Network Waitaki

ASSET MANAGEMENT PLAN 2025-2035

Powering Our Future

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Introduction

01 Introduction

Welcome to our Asset Management Plan (AMP) for the planning period 1st April 2025 to 31st March 2035.

As we provide an essential service to the communities we serve, it is vital that our electricity network meets the evolving needs of our customers and other stakeholders. Our AMP plays a central role in determining the appropriate levels of network planning and investment required to achieve this.

This chapter introduces the AMP and is structured as follows:

Executive summary: Explains our asset management approach and how this aligns with our company strategic priorities and summarises key development driver and related expenditure forecasts.

Purpose: Explains the purpose and objectives of the AMP; the period and assets covered; the date it was approved by our Board of Directors (the Board); and the intended audience.

Key themes and initiatives: Presents key themes and initiatives outlined throughout the AMP.

Document structure: An illustration of how the AMP is structured.

1.1 Executive Summary

1.1.1 Our Company

Network Waitaki is a consumer trust owned electricity distribution business (EDB). We have a single shareholder, the Waitaki Power Trust (the Trust), which holds the shares of NWL on behalf of the NWL consumers (our connected customers). The Trust has five elected trustees and appoints directors to the Board to carry out the governance function of the business.

Figure 1 - Overview of Network Waitaki area of supply

We manage a largely overhead rural network that services the North Otago, Hakataramea, and Ahuriri regions, as illustrated above. Our network provides electricity to the town of Oamaru, as well as several smaller townships.

1.1.2 Our Vision

"Powering a vibrant Waitaki"

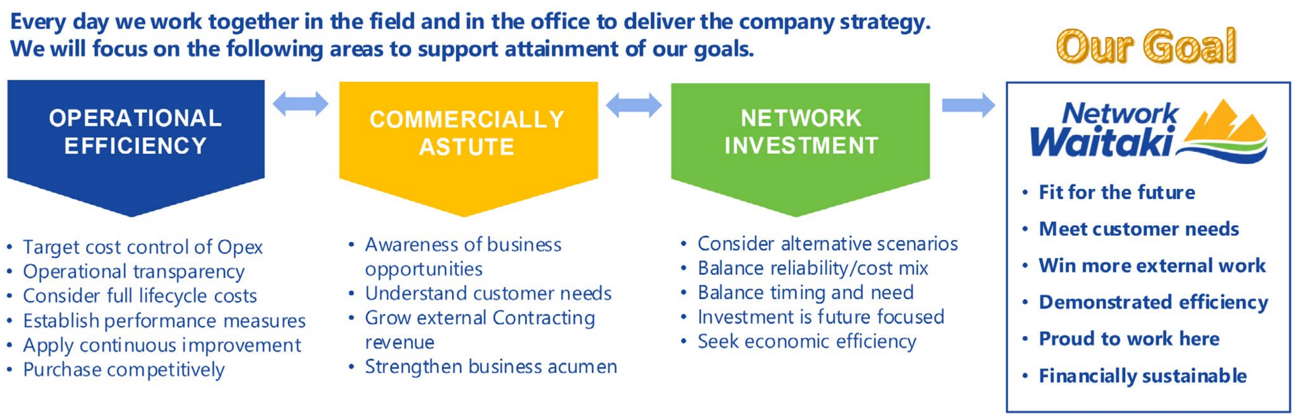
1.1.3 Our Strategy

"Utilise our core assets, operating expertise, reputation and financial strength to develop growth opportunities for a sustainable future"

1.1.4 Alignment with Key Strategic Priorities

In 2023 we revised our 10-year strategic plan that guides our business to deliver our Vision and Mission. Our strategic priorities are shown below:

Our Strategic Priorities



This Asset Management Plan details the asset management priorities aligned to these strategic priorities.

1.1.5 Managing our assets

We view effective asset management as a continuing cycle with direction, planning, implementation, and review working together to improve our performance.

We seek out best practice from within our industry and from other industries where appropriate. Examples include:

- Involvement in industry working groups related to new technologies
- Attendance at industry conferences and training
- Hosting onsite industry training courses to improve the capability of our engineers and field staff, such as the Electrical Engineers' Association (EEA) Safety in Design course
- Collaboration with other EDB's in the development of common standards.

In a drive to improve our asset management practises, we continue to get independent reviews of our asset management practices based on the EEA's Asset Management Maturity Assessment Tool (AMMAT). We are using the outcomes of this assessment to monitor progress against an improvement plan focused on providing excellence in asset management.

A key theme over the next few years is developing our Asset Management skills and capability to better align with ISO 55000 principles. Key focus areas are:

- Improving the accuracy, management and efficient use of data we record about our assets
- Improving our operational technologies as the platform for enabling our operational and management systems
- Ensuring our network capabilities allow for the efficient and cost effective integration of DER (Distributed Energy Resources)
- Improving visibility and engagement opportunities for stakeholders.

Key features of the network are shown in the table below.

Table 1 - Key features of NWL network

Parameter	Value
Number of Poles	21,759
Length of 33 kV lines and cables	254 km
Length of 11 kV lines and cables	1,356 km
Length of LV lines and cables	329 km
Number of zone substations	19
Number of connected customers	13,528
Coincident max demand	70 MW
Annual energy delivered to customers	308 GWh

These assets are discussed in detail in **Section 8, Maintenance and Renewals.**

We have traditionally managed asset life via condition-based renewals and replacements, but we aim to employ better analytical and predictive methods to assess risk throughout the asset lifecycle. We will:

- Introduce processes that capture information digitally in the field and remove paperwork
- Integrate electrical modelling software with our GIS system
- Use integration software to combine disparate data for analysis

Key to managing asset lifecycle is maintaining a safe, reliable operation while providing value to our customers.

1.1.6 Developing our Network

We present our strategy around how we will enable the energy transition from carbon based fuels to electricity in Chapter 4 – Enabling the energy transition.

We detail our plans to deliver this strategy in Chapter 9 - Future Network Plan.

Key themes of this plan are:

1.1.6.1 Supporting our customers' energy transition

Our planning assumptions for future energy scenarios include the initial phase of electric vehicle (EV) growth, with demand expected to become material at the tail end of the decade, and high confidence in process heat electrification, anticipating 6 MVA of new electricity demand by 2027 in addition to 4.5 MVA of decarbonisation projects we have already connected. For irrigation, we expect a moderate increase in demand, with 2.1 MVA expected by 2027, after which growth will stall as most viable land will be irrigated.

We are also starting to see retailers and aggregators interested in taking over control of hot water demand

We present our plan in **Section 4 – Supporting our customers' energy transition** with more detailed planning assumptions in **Section 9.4, Our planning assumptions**.

1.1.6.2 Transforming our network

While our traditional methods remain important, advancements in technology and evolving customer expectations make it important to transform how we understand our customers, operate our networks, and engage with stakeholders. This transformation will allow us to capitalise on new opportunities, manage emerging risks, and deliver optimal value to our customers.

Key initiatives to transform our network include:

Refining our future energy scenarios: In 2023, the ENA engaged Sapere Consulting to create national peak electricity demand scenarios out to 2050, which were peer-reviewed and factored down to fit regional conditions, reducing uncertainty in future energy scenarios and investment plans. We will continue refining these scenarios over the next year in collaboration with the Future Networks Forum.

Understanding our low voltage networks: We aim to benchmark, monitor, and model our low voltage networks to anticipate issues and develop optimal solutions, with key projects including low voltage feeder monitoring and a smart meter data trial. We plan to extend low voltage feeder monitoring coverage to 90% of Ōamaru residential customers over the next two years.

Enhancing our network model: We created a load flow model of our network to perform studies and analyse hosting capacity, and plan to regularly synchronise this model with our GIS system and demand forecasting tool to increase accuracy and produce hosting capacity maps regularly.

Delivering hosting capacity maps: Hosting capacity maps provide visual representations of available capacity on our networks, enabling customer self-service and planning for new generation or load without significant infrastructure upgrades. In 2024, we published hosting capacity maps for generation capacity and in 2025, we will publish maps for available load capacity and extend these to cover our subtransmission network.

Aligning our standards and processes: We are aligning our standards and processes with best-practice national EDBs to create a consistent customer experience, increase buying power, reduce spare holdings, and facilitate assistance during major events. Over the next year, we will continue to align customer-facing documentation across EDBs.

Supporting the ENA Future Networks Forum: As committed members of the ENA Future Networks Forum, we support initiatives to help Aotearoa reach its climate change goals, including developing standard protocols, defining future system roles, and improving customer experiences. We will continue participating in Innovation Forums and Communities of Practice to facilitate further sharing and collaboration among EDBs.

Further detail on our plans to transform our are presented in **Chapter 9.2 – Transforming our network.**

1.1.6.3 Regional transmission capacity

Transpower currently has a capacity constraint on the 110 kV transmission system supplying Oamaru GXP and the lower South Canterbury area. The firm capacity at Ōamaru GXP is 45 MVA and our current maximum demand is 44 MVA.

In FY24, Transpower allowed us to use a Special Protection Scheme (SPS) at Oamaru GXP to provide additional capacity at reduced security levels provided we commit to a permanent solution to the capacity constraint. Until this is in place we will connect new customers with significant load at a lower security level, meaning a single transmission level fault will result in a power outage until the fault is repaired.

After examining all viable options, the best value permanent solution was determined to be a new GXP in North Otago. This will provide energy security into our region and will be designed to be upgradeable as required to provide for all future energy scenarios. We are working to ensure that any investment is structured to give best value to our customers and that costs are shared fairly between beneficiaries.

We will continue to review the drivers and timing of our growth investments to deliver affordable outcomes to our customers.

We present further details in **Chapter 9.5, GXP Capacity and Security and Appendix E- GXP Projects.**

1.1.7 Our summary of forecast network expenditure

The summary of our forecast expenditure on our network for the planning period is shown in Table 2 below. Note that these figures do not cover non-network expenditure or expenditure outside the core EDB business. We have more certainty in our investment requirements for the first five years of the planning period. However, the economic environment has recently impacted on business growth discussions and we continue to review our investment decisions regularly. We also note recent significant increases due to inflation, supply chain issues, and exchange rates.

Table 2 - Summary of forecast network expenditure

Network Capital Expenditure	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
System Growth	11,239	14,143	8,706	1,388	2,700	2,300	2,130	2,300	2,600	14,585
Reliability, Safety & Environment - Quality of Supply	1,323	-	-	-	200	100	270	-	-	30
Reliability, Safety & Environment - Legislative & Regulatory	-	-	-	-	-	-	-	-	-	-
Asset Replacement & Renewal	13,001	9,110	7,083	8,827	6,846	8,659	6,731	8,804	6,886	8,910
Consumer Connection	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711
Asset Relocations	-	-	-	-	-	-	-	-	-	-
Total Capital Expenditure	**27,274**	**24,964**	**17,500**	**11,927**	**11,457**	**12,770**	**10,843**	**12,816**	**11,197**	**25,236**
Network Operational Expenditure	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY32**	**FY33**	**FY34**	**FY35**
Asset Replacement and Renewal	296	267	267	222	222	222	222	222	222	222
Routine & Corrective Maintenance and Inspections	1,602	1,998	1,973	1,936	1,973	1,936	1,973	1,936	1,973	1,936
Vegetation Management	807	807	807	807	807	807	807	807	807	807
Service Interruptions and Emergencies	735	723	723	723	723	723	723	723	723	723
System Operations and Network Support	78	78	78	78	78	78	78	78	78	78
Total Network Operational Expenditure	**3,517**	**3,873**	**3,849**	**3,766**	**3,803**	**3,766**	**3,803**	**3,766**	**3,803**	**3,766**
Total Network Expenditure	**30,791**	**28,837**	**21,349**	**15,693**	**15,260**	**16,536**	**14,646**	**16,582**	**15,000**	**29,003**

1.2 Purpose

The purpose of this AMP is to align the management of our assets with our corporate objectives and our mission of "Promoting regional growth and wellbeing through the provision of innovative and sustainable energy solutions for our customers".

The AMP is an integral part of our business planning process alongside our Statement of Corporate Intent, internal strategy plans, annual business plan and budget, Future Networks Plan, monthly board reports, and our emergency preparedness documents.

The objectives of this AMP are:

- To link the asset management processes to customer and stakeholder preferences for prices, supply reliability, and the health and safety of our staff and the public
- To ensure that all asset lifecycle activities, plans, and associated costs are systematically planned with a long-term view towards minimising lifecycle costs, which promotes efficiency
- To ensure the company's sustainable financial future by understanding the resources needed to deliver capital and operational workstreams and when those resources will be needed
- To ensure that physical, commercial, and regulatory risks are appropriately managed and understood throughout the life of the asset

1.3 Scope

The scope of this AMP includes all areas of planning that relate to NWL's regulated electricity distribution services as an Electricity Distribution Business (EDB). This does not include business streams outside the core EDB business, such as electrical and vegetation contracting, metering services, electric vehicle charging, generation, and the fibre optic and private electricity networks.

