73.0	73.8	
Alexander Street 11kV	14.0	14.7	14.8	15.0	14.0	14.1	14.3	14.4	14.6	14.7	14.9	15.0	Load transfer to Maunu
Hikurangi 11kV	6.9	6.4	6.5	6.5	6.6	6.7	6.3	6.4	6.4	6.5	6.6	6.6	Load transfer to Helena Bay
Helena Bay 11kV [planned 2020]							1.5	1.5	1.5	1.5	1.6	1.6	Planned new substation
Kamo 11kV	11.2	11.9	12.1	12.3	12.4	12.6	12.8	13.0	13.2	13.4	13.6	13.8	
Ngunguru 11kV	3.2	3.2	3.3	3.3	3.4	3.5	3.5	3.6	3.7	3.7	3.8	3.9	
Onerahi 11kV	8.4	8.3	8.4	8.5	8.6	8.6	8.7	8.8	8.9	9.0	9.1	9.2	
Parua Bay 11kV	3.2	3.3	3.3	3.4	3.5	3.5	3.6	3.7	3.7	3.8	3.9	4.0	
Tikipunga 11kV	15.5	15.7	15.8	16.0	16.1	16.3	16.5	16.6	16.8	17.0	17.1	17.3	
Kauri [Industry 1] 33kV	7.6	7.7	7.7	8.5	8.5	8.5	9.0	9.0	9.0	9.0	9.0	9.0	Expected step load increases
Bream Bay (no generation)	46.5	51.8	53.4	53.7	54.0	54.3	54.7	55.0	55.3	55.7	56.1	56.4	
Bream Bay [industry 2] 33kV	4.5	4.5	4.6	4.6	4.7	4.7	4.8	4.8	4.9	4.9	5.0	5.0	
Bream Bay [industry 3] 33kV	33.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	Step load increase
Bream Bay 11kV	4.0	3.9	4.5	4.6	4.8	4.9	5.1	5.2	5.4	5.5	5.7	5.9	Expected step load increase
Ruakaka 11kV	6.4	6.6	6.7	6.9	7.0	7.1	7.3	7.4	7.6	7.7	4.7	4.8	Load transfer to Waipu
Waipu 11kV [planned 2023]											3.2	3.2	Planned new substation
Maungatapere (no generation)	41.4	42.5	43.4	43.8	44.6	45.0	45.4	45.8	46.3	46.7	47.2	47.6	
Maungatapere [industry 4] 33kV	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Maungatapere [industry 5] 33kV	12.3	12.0	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	
Maungatapere 11kV	7.0	6.9	7.0	7.0	6.4	6.5	6.5	6.6	6.7	6.7	6.8	6.9	Load transfer to Maunu
Kioreroa 11kV	10.1	10.4	10.6	10.8	11.0	11.3	11.5	11.7	11.9	12.2	12.4	12.7	
Poroti 11kV	3.0	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.4	3.5	3.5	3.5	
Maunu 11kV [planned 2017]					3.0	3.0	3.1	3.1	3.1	3.2	3.2	3.2	Planned new substation
Whangarei South 11kV	11.7	12.8	12.9	13.1	11.3	11.4	11.5	11.6	11.8	11.9	12.0	12.1	Load transfer to Maunu
Dargaville	12.7	11.4	11.5	11.6	11.7	11.9	12.0	12.1	12.2	12.3	12.5	12.6	
Dargaville 11kV	12.7	11.4	11.5	11.6	11.7	11.9	12.0	12.1	12.2	12.3	12.5	12.6	Load transferred to Ruawai
Maungaturoto	17.5	18.1	18.4	18.6	18.8	19.1	19.3	19.6	19.8	20.1	20.3	20.6	
Maungaturoto 11kV	3.0	3.0	3.1	3.1	3.1	3.2	3.2	3.2	3.2	3.3	3.3	3.3	
Maungaturoto [industry 6] 11kV	4.5	4.4	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	
Ruawai 11kV	2.7	3.1	3.1	3.2	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.4	Load transferred from Dargaville
Kaiwaka 11kV	1.6	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.9	1.9	
Mangawhai 11kV	6.0	6.2	6.4	6.5	6.7	6.8	7.0	7.2	7.4	7.6	7.7	7.9	
Mareretu 11kV	3.0	2.7	2.7	2.8	2.8	2.8	2.8	2.9	2.9	2.9	3.0	3.0	
Network ADMD (no generation)	172.9	172.8	181.4	183.8	184.8	186.5	189.7	191.4	193.2	195.0	196.9	198.7	Average increase: 1.4% pa
Generation (at TOSP)	-6.1	-4.9	-5.0	-5.0	-5.0	-5.0	-5.0	-5.0	-5.0	-5.0	-5.0	-5.0	
Wairua PS (Maungatapere GXP) 33kV	-4.4	-4.9	-5.0	-5.0	-5.0	-5.0	-5.0	-5.0	-5.0	-5.0	-5.0	-5.0	Assumed station output at TOSP
Trustpower PS (Bream Bay GXP) 11kV	-1.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Assumed station output at TOSP
Network ADMD (with generation)	166.8	167.9	176.4	178.8	179.8	181.5	184.7	186.4	188.2	190.0	191.9	193.7	Average increase: 1.4% pa

Substation 10YR Load Forecast (MW Peak)

Notes to the load forecast table

1. Kensington and Maungatapere 110/33kV transformer loading is managed by transferring load (Kioreroa, Whangarei South and Alexander Street substations) between these two stations as required.
2. Northpower's Wairua hydro power station output (run of river) is dependant on rainfall and Trustpower's diesel generator plant at Bream Bay is a peaker plant. The output of these plants is therefore unpredictable and may or may not reduce network peak loading.

5.3.5 Zone Substation Loading and Load Growth Expectations

The following is an overview of present loading and future load growth expectations for each zone substation. The data given in the tables refers only to 33/11kV transformation and associated 11kV feeder loads at these stations. Large industrial loads are supplied at 33kV at Bream Bay (2 customers), Maungatapere (2 customers) and Kauri (Fonterra) substations and present and expected future peak demand values for these loads are given in the load forecast table above.

5.3.5.1 Bream Bay Zone Substation

Zone Substation	Bream Bay			
Transformer 1 (MVA)	-			
Transformer 2 (MVA)	7.5/10			
Peak load (MW)	3.9			
ICP's connected (No.)	1086			
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**	**Peak current (A)**
Trustpower Generator	1106	11	1	-484
Marsden South	1107	11	1078	160
Port	1110	11	8	66
Ripple	1111	11	0	30

This substation supplies a mixture of industrial, commercial and residential load. The potential for growth in the surrounding area is very high, with the District Council designating large areas of land for heavy industry, service industry and residential development. The present 11kV load is relatively small but is expected to increase substantially in the medium to long term due to the development of the deep-water port at Marsden Point, a newly established marina in the One Tree Point area and other growth potential noted above.

Although it is possible to back feed part of the 11kV load from Ruakaka substation in the event of a contingency on the single 10MVA 33/11kV transformer, installation of a second transformer is planned in future (2021) to increase security of supply as the load grows. The need for and timing of a second transformer will need to take into consideration the recent commissioning of a 10MW peaker generation plant (connected to the station's 11kV bus) by an energy company as this plant could be used for backstopping purposes but at a relatively high cost. An additional 11kV feeder is also planned in future to offload one of the feeders and also improve feeder backstopping capability.

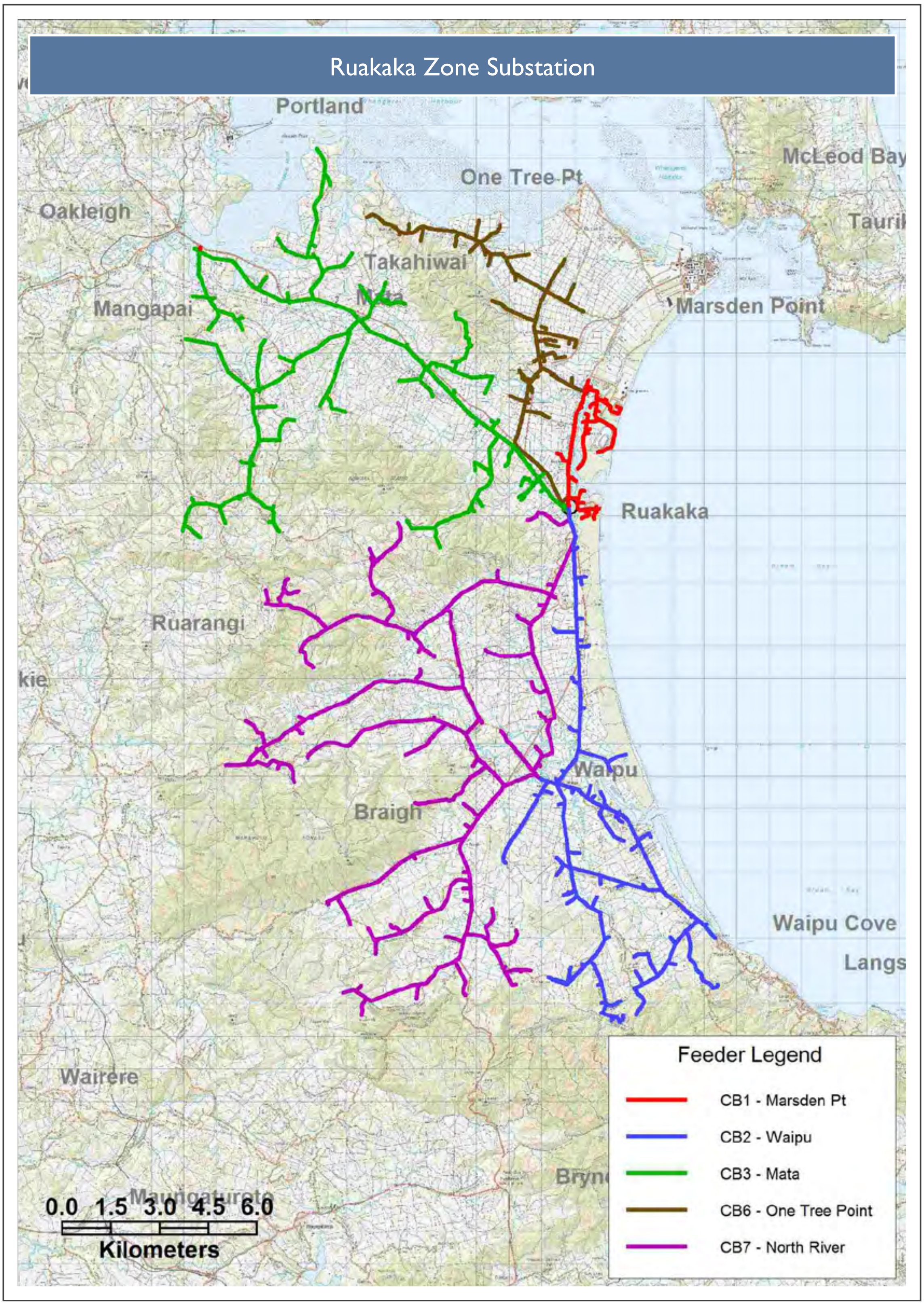
Bream Bay Geographic Feeder Layout

5.3.5.2 Ruakaka Zone Substation

Zone Substation	Ruakaka			
Transformer 1 (MVA)	10			
Transformer 2 (MVA)	10			
Peak load (MW)	6.6			
ICP's connected (No.)	3442			
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**	**Peak current (A)**
Marsden Point	1	11	1241	122
Waipu	2	11	847	132
Mata	3	11	390	50
One Tree Point	6	11	249	31
Northriver	7	11	715	66
Spare	8	11	0	0

This substation is centred on Ruakaka Township and also feeds the surrounding dairy farming rural area, Waipu Township and the south-east coast holiday resort area. The rural area is becoming more lifestyle in nature with significant subdivision activity and the growth rate is expected to be high in future.

Ruakaka substation was recently upgraded to 2x10MVA 33/11kV transformers and the old 11kV oil circuit breaker switchboard was replaced with modern gas insulated switchgear in 2008. The new switchboard incorporates a spare feeder for the anticipated future growth. A voltage regulator is planned for installation on the Waipu feeder in 2016 to support the growing load on this feeder.



Ruakaka Geographic Feeder Layout

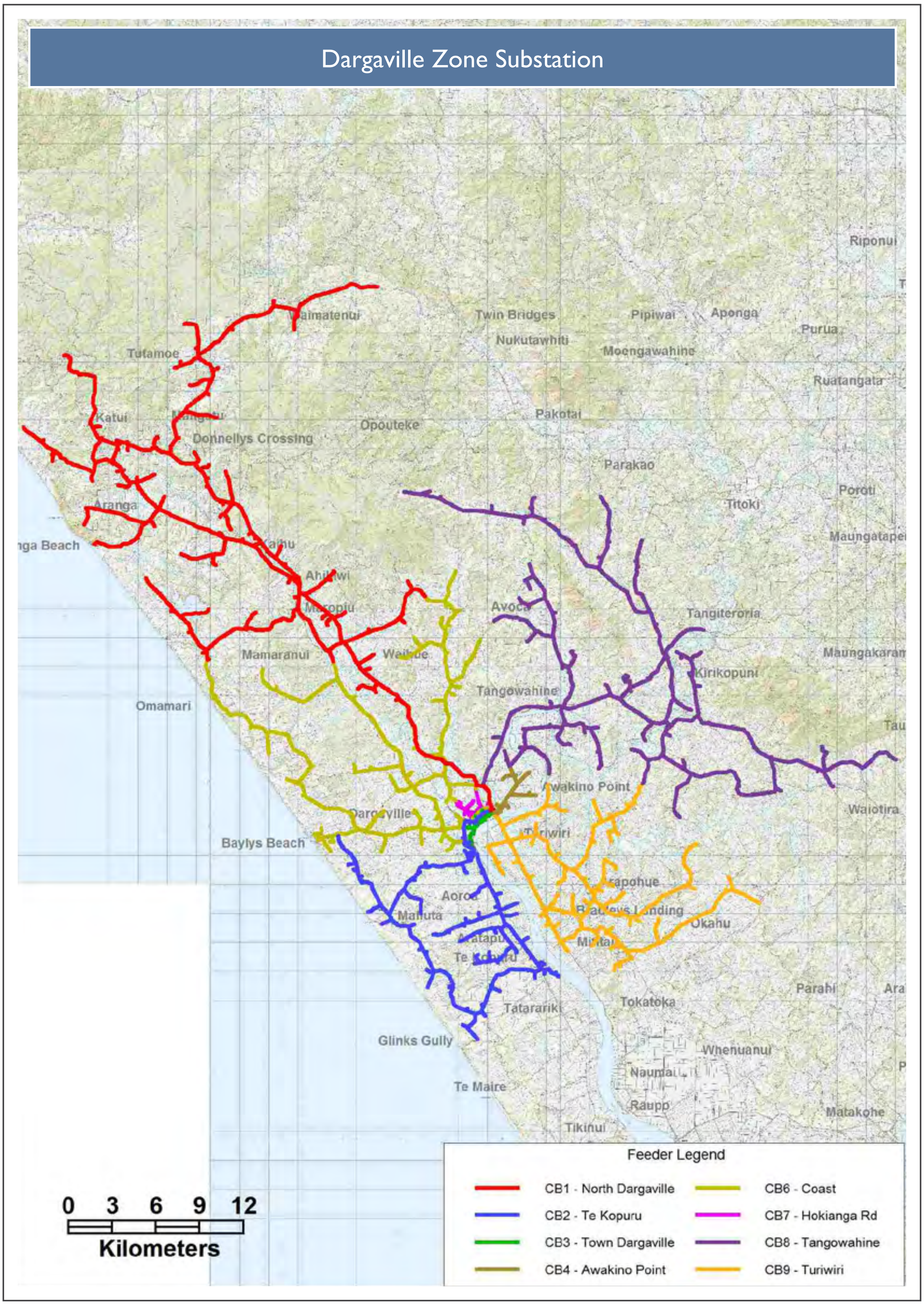
5.3.5.3 Dargaville Zone Substation

Zone Substation	Dargaville			
Transformer 1 (MVA)	7.5/15			
Transformer 2 (MVA)	7.5/15			
Peak load (MW)	11.4			
ICP's connected (No.)	5627			
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**	**Peak current (A)**
North	1	11	616	81
Te Koporu	2	11	865	96
Town	3	11	869	128
Awakino Point	4	11	345	129
Coast	6	11	866	75
Hokianga Rd	7	11	1002	120
Tangowahine	8	11	572	54
Turiwiri	9	11	492	58

Northpower recently acquired the 50kV yard and 50/11kV transformers at this station from Transpower. A new switch room building equipped with modern gas insulated switchgear was recently commissioned at this station in order to replace the very old 11kV oil switchgear which was located within Transpower's switchroom. A major reconfiguration of the 11kV feeders at this station was completed in 2015 in order to remove a double circuit line running through the town and to optimise feeder loading.

In addition to Dargaville town, this substation supplies a very large rural area (mainly dairy farming) centred on Dargaville town and this load dominates the substation load. The meat works on the outskirts of the town and a sawmill to the north are the only significant industrial loads. Load growth has historically been very low although there is a small amount of seasonal growth due to subdivision activity along the coast west of Dargaville town.

The mostly likely sector for significant load growth in future is forestry as there as there are large plantations to the north of Dargaville. The growth in the medium to longer term is expected to be low but this could change should any major new developments materialise.



Dargaville Geographic Feeder Layout

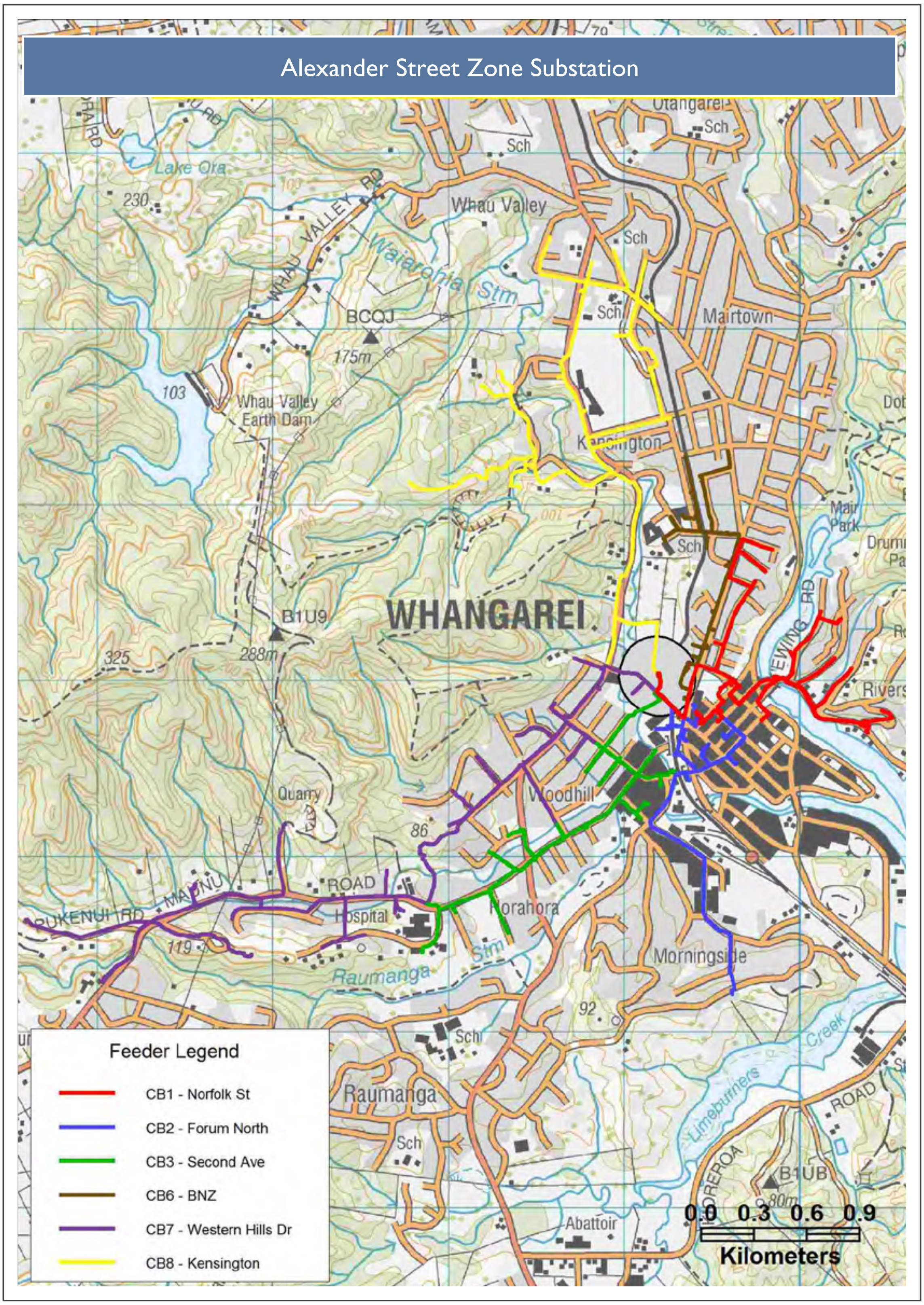
5.3.5.4 Alexander Street Zone Substation

Zone Substation	Alexander Street			
Transformer 1 (MVA)	7.5/15			
Transformer 2 (MVA)	7.5/15			
Peak load (MW)	14.7			
ICP's connected (No.)	4500			
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**	**Peak current (A)**
Norfolk St	1	11	808	163
Forum North	2	11	374	154
Second Ave	3	11	933	132
BNZ	6	11	457	164
Western Hills	7	11	1208	147
Kensington	8	11	720	97

This substation supplies the Whangarei City CBD as well as central residential areas and is now supplied directly from Kensington GXP as a result of the recent commissioning of a new 33kV cable.

The long term load growth in the area is expected to be moderate as the CBD area is almost fully developed. Business expansion is taking place in Whangarei but this tends to be outside the current CBD area and a number of businesses have also relocated away from the central commercial area.

Some residential load will be transferred from this station to the planned new substation in Maunu in future, thus delaying the need to upgrade the transformers for some time. Alexander Street substation is an important backstop for any contingency at Whangarei South or Tikipunga substations.



Alexander Street Geographic Feeder Layout

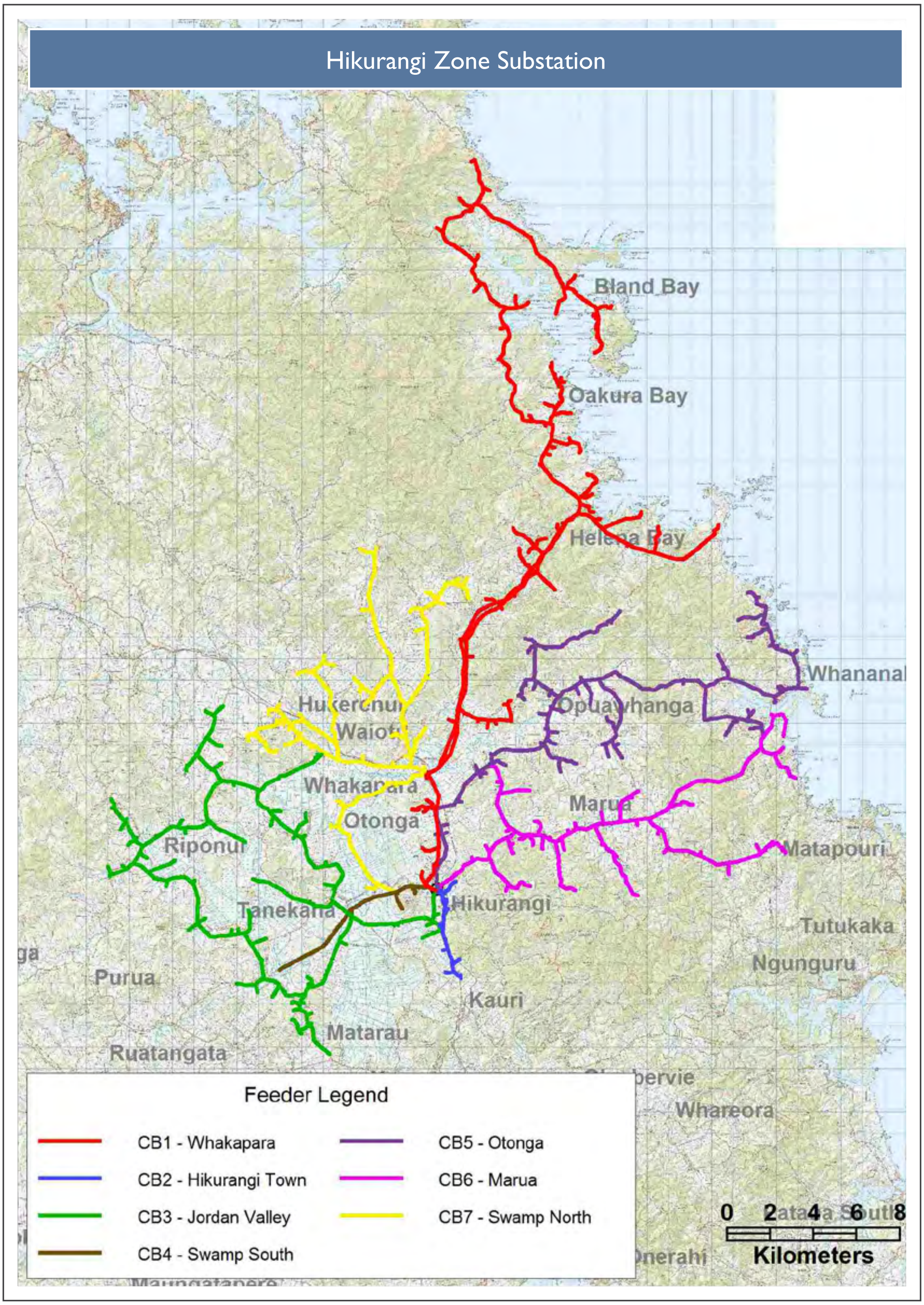
5.3.5.5 Hikurangi Zone Substation

Zone Substation	Hikurangi			
Transformer 1 (MVA)	5			
Transformer 2 (MVA)	5			
Peak load (MW)	6.4			
ICP's connected (No.)	3123			
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**	**Peak current (A)**
Whakapara	1	11	995	94
Town	2	11	500	76
Jordan Valley	3	11	437	89
Swamp South	4	11	21	55
Otonga	5	11	522	54
Marua	6	11	279	26
Swamp North	7	11	369	87

At present the rural load (mainly dairy farming) centred on Hikurangi township dominates Hikurangi substation load but there is also some industrial load in the Town. The substation also supplies a large flood-pumping scheme in the Hikurangi swamp area (occasional operation) as well as the coastal resort areas along the east coast as far north as Bland Bay.

The most likely prospect for growth is life-style section and holiday resort development in the scenic east coast area but Hikurangi town itself could see development in future as an overflow from Whangarei. To date most of the coastal growth has been south of Whangarei and, to a lesser extent, in the Tutukaka area. As these areas become more populated it is expected that the demand for coastal properties North of Whangarei will increase.

The load growth in the short to medium term is likely to be moderate but could increase in the longer term in association with growth in Whangarei. Northpower has plans in place to upgrade and strengthen the 11kV network feeding the Helena Bay, Oakura and Bland Bay areas but actual upgrade expenditure will only be incurred when the the capacity of the existing network needs to be increased (currently planned for 2019/20).



Hikurangi Geographic Feeder Layout

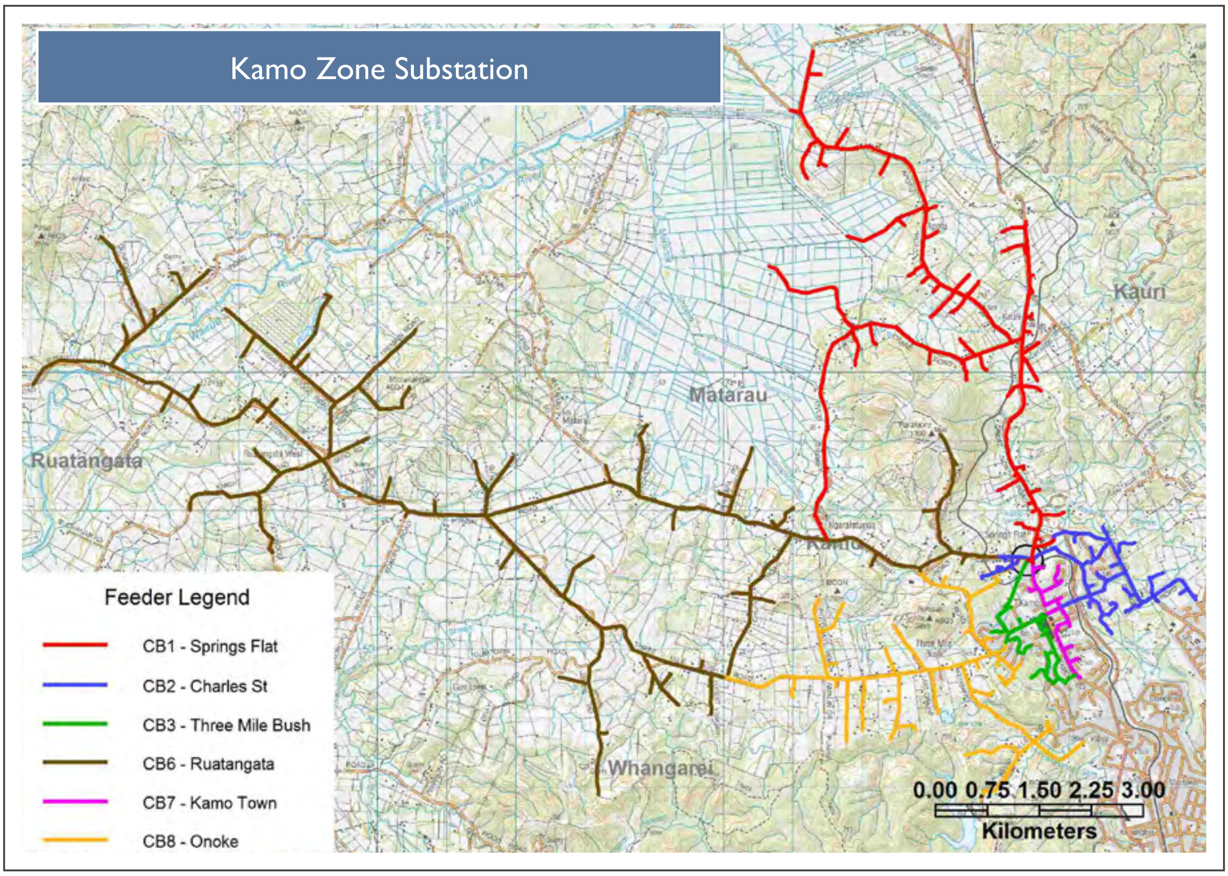
5.3.5.6 Kamo Zone Substation

Zone Substation	Kamo			
Transformer 1 (MVA)	7.5/15			
Transformer 2 (MVA)	7.5/15			
Peak load (MW)	11.9			
ICP's connected (No.)	4924			
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**	**Peak current (A)**
Springs Flat	1	11	582	125
Charles St	2	11	1163	134
Three Mile Bush	3	11	863	110
Ruatangata	6	11	658	80
Kamo Town	7	11	617	73
Onoke	8	11	1041	138

Located on the northern boundary of Whangarei City, this substation supplies a mixture of load types, including industrial, commercial, residential and rural.

The industrial and commercial load is currently faily small with the main growth occurring in the residential sector due to a high number of lifestyle blocks and new residential subdivisions being developed. This trend is likely to increase with planned development to the west, and a relatively high growth rate can be expected over the next 5-10 years. Associated moderate commercial and light industrial load growth is also expected.

The present 15MVA firm capacity at Kamo substation is adequate for the medium to long term. The 11kV switchboard upgrade was completed in 2011 and a new 11kV feeder was commissioned in 2015 to offload the Three Mile Bush feeder and reconfigure two other feeders to allow for load growth.



Kamo Geographic Feeder Layout

5.3.5.7 Ngunguru Zone Substation

Zone Substation	Ngunguru			
Transformer 1 (MVA)	3.75			
Transformer 2 (MVA)	-			
Peak load (MW)	3.2			
ICP's connected (No.)	1878			
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**	**Peak current (A)**
Tutukaka Block	1	11	577	61
Capacitor	2	11	0	40
Kaiatea	4	11	628	65
Matapouri	5	11	673	75

This substation supplies Ngunguru township and the coastal area to the north-east of Whangarei. The area has a mix of residential, rural and lifestyle load and the load peaks during holiday periods. Moderate growth is likely to continue in the short to medium term. However, potential new holiday resort type developments centred on Tutukaka, Matapouri and Ngunguru itself could increase demand on the substation significantly in future.

The 3.75MVA transformer will need to be upgraded in the medium term (planned for 2021) to accommodate the anticipated increase in load and the aging 11kV switchboard will be replaced at the same time.

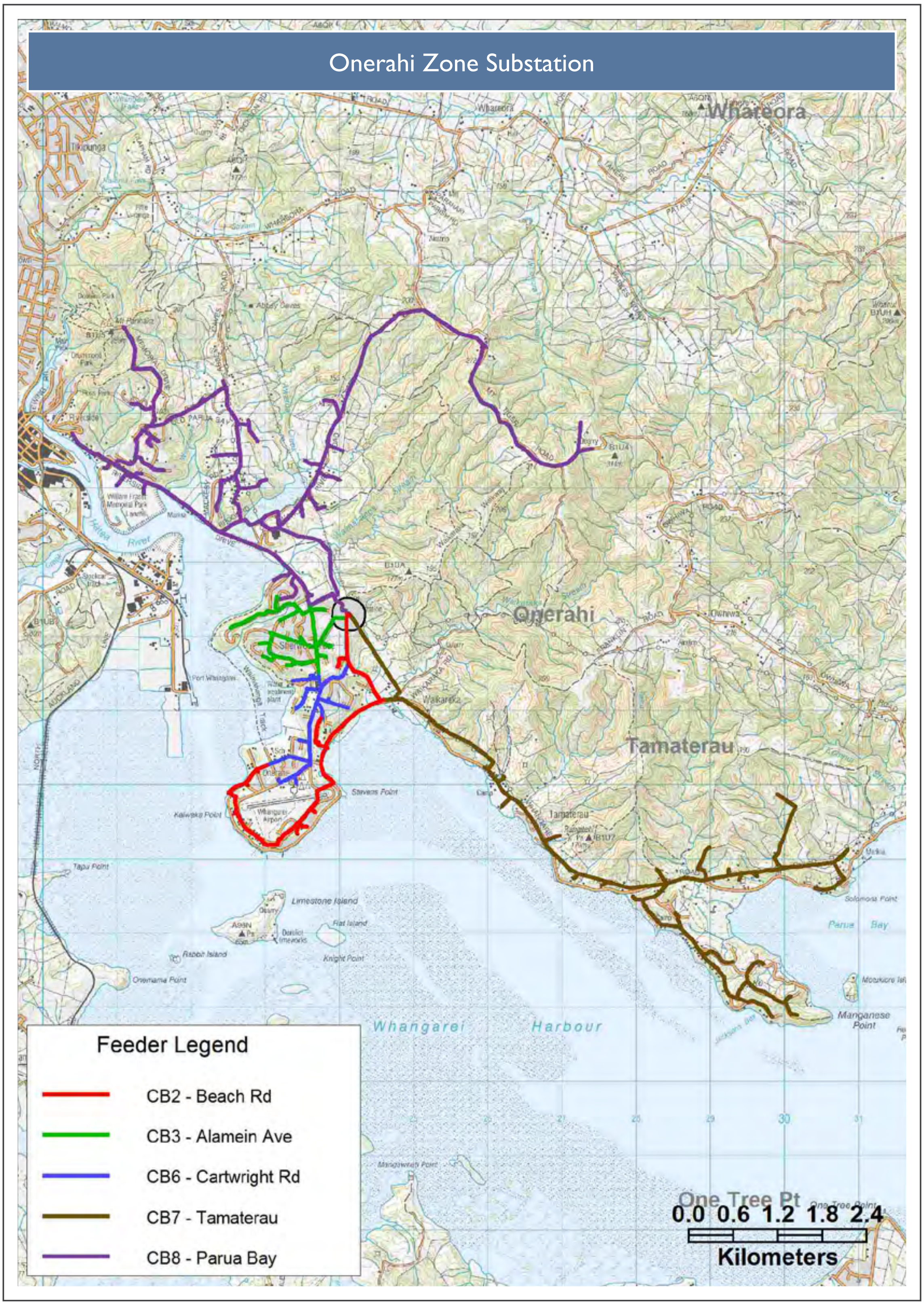
Ngunguru Geographic Feeder Layout

5.3.5.8 Onerahi Zone Substation

Zone Substation	Onerahi			
Transformer 1 (MVA)	7.5			
Transformer 2 (MVA)	7.5			
Peak load (MW)	8.3			
ICP's connected (No.)	3872			
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**	**Peak current (A)**
Capacitor	1	11	0	40
Beach Rd	2	11	616	70
Alamein Rd	3	11	985	105
Cartwright Rd	6	11	781	99
Tamaterau	7	11	501	75
Montgomery Rd	8	11	989	109

This substation supplies the suburb of Onerahi (mainly residential with some commercial load) but the 11kV network also feeds out to the residential areas of Tamaterau, Manganese Point and part of Riverside as well. There is currently a moderate amount of residential development in the area fed from this substation and this is expected to continue.