1.4 Intended audience

The AMP is published on our website (www.networkwaitaki.co.nz) and is aimed at the following readership:

- Our trustees, directors, and management
- Our staff
- Our customers
- Our other stakeholders
- Interested members of the public
- The Commerce Commission
- Other Electricity Distribution Businesses (EDBs)

1.5 Key themes

The key themes for the planning period are:

- The importance of safety on and around the network, both as a healthy and safe workplace for staff and as a safe utility for the public
- Understanding and meeting our customers' needs
- Adapting for climate change
- Enabling the energy transition to electricity for process heat and transport
- Transforming our network to enable new technologies for our customers
- Reviewing and ensuring affordable solutions delivered at the right time
- Continuing to improve our asset management processes for better delivery of services
- Continuing to improve deliverability of the AMP

1.6 Document structure

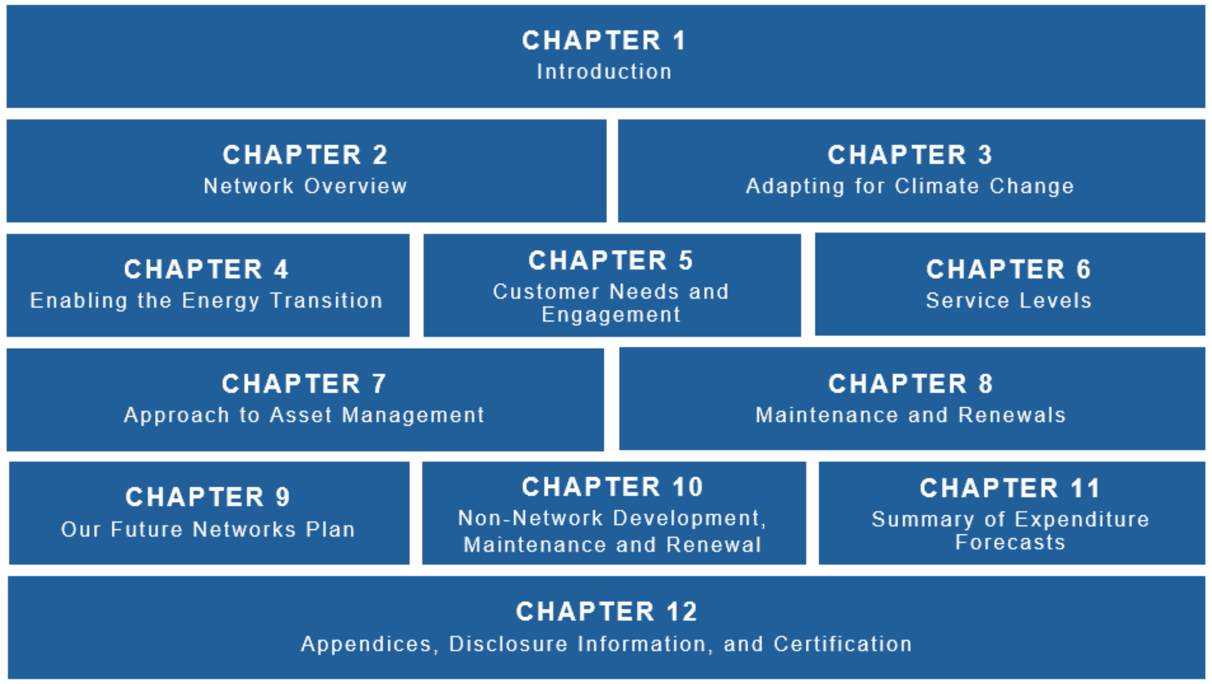


Figure 2 - Structure of Network Waitaki's AMP

1.7 Use of constant dollar values

Capital and operational expenditure values are presented in constant 2024 dollars. To allow for better comparison of expenditure between years, we have not included an adjustment for inflation.

1.8 Approval date

The 2025-2035 AMP was approved by the Network Waitaki (NWL) Board of Directors on 31st March 2025 . See Appendix G for a copy of the signed Certificate of Approval.

Network Waitaki Overview

02

02

Network Waitaki Overview

This chapter describes who we are and what we want to achieve, and is structured as follows:

- **Our company:** outlines our corporate objectives, organisational and governance structures.
- **Operating environment:** an overview of the issues that impact our approach to asset management, such as geography, vegetation management, and changes in demand.
- **Stakeholders:** who our stakeholders are and how their interests and expectations are accounted for in our asset management practices.
- **Our customers:** an overview of our customers, including total number of connections; our major customers and their impact on network operations and our asset management objectives; and the load characteristics of our network.
- **Our network:** an overview of the network including coverage areas; extent of overhead and underground lines; and our substation arrangements.
- **Our Assets:** a population summary of our assets by category.

2.1 Our Company

Network Waitaki (NWL, or the Company) operates predominantly as an Electricity Distribution Business (EDB) in the Waitaki District and parts of South Canterbury. We operate an electricity distribution network (the subject of this AMP), a fibre network, a metering business, and public electric vehicle chargers, and provide private electricity network services to some major customers. A contracting division undertakes distribution, construction, and maintenance activities, including specialist electrical services and vegetation management services. Our contracting division primarily undertakes work for the Network Waitaki network, as well as providing services to other asset owners and contractors.

2.1.1 Ownership structure

NWL is 100% owned by the Waitaki Power Trust (the Trust). The Trust holds all shares on behalf of NWL's consumers (our connected customers) and appoints directors to the Board to carry out governance. The Trust has five trustees. Every three years, three trustees are elected by the network's consumers. In 2022 the Trust completed a 10-yearly ownership review of the Company. This included an independent review of ownership options, with the goal of delivering the best outcome for Network Waitaki's customers. The independent review recommended that continuing Trust ownership was the most suitable model for Network Waitaki.

In engagement with customers and other stakeholders as part of the ownership review, over 99% of respondents supported the Trust ownership model.

Based on this work, the Waitaki Power Trust will retain the total shareholding of Network Waitaki Ltd on behalf of electricity consumers connected to the network.

2.1.2 Mission statement and corporate objectives

Our mission statement and corporate objectives are published in our Statement of Corporate Intent (SCI) and provide direction for company operations, including asset management practices.

Our mission statement is:

"Promoting regional growth and wellbeing through the provision of innovative and sustainable energy solutions for our customers."

Our principal corporate objective is *"to preserve and grow the value of the business for the long-term benefit of consumers".* This is enabled by focusing on four core areas, which are covered in the following sections.

2.1.2.1 Health and safety

Our commitment to health and safety is paramount. Our goal is to cause no harm to our people or the public as a result of our operations. Health and safety is a priority in every operational decision, from planning a new zone substation to driving to a work site, or opening a low voltage cubicle on the side of the road. We will maintain an accredited public safety management system.

To meet this objective, we provide a staff health and wellbeing programme and training in areas such as risk management, safe driving, work site planning, and safety in design. Our crews are equipped with quality tools, plant, and personal protective equipment, and trained to use it safely.

2.1.2.2 Our people and culture

Our goal is to be employer of choice in North Otago and in our industry, so we attract and retain top talent. A motivated, competent workforce is one of the most important factors in delivering a safe and reliable network service effectively and efficiently.

We train and develop people across the business to stay abreast of current practices. We employ trainees and graduates and offer tertiary scholarships to encourage locals to enter our industry. The size and skill of our workforce are treated as part of our AMP planning process to ensure we have the capability to deliver on current and future work plans.

The company provides an equal opportunity workplace and promotes inclusiveness and diversity.

2.1.2.3 Our customers and community

We aim to provide customers with safe, reliable, cost-effective and innovative energy solutions, with top tier performance in our peer group. This will enable us to support activities for economic growth and wellbeing in our network area and make us the first choice for our customers when they are examining options for their energy needs.

We believe Trust ownership provides the best value for customers and allows us to deliver a modern, reliable, effective electricity network with maximum efficiency.

2.1.2.4 Building a sustainable future

We must operate our business in a commercially sustainable manner and continually improve our efficiency. We must invest wisely to preserve and grow the value of the business to fund the discounts and community support we give our customers and secure the long-term stewardship of the electricity assets.

We aim to minimise the impact of our operations on the environment and ensure compliance with the Resource Management Act, and to comply with all obligations under relevant legislation and regulations. This includes promoting efficient energy use to our customers.

2.1.3 Organisation structure

The Trustees of the Waitaki Power Trust appoint Directors to our Board to govern the company, and they in turn appoint the Chief Executive. Ultimate accountability for the performance of the business (including the network assets lies with the Board who approve this AMP. The Board are also accountable to the Trustees for meeting the requirements set out in the Statement of Corporate Intent (SCI), which includes safety, performance, and asset management objectives and service targets.

The Chief Executive and the management team report to the Board monthly to update them on risks, performance, and work programme progress. Quarterly reports comparing year-to-date performance against the SCI are provided to the Trust. Annual reports are prepared by both NWL and the Trust.

Staff are organised into functional teams for effective operation of the network and delivery of our works programme. Most of the annual works programme is undertaken by our integrated contracting business unit, which has about 60 staff in Oamaru. Specialist skills are contracted in as needed.

2.1.4 Asset management governance

Asset management responsibilities are allocated to senior staff as follows:

Chief Executive

The Chief Executive is accountable to the Board for delivery of the strategic objectives of the Board and the Trust.

Chief Financial Officer

The Chief Financial Officer is responsible for the Company’s financial activities. These include preparation of annual budgets for operating and capital expenditure with input from all areas of the business, and providing reports to monitor financial performance of works programmes against budgeted costs.

General Manager Network

The General Manager Network provides leadership, coordination, and oversight to all aspects of network operations, including asset management and network development. This role coordinates resources across teams to deliver the outcomes of the AMP and drives continual improvement of our asset management practices.

Network Lifecycle Manager

The Network Lifecycle Manager is responsible for development of asset management processes and systems, standards and policies. They initiate projects and programmes of work to address performance, safety, and reliability risks on the network.

Network Development Manager

The Network Development Manager is responsible for developing strategies and plans to deliver our customers’ energy needs.

Engineering Manager

The Engineering Manager has responsibility for day-to-day operation of the network and the efficient delivery of the annual capital and maintenance work programmes.

Network Information Manager

The Network Information Manager has the responsibility for ensuring the stewardship of the network asset and associated data that is utilised across the business. This includes the integration and visualisation of data across business systems.

Regulatory Manager

The Regulatory Manager is responsible for preparation of regulatory disclosures, compliance, and pricing.

Customer Service Coordinator

The Customer Service Coordinator is responsible for leading our customer services function and developing and maintaining the interface between the company and consumers/community.

General Manager People and Safety

The General Manager People and Safety is responsible for leading strategic implementation of our company and staff resourcing and health and wellbeing programmes, and safety management systems. They support the business managers to enable a high performing work environment. Also included is the responsibility for setting performance initiatives to measure and monitor the effectiveness of critical controls and ensuring risk owners are regularly reviewing and updating their risks.

General Manager Contracting and Operations

The General Manager Contracting and Operations is responsible for the provision of construction and maintenance staff and equipment to complete the annual works plan provided by our in-house contracting team. This person role is also responsible for seeking out and managing any work outside our network for other network companies or private customers.

2.1.4.1 Expenditure approvals

Operational and capital budgets are prepared annually and approved by the Board. For larger projects, investments in new areas, and projects committing the company to expenditure over several years, the approval process includes a formal business case. This gives the Board an overview of risks and options, and an economic assessment of the proposed solution.

All roles are subject to approved delegated financial authorities. Any expenditure beyond these limits requires approval from a manager, the Chief Executive or the Board, depending on the expenditure amount.

2.1.4.2 Asset management capability and delivery

Our organisational and governance arrangements are structured to ensure the capability needed to implement this AMP. We ensure the AMP work programme can be achieved by tracking our progress. This involves regular reporting and review of the programme’s physical and financial progress against our plans and budgets. This reporting includes operational metrics such as SAIDI and SAIFI.

Planning delivery of the AMP in any given year balances the requirements of the business to complete specific parts of the works programme (e.g., risk, capacity constraints, customer requirements) against our ability to cost effectively deliver the works plan. The goal is to develop a works programme that is well balanced across the planning period and to avoid major peaks and troughs in work so our resources can be well matched to the programme. The network then benefits from a stable and experienced workforce, without having to upsize in busy years or downsize in quieter years. This balancing act is evident in the phasing of some renewal and maintenance category budgets later in the planning period. We know the total amount of work (e.g. switchgear maintenance and renewal) that we need to complete over the planning period. We have allocated that work across the years to smooth the delivery around fixed workstreams such as major line builds and new substations.

Most of the AMP is delivered by our internal Engineering and Contracting teams. The Contracting team’s skill set is focused on core line construction, maintenance and vegetation roles, including live line work, cable jointing and line construction. We also maintain a base level of specialist experience for HV, primarily plant, power and communications technicians. These resources are supplemented with specialist external providers with whom we maintain strong relationships.

The sustainable delivery of our AMP requires suitable skills within our Contracting team. We recognise that the average age of staff in many of our departments is increasing, and we are at risk of a future skills shortage as people retire. To address this, we are bringing on board contracting trainees and trade apprentices and providing scholarship opportunities for technical education. These resource development initiatives are factored into the overall delivery of the AMP.

Sustainable delivery means balancing the works programme to use our available resources in the most cost effective way while meeting the requirements of the plan. This means scheduling large projects across the planning period to avoid peaks and troughs of planned work where we expect our own field teams to deliver. When this levelling is combined with capital intensive activities that do not require our internal resource (such as purchase of a new zone substation transformer) it can result in what appears to be a "peaky" works programme, when considered strictly on an expenditure basis. Where peaks cannot be met with our contracting team, we will engage contractors to supplement our own resources.

We monitor, report and correct progress to the AMP at various levels within the business. Project level reporting is the domain of our Project Engineers and Supervisors, who are tasked with keeping individual jobs on track. Progress against major projects and programme level activities such as inspections is monitored by department managers. Programme level financial and status reporting is monitored by the Chief Executive and the Board.

This reporting gives us good awareness of historical performance against the works programme budgets, but there is room to improve forecasting for ongoing delivery of the works programme. This would create opportunities for efficiency in areas such as resource scheduling. Our strategic plan targets improvements in project management practice, financial monitoring and reporting, and forward scheduling of the work programme.

We regularly adjust the work programme and coordinate work to take advantage of other activities - such as a planned outage - to respond to a driver such as a weather event or a customer's unexpected requirements. Exercising this flexibility while maintaining delivery of the AMP is a key focus for our staff.

2.2 Our Operating Environment

2.2.1 Present environment

The operating environment of the Waitaki region is a mixture of coastal plains and alpine areas.

The climate is traditionally dry and cold in winter, and dry and hot in summer. The area is known to suffer from drought.

Extreme weather events include wind and snowstorms, and floods. We expect at least one significant weather event every year. The impact of these events is typically restricted to the inland area of the network but can occasionally affect the whole region, and extreme events can affect neighbouring regions as well.

Coastal conditions are relatively benign. There is a small zone where equipment corrosion is a concern, although coastal erosion is starting to impact some areas, and some local road networks are being affected. We are monitoring these situations with respect to our assets in the affected areas.

The major urban population is in Oamaru, a coastal town of approximately 14,350 people located on the east coast of the South Island. The population of the wider Waitaki region is about 22,300.

There are several small townships in the region. Most are on the two state highways that run north to south (SH1) and east to west (SH83).

The rural economy is based on a mixture of beef and sheep farming, crops, and dairy. Irrigation is widely used via schemes that include border-dyke systems, direct pumping from local water sources, or reticulated systems to the farm gate. Irrigation is a major source of growth on our network.

Despite the typically dry summer conditions, vegetation growth is robust throughout most of our network, and management of vegetation near our assets is an ongoing focus of operations.

The economic environment is currently very challenging, with significant cost pressures occurring in the delivery of our works, especially with sourcing of materials incorporating overseas components. This means we continue to focus on prudent investments and investment in efficiencies within our business.

Whilst we are attempting to minimise the impact on our customers, we are seeing this being reflected in increased distribution pricing. We are endeavouring to ensure that our customers are fairly charged appropriately reflecting the benefits they receive from our network investments. Whilst our current pricing policy currently reflects this with appropriate weighting for both capital contributions and ongoing delivery charges, we continue to advocate to ensure an appropriate regulatory pricing regime that allows more flexibility to fairly reflect both risks and benefits.

2.3 Regulatory Environment

2.3.1 Pricing

It is vital that we can deliver this Asset Management Plan sustainably. To achieve this, we have developed a financial model showing the impact of the required investment, over and beyond the planning period, under various growth and asset renewal scenarios. This model is used to plan appropriate funding sources considering the estimated useful life of the investment, the major beneficiaries, and the concentrated nature of some system growth investments.

Network Waitaki is subject to regulation by the Commerce Commission under Part 4 of the Commerce Act 1986. As Network Waitaki meets the 'consumer-owned' criteria set out in section 54D of the Commerce Act, the company is exempt from price-quality regulation. However, compliance with information disclosure regulation is required, and we must deliver value to our connected customers in terms of price of service vs. quality of supply.

Network Waitaki is also subject to regulations set by the Electricity Authority, which is the regulator responsible for the efficient operation of the New Zealand electricity market. One of the Electricity Authority's focus areas is improved efficiency of distribution prices to become more cost-reflective, especially with new technologies entering the market and changing the way electricity is consumed and produced.

As an Electricity Distributor, our the cost of service is largely fixed and we generate most of our revenue through fixed charges.

2.3.2 Climate change policy

The Climate Change Response (Zero Carbon) Amendment Act 2019 sets New Zealand's emission reduction targets at zero net greenhouse gas emissions by 2050 (excluding biogenic methane). This will contribute to the Paris Agreement goal of limiting global warming to well below 2, preferably to 1.5, degrees Celsius, compared with pre-industrial levels.

Our position on climate change is presented in **Section 2.4.1.**

2.4 Stakeholders

2.4.1 Stakeholders and their interests

Stakeholders are the people and organisations that can affect, be affected by, or perceive themselves to be affected by our decisions or activities. Stakeholder requirements are an important driver for our performance, and we place considerable focus on identifying and meeting stakeholder expectations. Our stakeholders are described in Table 3 below, along with their requirements, how those requirements are identified and how they are incorporated into our asset management practices.

Table 3 - Network Waitaki stakeholders

Stakeholder	Requirements	Identification of requirements	Requirements incorporated into asset management practices
Customers	Health and safety; reliability; value for money; effective communication, particularly during emergencies and faults; emergency and lifeline preparedness.	Bi-annual customer surveys; regular meetings with major customers; VOC survey sent after work is completed, feedback sought after major outages; public safety performance measures.	Maintaining audited Public Safety Management System and other safety initiatives; price/quality trade off; network development plans; investment planning; asset lifecycle management.
	Ensuring appropriate network provides for customer needs	customers; feedback sought regarding customer service levels, proposed future requirements.	Recognise energy affordability issues and regional development opportunities.
Staff and other workers	Healthy, safe and enjoyable work environment; job satisfaction; assurance of work continuity; visibility of forward workload requirements; work/ life balance; career development opportunities; fair remuneration; effective support.	Staff feedback; regular staff briefings and communications; staff input into decisions affecting work environment and methods.	Health and safety initiatives and reporting; integration of risk management into all business processes; forward planning of work.
Public, and landowners	Health and safety; emergency and lifeline preparedness; protection of property and amenity values; effective communication regarding access and maintenance.	Meetings; feedback; consultations.	Health and safety initiatives; emergency preparedness planning; service levels.
Board of Directors	Governance; risk management; health and safety performance; business direction and sustainability; Performance of Chief Executive; statutory and regulatory compliance.	Regular board meetings and directives; performance measures.	Integration of risk management into all business processes; regular reporting.

Stakeholder	Requirements	Identification of requirements	Requirements incorporated into asset management practices
Waitaki Power Trust	Fair and reasonable rate of return on equity; incentives to invest and innovate; good governance; risk management; business sustainability; good reputation with the community; effective asset management.	Trustee meetings; performance measures.	Network development planning; investment planning; asset lifecycle management; organisation and governance structures; integration of risk management into all business processes; quarterly and annual reporting.
Councils	Alignment with district and regional requirements; statutory compliance.	Meetings; consultations on regional and district plans.	Network development planning for system and demand growth.
Iwi/Runanga	Ensure participation to enable responsible stewardship of the environment.	Understand and respect the importance of equity and build relationships with local Iwi and Runanga.	Ensure processes adequately cater for recognition of cultural and governance of our impact on local land and resources.
Electricity generators and retailers	Safety, reliability, effective communication; statutory and regulatory compliance; fair contractual arrangements; transparency; effective delivery of business-to-business services.	Industry forums, conferences, and seminars; regular consultation, statutory and regulatory requirements; contractual arrangements.	Network development planning; service levels.
Regulators and Governmental Agencies	Statutory and regulatory compliance; ensure our connected customers receive a reliable supply of electricity accounting for price/quality trade off; compliance with health and safety requirements.	Statutory and regulatory requirements; consultations; industry forums, conferences, and seminars.	Network development planning; service levels; risk management; governance arrangements; inclusion of safety-by-design principles.
Transpower (as grid owner and System Operator)	Security of supply; new grid investment and planning provisions; effective and timely communication; statutory and regulatory requirements; sustainable earnings from connected and interconnected assets.	Operational standards and procedures; regular meetings.	Network development planning; investment planning; asset lifecycle management; risk management.
Neighbouring EDBs	Coordinated investigation into shared transmission constraints, opportunities for sharing common operating standards and practices.	Meetings/participation in working groups to discuss and undertake collaboration opportunities.	Decisions will be incorporated in future AMPs, Network Design and Operating standards and Practices.
Suppliers and Contractors	Ensure efficient supply of products and services to enable ongoing sustainable management of the business.	Clear specifications / scope of work, fair and reasonable terms of trade, and as required delivery.	Effective delivery of the asset management plan. Asset management systems have appropriate standards and business practices.

2.5 Our Customers

2.5.1 Major customers

Our major customer groups are urban-residential around Oamaru and other townships, and large rural agricultural customers (typically dairy and cropping). We have a small but important level of commercial and industrial demand on our network and our top 10 customers, by volume of energy consumption, operate in the industry categories below:

- Meat processing
- District irrigation schemes
- Council utilities and infrastructure
- Supermarkets
- Food manufacturing

We aim to engage with our customers regularly so we can understand their needs and provide a reliable network to meet them. We also look to engage when we are planning work that involves a power outage, so we can minimise disruption to their operations.

2.5.2 Maximum demand and energy delivered

A comparison of the network maximum demand and energy delivered since 2011 is presented below. This is separated into winter (June, July, August) and spring /summer/autumn to remove the effect of irrigation from the winter data.

Winter maximum demand and energy delivered are trending upwards at 1.1% per year. Variability from year to year is influenced by winter temperatures and associated changes in heating demand.

Maximum demand for the rest of the year has increased on average 3.0% a year and energy delivered has increased by 2.8%. This is driven largely by irrigation growth.

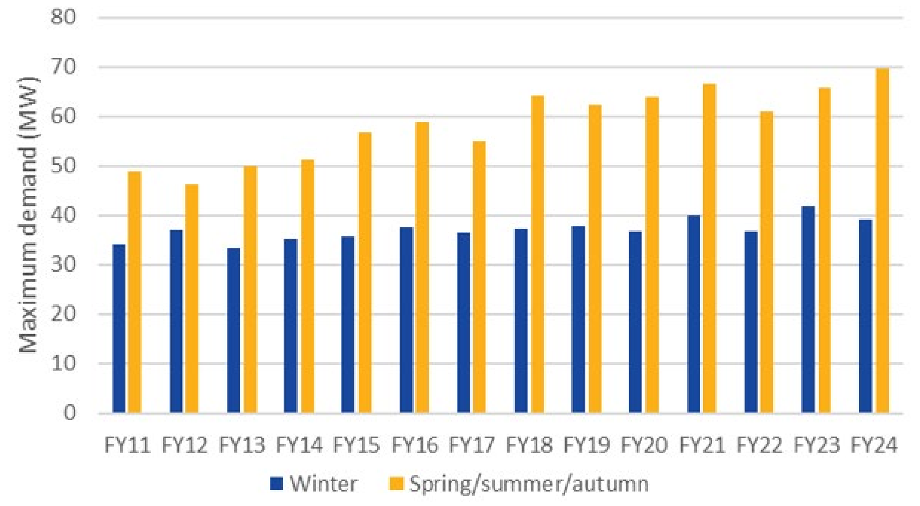


Figure 3 – Historical total network maximum demand

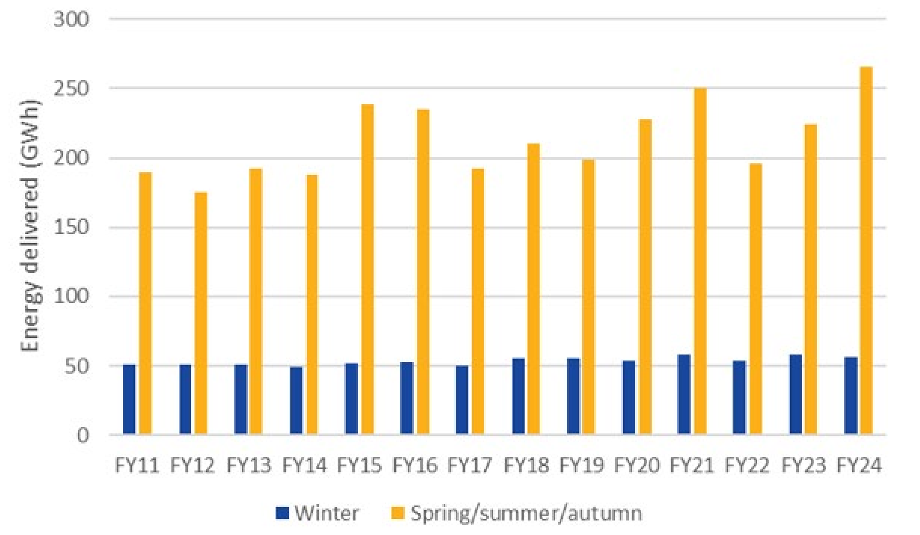


Figure 4 – Historical total network energy transported

2.6 Overview of Our Network

We operate a predominantly overhead rural network supplying the North Otago, Hakataramea, and Ahuriri regions as shown in **Figure 5 below**. We supply one major urban area, Oamaru, and several smaller townships.