The 11kV switchboard at Onerahi substation was upgraded in 2010 and two 11kV feeders were reconfigured in 2015 to offload the Montgomery Road feeder. There are no plans to upgrade the transformers within the next 10 years as partial backfeed is possible from adjacent zone substations.

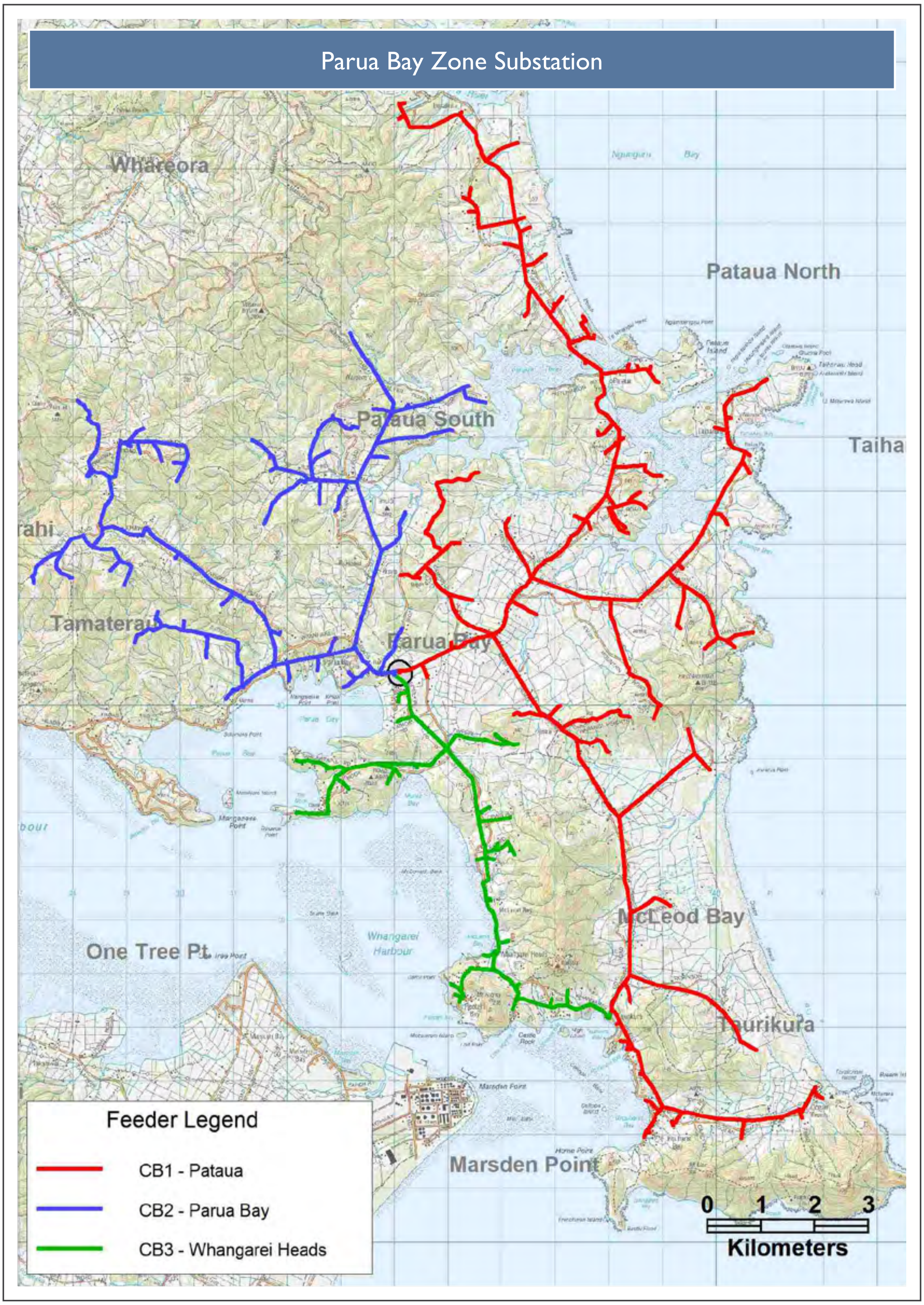


Onerahi Geographic Feeder Layout

5.3.5.9 Parua Bay Zone Substation

Zone Substation	Parua Bay			
Transformer 1 (MVA)	3.75			
Transformer 2 (MVA)	-			
Peak load (MW)	3.3			
ICP's connected (No.)	1996			
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**	**Peak current (A)**
Pataua	1	11	820	54
Parua Bay	2	11	481	48
Whangarei Heads	3	11	694	64

This substation supplies the Parua Bay, McLeod's Bay, Whangarei Heads and Pataua area comprising of mainly residential type load. Load growth has been fairly low during the past 5 years but there is potential for significant development. This substation was commissioned early in 2007 utilising one of the refurbished 3.75MVA transformers ex Hikurangi substation. A second 3.75MVA unit is held on site as a spare and will be permanently installed and connected in parallel with the other unit in the medium term (planned for 2020) to provide additional peak load capacity as well as N-1 security.



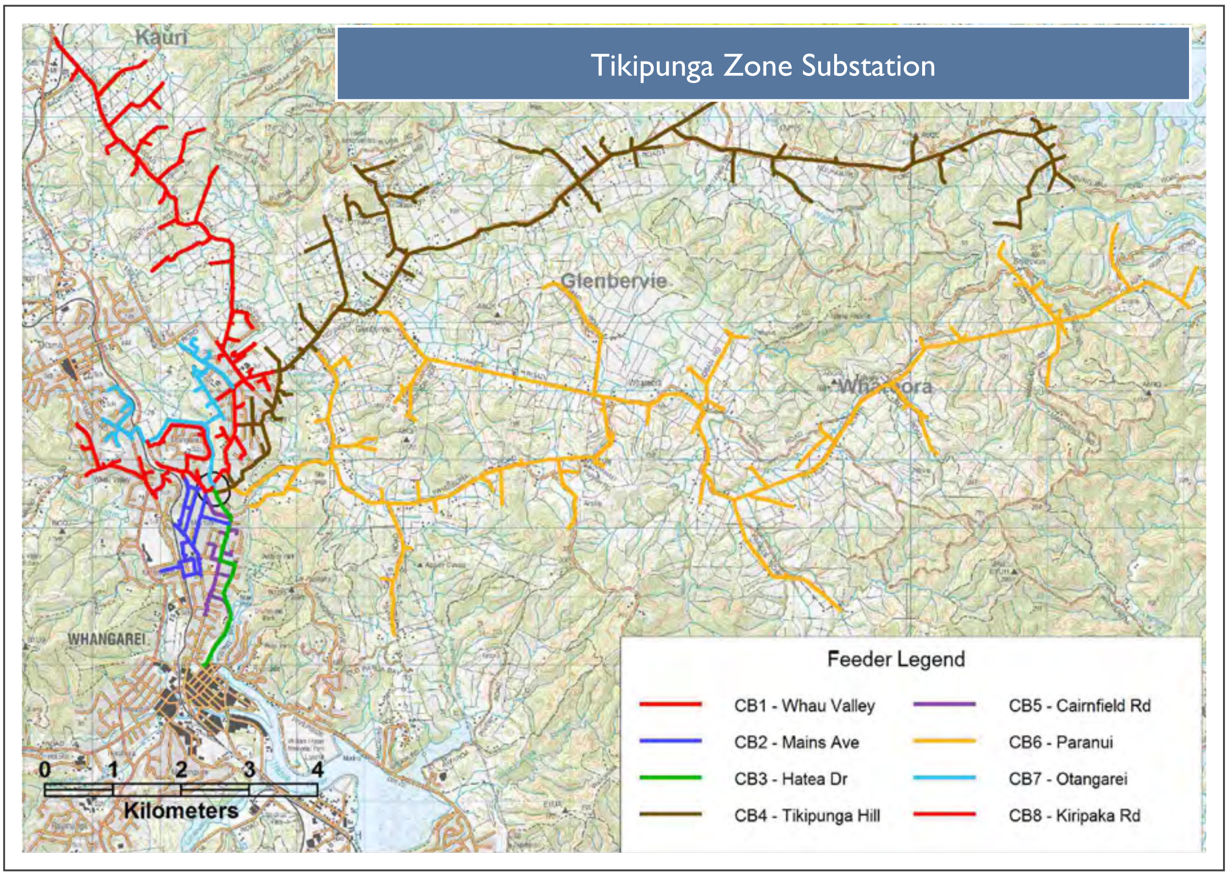
Parua Bay Geographic Feeder Layout

5.3.5.10 Tikipunga Zone Substation

Zone Substation	Tikipunga			
Transformer 1 (MVA)	20			
Transformer 2 (MVA)	20			
Peak load (MW)	15.7			
ICP's connected (No.)	7027			
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**	**Peak current (A)**
Whau Valley	1	11	1280	145
Mains Ave	2	11	846	97
Hatea Drive	3	11	0	0
Tikipunga Hill	4	11	949	122
Cairnfield Rd	5	11	1168	124
Paranui	6	11	574	118
Otangarei	7	11	911	121
Kiripaka Rd	8	11	1299	145

This substation is Northpower's largest zone substation in terms of number of premises connected and supplies the residential areas to the north of the CBD as well as the rural area to the north-east of Whangarei which includes a fairly large sawmill load. The substation load peaks in winter due to heating load. Load growth is moderate, driven mainly by residential growth in the Kensington and Tikipunga suburbs due to urban 'in-fill' but development is expected to continue in the area to the north and east of the substation.

The old 11kV oil switchgear at this station was replaced with modern gas insulated switchgear in 2008 and the transformers were upgraded to 2x20MVA units in 2009. Some changes were recently made to feeder configurations resulting in the transfer of some load from Kamo substation to Tikipunga substation.



Tikipunga Geographic Feeder Layout

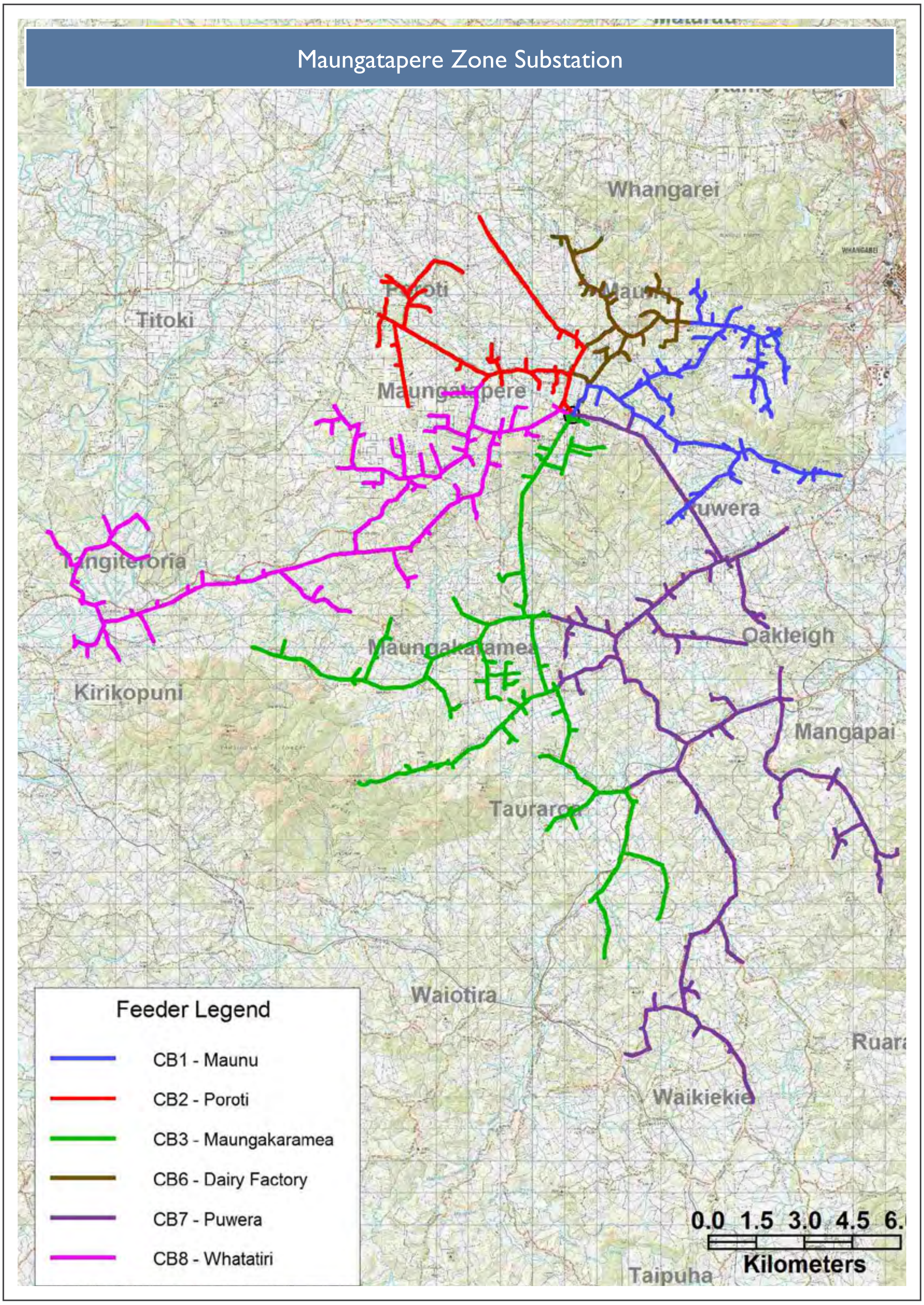
5.3.5.11 Maungatapere Zone Substation

Zone Substation	Maungatapere			
Transformer 1 (MVA)	5			
Transformer 2 (MVA)	5			
Peak load (MW)	6.9			
ICP's connected (No.)	3174			
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**	**Peak current (A)**
Maunu	1	11	921	113
Poroti	2	11	346	41
Maungakaramea	3	11	558	66
Dairy Factory	6	11	398	52
Puwera	7	11	387	47
Whatatiri	8	11	564	65

This substation supplies the predominantly rural area (dairy and fruit farming) around Maungatapere village which includes Maungakaramea, Poroti, Tangiteroria, Puwera and Mangapai. One of the feeders also supplies part of the Maunu residential area to the west of Whangarei City. There is a significant amount of life-style type development in the rural areas and this trend is expected to continue in future.

A large amount of upmarket subdivision activity is expected in the Maunu area pending economic upturn as Whangarei City spreads westward and this is expected to result in substantial residential load growth in the medium to long term. Some load was transferred to Kioreroa substation in 2010 in order to maintain N-1 security (it is also possible to backfeed some of the Maungatapere load via the 11kV network from Poroti substation in the event of a contingency).

Some feeder reconfiguration work is planned for 2016 in order to provide additional capacity in the Maunu area as an interim measure until the planned new zone Maunu substation is constructed (planned for 2018). Maunu substation will relieve Maungatapere substation of some load and delay the need to upgrade of the 2 x 5MVA transformers. The 11kV switchboard at Maungatapere was upgraded in 2010.



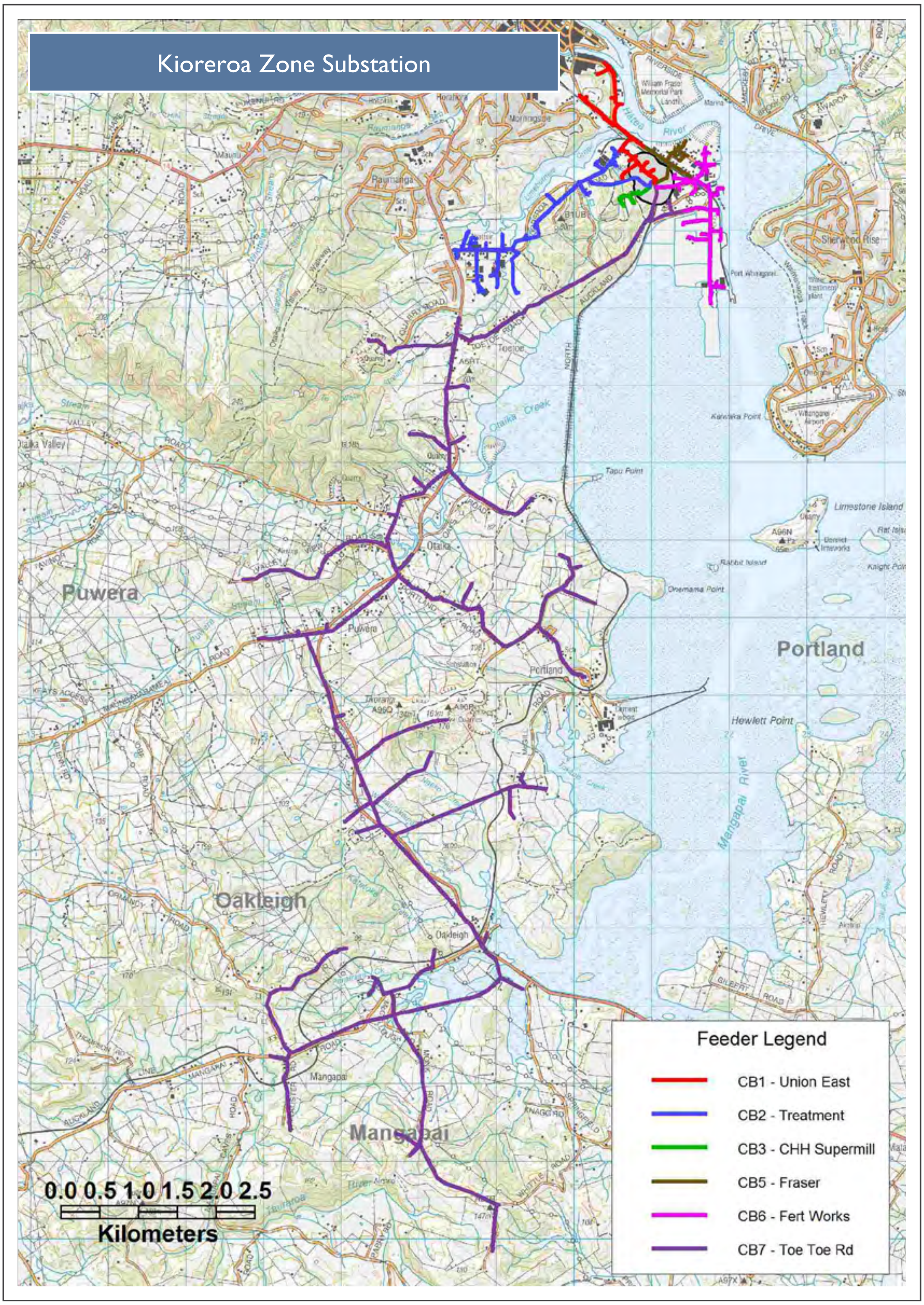
Maungatapere Geographic Feeder Layout

5.3.5.12 Kioreroa Zone Substation

Zone Substation	Kioreroa			
Transformer 1 (MVA)	15/20			
Transformer 2 (MVA)	15/20			
Peak load (MW)	10.4			
ICP's connected (No.)	992			
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**	**Peak current (A)**
Union East	1	11	59	162
Treatment	2	11	198	159
CHH Super Mill	3	11	1	153
Fraser	5	11	73	75
Fertiliser Works	6	11	82	113
ToeToe Rd	7	11	579	86

The area supplied by this substation is dominated by heavy industry with associated light industry and commercial loads. The Portland area to the south of Whangarei is also supplied from this substation and includes some rural load. Load growth has been high in the past due to the expansion of some industries but growth growth has been marginal in recent years. The development of the deep-water port at Marsden Point will see a continuation of the downsizing of the existing port activities resulting in a substantial amount of land being available for the establishment of new industries to the south-west of the substation. Significant load growth can be expected if development of this area proceeds.

The 2x10 MVA transformers at this station were upgraded to 2 x 15/20 MVA in early 2006 in anticipation of the expected future load growth as well as to facilitate the upgrading of the transformers at 3 other zone substations. Some rural load south of Whangarei was transferred to this station from Maungatapere substation in 2010 in order to offload the transformers at the latter station. An additional 11kV feeder was commissioned 2014 to offload Whangarei South substation and optimise feeder loadings.



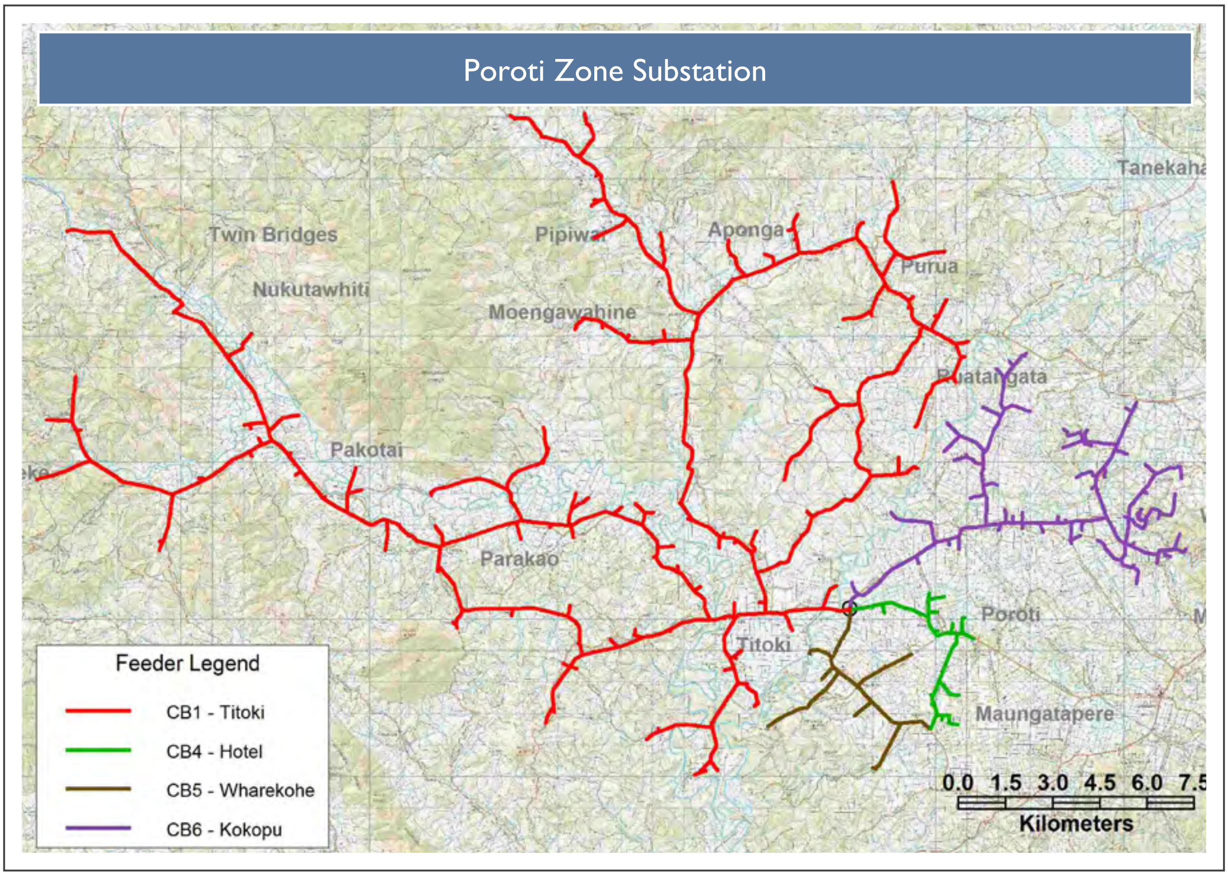
Kioreroa Geographic Feeder Layout

5.3.5.13 Poroti Zone Substation

Zone Substation	Poroti			
Transformer 1 (MVA)	5			
Transformer 2 (MVA)	-			
Peak load (MW)	3.2			
ICP's connected (No.)	1249			
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**	**Peak current (A)**
Titoki	1	11	711	111
Capacitor	2	11	0	42
GFN Cap Bank	3	11	0	0
Hotel	4	11	106	33
Wharekohe	5	11	68	20
Kokopu	6	11	364	48

This substation supplies a predominantly rural with no significant urban centres other than Titoki village. The substation covers a large area considering the relatively small total load. The present load growth is low and with no signs of development, future growth is also expected to be low. Poroti substation was built in 1990 to provide capacity for a large irrigation scheme proposed for the area. The scheme never developed as planned but some dairy farms in the Titoki area later installed irrigation schemes.

The load is seasonal and also weather dependent. Residential and lifestyle growth is relatively low and any significant growth is more likely to come from additional irrigation schemes. The present 5MVA transformer capacity at the substation is considered adequate for the medium term barring any new developments. A ground fault neutraliser was commissioned at Poroti substation in 2010 as a pilot project in order to evaluate the effectiveness of this technology and switched capacitors are employed on the Titoki feeder for voltage regulation purposes. The transformer and 11kV switchboard are planned to be replaced within the next 10 years due to their age.



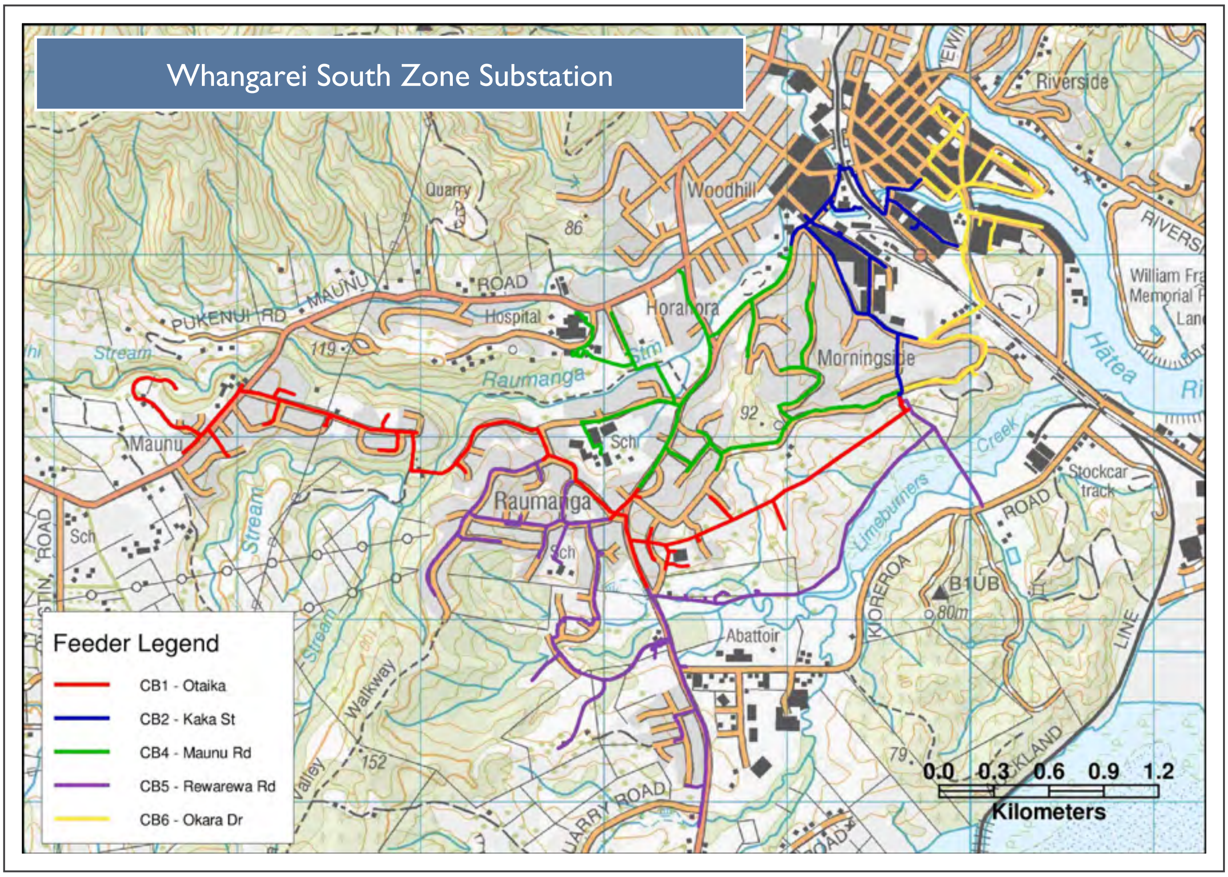
Poroti Geographic Feeder Layout

5.3.5.14 Whangarei South Zone Substation

Zone Substation	Whangarei South			
Transformer 1 (MVA)	10			
Transformer 2 (MVA)	10			
Peak load (MW)	12.8			
ICP's connected (No.)	3716			
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**	**Peak current (A)**
Otaika	1	11	968	127
Kaka St	2	11	461	135
Walton St	3	11	0	0
Maunu Rd	4	11	896	174
Rewa Rewa Rd	5	11	863	111
Okara Drive	6	11	528	191

This substation is situated to the south of Whangarei central business district and supplies a mixture of residential, commercial and light industrial load. Two major customers supplied from Whangarei South are the Whangarei Hospital and Northland Polytechnic. The transformers at this station were upgraded to 2 x 10MVA in 2006. The peak load exceeds the transformer n-1 capacity but, due to the close proximity of Alexander Street and Kioreroa substations, it is possible to transfer load in the event of a contingency.

The planned Maunu zone substation will result in the transfer of some residential load lying to the west of Whangarei South. This will free up capacity to accommodate anticipated new load to the south as well as some marginal growth of existing load. The commissioning of a new feeder at Kioreroa substation in 2014 allowed some load to be transferred to that substation.



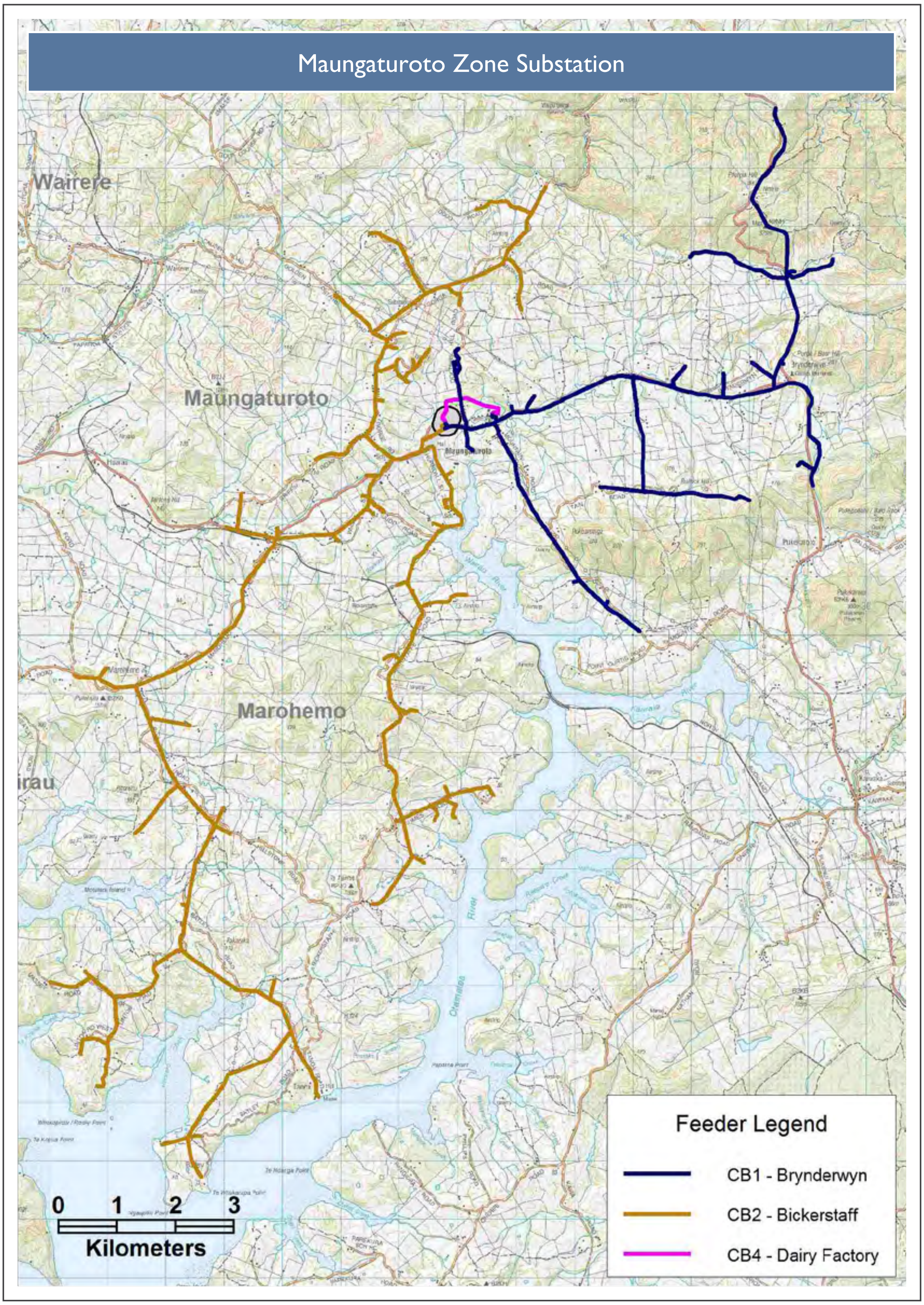
Whangarei South Geographic Feeder Layout

5.3.5.15 Maungaturoto Zone Substation

Zone Substation	Maungaturoto			
Transformer 1 (MVA)	7.5			
Transformer 2 (MVA)	7.5			
Peak load (MW)	7.4			
ICP's connected (No.)	869			
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**	**Peak current (A)**
Brynderwyn	1	11	176	62
Bickerstaffe	2	11	691	82
Dairy Factory	4	11	2	251

The load on this substation is dominated by the local dairy factory, which accounts for approximately 75% of the substation's maximum demand. The dairy factory load is not expected to increase in the short to medium term. The remainder of the load is made up of the Maungaturoto town and large surrounding rural area in which the load is predominantly dairy farmimg. Maungaturoto substation is an important backstop for Kaiwaka and Mareretu single transformer substations.

The growth in the township and surrounding area is low and the future load growth potential is mainly driven by the possible expansion of the Dairy Factory in the longer term. The 2 x 5MVA transformers at this station were replaced with 7.5MVA units in 2006 and the 10 year plan makes provision for upgrading the 11kV switchboard in 2024 and replacing the transformers in 2023 for age reasons.