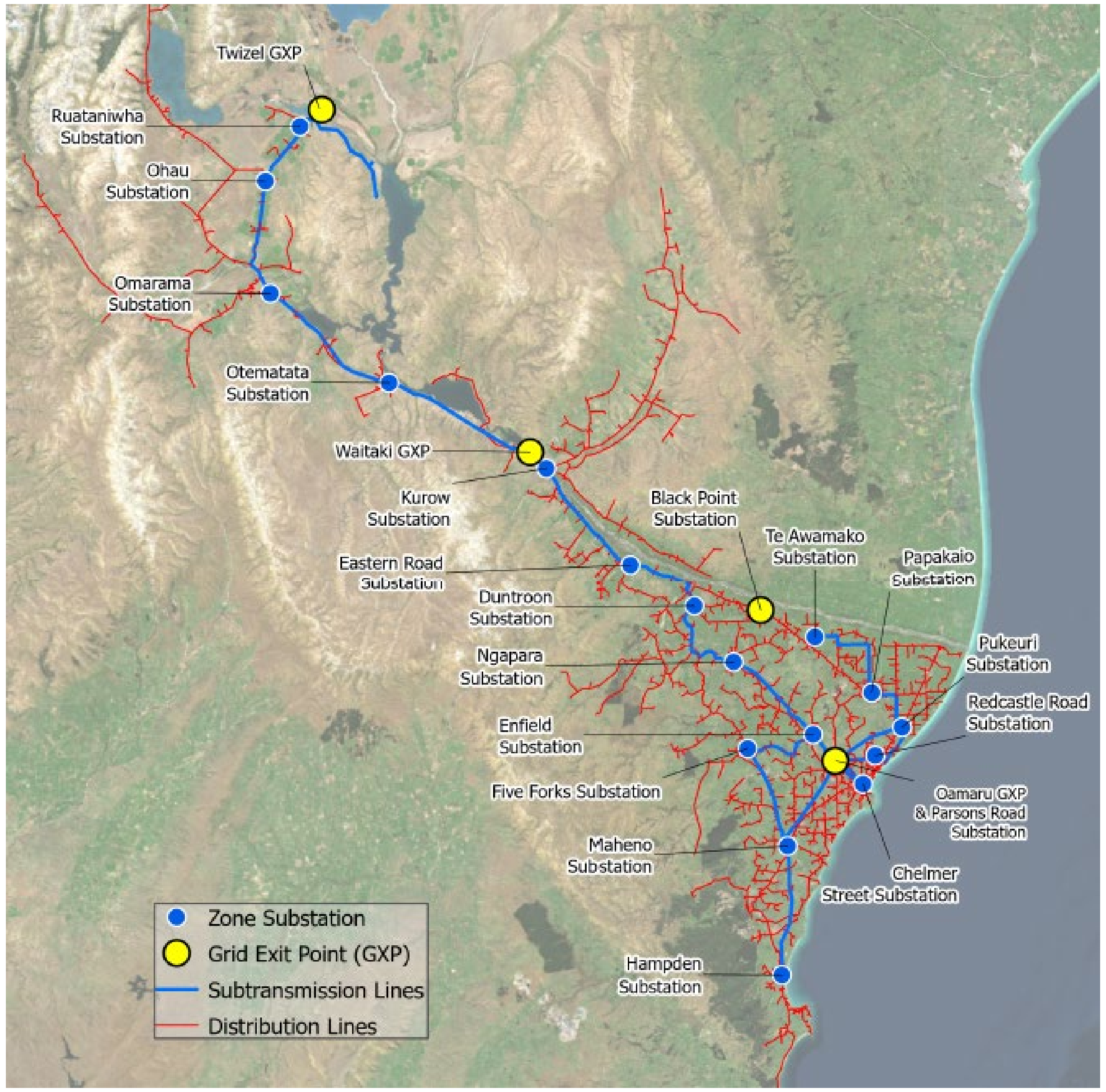


Figure 5 - Map of NWL area of supply and network extent

Bulk electricity supply is taken from Transpower's network (the national grid) at our four grid exit points (GXPs). This energy is transported via our sub-transmission network at 33,000 volts (33 kV) to the zone substations. Power transformers at the zone substations convert the 33 kV supply to a lower distribution voltage of 11,000 volts (11 kV). This is supplied to some customers directly (generally large commercial and industrial customers) but is more commonly stepped down via distribution transformers to our low voltage system (400 volt, three phase/230 volt single phase), which supplies most of our customers.

The characteristics of our grid exit points (GXPs) are listed in the following table:

Table 4 - Characteristics of NWL grid exit points as of 31 March 2024

Grid Exit Point	Voltage	Supply Configuration	Capacity	Max demand FY24 (Non-Coincident)	FY24 Zone Substations supplied
Ōamaru GXP	33 kV	(n-1) (n)	45 MVA 53 MVA	44 MVA	11
Twizel GXP	33 kV	(n-1)	27 MVA	4 MVA	3
Waitaki GXP	11 kV 33 kV	(n) (n-1) switched	24 MVA 13.5 MVA	13 MVA	4
Black Point GXP	110 kV	(n)	25 MVA	17 MVA	0
North Otago GXP (proposed)	33 kV (FY27) 110 kV (FY33)	(n-1) (n-1)	27 MVA 120 MVA	-	-

A 33 kV sub-transmission network connects the GXPs to our zone substations. The 33 kV sub-transmission network is predominantly overhead construction, apart from a few short cable sections.

2.7 Our Assets

Table 5 - Key features of NWL network

Parameter	Value
Number of poles	21,759
Length of 33 kV lines and cables	254 km
Length of 11 kV lines and cables	1,356km
Length of LV lines and cables	329 km
Number of zone substations	19
Number of connected customers	13,528
Coincident max demand	70 MW
Annual energy delivered to customers	308 GWh

These assets are discussed in more detail in **Section 8 - Renewals and Maintenance.**

Adapting for Climate Change

03

Adapting for Climate Change

This chapter provides an overview of how climate change can impact our network, and how we are planning to ensure we our network is resilient in the face of it.

Changes in historic weather patterns are directly and indirectly impacting on our network operations and business.

Indirectly, the climate change regulatory environment driving carbon reduction initiatives that are causing changes in customer behaviour such as:

- Decarbonisation of process heat activities
- Changing land use and changes to location-specific farming techniques
- Proliferation of "green" distributed generation
- Widespread adoption of electric vehicles

These indirect aspects of climate change are dealt with in the section on Enabling the Energy Transition.

Our network experiences a wide range of climates, from coastal conditions in the east to near alpine conditions in the west. We straddle the boundary between Otago and the Canterbury Plains and experience weather patterns and climatic conditions that are a blend of both regions. Climate change has the potential to change and/or amplify the weather patterns in these regional climates.

The science associated with climate change is continuously developing. Ongoing international research informs and updates climate models, providing more accurate predictions. The current best source of information for our region is climate change predictions from NIWA[1]. This modelling shows the following expected trends for our network area over the next 50-70 years:

- More days with temperatures > 25°C;
- Fewer frosts
- Winter and spring likely to be wetter
- Less snow in winter as precipitation falls as rain instead
- Frequency of extremely windy days likely to increase
- Storm patterns unlikely to increase beyond the current norm
- Coastal erosion likely to continue

3.1 Effect on the network

The predictions show us that over the next 70 years the local conditions are likely to be wetter, warmer, and windier. The implications for our network are:

- Assets in coastal areas may be increasingly at risk from coastal erosion
- Assets in low lying areas will be subject to more flooding events
- Overhead lines will be subjected to more high wind events

3.1.1 Coastal Erosion

Coastal erosion is the loss of coastal and foreshore land due to the action of waves and storms. It is expected that rising sea levels and changing weather patterns will exacerbate these actions in the future. Predictions are for a maximum of 200m of coastline erosion in some areas over the next 100 years, although most of the coast will recede less than this.

Some areas of the Waitaki coastline have been subject to documented coastal erosion for over 50 years, in the order of up to one metre a year. Fortunately, these historic events have been factored into the design of the network and the community, so our assets are traditionally located well clear of erosion risk areas.
It is not possible to maintain operating assets where this sort of erosion is occurring. Most at-risk assets are located to serve specific properties and the loss or abandonment of these properties will allow us to remove our assets in a controlled manner. This approach has already been used on occasion when storm-related erosion caused the removal of poles associated with properties that have been abandoned due to land loss.

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1 NIWA/IPCC Climate Change Projection Guidance report April 2023 – 6th Edition of the assessment. Provided by the Ministry for the Environment at https://environment.govt.nz/publications/aotearoa-new-zealand-climate-change-projections-guidance/

3.1.2 Rain and Flooding Events

NIWA predictions show that flooding due to heavy rain is likely to increase by 5 to 10%. It is likely that these floods will be similar in scope to those we are already seeing but will become more common.

Flood events are already a regular hazard. Outages result when ground mount equipment such as switchgear and transformers are flooded. Flood water and debris can cause outages at substations and deliver lasting damage to switchyards and substation buildings. Flowing flood water can undermine and damage buried cables and pole foundations and damage bridges carrying electricity and communications cables. In addition, flood waters can cut off roads and cause landslides, affecting our ability to respond to events and leading to longer outages.

In the long term, more rain in the region will also increase the growth of vegetation near our lines. More vegetation encroaching on live assets will increase the cost and difficulty in managing this risk. This will be exacerbated by wetter soil conditions affecting the root stability of trees.

3.1.3 Extreme Winds

Extreme winds are the top 1% of daily wind speeds. NIWA modelling out to 80 years predicts increases in extreme wind conditions. Extreme wind can affect our network in various ways:

- Direct wind impact on the poles and wires that make up overhead lines
- Wind-blown debris becoming entangled with overhead lines
- Trees and vegetation being blown over onto overhead lines
- Increase in the occurrence and impact of wildfires
- Increased risk of fire initiation from our assets and operations

More high wind events will cause more wear and tear on our overhead network assets. This may result in higher maintenance costs over the assets' lifetime, including extra inspections, more repairs, and earlier asset replacement.

3.2 What can our customers expect?

Changing climate is likely to affect our communities. From the point of view of our network, more extreme weather events may have the following impacts:

- Building new network assets to higher standards, and renewing existing assets where necessary to provide reliability and resiliency for our communities in the face of extreme weather events.
- Increased challenges to customers' resiliency, with higher dependency on electricity for heating and industry. This will increase the impact of weather-related outages.
- More disruption due to fault outages. It is not economically feasible to make our network resilient against every weather event.
- More maintenance outages. More heavy weather will increase wear and tear on the network, necessitating more inspections and repairs.
- Road closures affecting fault response times. The effect of events such as flooding will combine with the cumulative effects of previous events such as slips and landslides and prevent rapid access in some areas.
- More vegetation growth and tree roots weakened by wet ground will increase the risk that customer trees pose to our network assets. This will lead to an increase in vegetation-related maintenance outages and the risk that customers carry for potential damage.

We will continue to monitor the climate change models particularly for the forecast impacts on the Waitaki region. Our GIS and risk models allow us to overlay these effects of climate change on the network and our communities, and adapt the network where there are likely to be unacceptable outcomes.

We will also continue to discuss climate change issues with other local stakeholders such as Councils, irrigation companies, farmers, and other groups with similar long-term concerns.

3.3 Planning for Resilience and Climate Change

Responding to climate change means integrating the predicted effects of climate change across the business, and where necessary adapting what we do to suit. The table below shows the 5-year work plan for improving network and business resilience, including climate change issues.

Area of focus	Workstreams
Capability Assessment	Continue delivery of workplan to close the gaps identified in our 2023 Resilience management maturity assessment tool (RMMAT) review
Vulnerability Assessment	Modelling the Network criticality and the associated climate change risks to our network assets Assessment of the supply resiliency of communities and major customers and providing guidance on how they can improve their resilience Working with Civil Defence authorities to identify community hubs that may benefit from improved resilience
Asset and Network Strengthening	Developing and updating design standards to include adaptations for NIWA worst case 2090 predictions for climate change impacts including snow, wind and ice levels Ensuring maintained/replacement assets increase resilience as appropriate Include adaptation mitigations into targeted renewal and upgrades such as strengthening structures and relocating ground mount assets Strengthen the voice and data communications networks based on good practice and lessons learnt from recent disruptive events
Impact Minimisation	Enhance network architecture to include targeted redundancy to reduce the impact of potential extreme events, creating more supply rings and back-feeds where they are effective Advanced distribution management system (ADMS) to provide insight into real-time network operation and to enable system automation and self-restoration during faults Utilise technology to ensure the visibility of real time asset status across the length and breadth of the network Integration of external data sources to enhance operational knowledge Investigate the use of non-network solutions such as distributed generation, batteries and load control to harden network
Supply chain resilience	Safe storage of strategic spares Standardisation of assets to simplify and speed response Service provider, supplier and peer support agreements to ensure resource and equipment availability
Resilient communities	Identification and planning of appropriate community hubs to focus resilience on Proliferation of distributed generation and energy storage systems throughout the network Communications systems and strategies to inform communities of risks and network condition

The workstreams above will be incorporated into broader business activities as far as possible to ensure resilience outcomes are properly integrated into the organisation.

Where required, we will engage external experts to develop regional information on climate change, to ensure we can make decisions based on the best targeted information.

Local hazards that may be amplified by the changing climate are considered whenever we build assets. Detailed investigation such as geotechnical assessment is completed for critical infrastructure such as zone substations.

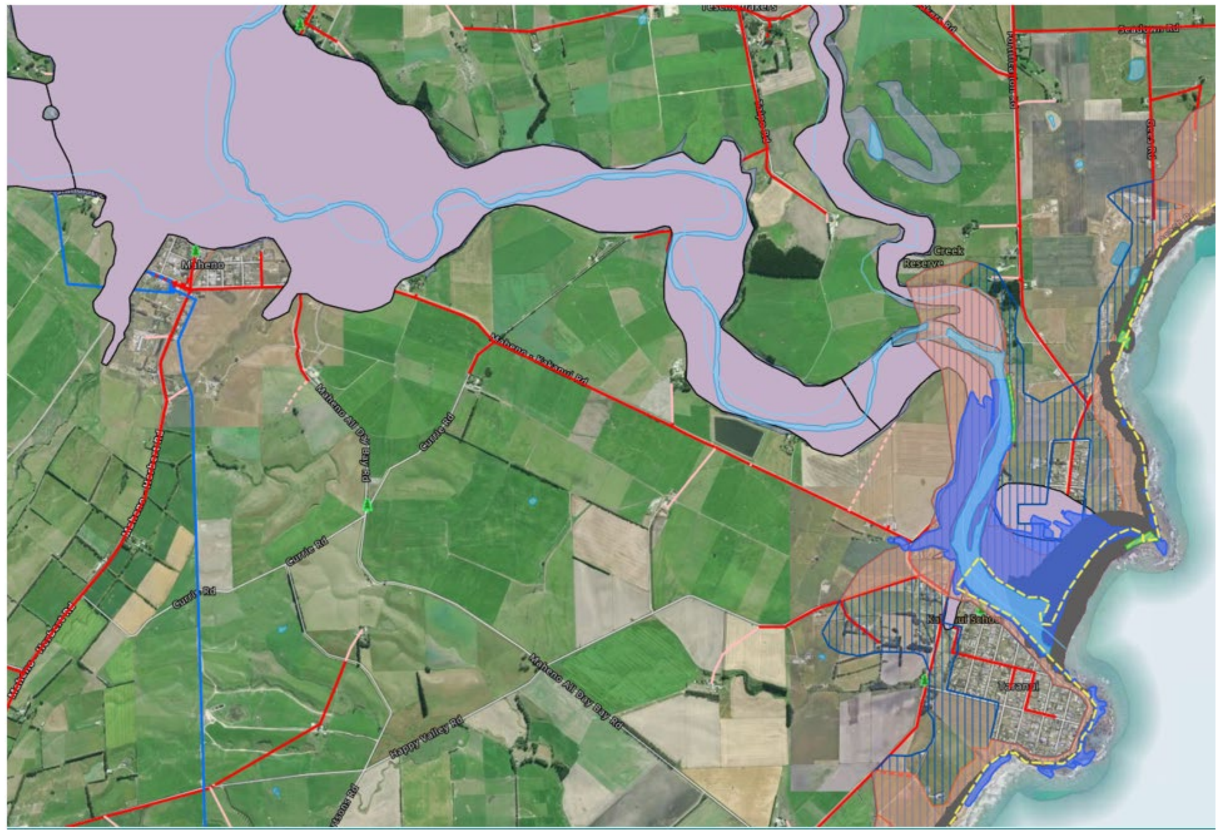


Figure 6 - Map showing risks from flooding and tsunami (blue areas) and liquefaction (pink areas) superimposed on our 11kV (red lines) and 33kV (blue lines) network.

We use our GIS to analyse these risks by overlaying hazard information onto maps showing where our customers and assets are located. The map shown in Figure 1 shows how this provides awareness of particular hazards (in this case flood, tsunami and liquefaction) in context with our network assets. This provides us a picture of what risks our network is exposed to now, and when combined with the climate change forecasts allows us to predict what the future effects of these risks may be, and how to prepare our network for these scenarios.

The hazard information is often supplied by local authorities such as the Otago Regional Council, Environment Canterbury and the Waitaki District Council. We review these sources and utilise the most up to date information that we can.

We work with our communities to help them understand the resiliency and risks related to their loads, and what they can do to improve their situation. This work is already underway with local Civil Defence authorities with the identification of key infrastructure such as water pump stations, cell phone towers and community support hubs, and working with stakeholders such as the Waitaki District Council or local Marae to to help them understand and increase their resilience.

We have worked with experienced partners to complete hazard risk assessments of our network substations and taken appropriate actions, such as reinforcing the buildings against earthquakes, high winds and snow.

Design standards are reviewed at regular intervals, and during these reviews we will use the most up to date climate guidance to ensure that we are building our assets resiliently enough to maintain service levels under future weather conditions. Significant changes to standards will trigger reviews of existing assets built to those historic standards to make sure that emerging risks are understood and dealt with as required.

3.4 Resilience Maturity Assessment

In 2023 we commissioned an independent review of our resilience capability using the Electricity Engineers Association (EEA) Resilience Management Maturity Assessment Tool (RMMAT). Developed alongside the EEA's Resilience Guide[1], this tool helps organisations assess the four Rs of their resilience planning – reduction, readiness, response, and recovery.

Our scores from the RMMAT assessment, shown by the blue line in the figure below, reflect our maturity against the 4 Rs of Civil Defence capability. A guide to the scores:

- 3 indicates maturity in a specific area
- 2 indicates awareness of a requirement with evidence of improvement underway
- 1 indicates awareness of a requirement with the intent to improve

3 is not necessarily the target score for a business like ours, as there are some areas where a 2 may be appropriate. We have taken advice from an independent specialist to provide appropriate targets. The target scores for our network are shown on the graph in red.

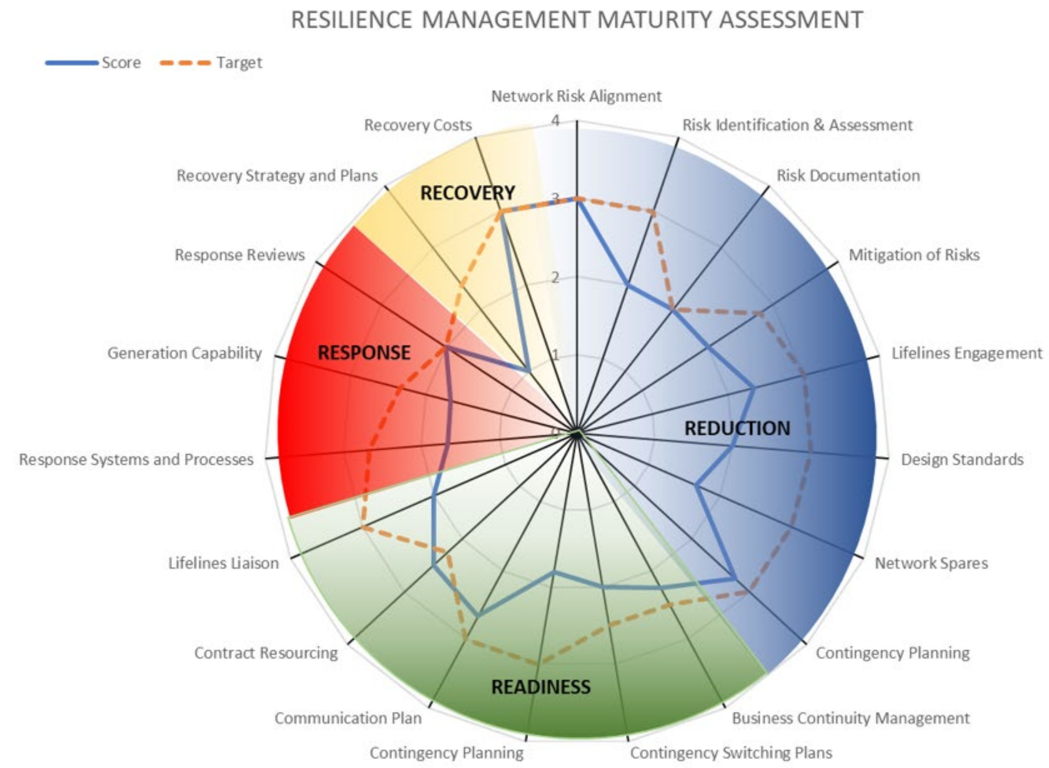


Figure 7 - RMMAT assessment output showing current against target scores

The review has enabled us to prioritise actions to close the gaps where appropriate. Completing these activities over the next five years will ensure we are well placed to deal with the evolving risks associated with climate change.

1 (https://www.eea.co.nz/tools/products/details.aspx?SECT=publications&ITEM=3049)

RMMAT Area	Work Planned to Close the Gaps
Reduction	Continue to improve risk management and communication systems Continue to work with the development of Lifelines Utilities plans Review and update design standards Continue to develop Network spares and contingency planning Develop resilient data and voice communications systems
Readiness	Complete business contingency planning Review and enhance systems for contingency switching Review and enhance stakeholder communication plans Enhance contractor readiness Continue to participate in Civil Defence Emergency Management exercises to better understand good practice and test our readiness
Response	Prepare response plans for specific contingencies Develop generator priority plan with local civil defence groups
Recovery	Review and enhance overall recovery plans

The RMMAT workplan will be completed over the next three years. An internal RMMAT assessment will be completed in 2026 to provide a snapshot of progress against planned areas of improvement.

Enabling the Energy Transition

04

Enabling the Energy Transition

In this chapter, we discuss our strategy to enable our customers' energy transition to electricity and lay out our plans to do this at each level of our networks.

Supporting our Customers' Energy Transition

Our region's economy relies on primary and associated service industries, with tourism playing a smaller role. These sectors are shifting to carbon-free energy for process heat, transport, and supply chains. We've helped many customers convert their process heat needs to electricity and aim for our largest user to convert by 2026. Electric vehicle use by tourists is also increasing.

Aligned with climate change commitments, New Zealand's light vehicle fleet is expected to be mostly electric by 2050, though we expect our region will lag due to lower incomes and farming vehicles. Our evolving customer needs will significantly boost electricity demand over the next 25 years. As an electricity distribution business, we play a crucial role in supporting this transition.

This chapter outlines our future energy scenarios and no-regrets actions we will take to ensure our customers can switch their process heat and transport to electricity.

4.1 Future Energy Scenarios

We developed our future energy scenarios to describe plausible futures out to 2050, which we use to evaluate development pathways for our business. Our electric vehicle growth assumptions are based on the ENA/Sapere nationally developed scenarios which we adjusted downwards to account for slower uptake due to regional wages being significantly lower than national averages and for regional usage profiles. We engaged Deta Consulting to independently review our scenario inputs, methodology, and electric vehicle growth assumptions to ensure they are appropriate for our region.

Network Optimised
• Regional population growth continues at steady historic levels. • EV uptake increases but lags larger centres. • Irrigation growth slows in 2027 after known conversion projects are completed. • Steady uptake in new smart technologies (customer energy resources or CER) • We understand constraints and can influence demand in constrained areas with our pricing and can override CER in a Network Emergency Event. *(Aligned with ENA/Sapere Network Optimised scenario)*

Balanced
• Regional population growth continues at steady historic levels. • Some process heat conversions occur. • EV uptake increases but lags larger centres. • Irrigation growth slows in 2027 after known conversion projects are completed. • Steady uptake in new smart technologies (customer energy resources or CER) • Spot market energy prices usually keeps flexible demand away from network peaks. We understand real-time network constraints and have some ability to influence demand in constrained areas through our pricing and can override CER in a Network Emergency Event. *(Aligned with ENA/Sapere Naïve scenario)*

Energy Optimised
• Regional population growth increases as larger centres become less affordable. • Process heat conversions occur. • EV uptake increases but lags larger centres. • Irrigation growth slows in 2027 after known conversion projects are completed. • High uptake in new smart technologies (customer energy resources or CER) • CER managed by aggregators using algorithms to maximize customer value and we have limited ability to influence the operation of CER but can override in a Network Emergency Event *(Aligned with ENA/Sapere Energy Optimised scenario)*

4.2 Key Drivers of Change

Transport Customers

Our EV growth projections are based on the ENA/Sapere 2050 scenarios model. We adjusted for our region, considering household incomes are 24% lower than the national average and a preference for traditional vehicles.

Public EV charging station usage is rising, especially along state highways, and we anticipate continued expansion of these stations in our region.

Public transport levels are low with minimal expected growth.

Heavy vehicle electrification could significantly impact the network at key highway points, but uptake will likely be slow due to immature technology and alternative options like hydrogen.

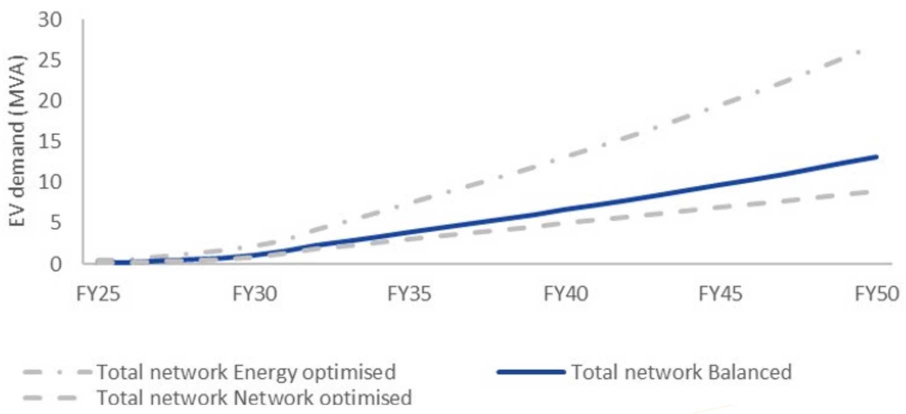


Figure 8 - Total transport demand scenarios

Owners of light and commercial electric vehicles generally expect capacity to be available upon purchasing their vehicle. Conversely, commercial charge point operators typically provide us with a notice period of at least six months.

Process Heat

We have identified all material process heat electrification opportunities in our area and anticipate customers will inform us of these projects 1-2 years before they require supply.

One of the two large customer electrification opportunities in our area has recently completed a 3 MVA electric boiler project. We are currently working with a second large user to understand their energy needs. Any conversion would be unlikely before 2030, and has been included in the energy optimised and balanced scenarios.

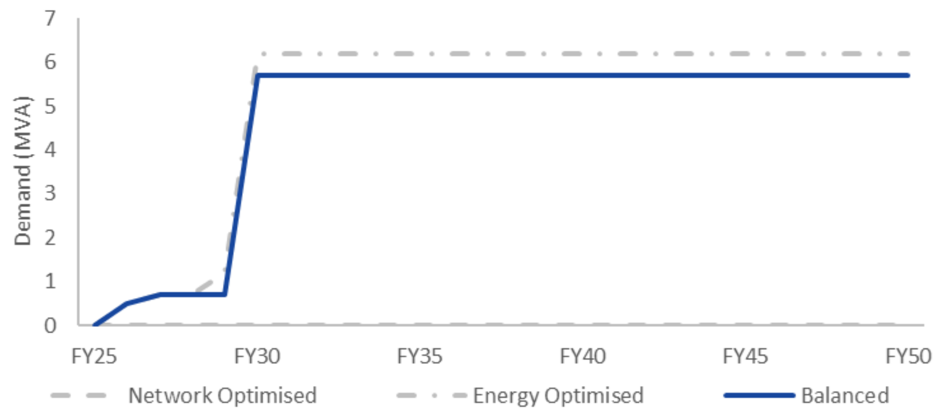


Figure 9 - Process heat demand scenarios

Additionally, there is a possible 8 MVA process heat conversion project at a local lime works projected for around 2030. We have low confidence that this project will occur due to the customer's preference for alternative energy sources. We will continue to explore the feasibility of electricity with this customer.