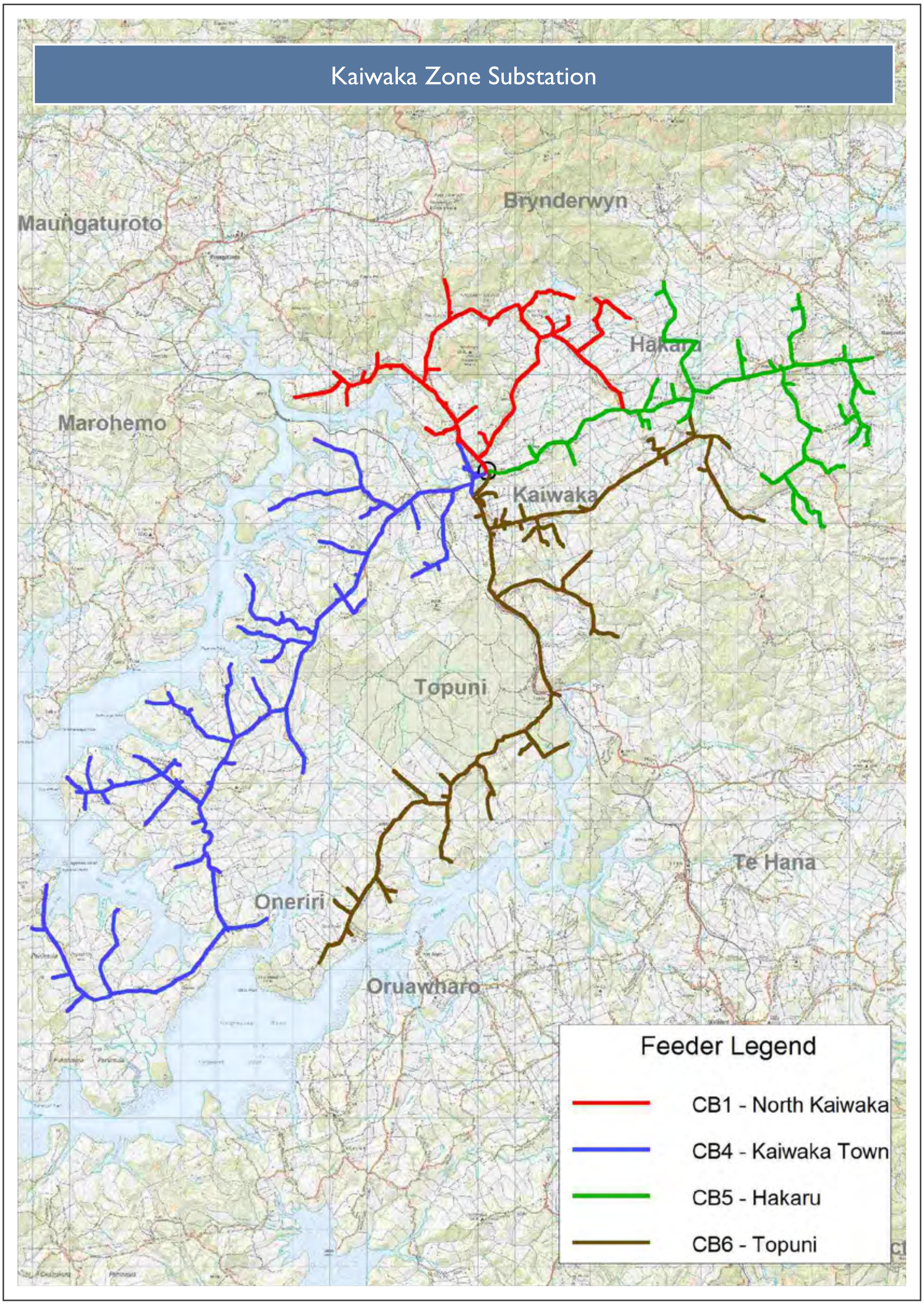


Maungaturoto Geographic Feeder Layout

5.3.5.16 Kaiwaka Zone Substation

Zone Substation	Kaiwaka			
Transformer 1 (MVA)	5			
Transformer 2 (MVA)	-			
Peak load (MW)	1.7			
ICP's connected (No.)	1360			
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**	**Peak current (A)**
North	1	11	172	52
Kaiwaka Town	4	11	401	34
Hakaru	5	11	361	35
Topuni	6	11	426	41

This substation supplies Kaiwaka Town and surrounding rural area which is predominantly dairy farming. There is however an increasing amount of lifestyle block development and the expectation is that the demand for lifestyle properties will continue or even increase due to the proximity to Auckland and the development in the Oneriri and Topuni (Kaipara harbour) area. The 11kV switchboard is planned to be replaced in 2021.



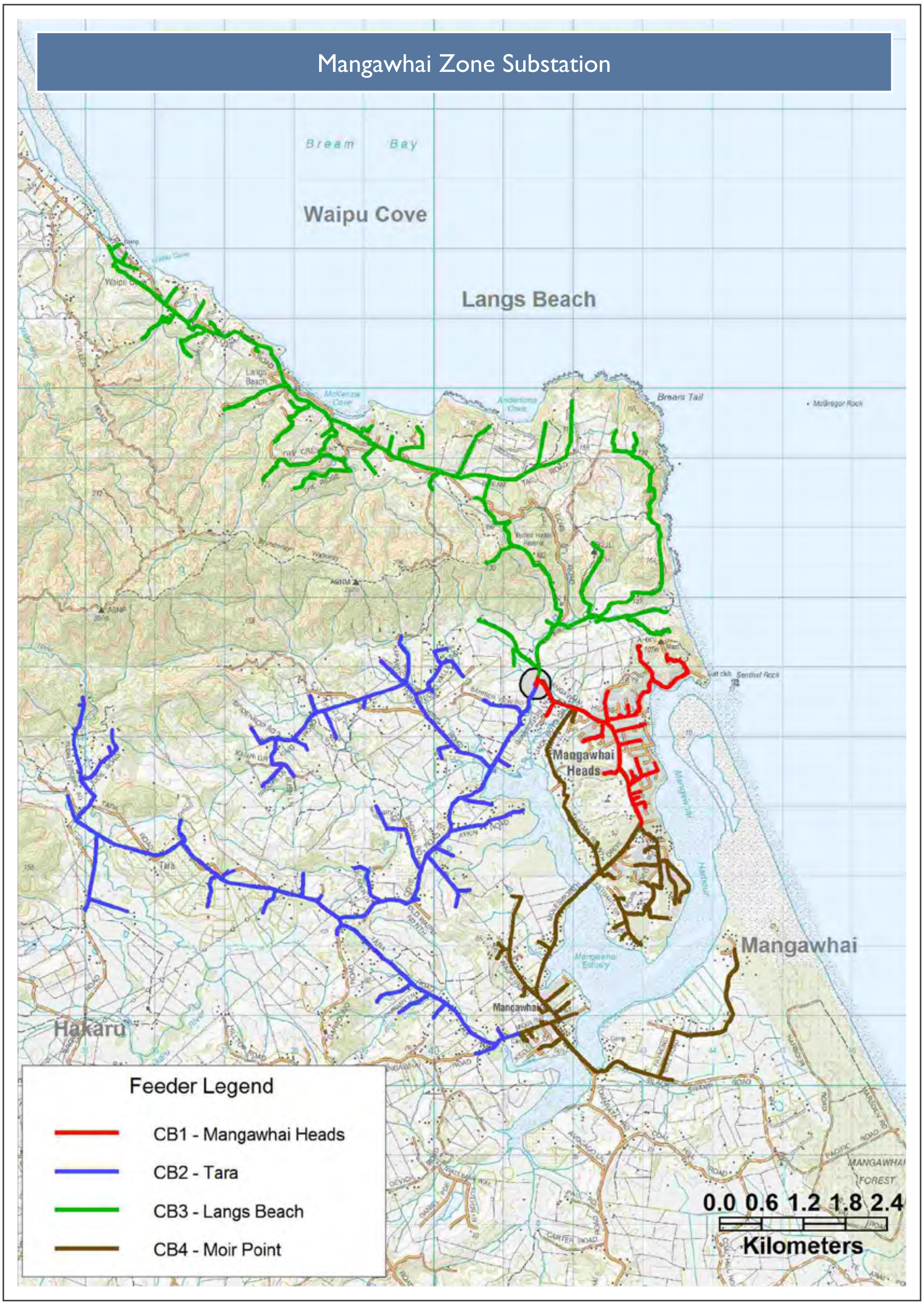
Kaiwaka Geographic Feeder Layout

5.3.5.17 Mangawhai Zone Substation

Zone Substation	Mangawhai			
Transformer 1 (MVA)	5			
Transformer 2 (MVA)	5			
Peak load (MW)	6.2			
ICP's connected (No.)	3542			
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**	**Peak current (A)**
Mangawhai Heads	1	11	1165	106
Tara	2	11	517	41
Langs Beach	3	11	585	61
Moir Point	4	11	1275	122

The load on this substation is mainly coastal residential, holiday home and rural life style with some commercial and there is also some some dairy farming in the Tara area. The urban areas include Mangawhai Heads, Mangawhai village, Lang's Cove and Waipu Cove. The substation load is characterised by high peak demands during holiday periods. The load has grown at a very high rate in the past but has reduced significantly in recent years. Further growth is expected in future due to Mangawhai's proximity to Auckland.

A second 5MVA transformer was commissioned at this station at the end of 2009 for both capacity and security of supply reasons and the Moir Point feeder was recently extended by means of a cable link in order to offload the Mangawhai Heads feeder and also provide feeder backstopping capability.

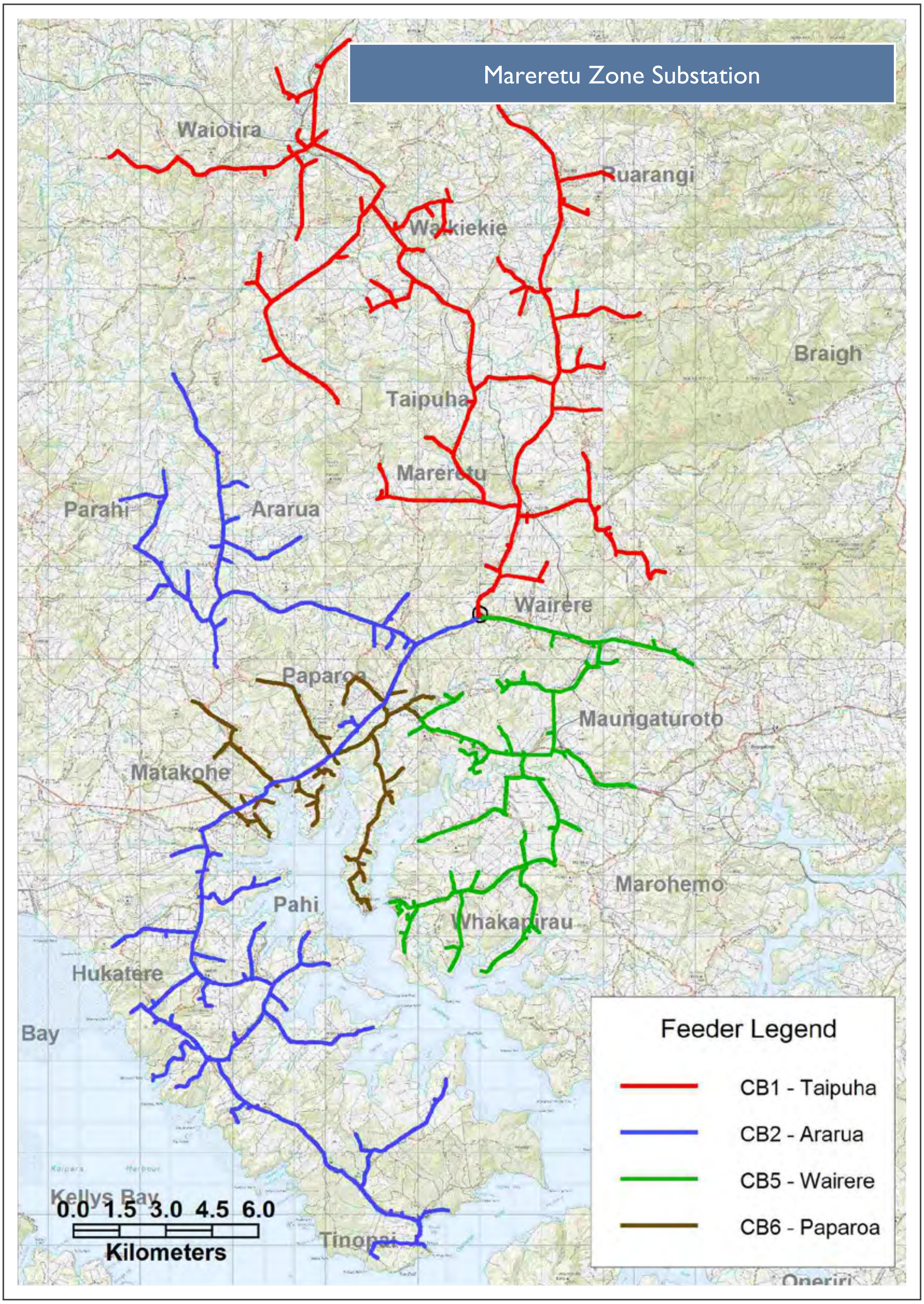


Mangawhai Geographic Feeder Layout

5.3.5.18 Mareretu Zone Substation

Zone Substation	Mareretu			
Transformer 1 (MVA)	5			
Transformer 2 (MVA)	-			
Peak load (MW)	2.7			
ICP's connected (No.)	1867			
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**	**Peak current (A)**
Taipuha	1	11	424	51
Ararua	2	11	573	44
Wairere	5	11	352	27
Pararoa	6	11	518	42

The load on this substation is predominantly rural dairy farmimg with no significant urban centres other than Paparoa village. The substation supplies a large area, although the total load is relatively small. The present load growth is low with no sign of significant development in the short to medium term with the result that growth is expected to remain fairly low. There is however significant potential for lifestyle type development in the Matakohe and Tinopai peninsula areas.



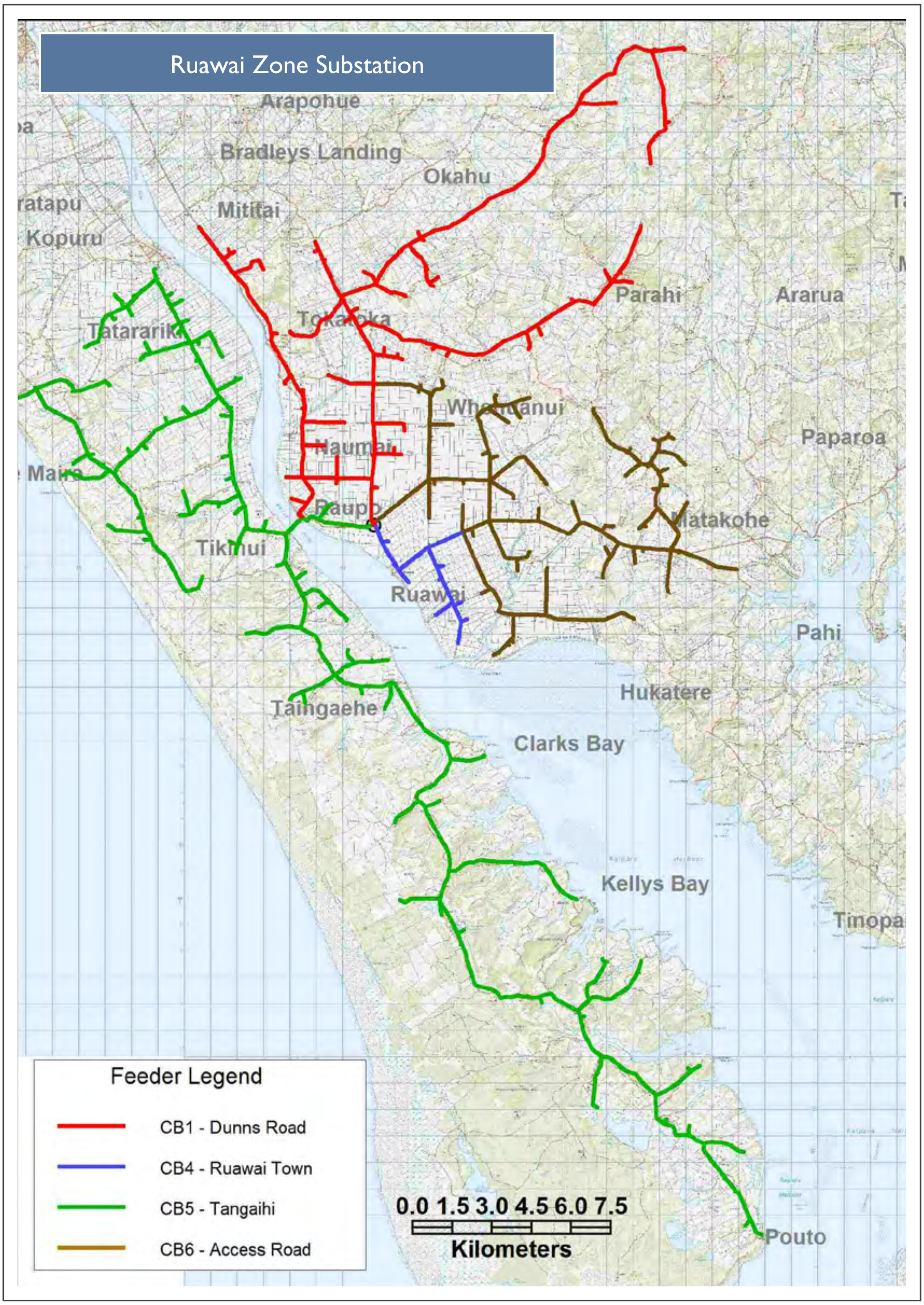
Mareretu Geographic Feeder Layout

5.3.5.19 Ruawai Zone Substation

Zone Substation	Ruawai			
Transformer 1 (MVA)	5			
Transformer 2 (MVA)	-			
Peak load (MW)	3.1			
ICP's connected (No.)	1630			
Feeder Name	**CB**	**Voltage (kV)**	**ICP's (No.)**	**Peak current (A)**
Dunns Rd	1	11	351	51
Ruawai Town	4	11	323	49
Tangaihi	5	11	628	80
Access Rd	6	11	328	49

This substation supplies Ruawai Town with the load dominated by the surrounding rural dairy farming area. The growth is currently low and this trend is expected to continue for the short to medium term barring any major developments in Ruawai or along the Pouto peninsular.

Some load was transferred from the Dargaville area in 2015 which resulted in a fairly significant increase in substation peak load. The 11kV switchboard is planned to be replaced in 2018 and the transformer in 2021 for age reasons.



Ruawai Geographic Feeder Layout

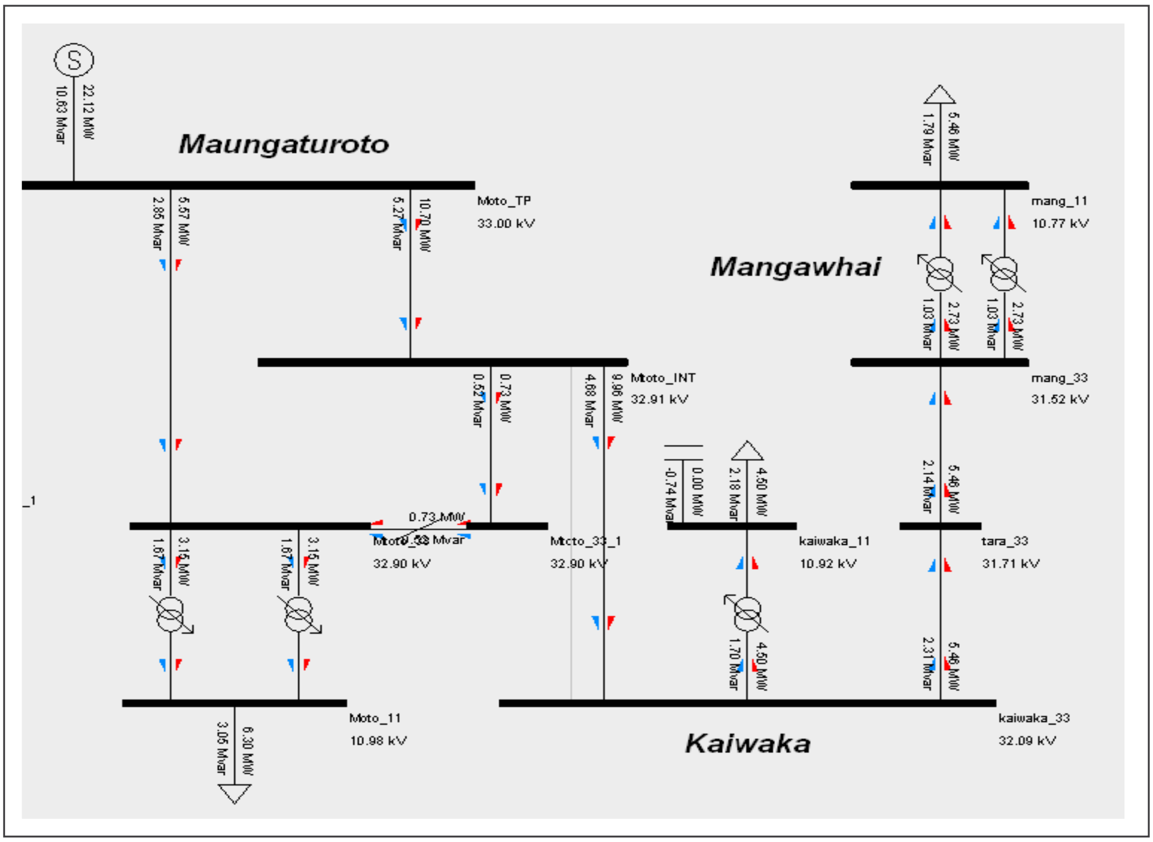
5.3.6 Network Capacity Constraints

Constraints need to be identified under both N (system normal conditions) and N-1 (system abnormal) conditions. The latter case refers to situations where, due to a fault or plant being temporarily out of service, the capacity of the remaining network components is determined.

Resolution of constraints usually involves upgrading of existing equipment but in some cases network reconfiguration or commissioning of new assets is required. In the case of N-1 capacity constraints, decisions on what action to take will be based on risk and required levels of security. Temporary load shedding may be considered an acceptable solution in some cases, especially where the cost of resolving the constraint is excessive.

Thermal constraints can sometimes be resolved more cost effectively by means of cooling (fans), improving ground thermal resistivity for underground cables or resagging of overhead line conductors to resolve ground clearance issues. Voltage constraints can be resolved by increasing conductor size, installing voltage regulators, improving the power factor with capacitor banks, changing to a higher voltage level or constructing new assets.

Northpower utilises power system modeling and thermal rating software together with the load forecast data to identify future capacity constraints on the network. Load flow studies are carried out for both system normal and contingency analyses and the results of these studies are used to maximize capacity utilisation and delay investment in new assets until they are absolutely necessary. Where a future capacity constraint is identified the software is used to model and evaluate alternative options available to resolve the constraint. An example of a network model load flow analysis is provided below.



Subtransmission Model

5.3.6.1 Subtransmission

The most significant constraints, both in terms of the number of customers potentially affected and the cost of overcoming the constraint exists at zone substations and on the subtransmission network feeding them. Constraints at this level are normally due to equipment current ratings (load as well as fault) rather than voltage and significant components are:

- Transformers.
- Circuit breakers and isolators.
- Busbars and jumpers.
- Cables and conductors.

The only constraints on the subtransmission network expected over the next 10 years (based on the 10 year load forecast) relate to subtransmission cable or line circuits and substation transformers.

Ssubtransmission cable/line circuit constraints anticipated over the next 10 years relate to the continued provision of N-1 capacity to key substations. They are the 33kV supply from Kensington to Kamo substations and the 33kV supply to Kioreroa substation. Provision has been made in the 10 year capex program for projects to remove these constraints.

The table below shows anticipated substation transformer capacity constraints (for both N and N-1 requirements) and planned resolutions during the next 10 years (refer 10 year capex program):

Substation	Voltage	Transformer	MD(MW)		N Constraint	N-1 Constraint	Backstop	Plannned Resolution
	KV	MVA	2015	2025				
Alexander Street	33/11	2x 7.5/15	14.7	15.0	None	None	Whangarei South, Tikipunga, Kioreroa, Onerahi	N/A
Bream Bay (1)	33/11	1x 7.5/10	3.9	5.9	None	No supply	Ruakaka, Trustpower peaker plant	Install 2nd trfr. (2021)
Bream Bay (2) Transpower	220/33	2x50/100	51.8	56.4	None	None	None	N/A
Dargaville	50/11	2x7.5/15	11.4	12.6	None	None	Maungatapere, Ruawai	N/A
Hikurangi	33/11	2x5	6.4	6.6	None	Trfr. rating	Kamo, Ngunguru, (Helena Bay)	Strategic spare trfr.
Kaiwaka	33/11	1x5	1.7	1.9	None	No supply	Mangaturoto, Mangawhai	Strategic spare trfr.
Kamo	33/11	2x 7.5/15	11.9	13.8	None	None	Hikurangi, Tikipunga, Poroti	N/A
Kensington	110/33	2x50	65.2	73.8	None	Trfr. rating	Maungatapere	Trfr. Upgrade (2024)
Kioreroa	33/11	2x15/20	10.4	12.7	None	None	Whangarei South, Alexander Street	N/A

Substation	Voltage	Transformer	MD(MW)		N Constraint	N-1 Constraint	Backstop	Plannned Resolution
	KV	MVA	2015	2025				
Mangawhai	33/11	2x5	6.2	7.9	None	Trfr. rating	Kaiwaka, Ruakaka	Strategic spare trfr.
Mareretu	33/11	1x5	2.7	3.0	None	No supply	Maungaturoto, Ruawai, Maungatapere	Strategic spare trfr.
Maungatapere (1)	110/50	2x25	11.4	12.6	None	None	Ruawai, Maungatapere	N/A
Maungatapere (2)	110/33	2x30	42.5	47.6	None	Trfr. rating	Kensington	Trfr. Upgrade (2026)
Maungatapere (3)	33/11	2x5	6.9	6.9	None	Trfr. rating	Poroti, Dargaville, Mareretu, Kamo and Kioreroa, (Maunu)	Strategic spare trfr.
Maungaturoto (1) Transpower	110/33	2x20	18.1	20.6	None	SG rating	None	Switchgear upgrade 2018
Maungaturoto (2)	33/11	2x7.5	7.4	7.8	None	Trfr. rating	Kaiwaka, Mareretu	N/A
Ngunguru	33/11	1x3.75	3.2	3.9	Trfr. rating	No supply	Tikipunga, Hikurangi	Strategic spare trfr. Trfr. upgrade (2022)
Onerahi	33/11	2x 7.5	8.3	9.2	None	Trfr. rating	Parua Bay, Alexander Street, Tikipunga	N/A
Parua Bay	33/11	1x3.75	3.3	4.0	Trfr. rating	No supply	Onerahi, Tikipunga	Strategic spare trfr. Install 2nd trfr. (2021)
Poroti	33/11	1x5	3.2	3.5	None	No supply	Maungatapere, Kamo	Strategic spare trfr.
Chip Mill	33/11	1x3.75	1.0	1.0	None	No supply	None	Strategic spare trfr.
Ruakaka	33/11	2x10	6.6	4.8	None	None	Bream Bay, Mangawhai, Maungatapere (Waipu)	N/A
Ruawai	33/11	1x5	3.1	3.4	None	No supply	Dargaville, Mareretu	Strategic spare trfr.
Tikipunga	33/11	2x20	15.7	17.3	None	None	Alexander Street, Kamo, Onerahi	N/A
Whangarei South	33/11	2x10	12.8	12.1	None	Trfr. rating	Alexander Street, Kioreroa, (Maunu)	N/A

5.3.6.2 Distribution

At distribution level, a number of 11kV rural distribution feeders are expected to become voltage constrained within the planning period. There are also some feeders which will become constrained due to load current or number of connected premises (in terms of number of customers affected after a feeder fault).

Each constrained feeder is unique in terms of length, conductor size, number of consumers, load distribution and load characteristics. A number of solutions are available to rectify these constraints such as:

- Shunt connected capacitor banks (voltage and current)
- Voltage regulators (voltage)
- Conductor upgrade (current and voltage)
- Feeder reconfiguration (voltage, current and number of consumers)
- Voltage upgrade (voltage and current)
- Distributed generation - diesel generator or PV stored energy (voltage and current)
- Zone substation (voltage, current and number of consumers

The following 11kV feeders have been identified as possibly requiring constraint resolution within the planning period subject to actual load growth experienced:

Substation	Feeder	Constraint	Resolution
Alexander Street	Western Hills Drive	voltage, customer numbers	Maunu Substation
Bream Bay	Marsden South	voltage and customer numbers	new feeder
Dargaville	North	voltage regulator capacity	200A regulator
Dargaville	Te Koporu	voltage	switched capacitors
Dargaville	Tangowahine	voltage	switched capacitors
Hikurangi	Jordan Valley	voltage	switched capacitors
Hikurangi	Whakapara	voltage and customer numbers	Helena Bay Substation
Hikurangi	Swamp North	voltage	switched capacitors
Kioreroa	Toe Toe Road	voltage	reconfiguration
Mangawhai	Moir Point	voltage	reconfiguration
Maungatapere	Maunu	voltage and customer numbers	Maunu Substation
Poroti	Titoki	Voltage	conductor upgrade
Ruakaka	Marsden Point	customer numbers	reconfiguration
Ruakaka	Waipu	Voltage	voltage regulator/Waipu Substation
Ruawai	Tangaihi	voltage	switched capacitors
Tikipunga	Whau Valley	customer numbers	reconfiguration
Tikipunga	Tikipunga Hill	customer numbers	switched capacitors
Tikipunga	Kiripaka Road	customer numbers	reconfiguration
Whangarei South	Otaika	customer numbers	Maunu Substation
Whangarei South	Okara Drive	Current	reconfiguration

5.3.7 Distributed Generation Policy

Northpower's policy on the connection of distributed generation follows the requirements as set out in the Electricity Industry Act 2010. Northpower's website includes guidelines on connection requirements, consultation and approval.

Northpower recognises the value of distributed generation in the following ways:

- Reduction of peak demand at Transpower GXP's.
- Reducing the effect of existing network constraints.
- Deferring or even avoiding investment in additional network capacity.
- Contributing to supply security.
- Making better use of local primary energy resources thereby avoiding line losses.
- Avoiding the environmental impact associated with large scale power generation.

Northpower also recognises that distributed generation can have the following undesirable effects:

- Increased fault levels, requiring protection and switchgear upgrades.
- Uncontrolled voltage levels
- Increased line losses where surplus energy is being exported through a network constraint.
- Stranding of assets or at least part of an asset's capacity.
- Potential for back-feeding into the network with inherent safety implications.
- The introduction of harmonic currents.
- Upgrading of line capacity where the generation exceeds the capacity of existing lines.

Notwithstanding the need to address these potential undesirable effects, Northpower actively encourages the development of distributed generation that will benefit both the generator and Northpower. The key requirements for those wishing to connect distributed generation to the network broadly fall under the following headings:

5.3.7.1 Connection Terms and Conditions

Connection terms and conditions are set out in accordance with the Electricity Industry Act 2010.

5.3.7.2 Safety Standards

A party connecting distributed generation must comply with any and all Northpower safety requirements, as well as all electrical industry codes and regulations. Northpower requirements are based on AS 4777 for small scale generation.

Northpower reserves the right to physically disconnect any distributed generation that does not comply with such requirements.

5.3.7.3 Connection Inquiries and Application Procedure

Information about the application procedure for potential connection of distributed generation (including relevant forms and required standards) is available on the Northpower website.

The applications are handled in a similar manner to processes currently employed to manage existing applications for power supply received from customers.

5.3.7.4 Distributed Generation and Development Planning

As at January 2016 there were approximately 280 small scale (mostly solar PV) distributed generation connections on the Northpower network. Total installed capacity is about 1.3MW with the average installation output being approximately 4.7kW. Because distributed generation is at such a low level and as yet does not incorporate battery storage, it has not yet had an impact on the network or affected the development plan.

It should be noted that solar PV generation without battery storage has the potential to increase voltage levels to beyond acceptable limits on 400/230V networks as maximum output occurs during sunlight hours when loading on these networks is generally low. For this reason the number of connections and total installed capacity per distribution transformer will need to be limited to avoid expenditure on voltage regulating equipment.

Distributed generation is a factor which is considered in long term planning and connections are monitored. As trends develop, these will be monitored and considered within the parameters of changing demand. Northpower currently does this with other technologies such as heat pumps and air-conditioners as increased installation of this type of load has changed some loading trends within the network.

Overall, Northpower recognises the potential for distributed generation to avoid capital expenditure required to increase capacity for peak loading. However, this generation needs to be significant as a unit or group of units as well as:

- Reliable.
- Cost effective in the long term.
- Managed.

5.3.8 Non Network Solutions

Where increases in demand for key service level parameters (capacity, reliability and security of supply) are identified, Northpower considers both non-network and traditional network methods of meeting that increase in demand. The preference is for non-network methods (due to long term asset stranding risks, capital cost, resource consents etc.) provided that they are sustainable in the long term and that the cost comparison of options is based on life cycle costs.

Non-network options for meeting these increased demands may include:

- Incentives for customers to not increase their demand through such means as interruptible or off-peak tariffs.
- Power factor recording or installation of half-hour metering to ensure customer compliance with power factor requirements.
- Technological solutions e.g. motor starting methods, switched capacitors, voltage regulators, line drop compensation (transformer tap changers).
- Load shifting or rearranging existing assets to optimise plant usage.
- Installation of distributed generation.
- Load control, although at present only GXP loadings are managed by way of ripple signal injection to shed domestic water heating load. Ripple control has been successful in delaying major capital expenditure. It has been estimated that without ripple control Northpower would need to spend around $10M in additional capacity in the sub-transmission network and at zone substations.
- Customer education.
- Promoting energy conservation practices.

Northpower is also actively engaged in the area of identifying and promoting any non-network incentives or solutions, such as:

- Monitoring and recording of electrical load information at HV feeder level using the SCADA system. This information coupled with network modelling software allows Northpower to optimise the electrical configuration of the HV distribution network.
- Employing a full time customer advisor promoting safe and efficient use of electricity and appliances. This includes having a presence at local field days and home shows. Northpower also uses this consumer interaction to gain feedback on its performance from the customer's perspective.
- Participation in energy saving programmes such as the nationwide eco-bulb implementation of compact fluorescent lamps (CFL's).
- Keeping a watching brief on developments in the field of emerging technologies related to electrical energy and distribution technology e.g. battery storage, fuel cells, photo-voltaic cells, smart metering, distribution automation etc.
- Providing guidance and support to customers considering and investigating privately owned distributed generation options.
- Engaging with third party organisations investigating or planning renewable energy generation schemes.

5.3.9 Network Development Options

Northpower's guiding principle is to ensure that the target service levels are met at the lowest life-cycle cost. Accordingly, Northpower considers the following broad classes of approaches to meeting service levels:

- Do nothing.
- Construct a new asset.
- Modify one or more features of an existing asset.
- Retrofit advanced technology that will allow greater operating ranges.
- Reconfigure assets.
- Install distributed generation.
- Influence consumers demand for levels of service.

The following table is a summary of network development options available to resolve constraints:

Network Development Options		
Constraint	**Network Options**	**Non-network options**
Voltage	Upgrade conductor	Install generator (peak load)
	Upgrade voltage	Promote demand side management
	Install voltage regulator	Promote distributed generation
	Install capacitor	
	Reconfigure feeder	
	Construct new feeder	
Capacity	Upgrade conductor	Install generator (peak load)
	Install forced cooling	Promote demand side management
	Improve power factor	Promote distributed generation
	Improve thermal resistivity	
	Increase line clearance	
	Upgrade voltage	
	Duplicate asset	

Network Development Options		
Constraint	**Network Options**	**Non-network options**
Security	Duplicate asset	Utilise mobile generator
	Install switches	Promote distributed generation
	Construct new feeder	
	Construct new zone substation	
	Ensure strategic spares available	
Reliability	Install recloses/sectionalisers	Promote distributed generation
	Install switches	Utilise mobile generator
	Increase preventative maintenance	
	Install earth fault neutraliser	
	Reconfigure feeder	
	Construct new feeder	
	Construct new zone substation	

The above range of available options forms the basis upon which decisions have been taken to determine the most appropriate solution for each constraint after careful analysis of all possible options. The network plan is a listing of proposed solutions covering the 10 year planning period.

Northpower uses a range of decision tools such as NPV analysis, payback period and risk assessment to determine which option will give the lowest life-cycle cost. The degree to which these decision tools are applied depends on the level of expenditure and significance involved. For example, recurring decisions made at the operational level of the business will typically use a pre-defined decision tool that considers a few simple parameters and identifies one of a few possible options as being optimal. In contrast, non-recurring decisions made at the executive level of the business may consider wide ranging and complex data and may use several decision tools to identify an optimal option from among a large number of possible options.

Impact of Smart Technologies

Northpower has been part of the ENA Smart Technologies Working Group evaluating the impact of solar PV, battery storage, and Electric Vehicles on Distribution Networks.