We have assessed remaining smaller process heat conversion opportunities and have included these in our demand scenarios.

Irrigation

We work closely with irrigation scheme management companies to track upcoming projects. Most of our district is fully irrigated, except for 2,300 Ha on the Papakaio Plains, which will switch from gravity-fed systems to pumped spray irrigation by winter 2027 to meet regional council requirements.

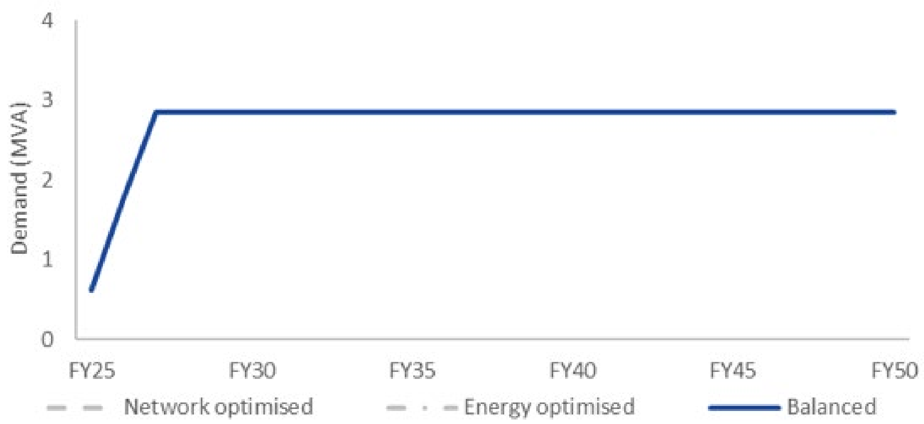


Figure 9 - Irrigation demand scenarios

We are confident about the scale and location of these irrigation conversions and expect customers to apply for capacity 6-12 months in advance.

Distributed Generation (DG)

In our area, most small-scale distributed generation (DG) consists of residential rooftop solar installations, though current penetration levels remain low. As up-front costs decrease, a steady increase in both rooftop solar installations and associated battery systems has been observed.

Our growth scenarios are based on the Boston Consulting Group's decarbonisation roadmap. It is assumed that solar power can reduce network demand by 5% of the nameplate rating due to its intermittent nature. Consequently, a significant reduction in peak demand from small-scale DG is not anticipated. Most small-scale DG customers expect to connect to the grid within 4-12 weeks after committing to a project.

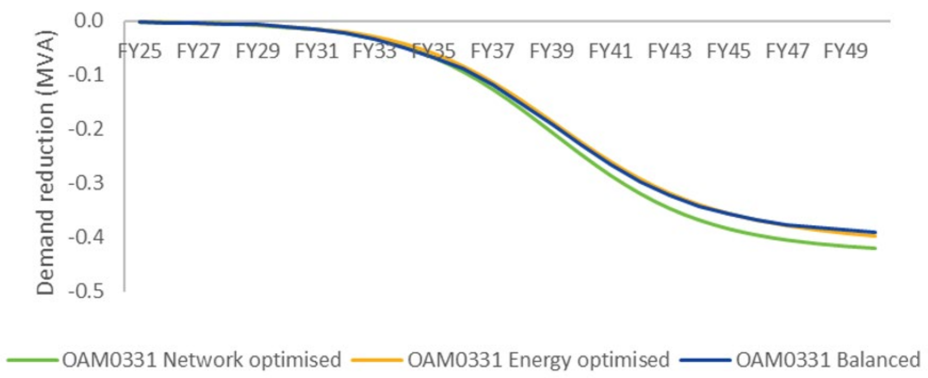


Figure 10 - Small scale DG demand scenarios

Applications for large-scale generation are expected to increase in our supply area over the next 10 years. The location, size, timing, and impact on network demand for these projects are difficult to predict and will be evaluated as applications are received. Large-scale DG customer timeframes vary between 3 and 5 years.

Consumer Energy Resources (CER)

CER includes hot water heating, electric vehicles, DG, and other controllable resources. Growth rates for some CER, such as EVs are detailed in other sections; this section focuses on future usage. Currently, we control many hot water cylinders with our ripple control system. We expect more customers to leave our controlled tariffs to gain value from retailers and aggregators.

Our three scenarios examine different ways our customers may use flexible demand. The Network Optimised scenario assumes high influence over CER to avoid peak times, while the Energy Optimised scenario allows "herding" by other parties, affecting peak times. In all scenarios, we assume the ability to control flexible load during System Emergency Events[1]. Understanding change drivers is crucial. The table below summarizes key inputs and assumptions guiding our planning process.

1 System Emergency Events are as defined in the Electricity Industry Participation Code and Load Management Protocol when this is released (currently being developed by the ENA Future Network Forum in consultation with traders).

	Network Optimised	Balanced	Energy Optimised
Base Growth			
Household			
Residential growth	Steady	Steady	Increased
Residential efficiency	Medium	Medium	Medium
Residential gas/solid fuels phase out	Medium	Medium	Medium
Industrial and commercial			
Economic growth	Medium	Medium	Increased
Electrical intensity	Medium	Medium	Medium
Transport			
Electrification update	Medium	Medium	Medium
Mode shift	Low	Low	Low
Process Heat			
Electrification of boilers	Low	Medium	High
Irrigation			
Papakaio plains area	High to 2027	High to 2027	High to 2027
Distributed Generation			
Rooftop solar uptake	Low	Medium	Medium
Utility scale generation uptake	Unknown	Unknown	Unknown
Consumer Energy Resources			
Battery uptake	Low	Medium	Medium
Vehicle to grid uptake	Low	Medium	Medium
Our management of hot water	Slow reduction	Medium reduction	Rapid reduction
Major customer demand response	No change	No change	No change
Our ability to influence residential flexibility	High	Medium	Low

While we model development and investment plans for all three scenarios within our business, our ten-year plan presented in Chapter 9 – Our Future Network Plan is based on the "Balanced" scenario only.

4.3 Enabling our Customers' Future Energy Needs

Our customers have diverse expectations around the timeframes they expect us to meet their energy needs. For instance, a residential customer may expect adequate capacity for their new electric vehicle on the day they purchase it, while a large-scale generation project requiring a new connection typically engages with us during the early stages of planning.

When we don't have sufficient capacity, solutions vary in complexity and delivery time based on the level of our network involved and we employ different strategies for each network tier to meet our customers' expectations. These are summarised below:

Transmission/Grid Exit Point (GXP) Level

Solutions at this level of the network can take 5 to 7 years to plan and build which significantly exceeds expectations across all of our customers. An example is the Ōamaru GXP where we are developing a no-regrets solution that can be delivered in stages so we can meet our customers' needs regardless of which customer growth scenario eventuates.

The Ōamaru Grid Exit Point (GXP) is one of four GXPs in our area where electricity is taken from Transpower's national grid and distributed to customers. Over the past twenty years significant demand growth from irrigation and dairy expansion has nearly exhausted capacity. With planned irrigation and process heat conversion projects, capacity would be depleted by 2028 if no action were taken.

Over the past five years, we have collaborated with industry experts to conclude that a new GXP is the only viable solution to meet the region's future energy needs. We will continue to review the drivers and timing of our growth investments to deliver affordable outcomes for our customers.

Transpower has granted permission to use a temporary special protection scheme, allowing the connection of new customer load until the new GXP is operational.

Until the new GXP is in service, we may need to offer significant new customer load connections capacity at reduced security levels.

Subtransmission and Zone Substation

Solutions at this network level may take up to three years to deliver. No capacity issues are expected in the next ten years for new load connections, and generation capacity will be allocated based on our policies upon receiving applications.

An initiative is currently in progress to develop and publish generation and load hosting capacity maps as an initial step towards enhancing customer self-service. In December 2024, we published generation hosting capacity for all zone substations and HV feeders. In the next 12 months we will expand these to include subtransmission and produce load hosting capacity maps.

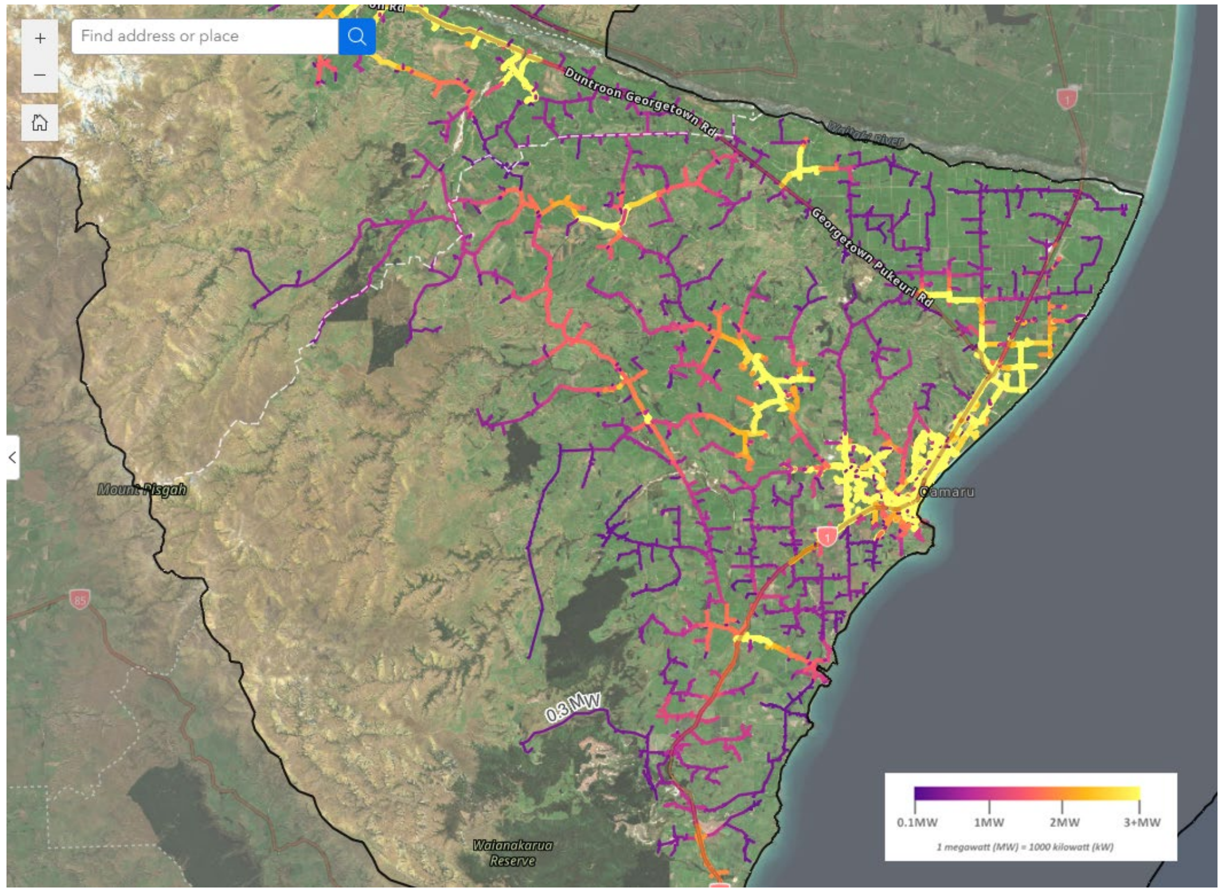


Figure 11 - Generation Hosting Capacity Map

High Voltage Feeders

Solutions in our network can take up to 18 months to plan and deliver.

We monitor existing performance in real-time and model load growth scenarios on top of historical demand. We usually see a security constraint arise before we hit a capacity limit on these assets. This usually allows us to schedule solutions as part of our annual AMP process.

In December 2024, we published generation hosting capacity for all zone substations and HV feeders. In the next 12 months we will expand these to include subtransmission and produce load hosting capacity maps. We thank Powerco for sharing their learnings with us.

Distribution Transformers and Low Voltage Feeders

Solutions at this network level typically take up to 12 months to deliver. Customer demand grows in smaller, predictable increments compared to higher network levels. Large connections like EV charging stations and process heat conversion rarely connect to LV networks.

Our strategy is to understand real-time existing performance and constraints, model future scenarios, and plan timely solutions for customer needs. We have three initiatives underway to achieve this:

1. **Low Voltage Feeder Monitoring:** Started in 2022, we now monitor 135 transformers and 320 low voltage feeders covering 60% of Ōamaru residential customers. We aim to increase coverage to 90% over the next three years

2. **Network Model Enhancement:** In 2022, we created a load flow model of our network to distribution substation level so we could perform network studies and analyse hosting capacity. Over the next year, we will develop a process to regularly synchronise this model with our GIS system and demand forecasting tool, which will increase the accuracy of our model and allow us to produce hosting capacity maps regularly.

3. **Smart Meter Data Trial:** We procured smart meter data for 1,000 customers and are trialling an analytics system to understand benefits and develop use cases.

Customer Needs and Engagement

05

05

Customer Needs and Engagement

This chapter provides an overview of our customers, their needs and expectations, and what Network Waitaki is doing to improve customer service outcomes. We have split our customer focus into two streams: our customers and their actual needs and experiences; and the transactional customer service we provide. This chapter focuses on the former.

Below we outline our customer service strategy and our roadmap for improvement. There are two areas of focus:

1. Stakeholder Engagement for Future Planning
2. Our Customer Service Experience

customer service
/drēm/ *noun*
Providing support for customers through a service, information, assistance, building relationships and creating a trusting environment.

5.1 Overview

Network Waitaki continues to build on its customer-centric business strategy. Our customers and their needs and expectations are at the core of what we do. We endeavour to understand our customers and provide an outstanding customer service experience.

Our world is changing, and customer expectations are changing with it. Over the next 20 years we will see significant changes as our customers adopt new technologies and decarbonise their businesses and transport. Our customers are diverse, and we recognise that there is no 'one size fits all' solution when it comes to servicing their requirements.

We are committed to enabling our customers' future energy needs while being mindful of security, sustainability, and affordability, as well as being accountable to our community owners. We have some big investments coming up and we value our customers' input as we plan for the future.

To understand our customers and stakeholders, we continue to engage primarily through surveys, face to face meetings, attendance at public events such as agricultural field days and expos, industry forums and conferences, and participating in industry consultations about statutory and regulatory changes and Regional and District Plans. In 2024 we continued to implement our Stakeholder Engagement Framework, resulting in further targeted customer and stakeholder engagement strategies.

We continue to develop our engagement framework in line with our Mission, Vision, and Values.

5.2 Stakeholder engagement to enable future planning

Overview

Our Stakeholder Engagement Framework includes a Customer Service Level Strategy which will help guide and support our planning. Historically we have used network-centric standards to measure customer service levels, but this has not allowed us to understand our individual customer experiences and expectations.

To help align our future customer service improvement plan, we refer to our Customer Service Level Strategy shown below. This provides a framework that will:

- Provide us with a strategic way to seek our community's views
- Establish customer expectations and priorities
- Guide future planning
- Ensure our customers feel seen and heard
- Help us enhance customer satisfaction
- Help us improve our business processes and systems
- Highlight any concerns that need to be addressed

In line with our *"Engage with our customers"* strategic priority, over the last year we have engaged with some customers in one-on-one and group settings to discuss community needs and expectations, some particularly interested in the resiliency of their community, understanding our Network, and how they can prepare for major events.

A frame work for Community and Stakeholder Engagement Workshops has been developed around three topics – reliability, resilience, and future planning with the purpose of gaining insight into our customers' future needs and their expectations of us as a service provider. The feedback from these sessions will help us with future planning in line with our strategic priorities. We look forward to holding these in 2025.

OUR CUSTOMER SERVICE LEVEL STRATEGY

OUR STRATEGY

"to provide outstanding customer service by understanding and meeting our customers' reliability, security, and resilience needs from their electricity supply"

OUR STRATEGIC CONTEXT

01 Historically, we've measured reliability as an average across all of our customers and applied a network-centric security of supply standard. This does not allow us to understand the reliability levels our customers experience

02 We currently survey our customers every two years and find in general they are satisfied with the balance of reliability and cost but there are areas to work on (notably communication and demonstrating value for money)

03 Our customers' service and reliability expectations will increase as they rely more on electricity for their energy needs. Their resilience needs will increase as climate change induced events increase.

04 Our customer service processes and transactions are not supported by modern, fit for purpose, business systems

05 Our customer service experience is generally good but is inconsistent and depends on a range of factors

OUR STRATEGIC PRIORITIES

Engage with our customers

We will consult with our customers to understand their existing and future reliability and resilience needs and incorporate these into our customer service level targets and Network Development Plan processes.

Develop customer service level targets

We will develop targets for:
- Customer supply service levels (e.g. reliability/ security/resiliency)
- Customer transactional service levels (e.g. connection work, communication, complaints handling)

and use data to understand our performance against these targets

Develop plans to close gaps

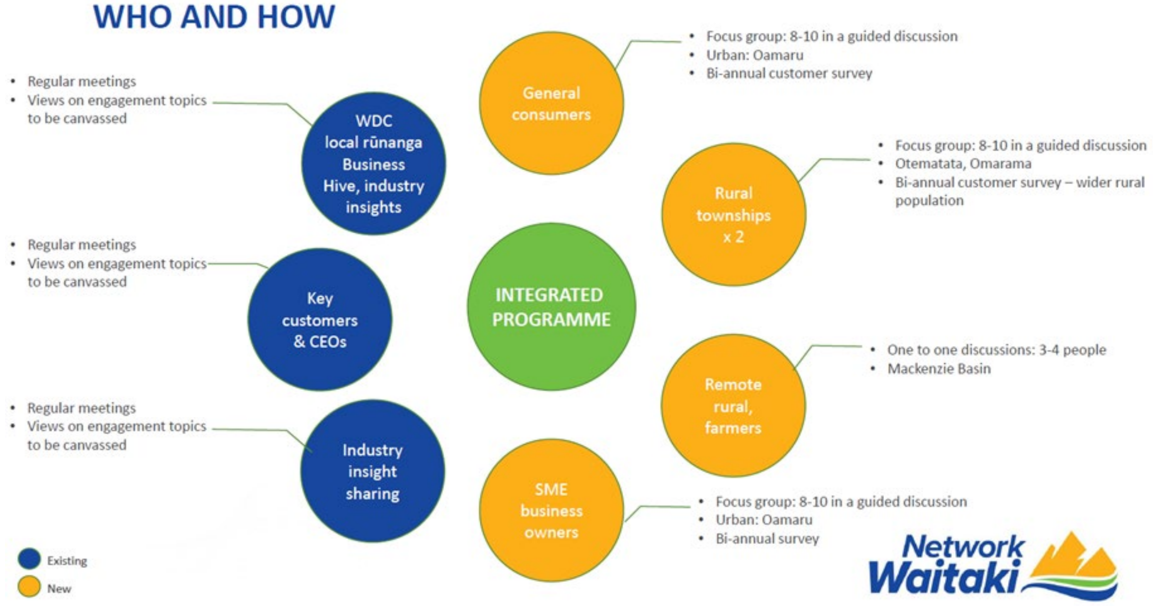
Our first priority is to understand where we do not meet our customers' reliability, security, or resiliency needs and to develop plans to meet these.

A further priority is to develop an improvement plan to close customer transactional service gaps

Improve our business processes and systems

We will review our business processes and systems and develop an improvement plan to bring these up to standard

WHO AND HOW

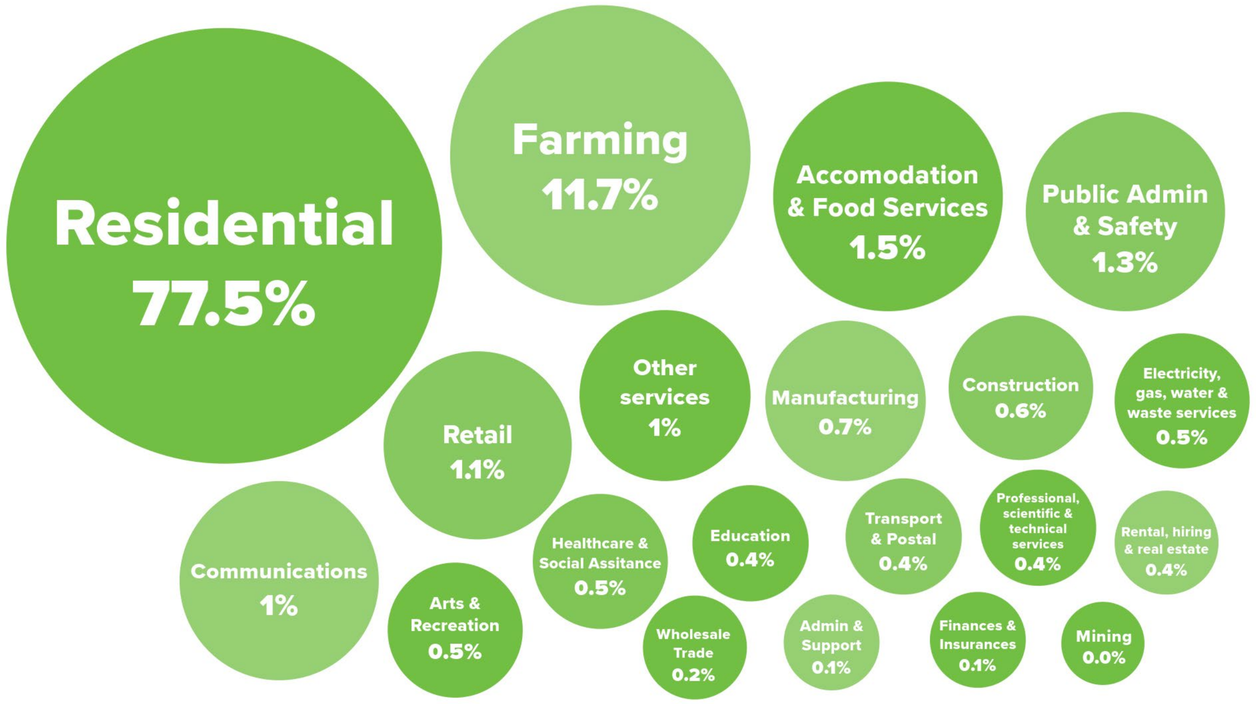


5.3 Our Customer Service Experience

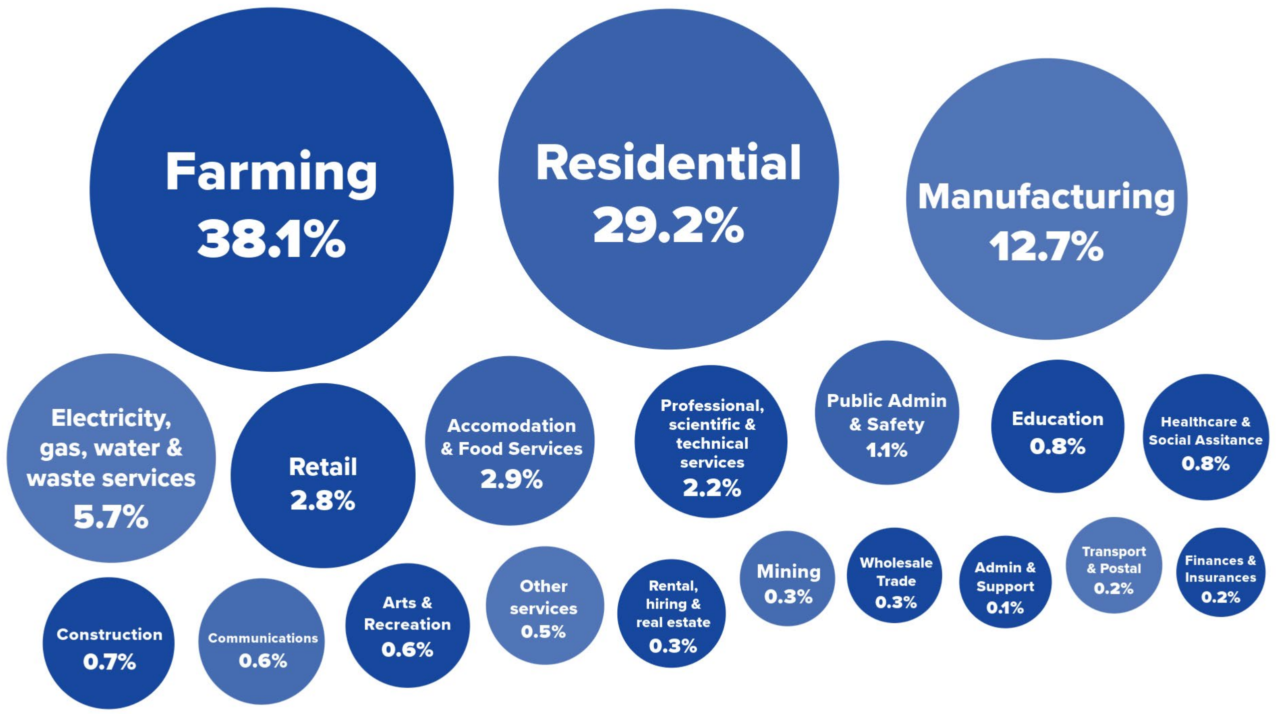
5.3.1 Understanding our Customers

To enhance our customers' experience in line with our strategic priorities, we need to understand who our customers are. Network Waitaki distributes electricity to over 13,500 customer connections across a network of more than 2,000km of power lines, traversing both residential urban and remote rural land. Our customers are diverse, and no one solution will meet all their expectations for a safe and reliable electricity supply.

Our Customers - Based on number of ICPs on the Network



Our Customers - Based on % of total KWH



- **Residential and Small Commercial/Business**
  Most of our customers are residential and small-to-medium businesses such as builders, contractors, health providers, electricians, farmers, retail operators, hospitality, utilities, public facilities, and education providers.

Farming accounts for 11.7% of our customers. This includes small-medium businesses as well as some major customers.

- **Major Customers**
  Our major customers are predominantly agricultural companies such as large farming enterprises, meat processing plants, and irrigation schemes, as well as production companies and local government.

While we are one of New Zealand's smaller EDBs, we serve a large geographical area. Most of our population is in Oamaru township, branching out into small towns and remote rural areas. In line with our strategic priority to *"Develop plans and close gaps",* we continue to develop processes to help us understand where we are not meeting customers' reliability, security or resiliency needs, and how we can improve.

All our customers need a safe, reliable, resilient and economically effective/efficient network, particularly as they take up new technologies and look to decarbonise. They have told us they want a reliable power supply with minimal outages. When outages do occur, they want us to respond quickly and restore power as soon as possible. They want us to communicate with them effectively, to be forward planning, and to invest in growth and development to continue improving their service.

5.3.2 The Customer Experience Journey

We are focused on making it easy for customers to do business with us. We continue developing ways to understand customer satisfaction and streamline processes. This supports the Network Waitaki Digital Utility Vision and Strategy, as well as being in line with our strategic priorities to *"Improve our business processes and systems"* and *"Develop customer service target levels".*

We are using information from our customer journeys to help develop our business processes and improve our use of digital systems and data. We want to enable customer self-service, where possible, by automating processes to deliver better outcomes. We have identified opportunities to enhance our customers' experience and are developing targets as key performance indicators in line with our strategic priorities. These include:

Enabling customers to help themselves -

We love connecting with our customers but we recognise that customer satisfaction can be improved by enabling customers to easily access information themselves. We are improving our business processes and systems to enable this. Automated online forms, up to date and detailed outage maps, and providing important information on our website have resulted in fewer phone calls to the customer service team. and an update of our website within the next three years will support this further.