Key points about the impact of smart technologies are:

- PV provides little, if any, benefit to network loadings in winter
- EV impact will be largely dependent on time of charging
- Battery storage could mitigate the effect of EV charging at peak times
- There is an opportunity to increase the utilisation of the existing network assets through coordinated management of load, generation and storage
- A breakthrough in winter energy technology would be required to significantly change the capacity requirements of the distribution network
- High penetration of PV would create summer reverse power flows. PV congestion management policies will be needed to address this

The likely outcomes will be:

- A stronger focus on monitoring the low voltage networks and possible use of new network technologies to assist PV export in summer
- A cautious approach to the expansion of our high voltage network
- Cost-reflective pricing to ensure that customers make appropriate decisions
- Greater customer choice around the use of the network – mainly in the summer
- New security / reliability-of-supply options for customers
- Provided we can control EV related peaks, there will be better utilisation of the network
- EV usage could counter solar generation, but will add to peaks in winter

The conclusion is that it is still too early to gauge the overall impact on capital expenditure on the distribution network. The strategy is to plan for the status quo and keep a very close watch on trends. It appears unlikely that new technology would reduce network peaks for several years and, mostly likely, well beyond the 10 year planning horizon. As such, solar, battery and EV technology have not been taken into account in the 10 year planning window.

5.4 Network Development Plan

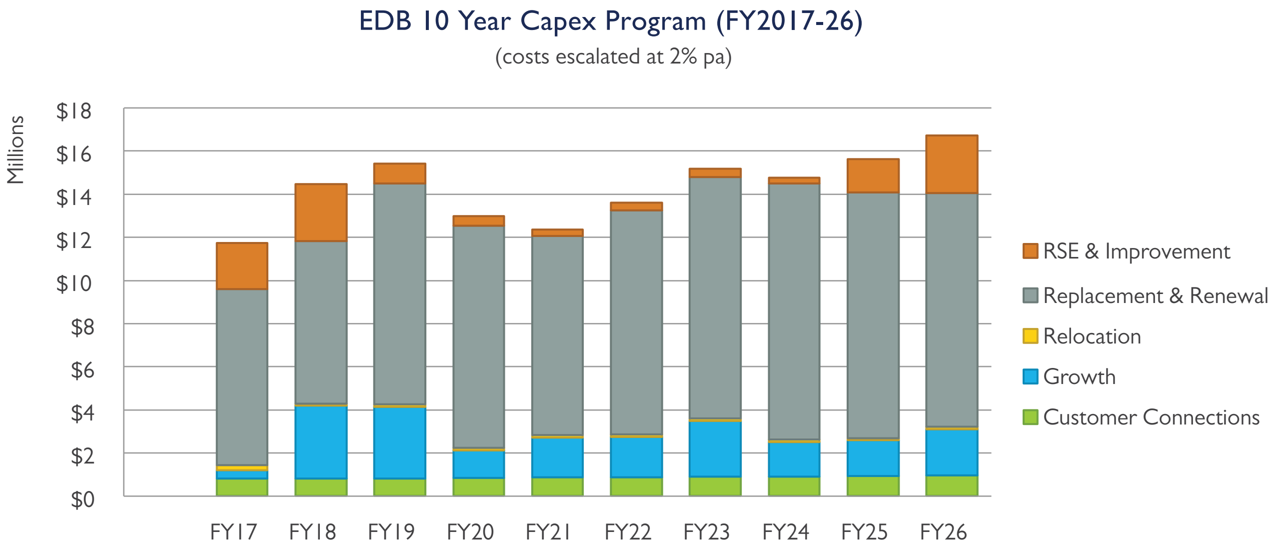
Northpower's 10 year network development plan encompasses all planned capital projects to ensure target levels of service are met or exceeded and are grouped according to the following primary information disclosure categories:

- Customer connection.
- System Growth.
- Reliability, Safety and Environment.
- Asset replacement and renewal.
- Asset Relocation.

The projects (and associated high level cost estimates) listed in the plan are requirements as foreseen at this point in time. The further out a project appears on the planning horizon, the more likely it is that it could change with time as better or new information becomes available or unforeseen developments arise necessitating changes to the plan. Northpower's current 10 year development plan with projects grouped as per the above-named categories is tabled at the end of this section.

5.4.1 Proposed 10 year CAPEX Program (FY2017-26)

The following chart shows the proposed expenditure per primary information disclosure category for each year of the 10 year period:



The following table shows the proposed expenditure ($000) per primary information disclosure category for each year of the 10 year period together with the average annual expenditure over the 10 year period and average annual expenditure expressed as a percentage of the total expenditure:

Category	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	Average
Customer Connections	803	812	828	844	861	878	897	915	932	951	872
Growth	388	3,383	3,310	1,286	1,865	1,865	2,583	1,590	1,649	2,137	2,006
Relocation	253	104	105	108	110	112	114	116	118	121	126
Replacement & Renewal	8,160	7,529	10,241	10,301	9,223	10,398	11,211	11,884	11,381	10,844	10,117
RSE & Improvement	2,135	2,628	947	445	288	359	386	257	1,531	2,663	1,164
TOTAL	11,739	14,457	15,431	12,984	12,347	13,613	15,191	14,762	15,612	16,716	14,285

5.4.1.1 Customer Connection and Asset Relocation

Proposed expenditure on customer connection and asset relocation accounts for about 7% (average) of total expenditure.

Expenditure in the customer connection category relates to the purchase of new distribution transformers to facilitate new connections and capacity upgrades. No allowance has been made for the creation of new assets for large customer supplies as these cannot be foreseen. Similarly, expenditure in the asset relocation category only includes presently known relocation projects for planned road works with a provisional amount per year for on-going minor relocation work.

5.4.1.2 Growth

Proposed expenditure in this category accounts for 14% (average) of total annual expenditure. Expenditure on growth related projects is dependent on future levels of economic activity and population growth together with network capacity in those areas where it occurs. Note has been taken of WDC identified growth points (Marsden Point, Waipu, Parua Bay, Maunu, Kamo and Hikurangi) and the 10 year load forecast (see appendix 4) and associated development plan specifically makes provision for higher than average growth in these areas. Provision has been made for new substations at Maunu, Helena Bay and Waipu (refer appendix 1).

In the case of Maunu substation, if the load growth required to justify the expenditure does not materialise in the next 2 years a further extension (in terms of the site designation) will be required over the 5 years granted in 2013.

Stage 2 of the Maungatapere-Whangarei South-Kioreroa 33kV Tee also needs to be completed (previously deferred project) to improve security of supply to Kioreroa substation and sub transmission system flexibility. Provision has also been made to improve security of supply at Bream Bay in accordance with expected higher than average growth in demand in this area (the installation of a second transformer at Bream Bay substation could be deferred if suitable arrangements can be made for utilisation of Trustpower's generation plant in the event of a contingency).

Growth in demand on Northpower's network in the past few years has been low, resulting in a number of previously planned capacity related projects being deferred year on year. However, there are signs of economic recovery and the 10 year network peak demand forecast is shown in the chart below (see detailed forecast in appendix 4). The forecast reflects an average annual growth rate of between 1.2% and 1.4% but this includes some possible industrial step load increases which may not materialise. The peak demand forecast is based on historical peak demand trends and anticipated growth scenarios at feeder and zone substation level and assumes the continued use of hot water load control to manage peak demand (as seen from the national grid) at a level consistent with that currently applied. The peak demand 'with generation' forecast assumes certain generation station outputs (Wairua power station and Trustpower diesel peaker plant) at time of system peak (TOSP).

The impact of developments in the following areas has not been specifically included in the load forecast (see discussion on Smart Technologies in 3.3 below):

1. Electric vehicle charging (dependent on vehicle uptake and possible time of use tariffs)
2. Distributed generation (dependant on installation rate and use of battery storage)

5.4.1.3 Asset Replacement

Proposed expenditure on asset replacement dominates, averaging approximately 70% of proposed total annual expenditure. This assumes a continuation of the current annual expenditure on follow-up work (which is predominantly lines based) which in turn accounts for approximately 70% of the proposed total asset replacement expenditure. The balance of the proposed expenditure on asset replacement is mainly for end of life (EOL) switchgear, transformer and SCADA and communications asset replacements.

Included in this expenditure toward the end of the 10 year period is the replacement of the 110/33kV transformer banks at Kensington and Maungatapere (ex Transpower assets). However, it is possible that the Kensington transformers could be relocated to Maungatapere (subject to an assessment of remaining life and economic viability closer to the time) in which case the proposed expenditure would be significantly less. It should be noted that these proposed transformer replacements are associated with transformer capacity increases required at these stations to maintain n-1 security (refer load forecast in appendix 3).

5.4.1.4 Reliability, Safety, Environment and Improvement

Proposed expenditure in this category accounts for about 8% (average) of total annual expenditure and includes risk mitigation, security improvement, remote control of switchgear, reliability and performance improvement, systems upgrades and research and development expenditure.

5.4.2 Significant projects currently underway or planned to start within the next year (FY17)

Maungatapere substation 33kV circuit breaker upgrades	*Replace 4x33kV 33kV outdoor circuit breakers*	*$453,000*
Replacement of EOL bulk oil feeder circuit breakers to ensure continued reliabilty of supply		
The decision to replace these circuit breakers is based on risk assessment		
Alternative replacement of the entire outdoor switchyard (10x33kV bays) with an indoor switchroom has been identified as a possible long term solution which will also improve safety		
Waipu feeder volltage regulator	*Install 200A 11kV voltage regulator*	*$250,000*
Interim strengthening measure until planned Waipu zone substation can be justified		
Required to maintain acceptable voltage levels during winter peak load periods		
Alternatives considered: capacitor banks, distributed generation, new zone substation		
Ruakaka substation 33kV circuit breaker upgrades	*Replace 2x33kV 33kV outdoor circuit breakers*	*$180,000*
Replacement of EOL bulk oil circuit breakers to ensure continued reliabilty of supply		
The decision to replace these circuit breakers is based on risk assessment		
Alternatiove is to extend operational life but security of supply and safety risk makes this option unacceptable		
Whangarei City roading projects asset relocation	*Overhead to underground conversion of section of feeder along S.H.1*	*$200,000*
Undergrounding of 11kV and 400V overhead lines and installation of ground mounted switches to accommodate road widening in Whangarei City area		
Third party requirement (NZTA and WDC)		
Alternative relocation of the overhead network is not practical and undergrounding will also allow for feeder capacity upgrades, reduced maintenance costs, reduction in car versus pole incidents and improved visual impact		
Tikipunga substation 33kV circuit breaker upgrades	*Replace 3x33kV 33kV outdoor circuit breakers*	*$275,000*
Replacement of EOL bulk oil circuit breakers to ensure continued reliabilty of supply		
The decision to replace these circuit breakers is based on risk assessment		
Alternatiove is to run to failure but high safety risk makes this unacceptable		

Maungatapere substation 11kV feeder optimisation	*Reconfiguration of existing feeders*	*$130,000*
Removal of section of o/h 11kV double circuit line and reconfiguration of feeders		
Low cost Interim solution to increase feeder capacity in the Maunu area		
Alternative is to construct the planned Maunu 33/11kV substation		
Dargaville ripple plant relocation	*Relocation of plant from leased land to switchroom*	*$100,000*
Remove ripple plant from position on leased land outside Dargaville zone substation and install in new substation 11kV switchroom		
Decision based on long term cost savings		
Alternative is to retain existing location with long term security and cost issues		
Replacement of EOL 11kV distribution switchgear	*Replacement of aging Long & Crawford oil switchgear in Whangarei CBD*	*$225,000*
Multi year program to replace old oil switchgear		
Decision based on high safety risk (explosion/fire)		
Alternatiove is to extend operational life but high security of supply and safety risk makes this option unacceptable		
Communications systems upgrades	*Replacement of aging SCADA equipment*	*$100,000*
Replacement of critical communications hardware		
To ensure continued reliability and performance of SCADA communications		
No viable alternative		
Remote control 11kV pole mounted switches	*Installation of SCADA communications and switch control at selected switch sites*	*$530,000*
Multi year project to Install pole mounted radio/RTU control cabinets and 230V supplies at 60 sites equipped with motorised Sectos type switches and set up SCADA controls		
Required to speed up feeder fault isolation and backstopping to minimise extent of customer outages in order to improve reliability and security of supply in rural areas		
Alternative is to do nothing but this project is one component of Northpower's reliability improvement program to increase customer satisfaction by reducing SAIDI and CAIDI		
Zone substation risk mitigation	*Zone substation fire, explosion and oil leak risk mitigation*	*$900,000*
Multi year project to construct transformer firewalls and oil bunds at high risk substations		
Risk mitigation		
Alternative is to do nothing but this is not considered appropriate in terms of safety and property risks		

Zone substation RTU upgrades	*Replacement of communications equipment*	*$250,000*
Multi year project to upgrade aging radio communications links (including conversion from analog to digital technology) and remote terminal units		
Required to ensure continued reliability and enhance performance of the communications network		
Alternatives considered: no alternatives		
11kV O/H line conductor replacement	*Replacement of EOL HDBC and corroding ACSR conductor*	*$3,579,000*
Multi year project to replace old 7/.064 copper conductor and corroding ACSR conductor (including associated crossarms and insulators) based on sample conductor test results		
Timeous replacement of at risk conductor to maintain and also improve current levels of network reliability		
Alternatives considered: replacement on breakage – high risk with respect to safety and performance		
Abbey system upgrade	*Replacement of communications equipment*	*$200,000*
Replacement of EOL RT communications equipment providing SCADA facilities for distribution equipment (reclosers etc.)		
To ensure continued reliability and performance of communications network providing remote control and status monitoring of field equipment		
No alternative as operational life cannot be extended due to spares availability problem		
Substation AC/DC panel upgrades	*Replacement of old panels*	*$250,000*
Multi year project to replace old panels at all zone substations where panels have not been upgraded in conjunction with 11kV switchboard upgrades		
For compliance and safety reasons		
No viable alternative		
Zone substation security improvement	*Installation of security equipment*	*$180,000*
Multi year project to install electronic access security systems and CCTV at zone substations		
Required to improve security with respect to access and monitoring		
Alternatives considered: retain current levels of security – high risk with respect to vandalism, theft and security of supply		
Fault passage indicator installation	*Installation of FPI's on 11kV feeder*	*$450,000*
Multi year project to install fault passage indicators on 11kV feeders (in association with remote switch installations)		
To improve feeder performance with respect to customer outages (fault location and isolation)		
Alternative is not to install but this initiative is part of overall network performance improvement (SAIDI/CAIDI reduction)		

Communications network security	*To reduce communications network vulnerability during stormsy*	*$135,000*
Install backup power supplies to critical communications sites		
To ensure communications network reliability		
Alternative is not to improve but this initiative is part of overall network performance improvement (SAIDI/CAIDI reduction)		
Maungaturoto-Kaiwaka 33kV circuits protection upgrade	*Upgrade of protection scheme to improve security of supply*	*$120,000*
Upgrade protection from directional relays to fibre differential scheme on the 2 x 33kV circuits between Maungaturoto TP and Maungaturoto NP including the Kaiwaka T		
To improve security of supply		
Alternative is to retain existing protection scheme which has some performance issues		

5.4.3 Significant projects planned to start within the next 4 years (FY18-FY21)

Whangarei South-Kioreroa 33kV T reconfiguration (stage 2)	*Complete second 33kV T by upgrading and extending existing out of service No.2 33kV line*	*$884,000*
Required to increase security of supply to Kioreroa substation (from Maungatapere GXP)		
Alternative options: do nothing or rely on proposed peaker plant at Kioreroa if commissioned.		
Whakapara 11kV feeder express line extension	*Extend 33kV express line (11kV operation) back to Hikurangi substation*	*$536,000*
Required to extend the existing section of express line (no distribution transformers) which is insulated to 33kV but operated at 11kV from its present starting point back to Hikurangi substation to enable operation as a true express line from the substation to the 11kV voltage regulator at Helena Bay. This extension is required to improve feeder performance.		
Alternatives considered: interim measures to improve performance were implemented in 2012 comprising of the installation of additional 11kV automatic sectionalisers and auto reclose function on the feeder circuit breaker.		
Kaiwaka 11kV switchboard upgrade	*Replacement of EOL switchgear*	*$1,267,000*
Required to ensure personnel safety and plant reliability.		
Alternative options: continued operation (high risk)		

Hikurangi 11kV switchboard upgrade	*Replacement of EOL indoor switchgear*	*$1,508,000*
Required to ensure personnel safety and plant reliability.		
Alternative options: continued operation (high risk)		
Whangarei South 11kV switchboard upgrade	*Replace EOL indoor switchgear*	*$1,470,000*
Required to ensure personnel safety and plant reliability.		
Alternative options: continued operation (high risk)		
Parua Bay second transformer	*Commission second 3.75MVA transformer*	*$363,000*
Required to increase substation capacity (peak load) and provide n-1 capabilty		
Alternative options: installation of distributed generation (would require stored energy system)		
Ruawai 11kV switchboard upgrade	*Replacement of EOL indoor switchgear*	*$1,267,000*
Required to ensure personnel safety and plant reliability.		
Alternative options: continued operation (high risk)		
Bream Bay new 11kV feeder	*Installation of additional feeder*	*$323,000*
Required to improve feeder backstopping capability and provide additional capacity for growth in the Marsden Point industrial area.		
Alternative is to defer installation and accept performance and capacity risks.		
Whangarei Hospital 11kV switchgear replacement	*Replacement of EOL switchgear*	*$200,000*
Required to ensure personnel safety and plant reliability		
Alternative options: continued operation (high risk)		
Helena Bay substation	*New 33/11kV zone substation*	*$2,319,000*
Required to increase power transfer capacity to the Helena Bay, Oakura and Bland Bay coastal areas. As this express line will already be insulated to 33kV (refer express line extension project), the project will involve installation of a 33kV line bay at Hikurangi substation and 33/11kV step-down transformer at Helena Bay.		
Alternative options: upgrade feeder to 22kV operation/distributed generation		
Hikurangi 33/11kV transformer replacements	*Replace EOL transformers*	*$1,097,000*
Replace 2 x 5MVA transformers with 2 x 10MVA units		
Alternative options: none		

Maunu 33/11kV substation	*New zone substation*	*$4,128,000*
Required to strengthen the 11kV network in the growing residential area between Whangarei South and Maungatapere substations. Will also offload Alexander Street, Whangarei South and Maungatapere stations		
Alternative options: interim 11kV network strengthening/reconfiguration		
Chip Mill 33/11kV transformer replacement	*Replace EOL transformer*	*$450,000*
Required to ensure continuity of supply		
Alternative options: none		
Poroti 11kV switchboard upgrade	*Replace EOL indoor switchgear*	*$1,296,000*
Required to ensure personnel safety and plant reliability.		
Required to ensure personnel safety and plant reliability.		
Maungatapere 110/33kV transformer replacement	*Replace EOL 2x30MVA transformers*	*$2,813,772*
Required to ensure continued security of supply and capacity at GXP (these assets are currently owned by Transpower but will be transferred to Northpower 1 April 2013).		
Alternative options: none		

5.4.4 Significant projects planned to start within the next 10 years (FY22-FY26)

Ngunguru transformer upgrade	*Upgrade to 5MVA transformer*	*$250,000*
Replace existing 3.75MVA transformer with 5 MVA unit (ex service) to increase substation capacity		
Waipu 33/11kV substation	*New zone substation*	*$3,678,000*
Construction of new 5MVA zone substation, 33kV line and feeder to strengthen the 11kV network in the Waipu area and provide capacity for anticipated load growth		

Ngunguru 11kV switchboard upgrade	*Replace EOL indoor switchgear*	*$1,045,000*
Required to ensure personnel safety and plant reliability.		
Poroti 33/11kV transformer replacement	*Replace EOL transformer*	*$512,000*
Required to ensure continuity of supply		
Ruawai 33/11kV transformer replacement	*Replace EOL transformer*	*$492,000*
Required to ensure continuity of supply		
Maungaturoto 11kV switchboard upgrade	*Replace EOL indoor switchgear*	*$1,209,000*
Required to ensure personnel safety and plant reliability.		
Maungaturoto 33/11kV transformer replacements	*Replace EOL transformers*	*$1,141,000*
Required to ensure continuity of supply		
Maungatapere 33kV indoor switchboard	*Replace existing outdoor 33kV yard with indoor switchboard*	*$3,333,700*
Required to mitigate risk to maintenance personnel associated with the existing outdoor switchyard. *(this project is subject to risk review after asset transfer from Transpower in 2013)*		
Maungatapere 110/33kV transformer upgrade	*Replace 2x30MVA EOL transformers*	*$3,869,000*
Replace EOL transformers with larger units to maintain n-1 capacity (possible use of 50MVA transformers ex Kensington		
Kensington 110/33kV transformer upgrade	*Replace 2x50MVA transformers with larger units*	*$5,334,000*
Replace existing 50mVA transformers with larger units to provide increased capacity and continued n-1 security of supply to the greater Whangarei City area		
Bream Bay 2nd transformer	*Install second 10MVA transformer*	*$1,561,000*
Required to increase substation capacity to meet load growth and provide N-1 capacity to improve security of supply and facilitate outages for plant maintenance (possibility of utilising Trust Power 9MW peaker plant connected to Bream Bay 11kV bus for this purpose to be investigated).		

5.4.5 Capital Expenditure Forecast (10 year Development Plan)

NORTHPOWER EDB 10 YEAR CAPEX PROGRAM ($000) (costs escalated at 2% pa)			1	2	3	4	5	6	7	8	9	10
WS	PROJECT TITLE	CATEGORY	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26
6108	Transformer Acquisition Cost	Customer Connections	1,061	1,072	1,094	1,115	1,137	1,160	1,183	1,207	1,231	1,256
6109	Transformer Credits from Upgrades	Customer Connections	-258	-260	-265	-270	-276	-282	-287	-292	-299	-305
	Total	**Customer Connections**	**803**	**812**	**828**	**844**	**861**	**878**	**897**	**915**	**932**	**951**
6198	Power Factor Improvement	Growth		100				108				117
6400	Whangarei City additional 11kV RMU's	Growth			50			52				56
6401	Minor captial expenditure (growth)	Growth	53	54	54	56	57	58	59	60	61	62
6430	Distribution Transformer & LV Feeder Optimisation	Growth	60	58	60	61	62	63	64	66	67	68
6449	Power Factor Monitoring 11kV Feeders	Growth	75	77	78							
6461	Maunu Substation Construction	Growth		1,285	2,843							
6472	Whangarei South 33kV T - Stage 2	Growth		884								
6479	Waipu Zone Substation	Growth							2,437	1,241		
6480	Bream Bay Second 10MVA Transformer	Growth						1,561				
6481	Bream Bay New 11kV Feeder	Growth		323								
6483	Parua Bay Second Transformer	Growth					363					
6489	Kensington-Kamo Third Circuit	Growth									1,268	1,810
6492	Helena Bay substation	Growth				1,148	1,171					
6585	Maungatapere 11kV feeder optimisation	Growth	130									
6493	Waipu Feeder Voltage Regulator	Growth	50									
6531	Ahikiwi Voltage regulator upgrade	Growth		202								
6595	Distribution feeder voltage support	Growth		180			190			200		
6551	Land Purchases (future substations Waipu, Helena Bay)	Growth		200	204						230	
6573	EV Charging Stations	Growth	20	20	21	21	22	22	23	23	23	24
	Total	**Growth**	**388**	**3,383**	**3,310**	**1,286**	**1,865**	**1,865**	**2,583**	**1,590**	**1,649**	**2,137**
6402	Minor capital expenditure (relocation)	Relocation	53	54	54	56	57	58	59	60	61	62
6539	Dargaville ripple plant relocation	Relocation	100									
6540	Whangarei roading works asset relocations	Relocation	100	50	51	52	53	54	55	56	57	59

NORTHPOWER EDB 10 YEAR CAPEX PROGRAM ($000) (costs escalated at 2% pa)			1	2	3	4	5	6	7	8	9	10
WS	PROJECT TITLE	CATEGORY	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26
	Total	Relocation	253	104	105	108	110	112	114	116	118	121
6274	RTU Upgrades (Zone substations)	Replacement & Renewal	100	100	50						200	204
6596	Remote switch RTU and comms replacements	Replacement & Renewal							60	61	62	64
6597	Security systems replacements	Replacement & Renewal								75	77	78
6598	Ripple injection plant replacements	Replacement & Renewal					100	102	104	106		
6599	Battery bank and battery charger upgrades	Replacement & Renewal			50		52		54		56	
6600	SCADA system hardware and software replacements	Replacement & Renewal			60			300				120
6601	Microwave radio terminal (Airmux) link replacements	Replacement & Renewal							100			
6393	Power transformer refurbishment	Replacement & Renewal		150		155		160		165		170
6396	Protection Relay Upgrades	Replacement & Renewal	120	122	125	127	131	134	136	139	142	145
6397	33kV CT, VT and protection upgrades	Replacement & Renewal		75		80		85		90		95
6448	AUFLS Relay Upgrades	Replacement & Renewal	150									
6494	Ngunguru Transformer upgrade to 5MVA	Replacement & Renewal						250				
6501	Kaiwaka 11kV Switchboard replacement	Replacement & Renewal				1,267						
6502	Ruawai 11kV Switchboard replacement	Replacement & Renewal				1,267						
6503	Hikurangi 11kV Switchboard replacement	Replacement & Renewal			1,508							
6504	Whangarei South 11kV Switchboard replacement	Replacement & Renewal			1,470							
6505	Ngunguru 11kV Switchboard replacement	Replacement & Renewal						1,045				
6506	Poroti 11kV Switchboard replacement	Replacement & Renewal					1,296					
6507	Tap Changer Controller Upgrades	Replacement & Renewal	55			57			61			65
6510	Maungatapere 110/33kV Transformer replacement	Replacement & Renewal									1,944	1,925
6512	Kensington 110/33kV Transformer replacement	Replacement & Renewal							2,641	2,693		
6522	Abbey System Comms Upgrade	Replacement & Renewal	100	102								
6529	Maungaturoto 11kV Switchboard replacement	Replacement & Renewal									1,209	
6530	Whangarei Hospital 11kV Switchboard replacement	Replacement & Renewal		200								
6532	Chip Mill Transformer Replacement	Replacement & Renewal				450						
6533	Hikurangi Transformer Replacements	Replacement & Renewal					543	554				
6534	Poroti Transformer Replacement	Replacement & Renewal								512		

NORTHPOWER EDB 10 YEAR CAPEX PROGRAM ($000) (costs escalated at 2% pa)			1	2	3	4	5	6	7	8	9	10
WS	PROJECT TITLE	CATEGORY	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26
6535	Ruawai Transformer Replacement	Replacement & Renewal						492				
6536	Maungaturoto Transformer Replacements	Replacement & Renewal							565	576		
6563	Ruakaka 33kV CB Replacement x2	Replacement & Renewal	180									
6564	Tikipunga 33kV CB Replacements x3	Replacement & Renewal	275									
6571	WASP Replacement	Replacement & Renewal	450									
6586	Recloser replacements	Replacement & Renewal			60		65		70		75	
6587	Long & Crawford GMS replacement	Replacement & Renewal	70	75	80				100			110
6588	Recloser controller upgrades	Replacement & Renewal	20									
6589	Kensington-Maungatapere protection comms	Replacement & Renewal	40									
6583	Communications System Upgrades	Replacement & Renewal	100	75	75			100				100
	Subtotal (Projects)		**1,660**	**899**	**3,478**	**3,403**	**2,187**	**3,222**	**3,891**	**4,417**	**3,765**	**3,076**
9490	Battery banks	Replacement & Renewal	20	20	21	21	22	22	23	23	23	24
9490	Conductor replacement	Replacement & Renewal	1,500	1,530	1,561	1,592	1,624	1,656	1,689	1,723	1,757	1,793
9490	Distribution earthing	Replacement & Renewal	300	306	312	318	325	331	338	345	351	359
9490	Ground mounted subs	Replacement & Renewal	130	133	135	138	141	144	146	149	152	155
9490	Multiple asset groups	Replacement & Renewal	15	15	16	16	16	17	17	17	18	18
9490	Overhead lines	Replacement & Renewal	1,850	1,887	1,925	1,963	2,002	2,043	2,083	2,125	2,168	2,211
9490	Overhead switches	Replacement & Renewal	50	51	52	53	54	55	56	57	59	60
9490	Pillars	Replacement & Renewal	260	265	271	276	281	287	293	299	305	311
9490	Pole replacement	Replacement & Renewal	840	857	874	891	909	927	946	965	984	1,004
9490	Ripple plant	Replacement & Renewal	15	15	16	16	16	17	17	17	18	18
9490	Underground cables	Replacement & Renewal	20	20	21	21	22	22	23	23	23	24
9490	Crossarm replacement	Replacement & Renewal	1,500	1,530	1,561	1,592	1,624	1,656	1,689	1,723	1,757	1,793
	Subtotal (Follow up maintenance)		**6,500**	**6,630**	**6,763**	**6,898**	**7,036**	**7,176**	**7,320**	**7,466**	**7,616**	**7,768**
	Total	**Replacement & Renewal**	**8,160**	**7,529**	**10,241**	**10,301**	**9,223**	**10,398**	**11,211**	**11,884**	**11,381**	**10,844**
6348	New Reclosers	RSE & Improvement		40			45			50		
6370	Zone Substations Risk Mitigation	RSE & Improvement	200	350	350							
6374	Zone Substations Security Improvement	RSE & Improvement	60	62	65			70				75
6403	Communications system upgrades (fibre)	RSE & Improvement	90									

NORTHPOWER EDB 10 YEAR CAPEX PROGRAM ($000) (costs escalated at 2% pa)			1	2	3	4	5	6	7	8	9	10
WS	PROJECT TITLE	CATEGORY	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26
6404	Comms for remote control of motorised switches	RSE & Improvement	265	268								
6425	11kV feeder backstopping improvements	RSE & Improvement	75	75		80			85			90
6434	DSUB MDI Meters	RSE & Improvement	64	65	67							
6435	Minor capital expenditure (improvements)	RSE & Improvement	55	60	60	60	65	65	65	70	70	70
6447	AC/DC Panel Upgrades	RSE & Improvement	150	150								
6466	Replace VHF Analog with Digital (Mobile Radio)	RSE & Improvement	150	75								
6496	Depot Security improvements	RSE & Improvement	10									
6497	Whakapara Feeder Express Line to Hikurangi	RSE & Improvement		536								
6508	Maungatapere 33kV Indoor Switchboard	RSE & Improvement									1,268	2,069
6519	Fault Passage Indicators	RSE & Improvement	125	250	75							
6525	Operational Management System (Control)	RSE & Improvement	200									
6537	Maungaturoto 33kV Circuit Separation	RSE & Improvement		253								
6544	Chipmill RTU and Comms	RSE & Improvement	16									
6546	Research and Development (component testing)	RSE & Improvement	30	54	55	56	57	58	59	60	61	62
6560	Communications Network Security	RSE & Improvement	35	35				50				60
6562	SCADA Switch and GPS Time Sync Upgrade	RSE & Improvement	20									
6565	Zone Substation Neutral Earthing Resistors	RSE & Improvement		120	122	125			100			105
6566	KEN-TIK 33kV cables protection upgrade	RSE & Improvement	90									
6567	Busbar Arc Flash Protection	RSE & Improvement	50	51	52	53						
6568	MTOTP-MTONP Protection Upgrade	RSE & Improvement	120									
6569	Aerial Imagery (GIS)	RSE & Improvement	30					40				50
6572	Engineering Software	RSE & Improvement	40				50				55	
6574	UAV Asset Inspection Platform	RSE & Improvement	25	30	30							
6577	University Project Collaboration	RSE & Improvement	15	15	16	16	16	16	17	17	17	17
6590	Research and Development (new technology)	RSE & Improvement	50	50	55	55	55	60	60	60	60	65
6591	SCADA comms transfer to dark fibre	RSE & Improvement	40	40								
6592	Remote station SCADA monitoring	RSE & Improvement	50	50								
6593	33kV ABS replacements x4	RSE & Improvement	20									
6594	FTCE Wilde unit replacements x2	RSE & Improvement	60									
	Total	**RSE & Improvement**	2,135	2,628	947	445	288	359	386	257	1,531	2,663
	Grand Total		11,739	14,457	15,431	12,984	12,347	13,613	15,191	14,762	15,612	16,716

Section 6:
Life Cycle Asset Management Plan

"safe, reliable, hassle free service"

Life Cycle Asset Management Plan

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Section 6: Life Cycle Asset Management Plan

6.1 Planning Criteria and Assumptions

6.1.1 Objective

The overall purpose of the plan is to provide documented direction for achieving Northpower's strategic goals and objectives. The lifecycle asset management planning objectives support the strategic goals. The primary drivers for maintenance and renewal are:

- Safety – for the public, for those working on the network and the environment
- Reliability – meet or exceed the expectation of our customers
- Economic efficiency – operation in accordance with cost/benefit analysis
- Foundation for growth – provide the ability for expansion without compromising flexibility
- Long term sustainability – no degradation of the owners' investment in the asset

6.1.2 Determining Optimal Level of Maintenance Expenditure

Northpower's approach is similar to others in the industry and is structured to facilitate the delivery of the desired outcomes. Lifecycle asset management is divided into three principal areas or practices:

Preventative maintenance – the systematic inspection and detection of incipient failures through the recording of changes in equipment condition. The systematic inspections are refined as more knowledge is gained based on good engineering practice, manufacturers' recommendations, and technology improvements. In addition, preventative maintenance activities include partial or complete refurbishment at specified intervals.

Follow-up maintenance – a corrective action for a defect that is identified as a result of a preventative maintenance inspection or a remedial maintenance attendance. Follow-up maintenance may be further categorised as operational expenditure or capital expenditure in accordance with the business rules. Follow-up maintenance is seen as an area of increased focus on improved processes and categorisation in order to increase network performance.

Remedial maintenance – maintenance which must be performed immediately or urgently to protect any person or property from imminent harm or danger, restore electricity supply, perform work after power restoration to restore the electricity network to normal operating condition and normal installation standard, protect the electricity network from imminent damage, or ensure that Northpower complies with any legal obligation or generally accepted industry standards.

Each asset has been categorised in accordance with its primary function. The following list shows the asset category for maintenance activities. This categorisation has been used in the asset management plan to provide consistency of data presentation across the different sections.

Distribution Assets:

- Lines
- Cables
- Overhead switches
- Distribution earthing
- Regulators
- Ground mounted distribution substations and switchgear
- Low voltage pillars

Zone Substation Assets:

- Zone substation and radio repeater sites
- Battery banks
- Sub-transmission transformers and tap changers
- Circuit breakers
- Outdoor structures
- Zone substation earthing
- Relays
- Ripple plant
- SCADA
- Communications

Sub-transmission Assets:

- Cables and Lines

Transmission Assets:

- Towers and Lines

6.1.3 Maintenance Strategies

Northpower adopts a range of network maintenance strategies for each category of asset. A cost-benefit approach to maintenance obviously gives priority to assets serving either large numbers of customers, specific high electrical demand customers or where public safety is a concern (for which, condition based maintenance is the most likely strategy). This also means that assets serving only a small number of customers are likely to receive a lower priority (often meriting only a break-down strategy).

Northpower also uses the considerable volume of data gathered by various means to modify its maintenance strategies or to adopt more cost-effective strategies such as design-out. For instance, as classes of assets (or individual assets) age or begin to deteriorate at increasing rates, their maintenance programs may be varied.

The broad maintenance strategies adopted for major categories of assets are shown in the table below.

Asset Category	Maintenance Strategies
110kV Overhead line	Condition based
50kV Overhead Line	Condition Based
33kV Overhead line	Condition based
33kV Cable	Condition based
110/50kV and 110/33kV Transformers	Condition Based
33/11kV Transformer	Condition based
33kV switchgear and line hardware	Event and condition based
11kV Overhead line	Condition based and breakdown
11kV Cable	Breakdown
11kV / 400V transformers ≥ 500kVA	Condition based
11kV / 400V transformers ≥ 50kVA	Condition based
11kV / 400V transformers < 50kVA	Condition based and breakdown
11kV switchgear, RMU‟s, regulators etc.	Event based and condition based

Asset Category	Maintenance Strategies
400V overhead line	Condition based
400V cable	Breakdown
400V service pillar	Condition based and breakdown
Earthing system – Zone substations	Condition based
Earthing system – Distribution	Condition based
Structure – Zone substation	Condition based
Ripple plant	Condition based
SCADA and communication system	Condition based
Battery bank	Condition based

Broad Maintenance Strategies

6.2 Inspection, Condition Monitoring and Routine Maintenance

Each asset group is governed by a maintenance policy which explains the purpose, the strategy, the technical standards and the identified risks that apply to the particular asset class.

Maintenance Policies in place include those for:

- Distribution earths
- Ground mounted distribution switchgear
- Ground mounted distribution substations
- Overhead switches
- Overhead lines
- Pillars
- Regulators
- Zone substation transformers
- 11kV circuit breakers
- 33kV circuit breakers
- 33kV structures and isolators
- Buildings and grounds

Documentation of formal policies for a number of the remaining asset groups is currently in progress. The existing policies are also currently under review.

Each policy is further supported by a work instruction which details requirements for resources (people and equipment), work planning, site safety, data capture, service instructions and site completion. The work instruction is in turn supported by a data capture sheet which is to be completed by the person undertaking the maintenance activity.

6.2.1 Routine Preventative Inspection and Maintenance Practices

Northpower has a robust, planned approach to the routine and preventative maintenance inspections undertaken on the various categories of assets that make up the network.

A more detailed analysis of the routine preventative inspection and maintenance regimes for each of the asset categories is shown in the following table. Frequency of inspection and the scope of work are also shown. The scope of work briefly outlines the actions to be taken for each asset category.

Preventative Maintenance	Timing	Scope of work
Transmission Line inspection		
Transmission Line Patrol	Annual	Visual check of OH lines, structures, foundations, access tracks and all line hardware. Replace missing or damaged pole numbers and reflectors.
Transmission Line Condition Assessment	5 Yearly	A complete condition assessment of all structures. This includes tasks under the annual patrol as well. Capture any defects
Line inspection		
Overhead Line Inspection	5 yearly	Visual check of OH lines, poles, and all pole hardware including switches and distribution substations. Replace missing or damaged pole numbers and reflectors.
Helicopter Survey of Subtransmission overhead lines	As required, approx 5 yearly	Survey selected overhead subtransmission lines from a helicopter. Capture any defects.
Wood pole testing	5 yearly or condition based	Wood pole testing with DDD200 micro-drill as per pole testing policy. Visual hardware inspection.
NDC Data Capture	Annual	Capture remaining existing assets and their attributes and update GIS
Overhead Switches		
Oil Recloser oil change	8 yearly	Remove recloser from pole, take into workshop and service, change oil, re-install
Overhead Remote Switch Battery Change	2 yearly	Change the battery on all remote switch control units. Check alarms. Visual inspection
Distribution Earthing		
Inspect and test earthing of overhead switches (ABS, sectionalisers & reclosers), distribution substations, regulators, out of service overhead lines and associated lightning arrestors plus any stand-alone lightning arrestor installations e.g. cable terminations.	5 yearly	As per earth Testing Standard
Regulators		
Regulator Inspection	Annual	Visual inspection. Paint over graffiti and treat and paint surface rust. Remove rubbish, cobwebs and vegetation. Signs/labels. Silica gel. Record tap changer operations. Check voltage.
Regulator Thermal Image Survey	Annual	Thermal image survey of regulator and all associated equipment and connections.
Regulator Ultrasonic Survey	2 yearly	Ultrasonic survey of regulator and all associated equipment and connections.
Regulator Oil Change	4 yearly	Change the oil in all regulators
Regulator Controller Test	2 yearly	Control and alarm test

Preventative Maintenance	Timing	Scope of work
Ground mounted Distribution subs		
Inspect ground-mounted distribution substation	2 yearly	Visual inspection. Patch paint. Remove litter & cobwebs. Signs/labels, lightbulbs. MDIs. Thermal imaging, partial discharge (MTEV). Includes Wilde FTCE sites.
Ground mounted Oil filled HV switch service .	8 yearly (20 per year)	Service Oil Switches as per maintenance standard.
Weed control of distribution substations	6 months	Spray herbicide at selected sites to control vegetation.
Distribution substations MDI checks	annual	Check, record value and reset MDIs at selected Dsubs.
LV Pillars		
Service Pillar visual inspection	2 yearly	Visually identify any hazards or defects (eg. damage, screws missing, damaged hinges, pillar not straight, burial depth too great or too little). Includes opening pillars that have key locks and doing a thermographic (hand held) survey.
Link Pillar visual Inspection	2 yearly	Visually identify any hazards or defects (eg. damage, screws missing, damaged hinges, pillar not straight, burial depth too great or too little). Includes opening pillars that have key locks and doing a thermographic (hand held) survey.

Distribution Assets Preventative Maintenance Program

Task	Timing	Scope
Zone Substation and Radio Huts		
Zone Substation building maintenance	monthly	Inspect buildings, fittings, fencing. Check for damage, leaks and security. Check internal fittings and trench covers. Clean floors, toilet etc as required. Restock toiletries, replace blown light bulbs. Log defects
Zone Substation grounds maintenance	monthly	Mow lawns, trim edges, unblock drains, trim trees, remove rubbish, weed control, maintain gardens (if any).
Routine equipment inspections and checks	2 monthly	Substation equipment check and battery impedance test.
Ultrasonic testing of substations	Annual	Ultrasonic testing of transformers, cable boxes, switchgear, LV frames and distribution boards,
Air conditioning unit service	Annual	Check operation, clean filters and service.
Smoke detector testing	6 monthly	Check operation and service as necessary

Task	Timing	Scope
Battery Banks		
Battery maintenance	2 monthly	Battery and charger test. Undertaken with Zone sub equipment inspections
UPS battery change	4 yearly	Change rack mounted battery packs in rack mounted UPSs
Subtransmission Transformers and Tap changers		
Transformer oil test	Annual	Take oil samples and test for acidity, power factor, breakdown voltage, moisture content, interfacial tension, colour and DGA. Record and analyse test results
Tap changer service	4 yearly	Clean out tap changer. Inspect. Change oil. Includes regulator tapchangers
Transformer maintenance	4 yearly	Visual checks, insulation resistance test, Buchholz test, temperature gauge check, NER
Transformer PDC Test	4 yearly	Hire specialist contractor to carry out PDC tests on all zone sub transformers
Circuit Breakers		
11kV Oil Circuit Breaker major servicing	4 yearly or condition	Kelman tests, check operation, oil change
33kV Oil Circuit Breaker major servicing	4 yearly	Kelman tests, check operation, oil change
11kV Vacuum Circuit Breaker servicing	4 yearly	Kelman tests, check operation
33kV SF6 indoor	4 yearly	Kelman tests, check gas pressure and operation
33kV SF6 outdoor	4 yearly	Kelman tests, check gas pressure and operation
Partial Discharge Survey	2 yearly	Specialist contractor to undertake survey
5.5kV VCB	4 yearly	Kelman tests, check operation
Outdoor Structures		
Close inspection of outdoor structure	4 yearly	Shut down and close inspection as per maintenance standard
Zone Substation Earthing		
Test Zone substation earthing system	4 yearly	Test zone substation earth mats. Test bonding.
Monitoring Transformers		
33kV outdoor oil filled VT's & CT's	4 yearly	Insulation resistance test, oil change.
Capacitor Banks		
Pole mounted capacitor bank visual inspection (per site)	2 monthly	Equipment visual inspection

Task	Timing	Scope
Protection Relays		
Protection testing for electromechanical/static Relays	2 yearly	Secondary injection tests and check operation
Protection testing for numerical Relays	4 yearly	Secondary injection tests and check operation
Protection review	2 yearly	Relay attribute check including settings, standards, discrimination and records checks. Check for the impact of any changes in the Network
Oil containment		
Oil interceptor system checks	2 monthly	Inspect bunding around switchyards.
Ripple plant		
Equipment test	Annual	Maintenance contract with external service provider.
Communication and SCADA		
Radio site checks	4 monthly	Visual inspection and tidy. Battery tests. All radio sites except Manganui Bluff and Huruiki
Radio tests	Annual	Visual inspection and tidy. Battery test, UHF signal strength, frequency tests
Strategic spares	Annual	Check substations and store. Tag and check against register

Zone Substation Assets Preventative Maintenance Program

Maintenance Task	Timing	Scope of Work
Subtransmission Cables		
Subtransmission cable patrol of key circuits	Weekly	Drive through inspection to check for any building, excavation or encroachment activity
Check and record oil pressure readings and maintenance	Monthly	Read and record pressure readings (including spare cables). Clean out pressurisation pits, test gauge calibration and transducer alarms
Cable cover protection unit (SVLs), cross bonding link boxes and serving tests on key circuits.	3 yearly	Undertake all SVL, cross bonding and serving tests on cables.
Cable PDC tests	4 yearly	Hire a specialist contractor to carry out PDC tests on all subtrans cables except Refinery cables

Subtransmission Assets Preventative Maintenance Plan

6.2.2 Process for Rectification of Defects Identified as a Result of the Inspections or Condition Monitoring

Northpower follows the same process for the rectification of the defects identified as a result of the various maintenance inspections or condition monitoring activities, irrespective of the asset group concerned. Essentially, for any condition that falls outside the criteria listed in the work instruction for the inspection of a particular asset, the same format is followed. Varying levels of priorities are assigned to different defects based on key factors which are used in turn to drive scheduling of follow-up maintenance.

Defects and condition monitoring results are stored either in an electronic format or in hard copy. Individual defects or tasks are collated into a work pack which is created in the WASP (Works, Assets, Solutions, and People) system. Data contained within the system enables a cost to be allocated to each task and a value is applied to the work pack. Each defect is also registered against the particular asset as an open task.

The work pack is issued to a contractor for completion. Progress towards completion is monitored typically on a monthly basis through reporting services and any delay discussed with the contractor.

Upon completion, the contractor returns the work pack along with any as built information, attributes or data required to be captured. This information is entered into the system and the records updated prior to the contractor's invoice being passed for payment. In addition, random audits are undertaken on the completed work to monitor compliance to the network policies and work instructions for the particular task.

6.2.3 Systemic Issues and Addressing Actions

Northpower has developed sets of Maintenance Guidelines which identify systemic issues with components used on the network and provides a series of actions to address these. The guidelines are encapsulated in the asset specific maintenance Network Standards Manuals and are updated as issues are identified and as they are rectified.

The following table shows the current list of defect items and the action to be taken for each asset, equipment type or issue.

Asset Type	Equipment Type	Equipment Sub-type	Issue/Replacement Criteria	Replacement Type
Lines	General		When carrying out renewal work on a section of line/feeder, items that are not likely to last to the next maintenance cycle – typically 5 years should be replaced.	As required for the situation
	Dropout Fuses	Brand A	Fuses have a common fault problem, e.g. the steel bands at top and bottom are held by bolts that corrode and fail. Replace with modern cut-out wherever the opportunity arises. Note: Spur lines should be isolated with solid links if all transformers are individually fused and there are no vegetation issues.	Current approved model
		Brand B	Replace if there is any sign of corrosion (especially near bottom hinge), otherwise when an opportunity arises. Note: Spur lines should be isolated with solid links if all transformers are individually fused and there are no vegetation issues.	Current approved model
		Brand C	Replace if there is excessive corrosion (especially near bottom hinge). Note: Spur lines should be isolated with solid links if all transformers are individually fused and there are no vegetation issues.	Current approved model
	Lightning Arrestors	All types	Replace any 9kV rated lightning arrestors except lightning arrestors specific to overhead switchgear. Or replace if older than 10 years and the opportunity arises. Note: Check the Network Standards Manual Section 3.1.25 if replacement is required.	Current approved model
	Insulators	33 kV brand D	These are at risk of cracking at the joint between the two halves. Take every opportunity to remove any “brown – 2 part type” 33 kV insulators from the network.	Current approved model
		33kV clamp top	Clamp top connection known to fail. Take every opportunity to remove them from the network with the exception of Brand E.	Current approved model
		Kidney type	The age of the insulators presents a risk of electrical discharge tracking across the surface. Corrosion of the connection points could also result in failure. Replace in conjunction with other work and if replacing the crossarm.	Current approved model
		Pin types	Replace with approved post insulator when crossarm or insulators are replaced.	Current approved model
	Crossarms	-	Based on condition. Note: Replace crossarm if changing the pole or the insulators and the crossarm condition is mid life or worse. Do not replace a crossarm on a pole classed near end of life.	Current approved model

Asset Type	Equipment Type	Equipment Sub-type	Issue/Replacement Criteria	Replacement Type
Lines	Connections	PG clamps	Replace PG clamps with approved Wedge when other work is done onsite.	Current approved model
		Transition (Copper to Aluminium)	Replace Wedge connectors and PG clamps if used for transition (copper to Aluminium) and not covered. Use correctly sized wedge with standard gel airtight cover.	Current approved model
		Live Line Type	Replace connectors if 'live line' type, when the opportunity arises	Current approved model
	Possum Guards	-	Possum guards are generally removed by third parties. Replace where missing on HV poles only but also include stub poles.	Current approved model
	Pole	Wood	Failure generally due to decay. Replace pole in accordance to the notes if a crack in the head extends to the crossarm bolt or if rot exists at or below ground level or if a test with the wood drill shows excess decay. General Notes: For all situations pole design/calculation will be carried out as per the Network Standards Manual. For pole replacements in urban areas if access is not achievable – we will investigate the use of galvanised steel sectional poles (Oclyte or similar). For pole replacements in rural areas if access is not achievable – we will investigate the use of a helicopter to install a spun concrete or U pole. The use of softwood poles will be limited to harsh coastal environments or similar.	Current approved model (concrete preferred)
		Concrete	Spalling causes a structural strength risk and potentially a risk from falling debris. Replace the pole if there is excessive spalling and other work is happening at the same site. Apply the General Notes as per above.	Current approved model (concrete preferred)
		Concrete slab	Possibly insufficient engineering design was carried out when poles were originally manufactured. Recent testing shows that concrete slab poles still exhibit good strength characteristics. They are only required to be replaced when spalling is evident. Apply the General Notes as per above.	Current approved model (concrete preferred)

Asset Type	Equipment Type	Equipment Sub-type	Issue/Replacement Criteria	Replacement Type
Lines	Pole	2-pole transformer structure	Due to the prevalence of this type of structure installed in close proximity to kerbsides, there is a greater susceptibility of being hit by large trucks and coupled with potentially decayed timber, in greater danger of failing. If major maintenance is required then investigate a ground mount transformer option. Apply the General Notes as above.	Current approved model
		Telecom (especially Larch type)	Potential failure of pole as the mechanical strength may exceed design criteria due to presence of Northpower LV conductors. Engineer a solution and replace. ('Vesting Form' required). Apply the General Notes as above.	Current approved model
		All types	Shoulder of pole is exposed by stock rutting around the base of the pole. In extreme cases the stability of the pole could be compromised. Backfill with compacted limestone hard fill.	Current approved model (concrete preferred)
	HV Fuse Link	-	Nuisance tripping can occur due to incorrect fuse element having been installed. Solid links can be installed for spur lines with all transformers individually fused, if there are no trees in the vicinity of the line.	Current approved model
		Brand F	Knife links failed when operated. Manufacturers defect. Replace in conjunction with other work.	Current approved model
	Overhead LV Jumper Leads to Service Connection	-	Potential safety hazard to line mechanics as bare LV jumpers to the service connection may have been fitted in the past. Upgrade jumper leads to insulated conductor wherever upgrade work is taking place or other work is carried out and it is practical to upgrade the jumper.	Current approved model of Cu PVC conductor
	400V Fuses	Rewireable	Corrosion may exist at conductor termination on the fuse causing a burn off of the conductor. Replace fuse when other work is happening at the same site.	Current approved model
		Brand G	Corrosion may exist at conductor termination on the fuse causing a burn off of the conductor. Replace fuse when other work is happening at the same site.	Current approved model
	Conductor	11 kV jumpers	Corrosion may exist at the aluminium connection to the dropout fuse due to the presence of dissimilar metals. Replace with a copper jumper using correct bimetallic connectors at the main line connection.	Current approved model of Cu PVC conductor and connector

Asset Type	Equipment Type	Equipment Sub-type	Issue/Replacement Criteria	Replacement Type
Lines	Conductor	11 kV 7/.064 HDBC	Due to the age of the conductor there is an increased risk of failure due to corrosion or work hardening. A long term replacement strategy with a priority based on risk, likelihood, potential for public harm, risk to property and the impact of a fault has been implemented.	Current approved model of AAAC conductor
		11kV ACSR	Due to the age of the conductor there is an increased risk of failure due to corrosion particularly in coastal environments. A long term replacement strategy with a priority based on risk, likelihood, potential for public harm, risk to property and the impact of a fault has been implemented.	Current approved model of AAAC conductor
		Linking of LV Neutrals	Unlinked neutrals and undertake when the opportunity arises or in conjunction with other work.	Current approved model
		Joins	Replace section of conductor if there is a significant number of compression joins	Current approved model
	Conductor Clamping System	Wraplock tie	Failure of the binding to the insulator due to corrosion of the wraplock tie may cause the conductor to clash. Replace wraplock ties with approved preform ties when other work is happening at the same site or a site immediately adjacent.	Current approved model
		Binder Wire	Binder wire is to be replaced with approved preform distribution ties when the insulators or crossarm is replaced	Current approved model
	Cable Conduits on Pole Riser		Broken cable conduits up poles due to third party vandalism is a potential safety hazard. Provide additional mechanical protection if replacing the cable or the conduit or as notified. Note: A wooden cable trough in accordance with NSM 3.3.85 can be fitted.	Current approved model
	HV Cable Termination	Cast iron pot head	If removing pot head, install 11 kV working sealing end. In service pot heads to be replaced if in poor condition, e.g. badly rusting, leaking etc. Recommendation is NOT to re-terminate old cable, but cut in a new pole riser from in ground or near ground level, with approved cable.	Current approved model
		Termination without crucifix	Mechanical stress on termination hardware may cause premature failure. There is no program for a retrospective replacement but a crucifix should be fitted in conjunction with other work if it is cost effective.	Current approved model
		Heat shrink or cold shrink cable termination	In high pollution areas a premature breakdown of the insulation may result in a flashover. Replace the termination if it is in poor condition, e.g. signs of tracking or physical damage or decay. Re-terminate if the XLPE end is practical, otherwise cut in a new section of cable. Replace with an approved cable termination.	Current approved model

Asset Type	Equipment Type	Equipment Sub-type	Issue/Replacement Criteria	Replacement Type
Lines	HV Cable Termination	Existing termination onto O/H lines that do not have surge arrestors	Add surge arrestors if doing other maintenance, e.g. pole cross arm replacement, etc., only if practical to do so. Refer to ENS 3.1.25 surge arrestor requirements.	Current approved model
	Guy	Stiles	Stock may damage the guy due to deterioration of the timber stile. Replace with new timber stile to network standard where required.	Current approved construction standard
			Guy termination may rust off or be removed by third party from guy rod causing pole to lean. Reterminate guy when other work is happening in the vicinity.	Current approved model
Low Voltage Pillars	Pillars	General	Pillars that have had gardens created around them are not considered a high maintenance priority unless this poses a safety risk or it is likely to cause damage to the components within the pillar. Rectify any dangerous or unsafe pillars	Current approved model
		Temporary supply pillars	No isolation point exists at the boundary of properties fitted with an aged temporary supply pillar within private property. Fit fuse pillar on boundary to allow removal of the temporary supply pillar. Minor lid repairs can be fixed on site without replacement of the complete pillar.	Current approved model
		Concrete with steel face plate	Potentially unearthed metalwork is accessible to third parties. Replace the complete pillar in conjunction with other substantial repairs or if an upgrade is required at the same site.	Current approved model
		Concrete with aluminium cap	Potentially unearthed metalwork is accessible to third parties. Replace the complete pillar in conjunction with other substantial repairs or if an upgrade is required at the same site.	Current approved model
		Stud pillar	Studs may fail, disconnecting the supply and causing an outage. Replace the complete pillar in conjunction with other substantial repairs or if an upgrade is required at the same site.	Current approved model
		Neutral bars	Some pillars have only been fitted with a small single neutral stud which does not provide sufficient room for multiple neutral connections. A separate multi stud neutral bar should be fitted.	Current approved model

Asset Type	Equipment Type	Equipment Sub-type	Issue/Replacement Criteria	Replacement Type
Low Voltage Pillars	Pillars	Service fuses	Tails (supply or load) are corroded causing potential burn off issues. Re-terminate at existing fuse or replace complete fuse in conjunction with any other work at the same site.	Current approved model
		Meter pillars	The Retailer's meter reading contractor is unable to read the meter due to the window in the pillar becoming opaque. Where retaining the old meter pillar and replacing the window is not practical, the pillar should be replaced with a new pillar. Also, if the metering is uncertified, new meters should be installed and the metering certified. Cases where the meters would be shifted to the house are:- - When the old house is removed and a new house built. - Where there is a major alteration to the electrical mains to the installation. For minor repairs to the metering pillar, the metering does not have to be upgraded or certified.	Current approved model
Ground mounted distribution substations and switchgear	Transformer	Pad mounted	Rusting of the transformer may allow an oil leak which cannot be repaired easily on site. Extensive rust also may not be able to be repaired on site. Additional electrical load of which the network may not be aware may overload the transformer causing unplanned outages. Engineer a solution and replace the transformer.	Current approved model
		11 kV bushings	A risk of contact with live parts exists from exposed and uninsulated transformer bushings for electrical workers accessing the transformer enclosure. Fit a shroud or replace the transformer while undertaking other substantial repairs or if an upgrade is required at the same site.	Current approved model
		Neutral bars	The potential exists for high resistance neutral connections where neutral lugs have been "stack" connected on stainless steel studs. Lugs are to be fitted directly back to back when carrying out other work within the transformer enclosure.	
		Old kennel type	Access issues may exist due to tight tolerances between the transformer and the kennel cover. If the transformer and/or LV distribution panel needs to be replaced, then upgrade to a standard mini sub and LV panel. Minor maintenance, including kennel repairs and earthing work, can still be carried out without requiring the replacement of the kennel.	Current approved model of mini sub and LV panel.

Asset Type	Equipment Type	Equipment Sub-type	Issue/Replacement Criteria	Replacement Type
Ground mounted distribution substations and switchgear	Transformer	Room type	Non standard LV panels compromise the ability to cost effectively add additional outgoing circuits. If the transformer needs to be replaced or the existing LV panel needing significant maintenance, then upgrade the complete unit. Note: Transformers and LV panels are separate items. The upgrading of one does not necessarily mean that the other should be upgraded.	Current approved model of room type transformer. Current approved model of standard LV panel.
		All	Graffiti may cause offense to certain sections of society. This is a social problem as opposed to a systemic equipment issue however graffiti is to be removed or painted over when identified.	
	11 kV Switchgear	All	Excessive partial discharge may indicate catastrophic failure of switch unit is imminent. Replace equipment.	Current approved model
		Wilde unit	Excessive partial discharge may indicate catastrophic failure of unit is imminent. Replace equipment. The current capital project underway will see all of this type removed from system.	Current approved model
		Brand G fuse links	Striker may fall apart. Manufacturer's defect. Reactive replacement upon failure.	
Distribution earthing	Earthing and Bonding	Distribution earth mats	High resistance earth mat may cause electric shock hazard. Upgrade to the current standard and regulatory requirement if not legally compliant or in conjunction with other work, e.g. a replacement or upgrade of the transformer, pole or earthmat.	Current approved practice
		Equi-potential bonding	The potential exists for a third party to sustain an electric shock due to all metalwork not being bonded together. Bond ground mounted equipment to metal covers, if found to be not bonded. Directly bolted on covers are deemed to be electrically bonded. Doors of mini/micro sub to be bonded if found to be not bonded. Note: For the size of earth and bonding conductor, see NSM 3.1.95	Current approved practice

6.3 Asset Replacement and Renewal Policies

Northpower has a number of policies, guidelines and processes relating to asset replacement and renewal. These are regularly reviewed and network standards set against them. Consultation with suppliers has resulted in an approved suppliers list and a list of approved equipment. The processes and standards exist to evaluate the suitability of new products for the network.

6.3.1 Policy on Redeployment and Upgrade of Existing Assets

Northpower considers redeployment and upgrade of existing assets to be preferable to the purchase of new assets, to ensure that existing capital is better utilised. There are three primary classes of assets deployed on the network and each class is treated differently with regard to redeployment.

- There are items that are considered expendable such as cross arms and line hardware. These items are not generally reused largely because they are of relatively low value and their integrity cannot be relied upon once they have been initially deployed. Conductor could be included in this category because generally a long length of conductor replacement is driven by the existing conductor reaching end of life. Alternately, conductor that is replaced due to line alterations is typically of relatively short lengths and good engineering practice suggests multiple joints are undesirable. There are limited occasions such as in emergency fault conditions or where a temporary line is required, where these items may be redeployed for a short, finite time.
- The second class of assets are what is termed 'rotable distribution assets'. These are broadly defined as assets that are traceable by way of an individual identifier such as a serial number and can be redeployed on the network after having been recovered and refurbished. These include items such as distribution transformers, reclosers and some poles. Generally these items have a relatively high capital cost and a relatively long lifespan or a combination of these criteria.
- The third class of assets that are considered for redeployment or reuse as an upgrade option are generally those high value items associated with zone substations. Items such as 33kV to 11kV transformers fall into this category. Due to the high capital cost of a new zone substation transformer, a cost benefit analysis is undertaken to evaluate the merits of the refurbishment of a unit approaching end of life. The decision to proceed depends on the cost of the refurbishment and the extended life achieved relative to the cost of purchasing a new unit. There are additional zone substation assets of low value which may be kept as strategic spares and included in this are electronic circuit boards for SCADA, communication or protection relay systems.

6.3.2 Policy on Acquisition of New Assets

Northpower will ensure that new assets are acquired only when existing assets cannot be redeployed or if using previously used assets would be inappropriate. The guiding principle is to achieve the least life-cycle cost, which includes an implicit recognition that employing used assets carries the risk of higher operating or maintenance costs at a later date.

In addition a policy is in place that governs the acquisition of third party constructed distribution network. This policy also contains details of capital contributions and transformer capacity charges and is supported by technical and engineering standards to ensure the guiding principle of least life cycle cost is preserved.

6.3.3 Policy on Adoption of New Technology

Northpower adopts a sensible approach to new technologies by evaluating the risks associated with the introduction of new technologies against the potential benefits before proceeding. Technologies that Northpower has reviewed in detail and subsequently pursues are trialled in depth to confirm feasibility. Northpower endeavours to be a leader in technological improvements in the electrical distribution business and other ventures for the benefit and prosperity of our customers.

Northpower ranks near the top of the 2_{nd} quartile of NZ line companies (by ICP number) but is very small in global terms, hence Northpower considers itself well-placed to adapt and partner with global vendors in an increasingly emergent technology market to trial new technologies in network equipment.

A change management procedure is used to ensure that the adoption of any new technology, or change in existing technology, brought about by internal or external influences, is subjected to a robust assessment prior to any implementation. A Network Standards Committee meets regularly to assess any suggested change whether it is new technology or modified work practices. The committee is a cross functional team which has a representation from the network with engineers, the contractor, the logistics group and the HR group. Any recommendation made by the committee is required to have final approval from either the Network Engineering Manager or the Network Services Manager.

6.3.4 Policy on Disposal of Assets

Northpower will always aim to dispose of surplus assets in a responsible manner that includes obtaining the best price for the asset. In particular, Northpower will ensure that materials such as oil, lead, PCB's and asbestos that may cause harm are disposed of in an acceptable manner in accordance with ISO 14001.

6.4 Asset Replacement and Renewal by Network Category

The planned asset replacement and renewal forecast is developed from a combination of various inputs. Primarily preventative maintenance inspections highlight areas where renewal and refurbishment is required. The drivers are safety considerations, network reliability and customer satisfaction. Historical information also provides some indication of likely expenditure for any particular category on the assumption that the preventative maintenance inspections or remedial maintenance responses do not identify any possible developing systemic issues.

6.4.1 Distribution Network:

6.4.1.1 Lines

The main areas for renewal and refurbishment expenditure within the distribution lines category include poles, crossarms, insulators, fuses and conductor. Expenditure on vegetation control is also included in the broad category of 'asset refurbishment'.

Wood pole replacements continue as a result of preventative maintenance inspections. The replacement target has been revised downwards as a direct result of the focus in this area over past years. Spalling concrete poles continue to be routinely renewed as a result of the preventative maintenance inspections.

Typically identified as a result of the preventative maintenance inspections, cross arms are usually renewed as opportunity maintenance in association with other related assets. The majority of the crossarm replacement work has been reclassified as a project with the associated expenditure capitalised.

Insulator replacements are driven by preventative maintenance inspections and typically occur as a result of age related potential failures such as cracking. Asset renewals for these items are conducted in conjunction with other maintenance tasks on associated structures.

The majority of conductor renewal is covered in the capital expenditure table although there has been an inclusion in this area for conductor testing to determine replacement requirements.

Vegetation control accounts for approximately 43% of the expenditure in this area. Northpower has continued to build on the work completed over several years with a more proactive approach to vegetation management under the framework of the Tree Regulations. This process is to ensure that all Northpower feeders are inspected and the required follow up work executed within each three year period. As the project progresses, landowners along the particular feeder being targeted are kept informed about the project to ensure maximum co-operation.

6.4.1.2 Overhead switches

The capital project aimed at the total replacement of pole mounted distribution air break switches with fully enclosed gas filled switches has been completed and has resulted in a decrease of expenditure for follow up maintenance in this area.

6.4.1.3 Distribution earthing

The level of expenditure for replacement and renewal in this area continues to sit at lower levels than the historical annual expenditure. This is because the majority of expenditure in this area is classified as capital expenditure.

6.4.1.4 Regulators

Preventative maintenance inspections primarily highlight issues such as rust or paintwork deterioration on this class of asset. Where this defect is greater than can be remedied on site, the unit is swapped out and refurbished back in the work shop. The level of expenditure in this area is consistent with maintaining regulators in good condition through timely follow up maintenance.

6.4.1.5 Ground mounted distribution substations and switchgear

The focus in this area continues to be on safety to the public and contractors who work on the network. As a result there is ongoing expenditure on aspects such as lock replacements, labelling and signage. A significant proportion of the expenditure is targeted at dealing with graffiti and vandalism on this asset group. The balance of the work involves repairs of oil leaks, maintaining the paint work in good condition (other than from vandalism) and refurbishment of foundations, vegetation control and the renewal of cable terminations.

6.4.1.6 Low voltage pillars

Safety is also a driver in the refurbishment and renewal of low voltage pillars. A proactive program exists to replace known defective pillars as identified through the preventative maintenance inspections. The majority of expenditure with pillar replacement has been transferred to a capital project.

6.4.2 Zone Substation Assets:

6.4.2.1 Zone substation and radio repeater sites

Follow up maintenance attending to gate, fence, lock, signage and earthing refurbishment and renewals with this class of asset confirms the continued high priority that safety related maintenance attracts.

6.4.2.2 Battery banks

Although there is a capital replacement program for battery banks the renewal and refurbishment maintenance is driven from likely premature failure of items identified through the preventative maintenance inspections.

6.4.2.3 Subtransmission transformers and tap changers

A major focus with these assets continues to be the onsite refurbishment of paint along with rust treatment and panel repairs. As a result of the preventative maintenance testing, oil found to be out of specification is routinely replaced. Other items such as renewal of cable terminations, refurbishment of the cooling fans and the replacement of silica gel are also tasks that typically fall into the renewal and refurbishment category.

6.4.2.4 Circuit breakers

Refurbishment of cable terminations and work associated with the thermal imaging, ultrasonic and partial discharge testing accounts for the majority of the tasks completed for this group. Refurbishment of the paintwork and treatment of rust are other activities that make up maintenance tasks for this asset class.

6.4.2.5 Outdoor structures

As with the circuit breakers, work associated with the thermal imaging, ultrasonic and partial discharge testing accounts for the majority of the tasks completed for this group. The balance is primarily concerned with the physical refurbishment of the structure, replacing rusting or corroded components.

6.4.2.6 Zone substation earthing

Almost all of the forecast spend in this area concerns refurbishment with safety as the driver. Items such as connections, labels and signage make up the follow up work for this asset class.

6.4.2.7 Relays

Relay indication and setting adjustments to ensure the components remain in specification for the network requirements accounts for the forecast refurbishment spend in this area.

6.4.2.8 Ripple plant

The forecast refurbishment and renewal spend in this area will remain fairly static over time as the plant age profile improves. The preventative maintenance checks will highlight any potential issues and allow a timely resolution prior to them manifesting as faults.

6.4.2.9 SCADA and Communications

The preventative maintenance checks will highlight any potential issues and allow a timely resolution prior to them manifesting as faults. The forecast refurbishment and renewal spend is relatively low given the combined value of the asset group.

6.4.3 Subtransmission Assets:

6.4.3.1 Subtransmission cables and lines

The renewal and refurbishment forecast for the cable asset is primarily targeted to gauges, transducers and associated pipework (oil-filled cables). Oil maintenance is also undertaken.

For the sub-transmission lines there has been continued expenditure on the renewal of 33kV insulators as a follow up from the preventative maintenance inspections.

6.4.4 Transmission Assets

6.4.4.1 Transmission Lines and Towers

Newly acquired transmission assets are maintained in line with industry standards in New Zealand. This involves regular patrols and complete condition assessments. The forecast spend is relatively low given the condition of these assets.

6.5 Non-Network Assets Development, Maintenance and Renewal

Non-network assets include items such as IT systems, asset management systems, office buildings, depots and workshops as well as furniture and equipment, motor vehicles, tools, plant and machinery.

The company wide Project Office register and associated processes which include capital expenditure justification procedures are used to manage and coordinate system change within the organisation. Short to medium term capital expenditure on Network related systems assets include; upgrade of the Electricity Retailer Billing System largely driven by legislative changes around metering; replacement of the existing Outage Management tools for planning, notification and management of outages and outage statistics; replacement of the existing Asset Management System and expansion of formal document and records storage systems.

Various policies exist for the different groups of assets such as fixtures and fittings, and plant and equipment. The policies that guide the approach, maintenance and replacement of these non network assets are all based on GAAP. From a maintenance perspective, the likely expenditure over the AMP period is consistent with that undertaken currently. No material capital expenditure is planned for these classes of assets other than that which could normally be expected following disposal of aged assets in accordance with company policy.

A company motor vehicle policy exists which aims to meet the company's operational and financial objectives and to achieve consistency in the way vehicles are purchased, leased, assigned and used throughout the company, thereby ensuring fairness, efficiency and effectiveness in the use of company assets. The policy also seeks to promote the Northpower brand and profile in the communities where Northpower is active. No material capital expenditure is planned for these classes of assets other than that which could normally be expected following disposal of aged assets in accordance with company policy.

A number of alterations at the main office building will progressively be made over the short term. A relatively major piece of maintenance on the site and building housing the office's local service transformer is to be carried out primarily due to ground subsidence. In addition, some space currently used as storage will be converted to offices to provide more appropriate utilisation of these areas and better facilitate the information flow between work teams. The planned maintenance will only be undertaken following the approval of the appropriate sanctions for expenditure in accordance with company policies.

6.6 Asset Maintenance Expenditure Forecast (OPEX)

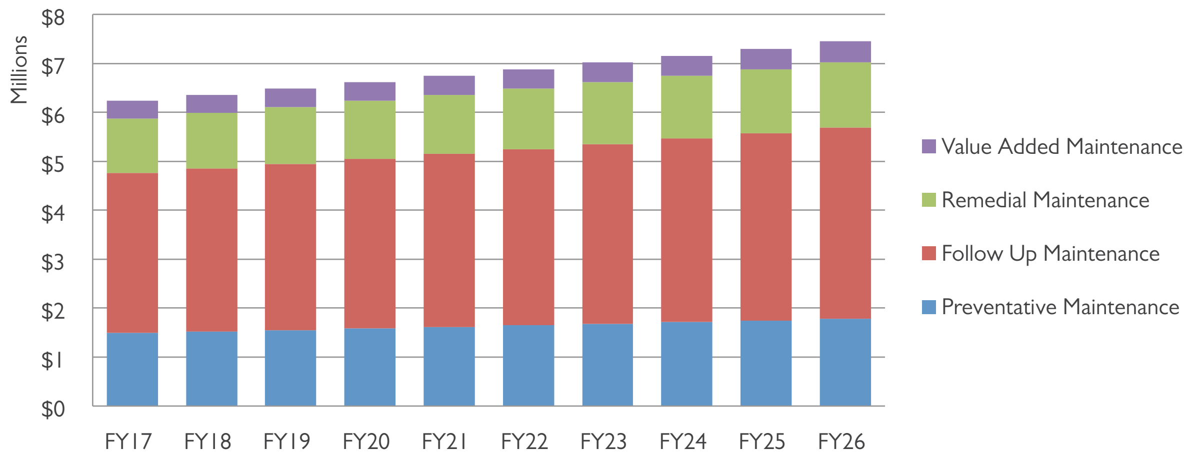
The detailed asset maintenance 10 year expenditure forecast (OPEX) is provided in the table at the end of this section and comprises of the following expenditure categories:

- Preventative maintenance
- Follow up maintenance
- Remedial maintenance
- Value added maintenance

A high level overview of the 10 year program showing total expenditure in each of the 4 categories is shown in the following graphic.

EDB 10 Year Opex Program (FY2017-26)

(costs escalated at 2% pa)



The forecast expenditure should be read in conjunction with the detailed notes above for each of the network asset categories. It should be noted that although forecast expenditure is provided for the 10 year period it is based on anticipated expenditure for the first year.

Expenditure on specific asset groups within the different maintenance categories could change in future years due to changing preventative maintenance cycles or the need to focus on particular assets as a result of unforeseen circumstances. There are no major projects planned at this point in time which would cause the annual maintenance spend to increase dramatically above what might be expected due to cost inflation.

All follow up asset maintenance expenditure (asset renewal and refurbishment) which results in extended asset life is classified as CAPEX and is included under replacement and renewal expenditure in the 10 year CAPEX forecast in Section 5.

6.6.1 Asset Maintenance 10 year Expenditure Forecast (OPEX)

MAINTENANCE EXPENDITURE PLAN (OPEX) $000	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
(costs escalated at 2% per annum)	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26
Preventative Maintenance										
Circuit breakers	52	53	54	55	57	58	59	60	61	62
Communications	9	9	10	10	10	10	10	11	11	11
Distribution earthing	277	282	288	293	299	305	311	318	324	330
Ground mounted substations	97	99	101	103	105	107	109	111	113	116
Overhead lines	302	308	315	321	327	334	341	347	354	361
Overhead switches	30	31	32	32	33	34	34	35	36	36
Overhead structures	42	43	43	44	45	46	47	48	49	50
Pillars	199	203	207	211	216	220	224	229	233	238
Protection relays	44	45	46	47	48	49	50	51	52	53
Regulators	37	38	39	39	40	41	42	43	43	44
Ripple Plants	24	24	25	25	26	26	27	28	28	29
Subtrans cables	125	127	130	132	135	138	140	143	146	149
Zone sub buildings and grounds	131	134	136	139	142	145	148	151	154	157
Zone sub transformers	123	125	128	130	133	135	138	141	144	146
	1,492	**1,522**	**1,552**	**1,583**	**1,615**	**1,647**	**1,680**	**1,714**	**1,748**	**1,783**
Follow Up Maintenance										
Battery banks	10	10	10	11	11	11	11	11	12	12
Circuit breakers	40	41	42	42	43	44	45	46	47	48
Communications	10	10	10	11	11	11	11	11	12	12
Distribution earthing	5	5	5	5	5	6	6	6	6	6

MAINTENANCE EXPENDITURE PLAN (OPEX) $000	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
(costs escalated at 2% per annum)	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26
Ground mounted substations	180	184	187	191	195	199	203	207	211	215
Multiple asset groups	80	82	83	85	87	88	90	92	94	96
Outdoor CT's and VT's	2	2	2	2	2	2	2	2	2	2
Overhead lines	750	765	780	796	812	828	845	862	879	896
Overhead switches	15	15	16	16	16	17	17	17	18	18
Overhead structures	40	41	42	42	43	44	45	46	47	48
Pillars	70	71	73	74	76	77	79	80	82	84
Protection relays	5	5	5	5	5	6	6	6	6	6
Regulators	5	5	5	5	5	6	6	6	6	6
Ripple Plants	3	3	3	3	3	3	3	3	4	4
Subtrans cables	10	10	10	11	11	11	11	11	12	12
Vegetation	1,900	1,938	1,977	2,016	2,057	2,098	2,140	2,183	2,226	2,271
Zone sub buildings and grounds	60	61	62	64	65	66	68	69	70	72
Zone sub earthing	3	3	3	3	3	3	3	3	4	4
Zone sub transformers	75	77	78	80	81	83	84	86	88	90
	3,263	**3,328**	**3,395**	**3,463**	**3,532**	**3,603**	**3,675**	**3,748**	**3,823**	**3,900**
Remedial Maintenance										
Battery banks	10	10	10	11	11	11	11	11	12	12
Capacitor banks	1	1	1	1	1	1	1	1	1	1
Circuit breakers	10	10	10	11	11	11	11	11	12	12
Communications	32	33	33	34	35	35	36	37	37	38
Distribution earthing	1	1	1	1	1	1	1	1	1	1

MAINTENANCE EXPENDITURE PLAN (OPEX) $000	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
(costs escalated at 2% per annum)	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26
Ground mounted substations	8	8	8	8	9	9	9	9	9	10
Multiple asset groups	5	5	5	5	5	6	6	6	6	6
Outdoor CT's and VT's	1	1	1	1	1	1	1	1	1	1
Overhead lines (including vegetation)	800	816	832	849	866	883	901	919	937	956
Overhead switches	10	10	10	11	11	11	11	11	12	12
Oil containment	2	2	2	2	2	2	2	2	2	2
Structures	1	1	1	1	1	1	1	1	1	1
Pillars	35	36	36	37	38	39	39	40	41	42
Protection relays	5	5	5	5	5	6	6	6	6	6
Regulators	1	1	1	1	1	1	1	1	1	1
Ripple Plants	2	2	2	2	2	2	2	2	2	2
Subtrans cables	12	12	12	13	13	13	14	14	14	14
Underground cables	105	107	109	111	114	116	118	121	123	125
Zone sub buildings and grounds	25	26	26	27	27	28	28	29	29	30
Zone sub earthing	1	1	1	1	1	1	1	1	1	1
Zone sub transformers	50	51	52	53	54	55	56	57	59	60
Voltage complaints	2	2	2	2	2	2	2	2	2	2
	1,119	**1,141**	**1,164**	**1,187**	**1,211**	**1,235**	**1,260**	**1,285**	**1,311**	**1,337**
Value Added Maintenance										
Cable location	100	102	104	106	108	110	113	115	117	120
Customer equipment	300	306	312	318	325	331	338	345	351	359
Data capture	18	18	19	19	19	20	20	21	21	22

MAINTENANCE EXPENDITURE PLAN (OPEX) $000	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
(costs escalated at 2% per annum)	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26
High loads	13	13	14	14	14	14	15	15	15	16
Load checks	20	20	21	21	22	22	23	23	23	24
Network initiated field switching	2	2	2	2	2	2	2	2	2	2
Safety disconnects and permits	150	153	156	159	162	166	169	172	176	179
Vegetation	54	55	56	57	58	60	61	62	63	65
Recovered costs (customers)	-300	-306	-312	-318	-325	-331	-338	-345	-351	-359
	357	**364**	**371**	**379**	**386**	**394**	**402**	**410**	**418**	**427**
Total Maintenance Expenditure (OPEX)	**6,231**	**6,356**	**6,483**	**6,612**	**6,745**	**6,880**	**7,017**	**7,158**	**7,301**	**7,447**

Section 7: Risk Management

"safe, reliable, hassle free service"

Northpower

Risk Management

7

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Section 7: Risk Management

7.1 Introduction

Risk management is an integral part of Northpower's overall business philosophy. The company's business objectives are managed and achieved through the application of sound and thorough risk management practices.

7.2 Risk Management Policy

To ensure that Northpower develops and maintains a comprehensive risk management process.

A risk is defined as:

"Anything that can prevent Northpower from achieving its goals and objectives"

Risk management is integrated into the business at all levels. This is achieved by:

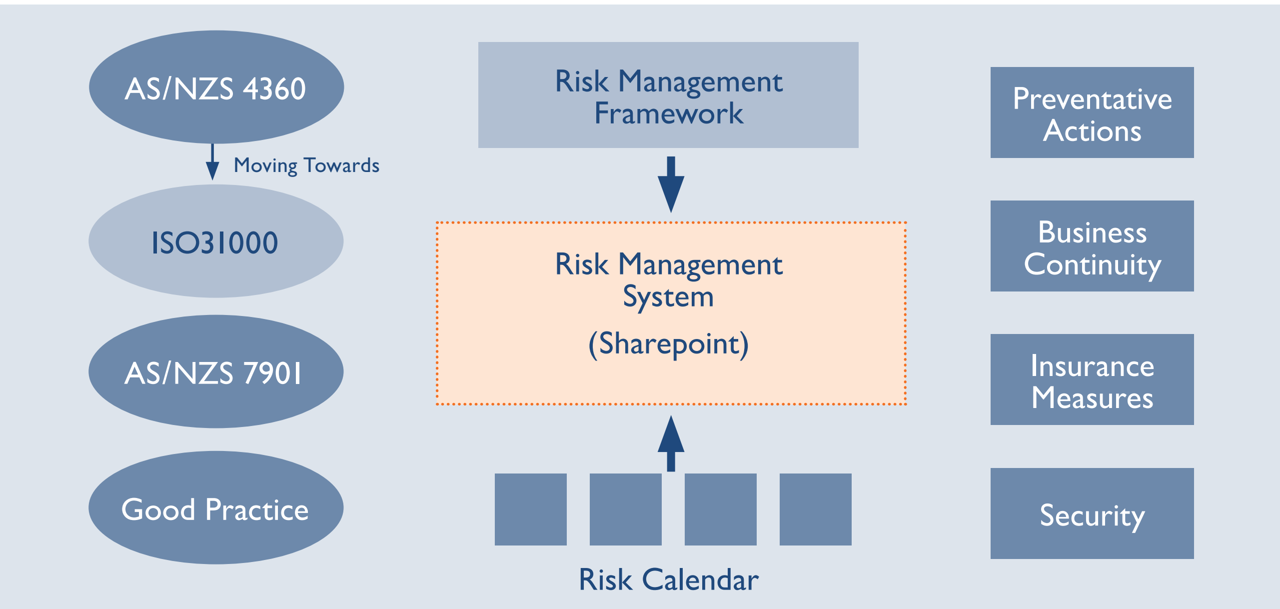
- Including senior management in the risk management team
- Monitoring risk in key business reporting
- Including risk mitigations as a key justification for expenditure
- Raising awareness through communication of the risk treatment plans
- Identifying clear responsibilities for risk treatment plans
- The audit and external review of the Manage Risk process

Risk management will be carried out generally in accordance with the following standards:

- AS/NZS 7901:2014 Electricity and Gas Industries – Safety Management Systems for Public Safety
- AS/NZS 4360:2004 Risk Management
- AS/NZS 3931:1998 Risk Analysis of Technological Systems - Application Guide

Northpower is currently reviewing AS/NZS ISO 31000:2009 Risk Management – Principles and Guidelines. This introduces an enterprise perspective that builds and improves upon the Australian and New Zealand standards. The basic process is summarised below.

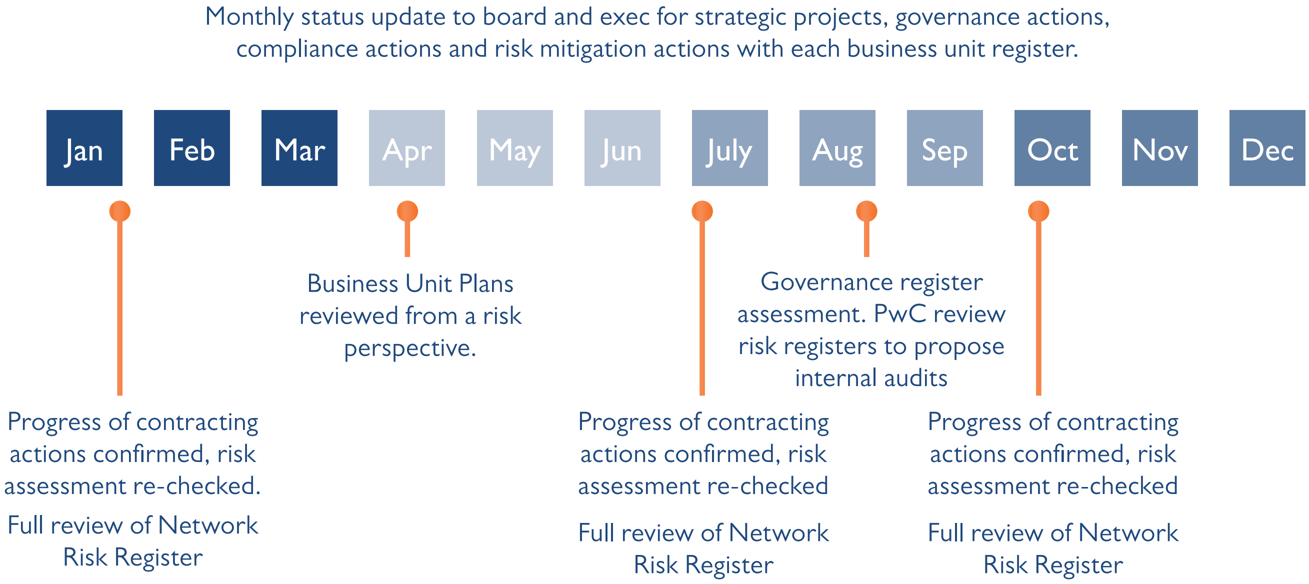
7.3 Risk Management Framework



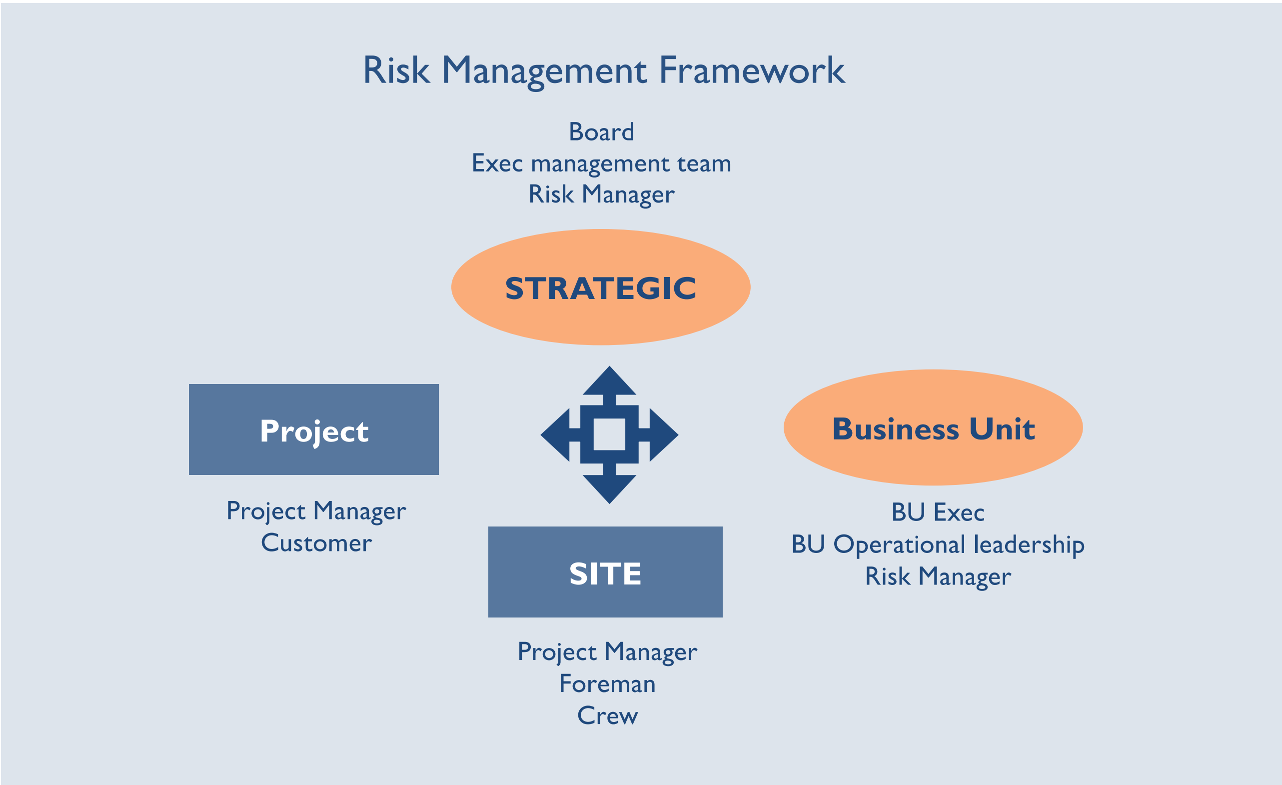
Risk Management Framework

7.3.1 Risk Analysis Governance

Northpower frequently evaluates and reassesses risk. Risk analysis (which involves consideration of both likelihood and impact) is undertaken across the business units and recorded in risk registers. These registers note not only raw risk, but also mitigated risk assessment. The results of the risk analysis are used to set priorities for risk mitigation plans.



Calendar



Risk Management Framework

The framework begins with a regular review of the risks involved with operating a multinational electrical utility business, its strategies, governance and operating models. From this each business unit reviews its plans based upon the Baldrige performance excellence criteria. Action plans are created, managed and reported upon the executive and board monthly.

The project management framework includes the management of risk as a key control mechanism to improve the reliability of project delivery. Whilst having a knowledge base of known, generic risks, the project manager is encouraged to review each job uniquely to assess and then manage risk.

On the day of service, the field crews are involved in the risk management process. A series of behavioural change initiatives have successfully moved the attitude towards risk from "something someone else does" to something that we all do as part of the job.

Northpower has a holistic approach to risk management, acknowledging that it is part of a community and that community wide risk management is necessary to ensure a robust and resilient electricity network.

Northpower does this by participating in the Northland Lifelines Group which meets 4 times each year to discuss risk to community assets, identify critical sites and inter-dependencies. This contributes civil defence and the long term ability of the community to respond to events.

Northpower also participates in the industry to regarding nationwide and regional issues that pose a risk to the supply of electricity.

7.3.2 Risk Analysis Methodology

The risk analysis methodology is based on the risk evaluation provided in ENS 01.07.001 Safety Management System.

Risks are ranked with a numerical value. This value is derived from two factors, probability and severity. Probability is derived from exposure and likelihood and is graded into 5 levels (A to E). Severity is also graded into 5 levels (1 to 5) giving a value of risk from 1 – 25. Each risk has both a "raw" (i.e. pre mitigation) and "mitigated" ratings. Mitigation measures include actions and systems put in place that either reduce the probably of an event/incident or lessen the consequences or both.

Based on the ranking, risks are grouped into low, medium & high risks. Priority is given to mitigation of risks with a high risk rating. Generally a watching brief is maintained over low risks. Risks that have a high raw risk but have been mitigated down significantly are audited internally to ensure that the mitigation controls are still in place and are effective.

Additional information on risk evaluation is provided in AQPC: 10.6.1 SMS-033 Procedure for Categorisation of Hazards/Risks. However this document utilises different category values.

The risk evaluation includes the following steps:

- Step 1 Assess the risk exposure (how frequently the potential risk event occurs)
- Step 2 Assess the likelihood (probability of a loss when the potential risk event does occur)
- Step 3 Determine the probability (combination of exposure and likelihood)
- Step 4 Assess the severity of the risk (how bad the losses would be)
- Step 5 Determine the risk (combination of probability and severity)
- Step 6 Determine the priority (based on risk)

All potential risks with a severity of 3 to 5 are a risk of serious harm or significant damage and are considered a significant risk. Refer to 8.4.3 Asset risk identification tables.

Risk Calculation Charts

Step 1 Assess the Risk Exposure

Assess the 'exposure' (or 'frequency') of the risk being encountered according to the following descriptors:

Exposure		Value
Continuous	Risk or hazard encountered continuously	6
Daily	Risk or hazard encountered daily	5
Weekly	Risk or hazard encountered once or twice a week	4
Monthly	Risk or hazard is faced infrequently and has been experienced once each month or approximately 10 to 12 times a year	3
Quarterly	Risk or hazard is faced infrequently and has been experienced more often than once a year	2
Yearly or less	Risk or hazard is faced infrequently and has been experienced once annually or less	1

Step 2 Assess the Likelihood

Assess the 'likelihood' (or 'probability') of the risk occurring according to the following descriptors:

Likelihood		Value
Almost certain	Happens repeatedly during the project life	6
Very likely	Could easily happen and has occurred on a previous project more than once	5
Likely	Could happen and has occurred on other projects	4
Unlikely	Could happen and has occurred rarely (infrequently) on other projects	3
Very Unlikely	Hasn't happened yet but it is possible that it could	2
Practically impossible	Hasn't happened and can't imagine it actually happening	1

Step 3 Determine the Probability

Combination of EXPOSURE and LIKELIHOOD from Steps 1 and 2

(A is high probability and E is low probability)

	Exposure (Step 1)							
Likelihood (Step 2)			**Yearly 1**	**Quarterly 2**	**Monthly 3**	**Weekly 4**	**Daily 5**	**Continuous 6**
	Practically Impossible	**1**	E	E	E	D	D	C
	Very Unlikely	**2**	E	E	D	D	C	C
	Unlikely	**3**	E	D	D	C	C	B
	Likely	**4**	D	D	D	C	B	B
	Very unlikely	**5**	D	D	C	B	B	A
	Almost certain	**6**	D	C	C	B	A	A

Step 4 Assess the Severity of the Risk

Categorise the 'severity' (or potential severity) according to the descriptors below and allocate the appropriate score:

Consequence	Criteria	Value
Catastrophic (strategic/acute)	· Death · Financial recovery could take many years · Ongoing damage to company reputation · Sustained impact upon our customers	**5**
Major (strategic/chronic)	· Permanent disability / life changing injury · Many resources will need to be diverted to recover · Major financial loss >$5 million · Potential litigation · Significant damage to company reputation	**4**
Moderate (high end efficiency)	· Moderate injury with on-going consequences · Event requires escalation · Moderate financial loss $1-$5 million · Impact on relations with others (customer) · Short term damage to company reputation	**3**
Minor (low end efficiency)	· Minor injury · Immediate recovery within operational teams · Minor financial loss $250,000 to $1M · Impact on others (customers) within expectations · Minimal impact on reputation	**2**
Insignificant	· No injury · Low financial loss <$250,000 · Does not impact reputation	**1**

Step 5 Determine the risk

Combination of PROBABILITY and SEVERITY from steps 3 and 4

		Probability (Step 3)				
		E	**D**	**C**	**B**	**A**
Severity (Step 4)	**1**	1	2	6	10	15
	2	2	5	9	14	19
	3	4	8	13	18	22
	4	7	12	17	21	24
	5	11	16	20	23	25

Step 6 Determine the Priority for Control

Priority	20-25	**High Priority** - Control the risk without delay
	11-19	**Medium Priority** - Control the risk as soon as possible
	1-10	**Low Priority** - Control the risk after High and Medium risks have been been addressed

Order of control

1 Eliminate
2 Isolate
3 Minimise

Risk Treatment

All potential risks identified (listed in 7.4.3) are responded to immediately and eliminated or are treated by isolation or minimisation. If there are multiple risks identified, depending on resources available, response may need to be prioritised according to severity and residual risk. The location can also affect the priority as a risk identified in remote location may present a lower potential risk than a similar risk in a built up area.

- High priority risks should be treated without delay.
- Medium priority risks should be treated as soon as possible after any high priority risks have been addressed.
- Low priority risks should be treated after any high and medium priority risks have been addressed.

In practice additional resources would generally be mobilised to respond to additional risks rather than prioritise the response.

The treatment of potential risk ensures that the residual risk of serious harm or significant property damage is as low as is reasonably practicable.

Potential risks are evaluated and control arrangements made by the Asset Management Group and escalated for action to the Network Management Team where required.

7.4 Risk Management Process

This Asset Management Plan focuses on physical risks to Northpower's electricity distribution business and associated assets. For clarity, the prime risks are risk to supply electricity supply (risk of outage) and risk of damage to operators to consumers (safety risk). Northpower has a companywide commitment to reduce (ideally eliminate completely) safety risks. Assessment of safety factors and risks must routinely be considered in every activity including asset management functions.

The major physical risks (and associated mitigations/solutions) to Northpower's network are summarised below. Risk ratings shown in the table are raw risk ratings.

7.4.1 Key Business Risks

Northpower collates and review risks on a quarterly basis for the Whangarei Network, the key risks on the register include the following asset related risks:

Risk Title	Definition
3.1 Network assets	If we do not identify and remedy unsafe assets we may injure the staff or the public
3.2 Public Safety	If we do not educate the public they may seriously injure themselves
3.3 Privately owned assets	If we do not address unsafe service lines in a timely manner, we may be found negligent if harm occurs.
5.1 Contractor Safety	If we do not monitor health and safety behaviours and ensure the contractor adopts safe working practices, we may have a fatality on the network.

Risk Management Process – Key risk from Network Business Unit register

7.4.2 Asset Risks – Faults and Outages

The risk of equipment failure is assessed regularly and is a key activity in setting strategy and budgets. Northpower draws upon records of incidents, inspections, experience and international best practice to determine the risk associated with assets and asset types.

Risk loss/fault/ event	Likely-hood	Impact	Consequential Damage Risk	Solution / Mitigations
Loss of Continuity of Supply from Transpower or Generators	Unlikely	Major	Severe reduction in supply capacity for hours, weeks or months over entire network	Load management
Loss of 33/11kV transformer at n security substation	Unlikely	Moderate	Loss of supply for up to several hours plus water heating cuts.	Restore supply via 11kV network and/or install replacement from another substation
Loss of 33/11kV transformer at n-1 security substation	Unlikely	Minor	Fire can spread to other assets, oil poses an environmental hazard	Reduce load on remaining transformer (if necessary). Design/install hazard containment
Damage to 11kV switchboard in Zone Substation	Very Unlikely	Moderate	Up to 24 hours loss of supply for some customers.	Isolate faulty section or repair. Transfer load to alternative source (e.g. back-feed or generator
Overhead Line	Almost Certain	Insignificant	Unlikely to cause major damage to other assets	Isolate faulty section or repair. Transfer load to alternative source (e.g. back-feed or generator)
Cable	Very Likely	Insignificant	Unlikely to cause damage to other assets	Isolate faulty section or repair. Transfer load to alternative source (e.g. back-feed or generator)
Individual Circuit Breaker	Unlikely	Insignificant	Catastrophic failure could damage other assets, for indoor switchboards some damage can be expected	Maintenance regimes, design (protection/housing) and equipment standards for breakers

Risk loss/fault/ event	Likely-hood	Impact	Consequential Damage Risk	Solution / Mitigations
33kV Outdoor Bus	Unlikely	Insignificant	Catastrophic failure could damage other assets	Assess and repair as soon as possible. Design and install risk treatment
Indoor switchboard	Very Unlikely	Major	Catastrophic failure could damage other assets including the building	Assess and repair as soon as possible. Design and install risk treatment
SCADA system	Unlikely	Minor	Major failure will result in loss of control	Redundancy and backup on key components (including software)
Earthquake	Practically Impossible	Major	Note 1	Mitigate by upgrade and specific design for major equipment. Repair damage as soon as possible
Storm	Likely	Moderate	Note 1	Mitigate by tree maintenance and line design Repair damage as soon as possible
Flood	Unlikely	Moderate	Note 1	Repair damage as soon as possible using response procedures
Tsunami	Practically Impossible	Major	Transmission supply at Bream Bay is at risk and could cause systemic outages	Repair damage as soon as possible using response procedures
Pandemic	Very Unlikely	Minor	Asset Management Capacity	Use corporate contingency
Safety	Very Unlikely	Moderate	Costly damage to plant or property or other assets	Quality design Strict safety specifications Safety orientated decision making Safe work practices Preventative Maintenance Schedules Follow up Maintenance Fault Response Asset Renewal/Replacement Program

Key Physical Risks to Assets

Note 1: Contingent upon the severity of the event, restoration will depend on accessibility to sites of damage and the extent of damage to the overall network. Typically, even for a major storm, the vast majority of customers are restored within 1 to 2 days. E.g. Cyclone Bola – maximum outage time was 3 to 4 days. Restoration involves repair or replacement of damaged equipment, where alternative routes of supply are not possible.

Northpower is able to leverage its extensive contracting business and increase resources from other locations across the North Island.

7.4.3 Asset Risk Identification Tables

Distribution Asset	Electrical Shock	Physical	Flash/Explosion	Environmental
Poles Structures and fittings	Pole becomes conductive. Pole/ fitting failure allows conductor to fall. Cables running up poles damaged or unprotected Ability to climb pole or structure near pole allowing access to live conductors.	Structural failure 3rd party contact e.g. car v pole. Excavating near pole Loose or disconnected guy	Failure causes fire	
Overhead lines and cables	Contact with live conductor e.g. mobile plant, boats, high loads, recreation, construction activities, structures etc. Trees growing or falling on lines Unauthorised tree trimming by lines Contact between HV and LV conductors. Conductor clearances, drop and failure (to ground and other structures)	Contact with live conductor e.g. mobile plant, aircraft, boats, high loads, construction activities etc. Conductor Drop. Perceived EMF risk.	Failure or clashing causes fire	
Underground cables	Contact with live conductors. Broken neutrals. Inadequate depth or protection Excavating near cables			Oil leak (oil cables only)
Distribution pillars	Contact with live conductors or metal components. Excavating near pillar	3rd party contact e.g. car v pillar.	Equipment failure causes fire	
Pole mounted transformer	Contact with live conductors. Site becomes alive (includes EPR risk)	Perceived EMF risk.	Internal fault that creates an explosive rupture of tank and or oil fire starts.	Oil leak.

Distribution Asset	Electrical Shock	Physical	Flash/Explosion	Environmental
Ground mounted transformer	Contact with live conductors. Tanks becomes alive (includes EPR risk)	3rd party contact e.g. car v transformer Perceived EMF risk.	Internal fault that creates an explosive rupture of tank and or oil fire starts.	Oil leak.
Pole mounted switchgear			Flash-over ("open" ABS type)	SF6 Leak
Ground mounted switchgear	Contact with live conductors. Tanks becomes alive (includes EPR risk)	3rd party contact e.g. car v switchgear.	Internal fault that creates an explosive rupture of tank and or oil fire starts.	Oil leak (oil type) SF6 leak.
Distributed Generation		Overvoltage damage to appliances		
Revenue Metering	Contact with live conductors		Equipment failure causes fire	
Design		Poles, lines, cables and equipment positioned in hazardous locations	Underrated or inappropriate conductors or equipment	
Construction	Phase and neutral crossed Conductor clearances inadequate	Open excavations eg trench, jointing pits, pole holes		
Asset Management	Reticulation not identified or inspected Generator feedback Unauthorised connections Inadequately secured sites and equipment		Voltage unbalanced or outside limits and earth fault, leakage or over currents	

Key Hazards with Physical Distribution Assets

Zone Substation	Electrical Shock	Physical	Flash/Explosion	Environmental
Site	Earth potential rise (EPR)	Perceived EMF risk.	Flying debris, spread of fire.	Noise, radio interference.
Outdoor yard (including switchgear)	Contact with live conductors, EPR of yard fence & other exposed metal.	Perceived EMF risk.	Arc flash, flying debris, spread of fire.	Noise, radio interference, SF6 (contained in some CB's)
Indoor switchgear and control systems	Contact with live conductors. EPR of exposed metal.	Perceived EMF risk.	Arc flash, explosive force.	SF6 (contained in some CB's)
Ripple Plants	Contact with live conductors or metal components.		Flying debris	(all capacitors are non PCB type)
Outdoor transformers	Contact with live conductors. Site becomes alive (includes EPR risk)	Perceived EMF risk.	Internal fault that creates an explosive rupture of tank and or oil fire starts. Flying debris (busing & surge arrestors)	Oil leak. Transformer noise.
Indoor Transformers	Contact with live conductors. Site becomes alive (includes EPR risk)	Perceived EMF risk.	Internal fault that creates an explosive rupture of tank and or oil fire starts. Flying debris (busing & surge arrestors)	Oil leak but contain within the building Ventilation noise.

Key Hazards with Physical Substation Assets

To mitigate the identified asset risks, Northpower starts with good design principles. Installed assets are inspected regularly and undergo a rigorous preventative maintenance programme to monitor condition and hazard risk. Additionally from a process perspective, each job starts with a risk identification step to ensure that countermeasures to the risk are observed.

7.4.4 Environmental Risk

Northpower's Environmental Management Plan defines the policies, procedures, organization and responsibilities that in total create the Environmental Management System (EMS) for Northpower

The EMS is designed for compliance and certification to the international standard ISO140001:2004 Environmental Management System. It is integrated with other major systems:

- Health and Safety in Employment ACT 1992,
- ISO9001:2008. Quality Management System,
- AS/NZS 7901;2008 Electricity and Gas Industries – Safety Management Systems

To maximise the positive impacts and minimise the negative impacts that Northpower's activities, products or services may have upon human health and the environment and to ensure compliance with the relevant environmental legislation.

Northpower will demonstrate leadership and continual improvement in environmental management. In all activities, Northpower will seek to identify, monitor and improve the impact on the environment. To this end, Northpower will:

- Aim to achieve a level of performance which, goes beyond that required of the Resource Management Act 1991 and all statutory requirements and conditions of consents relating to environmental matters.
- Continually improve our performance as measured by our environmental objectives and their associated targets.
- Prevent pollution, reduce waste and consumption and commit to recovery and recycling as opposed to disposal.
- Identify, implement and promote ways to improve efficient use of resources, including energy and water.
- Increase public awareness of environmental issues and the actions people can take by promoting environmental education and training both within Northpower and external contractors and the wider community.
- Incorporate environmental performance standards into contracts and service level agreements for suppliers and contractors who meet the same high environmental standards imposed on Northpower.
- Adopt a structured environmental management system using the ISO 14001 standard. This system will be the means by which, environmental objectives and targets, are set and reviewed.
- Include environmental considerations in all business planning, including options to reduce or eliminate adverse effects on the environment resulting from Northpower's activities.
- Produce an annual report on the state of the environment management system.
- Ensure that the environmental policy is communicated to all employees and made available to the public.

As with safety, at the start of a job, environmental risks are reviewed and mitigation controls established, the categories include:

- Death/Injury to Public
- Death/Injury to Northpower Staff/Contractors
- Oil Spill
- Chemical Spill
- Pollution of Waterways or Sea
- Air Pollution
- Visual Pollution
- Damage to Protected Tree/Area
- Damage to Trees/Vegetation
- Damage to Northpower Assets
- Damage to Other Utilities, e.g. water, gas
- Damage to Other People's Property
- Noise
- Dust
- Fire
- Flood
- Landslip and/or Erosion
- Unplanned Outage

7.5 Emergency response and contingency plans

Northpower has acknowledged two major risks, namely safety and outages. The following discusses outage risks. Incidents involving safety would be managed using the rules of first aid.

Northpower Business Continuity Framework

Focus		People	Infrastructure	Plans
Focus • Storm Response • Accident Response • Building Evacuation	Emergency Response	• Emergency team structures • Clearly understood roles • Appropriate nominations • Alternatives for key roles • External parties integration • Rehearsed / trained / tested	• Emergency operations • Onsite • Local off site • Remote off sites • Supporting resources • Communications systems • Tested	• Roles clearly defined • Emergency plans • Key scenario coverage • Action checklist for roles • Contact numbers • Reference information • Chart, plans, maps
Focus • Executive leadership • Business disruption • Manage consequences • Co-ordinate response • Lifelines response	Crisis Management	• Executive team structures • Clearly understood roles • Appropriate nominations • Alternatives for key roles • External parties integration • Rehearsed / trained / tested	• Management command Centres • Onsite • Local off site • Remote off sites • Supporting resources • Communications systems • Tested	• Roles clearly defined • Key scenario crisis plan • Civil defence lifelines plan • Action sheets / call trees • Reference information • Command Centre Kit
Focus • Core business • Core support functions • Recovery focus • Lifelines response • Contractors	Business Recovery	• B.U. team structures • Clearly understood roles • Appropriate nominations • Alternatives for key roles • External parties integration • Rehearsed / trained / tested	• Back up facilities • Plant & equipment • Vehicles & spares • Communications • Access to systems • Documents & records • Live tested	• Roles clearly defined • Recovery plans for key BU's • Recovery strategy overview • Action checklist for roles • Reference information
Focus • IT systems • Scada • Radio • Telephony • Security/CCTV	Technology Recovery	• IT team structures • Clearly understood support • Backup and support for roles • Clear recovery strategies • Rehearsed	• END USER • Meets BU needs • Fall back site • CENTRAL • Backup site tested • Logistics tested	• Roles clearly defined • Recovery strategy overview • Constraints and priorities • Action checklist / call trees • Reference available

Business Continuity Framework

Northpower has developed plans that outline emergency responses to a range of reasonably possible events. Northpower's guiding principle is to firstly avoid injury or loss of life, secondly to avoid property damage, and thirdly to restore electricity supply in an order that may give priority to certain classes of customers such as medical facilities.

Emergency response plans and contingencies cover 2 broad scenarios:

- Loss significant assets
- Natural disasters and large scale events

Northpower has confidence in these planned responses and contingencies. Northpower's emergency response plans were tested on the evening of 15 November 2002 when the entire 5MVA Mangawhai 33/11kV zone substation was destroyed by fire. Disaster recovery went extremely well with supply being restored to customers before the fire brigade even began to extinguish the fire. Within 48 hours, an 11kV regulator and an 800kVA generator had been installed, mainly to support voltage on the 11kV network. The substation was temporarily replaced by relocating a 33/11kV transformer from a 2 transformer substation and using three 11kV auto-reclosers in place of conventional circuit breakers. The substation has since been completely rebuilt.

7.5.1 Contingencies for loss of major assets

Every event is different and affects different assets. There may be 1 asset only affected or many. For example, loss of supply at a zone substation could be caused by a single fault on an N security sub-transmission line or a fire (such as the one that destroyed Mangawhai Substation). Northpower has addressed this by creating generic contingencies for individual assets. Multiple asset outages may need more than 1 contingency or a combination of them.

N Security denotes a system that, following the loss of a single power system element, is unable to accommodate the full load.

N-1 Security denotes a system that, following the loss of a single power system element, is still able to accommodate the full load.

The following table summarises the key generic contingency measures for failure of various types of electricity distribution assets.

Loss/Event	Contingencies	Other Mitigation Measures
Overhead Line	Circuits with N-1 or N-1 switchable security: run on the remaining circuit while the line is repaired Circuits with N security: back-feed as many consumers as possible on the distribution network. Use portable generation to support distribution back-feed for sustained outages	Large stocks of basic line hardware components are held for general use, e.g. poles, conductors, cross arms etc. Have own 500KVA mobile generator and access to other large generators.
Cable	Circuits with N-1 or N-1 switchable security: run on the remaining circuit whilst the line is repaired. Circuits with N security: back-feed as many consumers as possible on the distribution network. Use portable generation to support distribution back-feed for sustained outages	Strategic stocks of cables. Have own 500KVA mobile generator and access to other large generators. Access to specialist cable repair staff in Auckland.
Transformers	Substation with N-1 or N-1 switchable security: run on remaining transformer whist faulted transformer in repaired or replaced.	Have strategic spares for components such as bushings. Have stocks of transformers.
Individual Circuit Breaker	Most zone substations can supply load with an individual feeder CB out of service. Incomer CB of N-1 or N-1 switchable security: run on remaining incomer until CB is returned to service or replaced. Incomer CB of N security substation: back-feed as many consumers as possible on the distribution network, until CB is returned to service or replaced. Use portable generator to support distribution back-feed, for sustained outages	Many of the indoor CB's are "rackable"", in some cases can take a CB from a less critical location. Have strategic spares of most type of CBs, so simple defects can often be fixed relatively easily.

Loss/Event	Contingencies	Other Mitigation Measures
33kV Outdoor Bus	Substations with N-1 or N-1 switchable security have a bus section switch. Supply can be restored by opening the bus sections switch & re-livening the un-faulted section. Substations with N security option will vary depending on the situation: some faults can be isolated by switches and supply restored by the use of the bypass switch. In other situations, back-feed as many consumers as possible on the distribution network, until CB is returned to service or replaced. Use portable generator to support distribution back-feed, for sustained outages	Have stocks of insulators, copper bus-bar & conductor etc.
Indoor switch	Substation with bus couplers, open coupler &re-liven un-faulted section of bus: for 11KV switchboards, some configuration (by switching) of the HV distribution network will be required. For switchboards without bus couplers: back-feed as many consumers as possible on the distribution network until the fault can be repaired or isolated. In the worst case, may have to cut faulty section away. Use portable generation to support distribution back-feed for sustained outages.	Have some stocks of bushing & CTs for the more critical switchboards. For Bream Bay, 33KV switchboard have complete spare cubicles & CBs.
SCADA system	Able to "man" any substation. Note loss of SCADA will not cause any interruption to supply. The only communication that will cause a tripping is if the copper pilot wire circuits are damaged on the "Translay" protection. Disable "Translay" protection & restore supply, all circuits with "Translay" protection have back-up protection scheme.	Have a large range of the RTUs, radio system & communication cables. Have a least one means of communication that is independent from the communications used by Scada. In the process of removing protection using "copper" pilot cables.
Control Room	A back up control room is provided at an alternate location. Duplicate servers provided at an alternate location.	Man critical substations. Utilise radio and cell phone communications.

Asset Contingencies

There are two types of 33 kV arrangements at zone substations:

- Outdoor switchyard
- Indoor switchboards

Both arrangements have bus coupling circuit breakers or switches and a means of isolating individual circuit breakers. The 11kV switchgear is all indoor switchboard type, some with and some without bus coupling circuit breakers.

7.5.2 Responding to Natural disaster and large scale events

Northpower has a number of additional planning tools available to aid recovery in significant events. These include:

- Switching plans to restore power to areas affected by large scale outages
- Processes and procedures to manage operations and field staff involved in the event
- Guidelines to aid prioritisation of network restoration
- Policy and mutual agreement to provide assistance to and receive assistance from other networks.
- Storm Management Plan.

Section 8:
Evaluation of Performance

"safe, reliable, hassle free service"

Northpower

Evaluation of Performance

8

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Section 8: Evaluation of Performance

8.1 Purpose

The purpose of this section of the Asset Management Plan is to compare Northpower's annual results against its targets and identify areas for improvement.

The targets assessed are:

- Financial progress
- Physical progress through programmes of work (CAPEX and OPEX)
- Service levels and key performance indicators
- Asset management improvement initiatives

8.2 Progress against Capital Expenditure Plan

8.2.1 Financial Progress

The table below shows the forecast and actual capital expenditure for the 2014/15 financial year.

CAPEX Category	Actual ($000)	Forecast($000)	Variance (%)
Customer Connections	1,769	852	108
System Growth	311	746	-58
Asset Replacement and Renewal	9,631	9,927	-3
Reliability, Safety and Environment	1,158	1,875	-38
Asset Relocations	50	150	-67
TOTAL	**12,919**	**13,550**	**-5**

The table below provides an explanation of variances greater than 10%

CAPEX Category	Explanation for Variance
Customer Connections	Bream Bay NZR 33kV feeder cables project was not included in forecast and actual connections exceeded forecast
System Growth	Some projects deferred and others started late due to various constraints.
Reliability, Safety and Environment	Some projects deferred and others started late due to various constraints.
Asset Relocations	Project started later than expected

8.2.2 Physical Progress

The table that follows shows the progress made in FY15 with regard to planned capital projects. Where projects have been deferred, this is due to lack of load growth, re-prioritisation or resource constraint.

The following summary outlines significant projects which were progressed.

8.2.2.1 Asset replacement and renewal

- Continued replacement of 7/.064 copper and ACSR 'Gopher' conductor
- Continued replacement of 11kV air break switches with enclosed switches
- Continued replacement of overhead line poles, cross arms and insulators
- Continued replacement of underground cable low voltage pillars
- Continued replacement of earthing systems
- Replacement of Poroti substation 33kV transformer circuit breaker
- Zone substation RTU upgrades
- Maungatapere 110/50kVtransformer replacements
- Replacement of Hikurangi 33kV line circuit breaker
- Replacement of Kensington 33kV voltage transformers

8.2.2.2 Reliability, Safety and environment

- VHF communications coverage improvement
- Distribution network security improvements
- Dargaville SCADA link converted to digital UHF
- Zone substation security improvement
- Southern area communications network upgrades
- Communications links for remote control of 11kV switches
- Fibre link to Maungaturoto and Kaiwaka
- Dargaville feeder rationalisation
- Bream Bay to Ruakaka fibre link

8.2.2.3 System Growth

- Waipu feeder 11kV voltage regulator
- Distribution transformer and LV feeder rationalisation
- Bream Bay NZR 33kV feeders
- Kamo new 11kV feeder
- Electric vehicle charging stations

Progress on Specific Initiatives

The following is an update of the table which has been used over recent years to track progress on initiatives aimed at improving reliability and safety on the Northpower network.

Initiative	FY16	FY17	Notes
Urgent safety needs including low lines	Highest priority for resources	Highest priority for resources	On-going
Conductor replacement project (CAPEX for safety)	Year 5 Target 76km of conductor p.a. Plus cross-arms + poles as required	Year 6 Target 76km of conductor p.a. Plus cross-arms + poles as required	In progress but target under review following completion of urgent work
HV switch replacement. (CAPEX for reliability)	Program complete	Program complete	Complete
33kV insulators (CAPEX for asset replacement)	Program complete	Program complete	Complete
Cross-arm replacements (CAPEX for reliability)	Target is 1900 p.a. including those on conductor project	Target is 1900 p.a. including those on conductor project	In progress
HV switch remote control. (CAPEX for SAIDI reduction)	Year 5 of a 7 year program. Install comms to 30 motorised switches	Year 6 of a 7 year program. Install comms to 30 motorised switches	In progress
RTU upgrades. (CAPEX for asset replacement)	Year 7 of 9 year program	Year 8 of 9 year program	In progress
Red tag poles	Process is now well established	Process is now well established	On-going

Projects deferred

Consistent with the program for FY16, proposed expenditure for FY17 has been reduced by deferring some growth-related projects until activity in the Northland economy improves. Some other non-growth related projects have also been deferred where the risk associated with deferment is considered to be low or where requirements are being reassessed. Deferred projects are listed in the following table.

Project	Budget	Comment
Maunu substation	$5.1m	Previously deferred but can be deferred again due to lack of growth (allowance has been made in the FY17 budget to reconfigure 2 x 11kV feeders to increase capacity in the Maunu area in the interim)
Power factor improvement	$70k	Requirements being reviewed (need for switched capacitor banks)
Whangarei South-Kioreroa 33kV T (stage 2)	$850k	Previously deferred but can be deferred again (Kioreroa substation security of supply is currently n-1 switched)
Whakapara feeder express line extension	$515k	Previously deferred but can be deferred again (reliability improvements have been put in place)
Hikurangi 11kV switchboard upgrade	$1.4m	Remaining life of Hikurangi and 3 other 45 year old boards to be reassessed
Bream Bay additional 11kV feeder	$300k	Previously deferred but can be deferred again (capacity and backstopping)
Land purchases (future substation Helena Bay)	$150k	Can be deferred due to lack of growth
Zone substation neutral earthing	$80k	Deferred (low risk)
New reclosers	$90	Deferred (remote control switch program is being given preference)
Maungaturoto 33kV circuit separation	250k	Deferred (low risk)
Chip Mill substation transformer replacement	394k	Deferred (strategic spare available)

8.3 Progress against Operational Expenditure Plan

8.3.1 Financial Progress

The table below shows the forecast and actual operational expenditure for the 2011/12 financial year.

OPEX Category	Actual ($000)	Forecast ($000)	Variance (%)
Routine and preventative maintenance	1,942	2,643	-27
Refurbishment and renewal maintenance	2,328	2,251	3
Vegetation maintenance	1,833	1,668	10
Fault and emergency maintenance	3,163	1,587	99
TOTAL	9,266	8,149	14

The table below provides an explanation of variances greater than 10%

OPEX Category	Explanation for Variance
Routine and preventative maintenance	Forecast amount included an amount of $700k for 'value added work' (error)
Fault and emergency maintenance	Higher than expected expenditure due to severe weather winter 2014

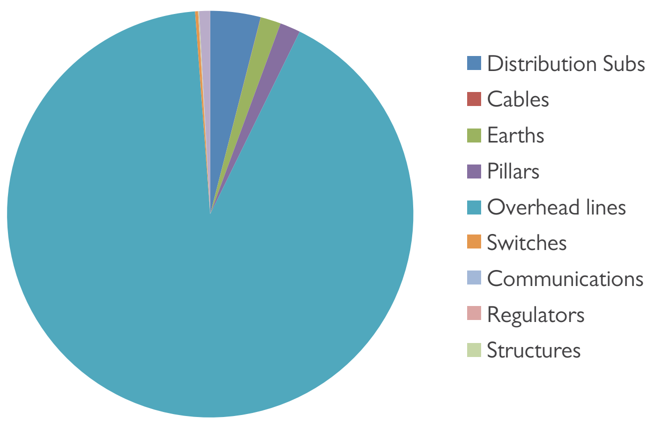
8.3.2 Physical Progress

8.3.2.1 Routine and Preventative Maintenance

Preventative maintenance inspections are progressing according to schedule with planned maintenance and inspection targets being met. Pole inspections intervals have reverted back to 5 years following the previous increase to 7 years. Pole inspections continue to identify a large number of equipment defects and where practical these are rectified in conjunction with the Conductor Replacement and the Reliability Improvement Projects. Urgent defects still need to be carried out separately.

The following table and graphic show the number of known defects on the network per asset group as at February 2016. As can be seen overhead line defects comprise more than 90% of the total number of defects.

Asset Group	Defects	% of total
Distribution Subs	517	4.0
Cables	2	0.0
Earths	210	1.6
Pillars	211	1.6
Overhead lines	11842	91.5
Switches	30	0.2
Communications	1	0.0
Regulators	4	0.0
Structures	7	0.1
Zone Subs	112	0.9



Electronic data capture is now fully employed for overhead line assets and this is currently being extended to other assets groups.

A significant quantity of non-urgent defects is also being accumulated within the 5 year inspection regime which will need to be actioned as follow up work in future to avoid increasing the volume of urgent work as time goes by.

It should also be noted that following the introduction of a new vegetation control initiative within the last 2 years all tree related maintenance is now part of follow up maintenance.

8.3.2.2 Refurbishment and Renewal Maintenance (Follow Up Maintenance)

Follow up maintenance expenditure is restricted by budget and overhead lines and vegetation management continue to be the dominant components. The overall quantity of outstanding overhead line defects has not decreased significantly despite a high asset replacement rate but the conductor replacement project is expected to assist in reducing the number of defects as associated line hardware is replaced with conductor replacement. High priority work is being incorporated with the conductor replacement project wherever possible. Due to a concerted effort in recent years there has been a significant reduction in urgent wood pole replacements.

Cross arm and insulator replacement due to end of life remains a high expenditure category with an estimated 15% of cross arms considered to be end of life and 50% considered to be half-life at the end of 2011. The present target replacement rate to prevent these percentages increasing is 1800 to 1900 cross arms per annum. The planned introduction of steel cross arms in place of hardwood arms in specific applications is underway and this is seen as a long term solution in terms of extending cross arm operational life.

There are still in excess of a thousand Northpower-owned wooden poles on the network and the number has increased slightly due to some private shared-service lines being transferred to Northpower ownership. The average life expectancy for woodpiles has been established as 40 years which results in an average target replacement rate of about 75 poles per year for the next 15 years.

The 33kV insulator replacement project has been completed and all 11kV air-break switches have been replaced with fully enclosed gas switches. Many of the older concrete type 400V pillars have been identified as having defects which are safety concerns and the program to replace these is well advanced and all high risk units have been replaced. Distribution earthing continues to require resources due to bonding defects and instances copper theft continue to occur. The introduction of copper coated steel for earthing requirements is expected to help reduce theft as well as cost. Ground mounted distribution substations continue to require attention due to corrosion, oil leaks and graffiti removal.

Vegetation continues to be the largest cause of network outages and despite the efforts being made to reduce tree contacts there are still trees currently in contact with both low and high voltage lines.

The recent focus on preventing vegetation related issues on the network has however resulted in a reduction of the number of faults caused by trees. Feeder prioritisation for line patrol by vegetation staff is determined by the reliability improvement project with criteria and priorities reviewed monthly. The vegetation budget has been overspent in recent years due to attempts to complete a full cycle of vegetation clearance before further growth dictates the commencement of a new cycle. For this reason the vegetation budget continues to be increased each year.

The conductor replacement project has been restricted due to resource issues in FY15 and FY16 but is expected continue as per the original planned replacement quantities in FY17:

Replacement of 7/.064 HDBC (415km remaining) at 50km per annum

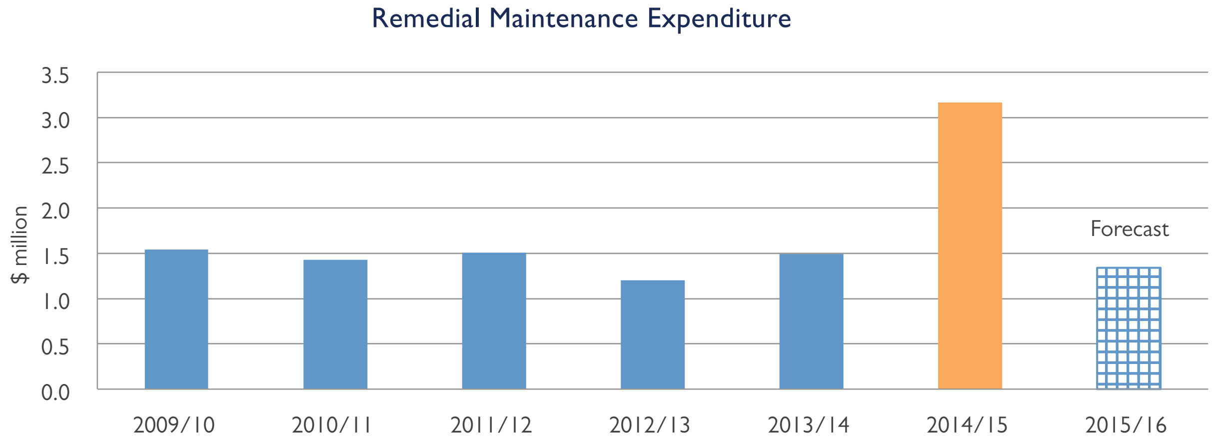
Replacement of ACSR Gopher (1125km remaining) at 10km per annum

EOL conductor in need of replacement is still being identified frequently from conductor faults and when attempting line maintenance and often causes postponement of planned maintenance or delays during line work.

8.3.2.3 Fault and Emergency maintenance (Remedial Maintenance)

Faults associated with overhead lines make up approximately 70% of remedial maintenance expenditure and an improvement in overhead line reliability (pertaining to faults caused by asset condition) and an associated decrease in remedial expenditure (excluding the impact due to severe weather incidents) are not expected until the quantity of known overhead line defects is significantly reduced.

As can be seen in the graph below, expenditure on remedial maintenance was trending downward until the winter 2014 storm damage. Forecast expenditure for 2015/16 (barring any severe weather incidents) indicates a continuation of the previous downward trend.



8.4 Performance against Service Levels

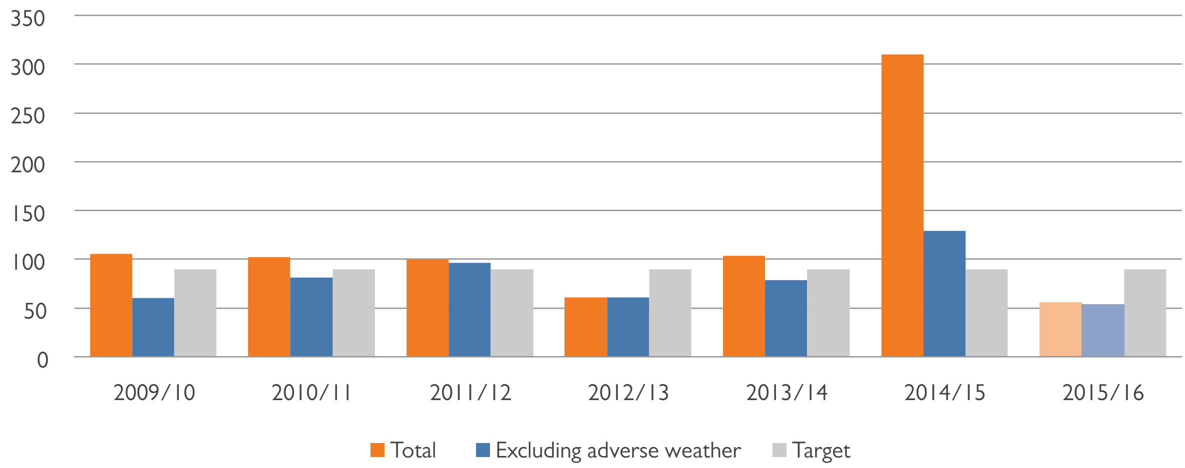
The following table lists network key performance indicators with target, actual and variance values for 2014/15 as well as long term goal values. Where targets were not achieved the actual value and associated variance are shown in red.

Network Key Performance Indicators (2014/15)	Target	Actual	Variance	Goal
Reliability Customer Satisfaction	>85%	86%	1.2%	>90%
Faults Service Customer Satisfaction	>80%	79%	1.3%	>85%
Overall Customer Satisfaction	>85%	87%	2.4%	>85%
System Average Interruption Frequency Index (Planned)	<0.3	0.25	16.7%	<0.3
System Average Interruption Frequency Index (Unplanned)	<2.5	3.33	33.2%	<2.5
System Average Interruption Duration Index (Planned)	<55	69.4	26.2%	<30
System Average Interruption Duration Index (Unplanned)	<90	310.2	244.7%	<90
Customer Average Interruption Duration Index (Planned)	<125	273.2	118.6%	<125
Customer Average Interruption Duration Index (Unplanned)	<39	93	138.5%	<39
Frequency Of Fault Interruptions (Line) Faults/100km 33kV	<2	8.2	310%	<2
Frequency Of Fault Interruptions (Line) Faults/100km 11kV	<7.5	12.84	71.2%	<5
Frequency Of Fault Interruptions (Cable) Faults/100km 33kV	<8	0	100%	<8
Frequency of Fault Interruptions (Cable) Faults/100km 11kV	<2.5	2.78	11.2%	<2

The key performance indicators for customer satisfaction exceeded target except for faults service satisfaction which did not quite meet target.

The reason for the poor performance and significant variances between actual and target values for interruption based key performance indicators is mainly attributable to the severe weather experienced in winter 2014. This can be seen in the graph below which compares SAIDI (unplanned interruptions) for the last 6 years and a forecast for 2015/16 based on extrapolated year to date January 2016 figures.

SAIDI (unplanned interruptions) 2009/10-2015/16



8.5 Gap Analysis and Improvement Initiatives

Capital project forecast expenditure versus actual expenditure variances due to projects starting late (late availability of final designs or late delivery of equipment) need to be reduced. There is a requirement to improve project planning lead times to ensure that projects are started on schedule to avoid late completion and expenditure carryover into the following financial year. In this regard significant improvements have recently been made by the introduction of Microsoft SharePoint software (Capex Central) to manage the life cycle of projects from initiation through to completion.

Customer satisfaction with respect to network reliability remains better than target and is a good indication that the continued effort to improve network performance is yielding results. However, improvements need to be made with regard to faults service.

System and customer average interruption duration for planned work has increased as expected as a result of the conductor and switch replacement program.

Customer average interruption duration (unplanned) continues to exceed target. Two major initiatives are underway to reduce or minimise interruption duration caused by faults. One of these is the remote control of feeder sectionalising switches and the other (which is designed to work in conjunction with the former) is the installation of SCADA linked fault passage indicators to reduce fault location and isolation times.

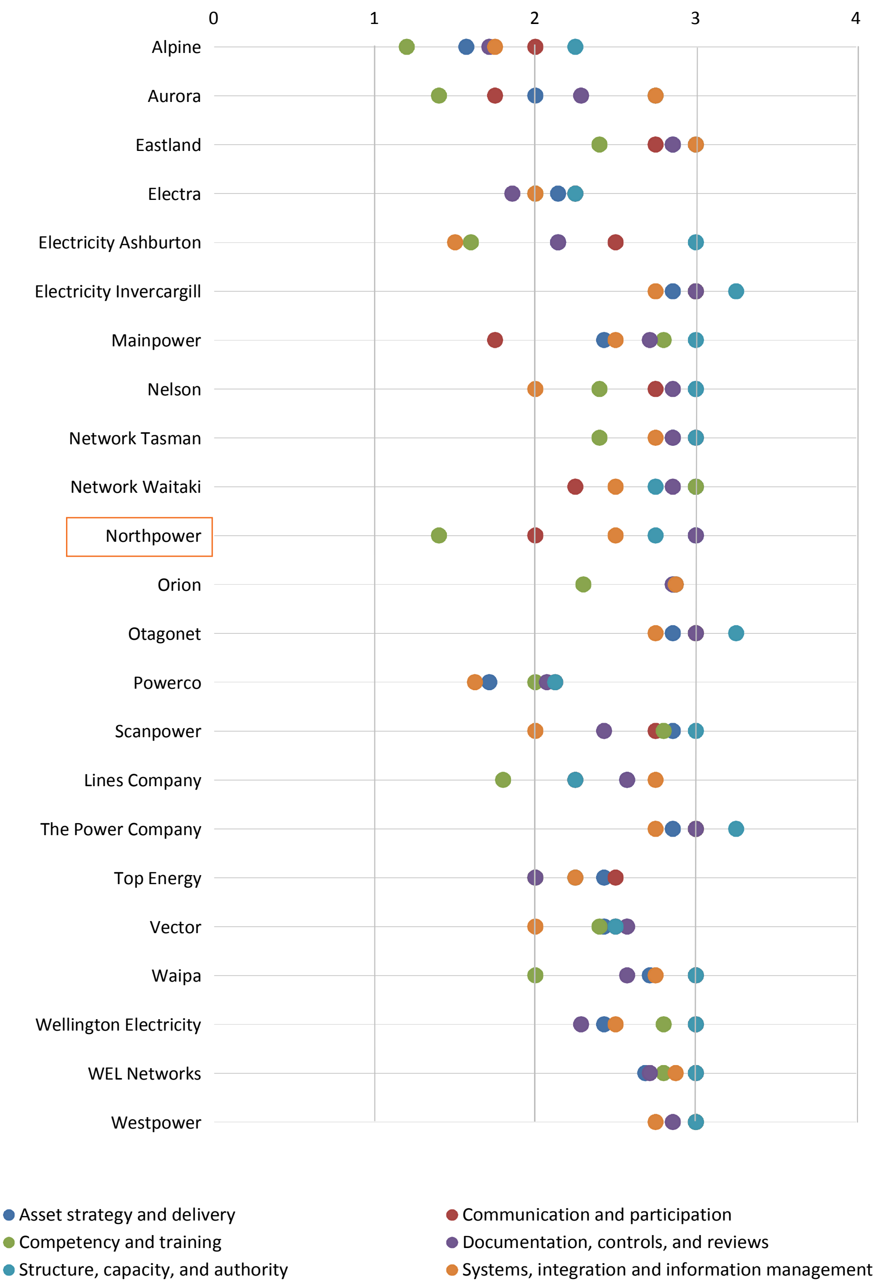
8.6 Review of Quality of Asset Management Planning

Northpower is certified to ISO 9001, ISO 14001 and the network is NZS 7901 certified which underpins a commitment to continuously improve systems and processes. For this purpose Northpower also works in and with the electricity supply industry to share knowledge and implement improvements whenever possible.

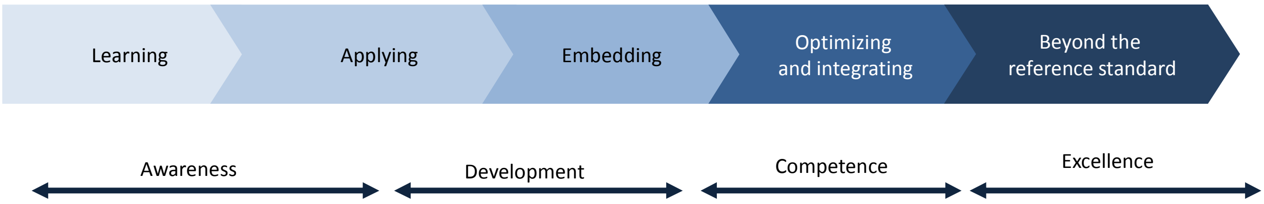
Benchmarking to ISO55000 (international asset management standard) is seen as way of measuring Northpower's asset management systems against international best practice and one of Northpower power's objectives is to achieve ISO55000 accreditation. The results of a 2015 asset management maturity (AMMAT) self-assessment based on a template aligned with ISO55000 are provided in the attached schedule 13.

The following graphic shows 2013 asset management maturity self-assessment scores achieved by Northpower and 22 other Lines New Zealand Companies. Northpower's scores indicate a need to focus on improving competency and training.

AMMAT 2013 **Average scores for each capability assessment area for each distributor**



The different asset management maturity levels in the AMMAT



Maturity level 0	Maturity level 1	Maturity level 2	Maturity level 3	Maturity level 4
The elements required by the reference standard are not in place. The organisation is in the process of developing an understanding of the reference standard.	The organisation has a basic understanding of the reference standard. It is in the process of deciding how the elements of the reference standard will be applied and has started to apply them.	The organisation has a good understanding of the reference standard. It has decided how the elements of the reference standard will be applied and work is progressing on implementation.	All elements of the reference standard are in place and are being applied and are integrated. Only minor inconsistencies may exist.	Using processes and approaches that go beyond the requirements of the reference standard. Pushing the boundaries of asset management development to develop new concepts and ideas.

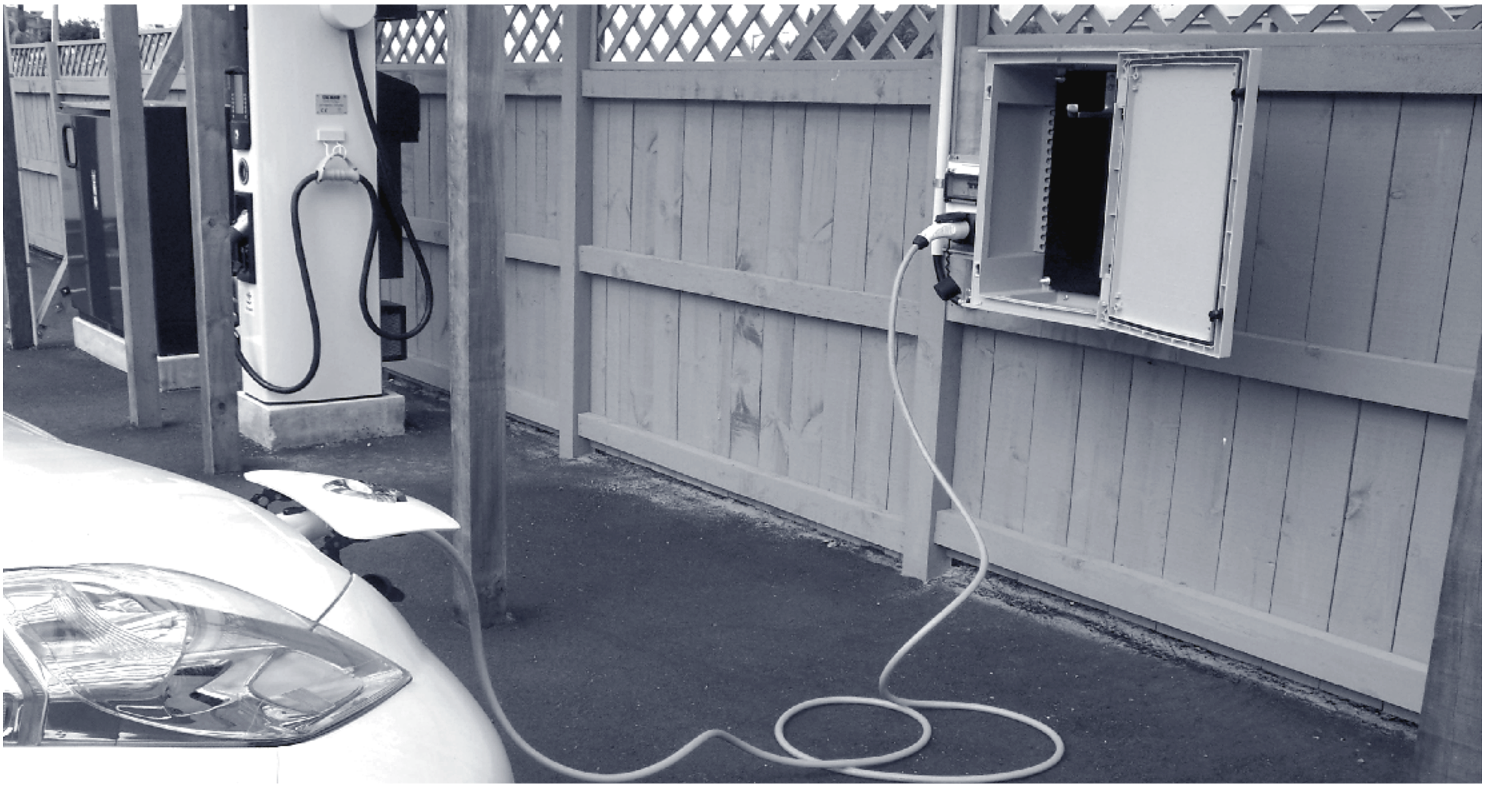
Areas within Northpower's internal systems and processes where recent improvements have been made include:

- Introduction of a Safety Management System in accordance with the Electricity (Safety) Regulations 2010
- Implementation of OSISoft PI System to facilitate real-time data acquisition for network data recording, storage and analysis
- Improvements to the management of capital projects

Current and future developments relating to improved asset management include:

- Reviewing maintenance standards and practices and improving systems and processes
- Improving network asset quantity, age and condition data
- Adoption of condition based risk management in asset replacement decision making policy
- Increased use of Smart Systems for enhanced operational control and network monitoring
- Increased focus on employment of non-network solutions where viable
- Increased research and development with respect to UAV asset inspection
- Increased power system data acquisition (e.g. power factor and harmonic distortion)
- Improving network protection settings analysis and management
- Improved substation and communications security
- Continued support for the commissioning of electric vehicle infrastructure assets
- Ongoing improvement in the quality of asset management in terms of meeting the ISO55000 standard by addressing those aspects identified in the gap analysis and asset management self-assessment

Appendixes



"safe, reliable, hassle free service"

Northpower

Appendix A: Glossary of Terms

A	Ampere
AAAC	All Aluminium Alloy Conductor
AAC	All Aluminum Conductor
ABS	Air Break Switch
AC	Alternating Current
ACSR	Aluminum Conductor Steel Reinforced
AMP	Asset Management Plan
BC	Bus Coupler
BIL	Basic Insulation Level
BU	Business Unit
CAIDI	Customer Average Interruption Duration Index
CAPEX	Capital Expenditure
CB	Circuit Breaker
CBD	Central Business District
CCTV	Closet Circuit Television
CE	Chief Executive
CT	Current Transformer
DC	Direct Current
DG	Distributed Generation
DGA	Dissolved Gas Analysis
E/F	Earth Fault
E/S	Earth Switch
EBIT	Earnings before Interest and Tax
EDB	Electricity Distribution Business
ELB	Electricity Lines Business
ELEC	Electronic
EOL	End Of Life
EPR	Earth Potential Rise
GFN	Ground Fault Neutraliser
GIS	Geographical Information System
GM	Ground Mounted
GM	General Manager
GPS	Global Positioning System
GWh	Gigawatt Hour
GXP	Grid Exit Point
HDBC	Hard Drawn Bare Copper
HR	Human Resources
HV	High voltage
ICP	Installation Control Point
KM	Kilometer
KPI	Key Performance Indicator
kV	Kilovolt
kVA	Kilovolt Ampere
kVAr	Kilovolt Ampere (reactive)

kW	Kilowatt
kWh	Kilowatt Hour
LTI	Lost Time Injury
LV	Low Voltage
MD	Maximum Demand
MDI	Maximum Demand Indication
MVA	Megavolt Ampere
MW	Megawatt
NEPT	Northpower Electric Power Trust
NER	Neutral Earthing Resistor
NPV	Net Present Value
O/C	Overcurrent
ODV	Optimised Deprival Value
OH	Overhead
OHUG	Overhead to Underground
OLTC	On Load Tap Changer
OPEX	Operational Expenditure
PCB	Polychlorinated Biphenyl
PDC	Polarisation Depolarisation Current
PILC	Paper Insulated Lead Covered
PM	Project Manager
PV	Photovoltaic
RAB	Regulatory Asset Base
RC	Replacement Cost
RMA	Resource Management Act
RMU	Ring Main Unit
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Duration Index
SCADA	Supervisory Control and Data Acquisition
SF6	Sulphur Hexafluoride
SFE	Sanction for Expenditure
STAT	Static
TRFR	Transformer
UAV	Unmanned Aerial Vehicle
UG	Underground
UHF	Ultra High Frequency
V	Volt
VAC	Vacuum
VHF	Very High Frequency
VOIP	Voice Over Internet Protocol
VT	Voltage Transformer
WASP	Works, Assets, Solutions and People
XLPE	Cross linked Polyethylene

Appendix

B

Appendix B: 2016 EDB Information Disclosure Schedules

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

Company Name	Northpower Ltd
AMP Planning Period	1 April 2016 – 31 March 2026

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8		for year ended	31 Mar 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		790	803	812	828	844	861	878	897	915	932	951
11	System growth		408	388	3,383	3,310	1,286	1,865	1,865	2,583	1,590	1,649	2,137
12	Asset replacement and renewal		6,825	7,710	7,529	10,241	10,301	9,223	10,398	11,211	11,884	11,381	10,844
13	Asset relocations		142	253	104	105	108	110	112	114	116	118	121
14	Reliability, safety and environment:												
15	Quality of supply		488	871	1,512	75	80	45	-	85	50	-	90
16	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment		678	944	1,072	826	349	177	303	284	190	1,459	2,506
18	**Total reliability, safety and environment**		1,166	1,815	2,583	901	429	222	303	369	240	1,459	2,596
19	**Expenditure on network assets**		9,331	10,969	14,412	15,385	12,968	12,281	13,557	15,174	14,745	15,540	16,649
20	Expenditure on non-network assets		395	847	123	126	97	149	140	103	105	162	158
21	**Expenditure on assets**		9,726	11,815	14,535	15,511	13,065	12,430	13,697	15,277	14,850	15,702	16,807
22													
23	*plus* Cost of financing												
24	*less* Value of capital contributions		1,365	1,542	1,506	2,048	2,060	1,845	2,080	2,242	2,377	2,276	2,169
25	*plus* Value of vested assets		224	272	334	357	300	286	315	351	342	361	387
26													
27	**Capital expenditure forecast**		8,585	10,545	13,363	13,819	11,305	10,871	11,932	13,386	12,814	13,787	15,025
28													
29	Assets commissioned		7,781	9,452	11,628	12,408	10,452	9,944	10,958	12,222	11,880	12,562	13,446

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31		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
32			**$000 (in constant prices)**										
33	Consumer connection		790	787	780	781	780	780	780	781	781	780	780
34	System growth		408	380	3,252	3,119	1,188	1,689	1,656	2,249	1,357	1,380	1,753
35	Asset replacement and renewal		6,825	7,559	7,237	9,650	9,517	8,263	9,233	9,760	10,143	9,523	8,896
36	Asset relocations		142	248	100	99	100	100	100	99	99	99	99
37	Reliability, safety and environment:												
38	Quality of supply		488	854	1,453	71	74	41	-	74	43	-	74
39	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment		678	925	1,030	778	322	160	319	262	177	1,281	2,111
41	**Total reliability, safety and environment**		1,166	1,779	2,483	849	396	201	319	336	220	1,281	2,185
42	**Expenditure on network assets**		9,331	10,754	13,852	14,498	11,980	11,033	12,088	13,224	12,599	13,064	13,713
43	Expenditure on non-network assets		395	830	118	118	90	135	125	90	90	135	130
44	**Expenditure on assets**		9,726	11,584	13,970	14,616	12,070	11,168	12,212	13,314	12,689	13,199	13,843
45													
46	**Subcomponents of expenditure on assets (where known)**												
47	Energy efficiency and demand side management, reduction of energy losses		-	-	-	-	-	-	-	-	-	-	-
48	Overhead to underground conversion		-	-	-	-	-	-	-	-	-	-	-
49	Research and development		52	80	100	100	100	100	100	100	100	100	100

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
52		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
53	**Difference between nominal and constant price forecasts**		**$000**										
54	Consumer connection		-	16	32	48	64	81	98	116	134	152	171
55	System growth		(0)	8	131	191	98	176	209	334	233	269	384
56	Asset replacement and renewal		(0)	151	292	591	784	960	1,165	1,451	1,741	1,858	1,948
57	Asset relocations		-	5	4	6	8	10	13	15	17	19	22
58	Reliability, safety and environment:												
59	Quality of supply		0	17	59	4	6	4	-	11	7	-	16
60	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment		0	19	42	48	27	17	(16)	22	13	178	395
62	**Total reliability, safety and environment**		0	36	100	52	33	21	(16)	33	21	178	411

			Company Name	Northpower Ltd
			AMP Planning Period	1 April 2016 – 31 March 2026

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref													
63		**Expenditure on network assets**	(0)	215	560	887	988	1,248	1,469	1,949	2,146	2,477	2,936
64		Expenditure on non-network assets	-	17	5	7	7	14	16	13	15	26	28
65		**Expenditure on assets**	(0)	231	564	895	995	1,262	1,485	1,963	2,161	2,503	2,965
66													

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
67		for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
68		**11a(ii): Consumer Connection**						
69		*Consumer types defined by EDB**	$000 (in constant prices)					
70		Transformer acquisition	780	787	780	781	780	780
71		Bream Bay NZR 33kV feeders	10	-	-	-	-	-
75		**include additional rows if needed*						
76		**Consumer connection expenditure**	790	787	780	781	780	780
77	*less*	Capital contributions funding consumer connection						
78		**Consumer connection less capital contributions**	790	787	780	781	780	780
79		**11a(iii): System Growth**						
80		Subtransmission	-	-	850	-	-	-
81		Zone substations	25	74	1,501	2,945	1,061	1,389
82		Distribution and LV lines	125	176	367	-	-	172
83		Distribution and LV cables	186	59	367	103	56	56
84		Distribution substations and transformers	-	-	-	-	-	-
85		Distribution switchgear	-	-	-	-	-	-
86		Other network assets	72	72	167	71	71	72
87		**System growth expenditure**	408	380	3,252	3,119	1,188	1,689
88	*less*	Capital contributions funding system growth						
89		**System growth less capital contributions**	408	380	3,252	3,119	1,188	1,689
90								

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
91								
92		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	-	-	-	-	-	-
95		Zone substations	322	886	453	3,042	3,167	1,855
96		Distribution and LV lines	5,500	5,583	5,583	5,583	5,583	5,583
97		Distribution and LV cables	220	205	205	205	205	205
98		Distribution substations and transformers	510	475	475	475	475	475
99		Distribution switchgear	68	152	328	195	63	122
100		Other network assets	205	259	193	150	23	23
101		**Asset replacement and renewal expenditure**	6,825	7,559	7,237	9,650	9,517	8,263
102	*less*	Capital contributions funding asset replacement and renewal	1,365	1,482	1,391	1,819	1,758	1,497
103		**Asset replacement and renewal less capital contributions**	5,460	6,077	5,846	7,831	7,759	6,766
104								

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
105								
106		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**						
108		*Project or programme**	$000 (in constant prices)					
109		Minor capital expenditure (relocation)	52	52	52	51	52	52
110		Dargaville ripple plant relocation	40	98	-	-	-	-
111		Whangarei roading works asset relocations	50	98	48	48	48	48
114		**include additional rows if needed*						
115		All other project or programmes - asset relocations	-	-	-	-	-	-
116		**Asset relocations expenditure**	142	248	100	99	100	100
117	*less*	Capital contributions funding asset relocations						
118		**Asset relocations less capital contributions**	142	248	100	99	100	100
119								

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
120								
121		for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21

Company Name	Northpower Ltd
AMP Planning Period	1 April 2016 – 31 March 2026

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

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This information is not part of audited disclosure information.

sch ref

122 11a(vi):Quality of Supply

sch ref	Project or programme*	$000 (in constant prices)					
124	New Reclosers	-	-	38	-	-	41
125	Communications system upgrades (fibre)	22	88	-	-	-	-
126	Comms for remote control of motorised switches	258	260	258	-	-	-
127	11kV feeder backstopping improvements	25	74	72	-	74	-
	Whakapara Feeder Express Line to Hikurangi	-	-	515	-	-	-
	Fault Passage Indicators	29	123	240	71	-	-
	VHF Coverage improvement	44	-	-	-	-	-
	Maungaturoto 33kV Circuit Separation	-	-	243	-	-	-
	Chipmill RTU and Comms	15	16	-	-	-	-
	Dargaville Town feeder rationalisation	95	-	-	-	-	-
	KEN-TIK 33kV cables protection upgrade	-	88	-	-	-	-
	MTOTP-MTONP Protection Upgrade	-	118	-	-	-	-
	SCADA comms transfer to dark fibre	-	39	38	-	-	-
	Remote station SCADA monitoring	-	49	48	-	-	-
129	**include additional rows if needed*						
130	All other projects or programmes - quality of supply	-	-	-	-	-	-
131	**Quality of supply expenditure**	488	854	1,453	71	74	41
132	*less* Capital contributions funding quality of supply	-	-	-	-	-	-
133	**Quality of supply less capital contributions**	488	854	1,453	71	74	41
134							

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
136	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**

137 11a(vii): Legislative and Regulatory

sch ref	Project or programme*	$000 (in constant prices)					
139	[Description of material project or programme]	-	-	-	-	-	-
140	[Description of material project or programme]	-	-	-	-	-	-
141	[Description of material project or programme]	-	-	-	-	-	-
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	-	-	-	-	-	-
146	**Legislative and regulatory expenditure**	-	-	-	-	-	-
147	*less* Capital contributions funding legislative and regulatory	-	-	-	-	-	-
148	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
149							

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
150	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**

151 11a(viii): Other Reliability, Safety and Environment

sch ref	Project or programme*	$000 (in constant prices)					
153	Zone Substations Risk Mitigation	200	196	336	330	-	-
154	Zone Substations Security Improvement	106	59	60	61	-	-
155	DSUB MDI Meters	62	63	62	63	-	-
	Minor capital expenditure (improvements)	53	54	58	57	55	59
	AC/DC Panel Upgrades	-	147	144	-	-	-
	Replace VHF Analog with Digital (Mobile Radio)	-	147	72	-	-	-
	Research and Development (component testing)	27	29	51	51	52	52
	Communications Network Security	100	34	34	-	-	-
	SCADA Switch and GPS Time Sync Upgrade	20	20	-	-	-	-
	Onerahi SCADA microwave to fibre	5	-	-	-	-	-
	Digital UHF to Dargaville	75	-	-	-	-	-
	Zone Substation Neutral Earthing Resistors	-	-	115	115	115	-
	Busbar Arc Flash Protection	30	49	49	49	49	-
	Research and Development (new technology)	-	49	48	52	51	50
	33kV ABS replacements x4	-	20	-	-	-	-
156	FTCE Wilde unit replacements x2	-	59	-	-	-	-
158	**include additional rows if needed*						

Company Name	**Northpower Ltd**
AMP Planning Period	**1 April 2016 – 31 March 2026**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref							
159	All other projects or programmes - other reliability, safety and environment	-	-	-	-	-	-
160	**Other reliability, safety and environment expenditure**	678	925	1,030	778	322	160
161	*less* Capital contributions funding other reliability, safety and environment						
162	**Other reliability, safety and environment less capital contributions**	678	925	1,030	778	322	160
163							
164		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
165	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme**	**$000 (in constant prices)**					
169	Aerial imagery	30	29	-	-	-	-
170	Engineering software	80	39	-	-	-	45
171	University project collaboration	15	15	14	15	15	14
172	Motor vehicles	50	75	75	75	75	75
173	Depot security improvements	-	10	-	-	-	-
174	**include additional rows if needed*						
175	All other projects or programmes - routine expenditure	-	-	-	-	-	
176	**Routine expenditure**	175	168	89	90	90	135
177	**Atypical expenditure**						
178	*Project or programme**						
179	Asset management system replacement	-	441	-	-	-	-
180	Operational management system	200	196	-	-	-	-
181	UAV asset inspection platform	20	25	29	28	-	-
184	**include additional rows if needed*						
185	All other projects or programmes - atypical expenditure	-	-	-	-	-	-
186	**Atypical expenditure**	220	662	29	28	-	-
187							
188	**Expenditure on non-network assets**	395	830	118	118	90	135

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

Company Name	**Northpower Ltd**
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.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,274	1,119	1,141	1,164	1,187	1,211	1,235	1,260	1,285	1,311	1,337
11	Vegetation management	1,715	1,900	1,938	1,977	2,016	2,057	2,098	2,140	2,183	2,226	2,271
12	Routine and corrective maintenance and inspection	1,223	1,492	1,522	1,552	1,583	1,615	1,647	1,680	1,714	1,748	1,783
13	Asset replacement and renewal	1,526	1,363	1,390	1,418	1,446	1,475	1,505	1,535	1,566	1,597	1,629
14	**Network Opex**	5,738	5,874	5,991	6,111	6,234	6,358	6,485	6,615	6,747	6,882	7,020
15	System operations and network support	2,804	2,910	2,968	3,028	3,088	3,150	3,213	3,277	3,343	3,410	3,478
16	Business support	3,891	3,969	4,048	4,129	4,212	4,296	4,382	4,470	4,559	4,650	4,743
17	**Non-network opex**	6,695	6,879	7,016	7,157	7,300	7,446	7,595	7,747	7,902	8,060	8,221
18	**Operational expenditure**	12,433	12,753	13,008	13,268	13,533	13,804	14,080	14,362	14,649	14,942	15,241

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 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**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,274	1,097	1,097	1,097	1,097	1,097	1,097	1,097	1,097	1,097	1,097
23	Vegetation management	1,715	1,863	1,863	1,863	1,863	1,863	1,863	1,863	1,863	1,863	1,863
24	Routine and corrective maintenance and inspection	1,223	1,463	1,463	1,463	1,463	1,463	1,463	1,463	1,463	1,463	1,463
25	Asset replacement and renewal	1,526	1,336	1,336	1,336	1,336	1,336	1,336	1,336	1,336	1,336	1,336
26	**Network Opex**	5,738	5,759	5,759	5,759	5,759	5,759	5,759	5,759	5,759	5,759	5,759
27	System operations and network support	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804	2,804
28	Business support	3,891	3,891	3,891	3,891	3,891	3,891	3,891	3,891	3,891	3,891	3,891
29	**Non-network opex**	6,695	6,695	6,695	6,695	6,695	6,695	6,695	6,695	6,695	6,695	6,695
30	**Operational expenditure**	12,433	12,454	12,454	12,454	12,454	12,454	12,454	12,454	12,454	12,454	12,454
31	**Subcomponents of operational expenditure (where known)**											
33	Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
34	Direct billing*	-	-	-	-	-	-	-	-	-	-	-
35	Research and Development	45	45	45	45	45	45	45	45	45	45	45
36	Insurance	100	100	100	100	100	100	100	100	100	100	100

37 ** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	22	44	67	90	114	138	163	188	214	240
43	Vegetation management	-	37	75	114	154	194	235	277	320	363	408
44	Routine and corrective maintenance and inspection	-	29	59	90	121	152	185	217	251	285	320
45	Asset replacement and renewal	-	27	54	82	110	139	169	199	229	261	293
46	**Network Opex**	-	115	233	352	475	599	727	856	989	1,124	1,261
47	System operations and network support	-	106	164	224	284	346	409	473	539	606	674
48	Business support	-	78	157	238	321	405	491	579	668	759	852
49	**Non-network opex**	-	184	321	462	605	751	900	1,052	1,207	1,365	1,526
50	**Operational expenditure**	-	299	554	814	1,080	1,350	1,626	1,908	2,195	2,488	2,787

SCHEDULE 12a: REPORT ON ASSET CONDITION

26/03/16

Company Name **Northpower Ltd**
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	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						Asset condition at start of planning period (percentage of units by grade)						
8												
9												
10	All	Overhead Line	Concrete poles / steel structure	52,238	No.	3.00%	41.00%	20.00%	18.00%	18.00%	3	5.00%
11	All	Overhead Line	Wood poles	1,602	No.	11.00%	5.00%	20.00%	6.00%	58.00%	2	10.00%
12	All	Overhead Line	Other pole types	2	No.	50.00%	-	50.00%	-	-	4	30.00%
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	293	km	-	74.00%	25.00%	1.00%	-	4	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	28	km	-	-	-	-	100.00%	1	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	10	km	-	6.00%	36.00%	58.00%	-	4	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	9	km	-	99.00%	1.00%	-	-	4	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	0	km							
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	3	km	-	95.00%	5.00%	-	-	4	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	0	km							
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	0	km							
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	0	km							
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	0	km							
23	HV	Subtransmission Cable	Subtransmission submarine cable	5	km	-	-	100.00%	-	-	4	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	24	No.	16.00%	68.00%	5.00%	11.00%	-	4	5.00%
25	HV	Zone substation Buildings	Zone substations 110kV+	1	No.	-	100.00%	-	-	-	3	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	30	No.	-	30.00%	37.00%	33.00%	-	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	59	No.	13.00%	17.00%	51.00%	19.00%	-	4	10.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	13	No.	-	-	-	32.00%	68.00%	2	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	40	No.	-	-	-	32.00%	68.00%	2	-
30	HV	Zone substation switchgear	33kV RMU	0	No.							
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	0	No.							
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	6	No.	-	-	100.00%	-	-	4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	151	No.	12.00%	32.00%	7.00%	49.00%	-	4	20.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	0	No.							
35												

26/03/16

Company Name **Northpower Ltd**

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	Voltage	Asset category	Asset class		Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
36						Asset condition at start of planning period (percentage of units by grade)						
37												
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	53	No.	11.00%	15.00%	11.00%	63.00%	-	4	17.00%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	3,497	km	4.00%	52.00%	21.00%	18.00%	5.00%	4	10.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	0	km							
42	HV	Distribution Line	SWER conductor	0	km							
43	HV	Distribution Cable	Distribution UG XLPE or PVC	212	km	-	3.00%	17.00%	76.00%	4.00%	3	-
44	HV	Distribution Cable	Distribution UG PILC	38	km	-	38.00%	35.00%	1.00%	26.00%	3	5.00%
45	HV	Distribution Cable	Distribution Submarine Cable	2	km	-	-	-	-	100.00%	1	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	32	No.	-	-	31.00%	69.00%	-	4	
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	0	No.							
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	6,491	No.	6.00%	8.00%	10.00%	38.00%	38.00%	3	15.00%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	29	No.	24.00%	38.00%	34.00%	-	4.00%	4	30.00%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	187	No.	-	6.00%	33.00%	61.00%	-	4	5.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	5,791	No.	28.00%	16.00%	30.00%	26.00%	-	4	25.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	1,343	No.	22.00%	23.00%	25.00%	30.00%	-	4	10.00%
53	HV	Distribution Transformer	Voltage regulators	7	No.	-	29.00%	29.00%	42.00%	-	4	30.00%
54	HV	Distribution Substations	Ground Mounted Substation Housing	117	No.	3.00%	5.00%	16.00%	2.00%	74.00%	2	5.00%
55	LV	LV Line	LV OH Conductor	1,200	km	3.00%	44.00%	21.00%	21.00%	11.00%	3	7.00%
56	LV	LV Cable	LV UG Cable	637	km	-	17.00%	14.00%	59.00%	10.00%	3	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	13	km	5.00%	1.00%	9.00%	1.00%	84.00%	2	5.00%
58	LV	Connections	OH/UG consumer service connections	55,940	No.	-	33.00%	46.00%	16.00%	5.00%	4	5.00%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	401	No.	-	25.00%	28.00%	42.00%	5.00%	3	15.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	1	Lot			100.00%			3	10.00%
61	All	Capacitor Banks	Capacitors including controls	29	No.	-	-	17.00%	66.00%	17.00%	3	-
62	All	Load Control	Centralised plant	6	Lot	33.00%	17.00%	50.00%	-	-	4	20.00%
63	All	Load Control	Relays	48,733	No.	-	-	-	-	100.00%	1	10.00%
64	All	Civils	Cable Tunnels		km							

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

Company Name: **Northpower Ltd**
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**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	Alexander Street	15	15	N-1	5	98%	15	95%	No constraint within +5 years	
10	Bream Bay	4	-	N	2	-	-	-	Transformer	Single transformer substation - backfeed via distribution network
11	Dargaville	11	15	N-1	3	76%	15	80%	No constraint within +5 years	
12	Hikurangi	6	5	N-1	2	128%	5	126%	Transformer	Transfer load in event of contingency
13	Kaiwaka	2	-	N	2	-	-	-	Transformer	Single transformer substation - backfeed via distribution network
14	Kamo	12	15	N-1	3	79%	15	85%	No constraint within +5 years	
15	Kioreroa	10	20	N-1	2	52%	20	56%	No constraint within +5 years	
16	Mangawhai	6	5	N-1	2	124%	5	140%	Transformer	Transfer load in event of contingency
17	Mareretu	3	-	N	2	-	-	-	Transformer	Single transformer substation - backfeed via distribution network
18	Maungatapere	7	5	N-1	3	138%	5	130%	Transformer	Transfer load in event of contingency
19	Maungaturoto	7	8	N-1	2	99%	8	103%	Transformer	Transfer load in event of contingency
20	Ngunguru	3	-	N	2	-	-	-	Transformer	Single transformer substation - backfeed via distribution network
21	Onerahi	8	8	N-1	2	111%	8	116%	Transformer	Transfer load in event of contingency
22	Parua Bay	3	-	N	2	-	4	96%	No constraint within +5 years	
23	Poroti	3	-	N	2	-	-	-	Transformer	Single transformer substation - backfeed via distribution network
24	Ruakaka	7	10	N-1	2	66%	10	73%	No constraint within +5 years	
25	Ruawai	3	-	N	2	-	-	-	Transformer	Single transformer substation - backfeed via distribution network
26	Tikipunga	16	20	N-1	4	79%	20	83%	No constraint within +5 years	
27	Whangarei South	13	10	N-1	4	128%	10	115%	Transformer	Transfer load in event of contingency
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: **Northpower Ltd**

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		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
7	**12c(i): Consumer Connections**						
8	*Number of ICPs connected in year by consumer type*			Number of connections			
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
11	*Consumer types defined by EDB**						
12	Very large industrial	-	-	-	-	-	-
13	Commercial and Industrial (demand based ND9)	1	1	1	1	1	1
14	Mass market	725	750	775	800	825	850
17	**Connections total**	726	751	776	801	826	851
18	**include additional rows if needed*						
19	**Distributed generation**						
20	Number of connections	140	180	200	210	215	215
21	Capacity of distributed generation installed in year (MVA)	1	1	1	1	1	1
22	**12c(ii) System Demand**						
23		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)** — for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
25	GXP demand	168	176	179	180	182	185
26	*plus* Distributed generation output at HV and above	5	5	5	5	5	5
27	**Maximum coincident system demand**	173	181	184	185	187	190
28	*less* Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
29	**Demand on system for supply to consumers' connection points**	173	181	184	185	187	190
30	**Electricity volumes carried (GWh)**						
31	Electricity supplied from GXPs	1,019	1,043	1,053	1,069	1,080	1,091
32	*less* Electricity exports to GXPs	-	-	-	-	-	-
33	*plus* Electricity supplied from distributed generation	25	26	27	28	29	30
34	*less* Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
35	**Electricity entering system for supply to ICPs**	1,044	1,069	1,080	1,097	1,109	1,121
36	*less* Total energy delivered to ICPs	1,002	1,026	1,037	1,053	1,065	1,076
37	**Losses**	42	43	43	44	44	45
38							
39	**Load factor**	69%	67%	67%	68%	68%	67%
40	**Loss ratio**	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%

SCHEDULE 12d: REPORT ON FORECAST INTERRUPTIONS AND DURATION

Company Name	**Northpower Ltd**
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*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	55.0	55.0	55.0	55.0	55.0	55.0
12	Class C (unplanned interruptions on the network)	60.0	90.0	90.0	90.0	90.0	90.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.24	0.24	0.24	0.24	0.24	0.24
15	Class C (unplanned interruptions on the network)	1.50	2.00	2.00	2.00	2.00	2.00

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

Company Name	**Northpower Ltd**
AMP Planning Period	**1 April 2016 – 31 March 2026**
Asset Management Standard Applied	**PAS55/ISO55000**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	1	Northpower PAS-55 Gap Analysis Review August 2008 by Maunsell Ltd. Draft policy in place.		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	AMP section 2. Company-wide values, common management systems certified to ISO 9001 and ISO 14001		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	AMP section 2. Purpose specifically refers to lifecycle and planning management asset information including age and condition. Refer statement of corporate intent.		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	AMP section 6. Process for assessing asset condition documented (Knowledge Central).		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	The organisation does not have a documented asset management policy.	The organisation has an asset management policy, but it has not been authorised by top management, or it is not influencing the management of the assets.	The organisation has an asset management policy, which has been authorised by top management, but it has had limited circulation. It may be in use to influence development of strategy and planning but its effect is limited.	The asset management policy is authorised by top management, is widely and effectively communicated to all relevant employees and stakeholders, and used to make these persons aware of their asset related obligations.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	The organisation has not considered the need to ensure that its asset management strategy is appropriately aligned with the organisation's other organisational policies and strategies or with stakeholder requirements. OR The organisation does not have an asset management strategy.	The need to align the asset management strategy with other organisational policies and strategies as well as stakeholder requirements is understood and work has started to identify the linkages or to incorporate them in the drafting of asset management strategy.	Some of the linkages between the long-term asset management strategy and other organisational policies, strategies and stakeholder requirements are defined but the work is fairly well advanced but still incomplete.	All linkages are in place and evidence is available to demonstrate that, where appropriate, the organisation's asset management strategy is consistent with its other organisational policies and strategies. The organisation has also identified and considered the requirements of relevant stakeholders.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	The organisation has not considered the need to ensure that its asset management strategy is produced with due regard to the lifecycle of the assets, asset types or asset systems that it manages. OR The organisation does not have an asset management strategy.	The need is understood, and the organisation is drafting its asset management strategy to address the lifecycle of its assets, asset types and asset systems.	The long-term asset management strategy takes account of the lifecycle of some, but not all, of its assets, asset types and asset systems.	The asset management strategy takes account of the lifecycle of all of its assets, asset types and asset systems.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	The organisation does not have an identifiable asset management plan(s) covering asset systems and critical assets.	The organisation has asset management plan(s) but they are not aligned with the asset management strategy and objectives and do not take into consideration the full asset life cycle (including asset creation, acquisition, enhancement, utilisation, maintenance decommissioning and disposal).	The organisation is in the process of putting in place comprehensive, documented asset management plan(s) that cover all life cycle activities, clearly aligned to asset management objectives and the asset management strategy.	Asset management plan(s) are established, documented, implemented and maintained for asset systems and critical assets to achieve the asset management strategy and asset management objectives across all life cycle phases.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2	The AMP is available on the corporate intranet and is part of the suite of documents that form the quality management system. The AMP is made available to the general public via Northpower's website or alternatively a copy can be obtained at Northpower's head office.		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	Roles are defined in section 2.5.2 of the AMP. Process and manual owners are defined in the management system.		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	There is a formal service level agreement (SLA) in place with principal contractor. Supplier arrangements are in place for key equipment and materials. Competitive commercial processes relating to procurement are well established. Smarter systems relating to electronic data capture, data management and information systems have been implemented and continue to be developed.		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	Storm plan is documented in the Operations manual and risk management process is outlined in section 7.4 of the AMP. Corporate plans include pandemic situations and Northpower is an active member of the Northland Lifelines group and is active in the regional CDEM group. Northpower has a dedicated strategic spare store and a process for managing these.		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	The organisation does not have plan(s) or their distribution is limited to the authors.	The plan(s) are communicated to some of those responsible for delivery of the plan(s). OR Communicated to those responsible for delivery is either irregular or ad-hoc.	The plan(s) are communicated to most of those responsible for delivery but there are weaknesses in identifying relevant parties resulting in incomplete or inappropriate communication. The organisation recognises improvement is needed as is working towards resolution.	The plan(s) are communicated to all relevant employees, stakeholders and contracted service providers to a level of detail appropriate to their participation or business interests in the delivery of the plan(s) and there is confirmation that they are being used effectively.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	The organisation has not documented responsibilities for delivery of asset plan actions.	Asset management plan(s) inconsistently document responsibilities for delivery of plan actions and activities and/or responsibilities and authorities for implementation inadequate and/or delegation level inadequate to ensure effective delivery and/or contain misalignments with organisational accountability.	Asset management plan(s) consistently document responsibilities for the delivery of actions but responsibility/authority levels are inappropriate/ inadequate, and/or there are misalignments within the organisation.	Asset management plan(s) consistently document responsibilities for the delivery actions and there is adequate detail to enable delivery of actions. Designated responsibility and authority for achievement of asset plan actions is appropriate.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Section 2.5 in the AMP outlines structure and responibilities. Senior staff have performance objectives to meet which are reviewed annually.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	Statement of corporate intent and strategic plans.		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?	2	Senior management have communicated a desire to align asset management practice with ISO55000 (project has been scoped).		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3	C ompliance ensured by service level agrrement (SLA) for field work. Decision-making regarding what activities are to be carried out resides with Network management.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	1	Department managers indentify long term human resorce requirements. Succession plans include the recruitment and appointment of young graduate engineers.		There is a need for an organisation to demonstrate that it has considered what resources are required to develop and implement its asset management system. There is also a need for the organisation to demonstrate that it has assessed what development plan(s) are required to provide its human resources with the skills and competencies to develop and implement its asset management systems. The timescales over which the plan(s) are relevant should be commensurate with the planning horizons within the asset management strategy considers e.g. if the asset management strategy considers 5, 10 and 15 year time scales then the human resources development plan(s) should align with these. Resources include both 'in house' and external resources who undertake asset management activities.	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of analysis of future work load plan(s) in terms of human resources. Document(s) containing analysis of the organisation's own direct resources and contractors resource capability over suitable timescales. Evidence, such as minutes of meetings, that suitable management forums are monitoring human resource development plan(s). Training plan(s), personal development plan(s), contract and service level agreements.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	2	Staff development is reviewed annually with each employee in the Network Planning section. Some staff participate in industry working groups such as the ENA asset management group. There is a work task competency system in place for field activities.		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	2	Professional engineers are encouraged to attend relevant courses or seminars relating to technology and asset management. Staff new to the industry are assisted with their development by exposure to engineering projects and related tasks under the guidance of senior staff.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	Publication and availability of the AMP on Northpower website, customer newsletters, meetings with Northpower Trust, simplified annual reports mailed to customers, Contractor given access to asset information and reports.		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	Section 2.5 in the AMP outlines asset management systems and processes. Standard asset management practices are outlined in the Network standards manual available on the intranet.		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	Data requirements are decsribed at a high level in section 2.6 of the AMP. Data rules relating to asset representation are defined in the Network Standards Manual. The GIS and WASP asset management system have data rules defined the the configuration of the asset.		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	Staff are in place whose role it is to maintain asset management information systems and ensure data quality is maintained and improved. Data quality is continuously improved by way of ongoing field capture and data analysis.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	The organisation has not recognised the need to formally communicate any asset management information.	There is evidence that the pertinent asset management information to be shared along with those to share it with is being determined.	The organisation has determined pertinent information and relevant parties. Some effective two way communication is in place but as yet not all relevant parties are clear on their roles and responsibilities with respect to asset management information.	Two way communication is in place between all relevant parties, ensuring that information is effectively communicated to match the requirements of asset management strategy, plan(s) and process(es). Pertinent asset information requirements are regularly reviewed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	The organisation has not established documentation that describes the main elements of the asset management system.	The organisation is aware of the need to put documentation in place and is in the process of determining how to document the main elements of its asset management system.	The organisation in the process of documenting its asset management system and has documentation in place that describes some, but not all, of the main elements of its asset management system and their interaction.	The organisation has established documentation that comprehensively describes all the main elements of its asset management system and the interactions between them. The documentation is kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	The organisation has not considered what asset management information is required.	The organisation is aware of the need to determine in a structured manner what its asset information system should contain in order to support its asset management system and is in the process of deciding how to do this.	The organisation has developed a structured process to determine what its asset information system should contain in order to support its asset management system and has commenced implementation of the process.	The organisation has determined what its asset information system should contain in order to support its asset management system. The requirements relate to the whole life cycle and cover information originating from both internal and external sources.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	There are no formal controls in place or controls are extremely limited in scope and/or effectiveness.	The organisation is aware of the need for effective controls and is in the process of developing an appropriate control process(es).	The organisation has developed a controls that will ensure the data held is of the requisite quality and accuracy and is consistent and is in the process of implementing them.	The organisation has effective controls in place that ensure the data held is of the requisite quality and accuracy and is consistent. The controls are regularly reviewed and improved where necessary.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	Strategic plans as well as business plans include information technology requirements. General managers meet monthly to discuss information technology and human resource issues. The management team decide on priorities in terms of Information technology resources. There is however a weakness in the operational reporting system which is primarily for reporting fault statistics.		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	Section 7 in the AMP outlines risk identification and mitigation policies. The corporate division monitors key risks across the business. An audited saftey managent system (SMS) in accordance with NZS 7901 is in place. ISO 9001 ISO 14001 also identify risks.		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	The board of directors is strongly averse to exposure to public harm and staff health and safety risk and priority is given to funding risk mitigation in these areas. Training and competency requirements are identified by departmental and area managers.		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	A senior manager is tasked with coordination responsibility for mapping compliance and ensures that requirements are communicated to the responsible person(s). A compliance register is also in place and this aspect is discussed at monthly meetings. The AMP is also reviewed by several senior managers before presentatation to the board of directors.		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	The AMP feeds into Opex and Capex budgets (section 6 in the AMP). Approved budgets feed directly into Contracting program of works which is governed by the SLA. Network standards are in place for design, approved equipment, commissioning etc.		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	There is a defined process for assessing work that is carried out on Network assets. Monthly progress reports are required to be submiited by Contracting and a relationship meeting takes place between Network and Contracting once a month. Regular meetings with Contracting and Supply Chain take place to review new products, equipment and material and resolve issues with existing.		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?	2	Regular reliability reports and incident monitoring. Debriefs are held following significant weather events and other incidents. Plans are in place to move to asset health or condition assessment in place of just noting defects. Geospatial data on fautls is now in place.		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?	2	Responsibility is in general outlined in the objectives and duties of the relevant staff. A company wide reporting system (NPSAFE) is in place to report and follow up on incidents and is used for all types of non-conformity, not just safety aspects.		Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

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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 conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	4	Northpower is certificated to ISO 9001. ISO 14001 and NZS 7901.		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?	4	Northpower's corrective action processes have been audited as complying with IS 9001.		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	Continual improvement is a core element of ISO 9001. Significant project sanctions for expenditure will normally require NPV analysis in support of the business case.		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

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?	4	This is done by way of key supplier communications, participation in the industry EEA, attendance of industry conferences, forums and trade displays by key personnel and having dedicated development staff. Key staff participate in industry working groups and there is a strong relationship with Auckland and Canterbury Universities with respect to research and development.		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 instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	**Northpower Ltd**
AMP Planning Period	**1 April 2016 – 31 March 2026**
Asset Management Standard Applied	**PAS55/ISO55000**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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 C: Mandatory Explanatory Notes on Forecast Information

Electricity Distribution Information Disclosure Determination 2012 – (consolidated in 2015)

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 disclosure year and 10 year planning period, as disclosed in Schedule 11a.

Future expenditures have been escalated at a rate of 2% per annum in accordance with published NZ Government CPI forecasts

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 disclosure year and 10 year planning period, as disclosed in Schedule 11b.

Future expenditures have been escalated at a rate of 2% per annum in accordance with published NZ Government CPI forecasts

Appendix D: Disclosure Certification

Schedule 17: Certification for Year-beginning Disclosures

Electricity Distribution Services Information Disclosure Determination 2012 as consolidated in 2015

Schedule 17: Certification for Year-beginning Disclosures
(Asset Management Plan and Forecast Information)

Clause 2.9.1

We, Russell Black and David Ballard, being directors of Northpower Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Northpower Limited prepared for the purposes of clauses 2.6.1, 2.6.3, 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 align with Northpower Limited's corporate vision and strategy and are documented in retained records.

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[Signatures of 2 directors]

"safe, reliable, hassle free service"

Northpower

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