When customers do need to contact us -

We aim to resolve customer enquiries first time whenever possible and limit the need for callbacks. Workflows are continually being improved to direct enquiries to the right people so we are able to respond in a timely manner.

Improved Digital Capabilities to Support Customer Needs and Engagement

Part of the Network Waitaki Digital Utility Roadmap recognised the need for the company to establish digital capabilities to support our customer engagement and service management, as well as our community and staff.

As well as the development and implementation of automated systems for customers to access, the company has also been looking at our internal systems and processes. We have conducted a review into our current Billing, ICP Management and Outage Notificaiton System and a replacement has been approved for implementation which will provide a modern system that is future-proof, with enhanced capabilities for integrating data across the business.

A Customer Information Management system is on our road map to run alongside our ICP Management and Billing system which will improve our processes and support a timely and seamless customer experience across the whole business.

A managed approach to customer feedback –

We value feedback because it helps us shape our customer service. We have a robust process for dealing with customer complaints to ensure customer satisfaction and to meet regulatory requirements. We track progress of all feedback in a log, allowing us to track complaint trends and how long they take to resolve. This is all reported to company management and the Board, and contributes to the annual survey we submit to Utilities Disputes.

In line with our strategic priority to *"Develop customer service level targets",* we are developing a dashboard to track metrics so we can report on customer satisfaction, as well as System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) metrics. The dashboard has been delayed by some system upgrades but we look forward to delivering this next year.

5.3.3 Customer Feedback and Insights

Feedback is important to us as we continue to improve our customer experience. It is critical that we understand:

- What is important to our customers
- How they feel when they interact with us
- Their expectations of us
- How we can improve their experience with us

Customer feedback supports us to make improvements in the right areas and to achieve our Business Strategy - especially around our core systems and processes and customer focus. We gather feedback from our bi-annual survey, our Voice of Customer survey, and when we engage with our customers.

5.3.4 The Voice of our Customers

Mid 2024 saw our Voice of Customer survey go live. The survey goes out every couple of weeks to customers that we have completed work for. Customers are asked to rate their experience with Network Waitaki, and give offers an opportunity for customers to add additional comments.

We look forward to being able to consistently monitor customers' satisfaction levels and see trends that show us where to focus improvements consistent with three of our strategic priorities: *"Engage with our customers", "Improve business processes and systems",* and *"Develop plans to close gaps".*

5.3.5 Customer Service Benchmarking

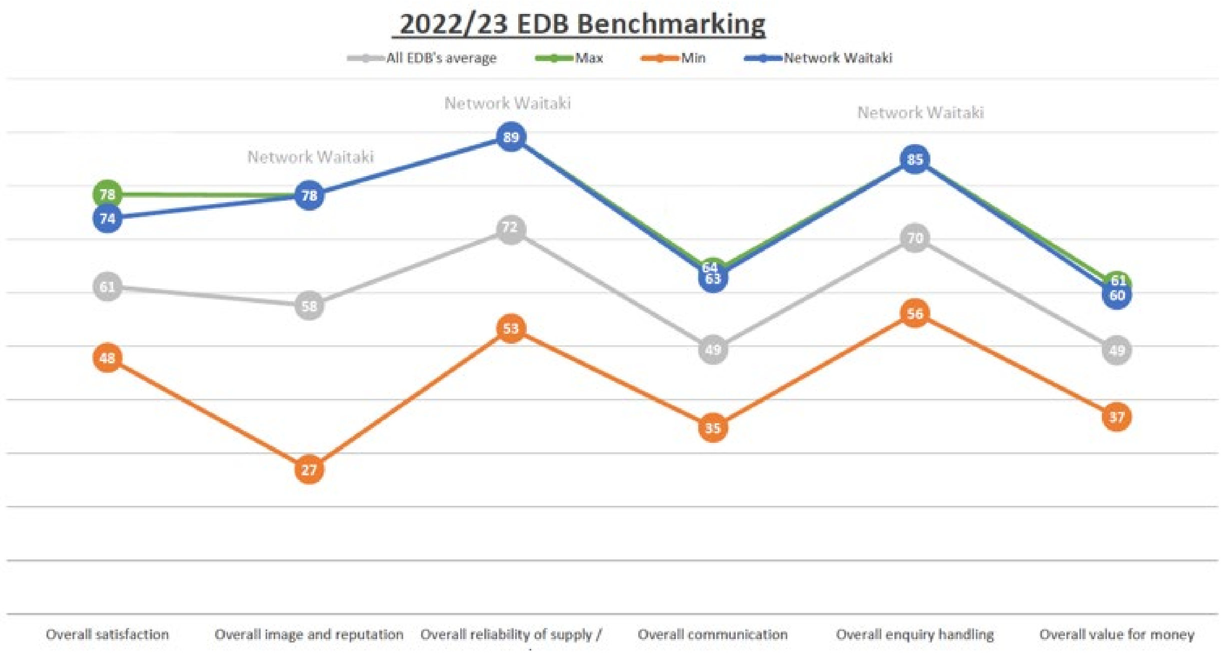
We conduct a customer survey every two years. We did not conduct a survey during 2024, but we continue to use the results from last year's survey as a guide for improvement.

In 2023 a total of 648 urban and rural customers responded to our online survey and 15 commerical customers were interviewed face-to-face. All interviews are conducted using an interview guide and a mostly standardised set of questions to ensure comparability. This enables us to benchmark our performance relative to other EDBs and measure ongoing performance and improvement.

The survey is intended to include all aspects of the customer experience, including awareness and recognition, quality of service, delivery, price, and quality of interaction with Network Waitaki. This helps us understand areas of focus within *all our strategic priorities.* The objectives of the research are:

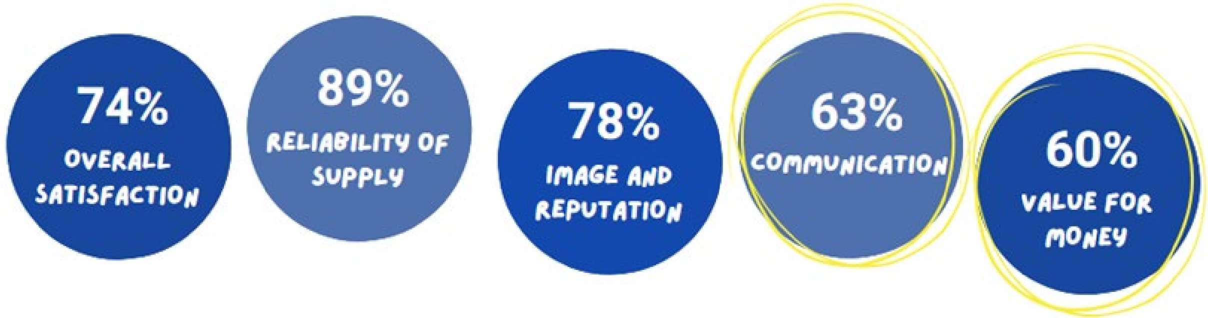
- To understand our customer's perceptions of the organisation, and our reputation.
- To understand satisfaction with the services provided by Network Waitaki
- To identify the key drivers of these perceptions
- To identify priority opportunities to enhance customer satisfaction.

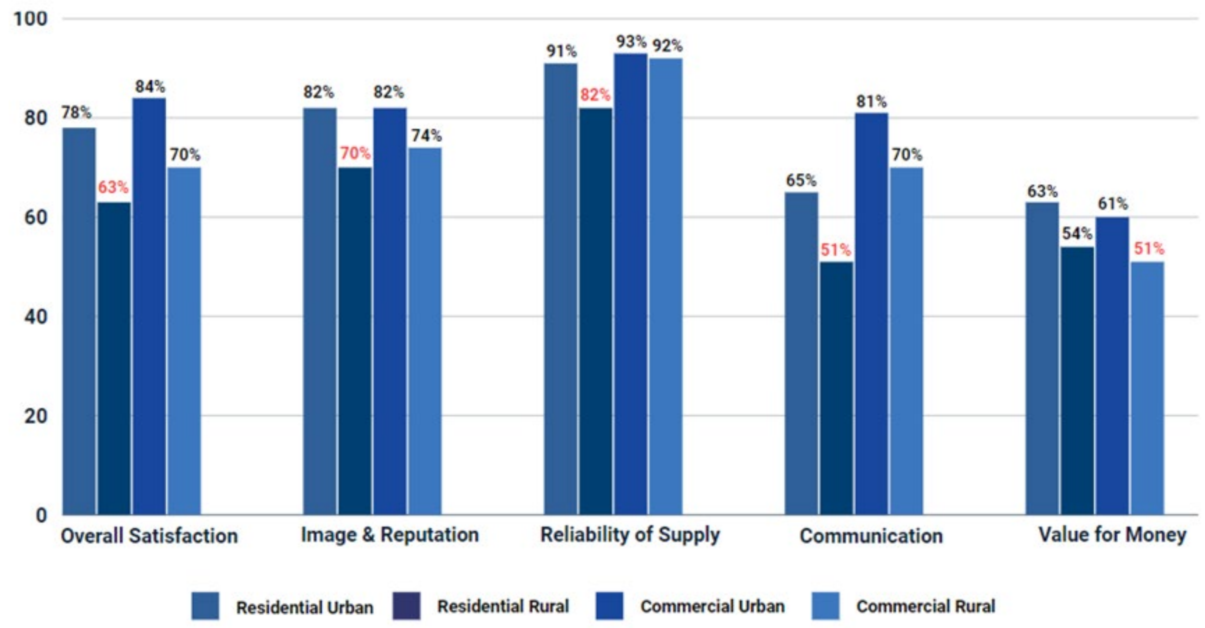
A series of comprehensive reports are compiled by Key Research and presented to the business, identifying industry trends and clear priorities to enhance the customer experience and develop our community presence. The results are included in an Industry Benchmark Report that compares key performance indicators of several other EDBs. This helps us understand customer satisfaction with the services provided by the electricity distribution industry.



5.3.5 What Our Customers are Telling Us

Last year's customer satisfaction survey indicated that Network Waitaki performs extremely well, particularly when bench-marked next to other EDBs. Overall, customers are very satisfied with Network Waitaki, the reliability of supply, and the company's image and reputation. The survey highlighted some opportunities to improve customer satisfaction around communication and value for money.





2023 Survey Results – Survey Participants were classified as either Residential Urban, Commercial Urban, Residential Rural or Commercial Rural, with results low for those classified as Residential Rural. We note that these results will be skewed due to an unclear definition around residential and commercial rural. For example, someone that lives and works on their farm could be either.

Looking at *'satisfaction with communication from Network Waitaki,'* we scored well on notifying customers about planned shutdowns, and the current level of communication is sufficient to customer needs. However, the survey results highlighted room for improvement around the following:

Communicating purposefully and effectively with our customers is part of providing great customer service. This supports our customer-centric strategy and our *"Engage with customers"* priority. Benefits include:

- Helping customers understand more about Network Waitaki and how we operate
- We can share plans and upcoming network development projects and their benefits
- Helping customers understand the value in their line charges
- Sharing power supply matters with them e.g. information about Utilities Disputes, PowerSwitch and EnergyMate
- Supporting community safety and wellbeing by providing information about safety around electricity
- Building trust and a sense of community

In line with the Network Waitaki Digital Utility Roadmap, a Customer Communications Strategy and Plan continues to be developed to deliver these improvements to customers and we look forward to these being reflected in the results of the our next bi-annual survey.

Service Levels

06

06

Service Levels

This chapter provides an overview of our network performance, customer service levels from a transactional perspective, its impact on our customers, and our targets for improving customer outcomes within our customer-centric business strategy.

6.1 Overview

This chapter outlines our performance and targets for the planning period. There are three areas of focus:

1. Health and safety
2. Customer experience
3. Network performance

6.2 Health and Safety

We are committed to ensuring our network always remains safe and we actively manage risks to the public, public property, and our staff. To facilitate safe outcomes, we are focused on:

We maintain an audited Public Safety Management System (PSMS) where we document known and probable hazards and risks to the public, along with the controls (eliminate or minimise the risk or the likelihood of it occurring). This system is audited annually, both externally and internally, against the standard *NZS7901:2008 Electricity & Gas Industries Safety Management Systems for Public Safety.* The external audit provider is Telarc, who are authorised to audit against NZS7901:2008. The outcomes of the audit process are analysed by our staff and used to make improvements to the PSMS and how we use it.

6.2.1 Health and safety objectives

Our objectives are determined by our strategic plan and through our health, safety, and wellbeing plan. Our objectives are to ensure that staff, workers, the public, and their property are safe and free from harm due to the operation of our network and work activities. We will not compromise the health or safety of our staff, workers, the public or their property.

In summary, our safety objectives are:

6.2.2 Measures and targets

- Monitoring of health and safety performance with targets, such as
  - The number of safety observances or site audits (leading indicators)
  - Third party, independent consultants to review work practices against industry practices and training
  - Monitoring the implementation and effectiveness of health and safety critical risk controls
  - Monitoring and assessing contractors and suppliers
  - Incident trend analysis to identify emerging health and safety trends for action
- Monitoring indicators of organisational impacts, such as
  - Total work hours within a given period and the number of times staff have worked to the stage where they need to stand down for rest breaks (leading indicators)
  - The amount of sick leave and ACC hours taken across the whole company (lagging indicators)
- Monitoring the number of incidents and accidents on our network involving the public.

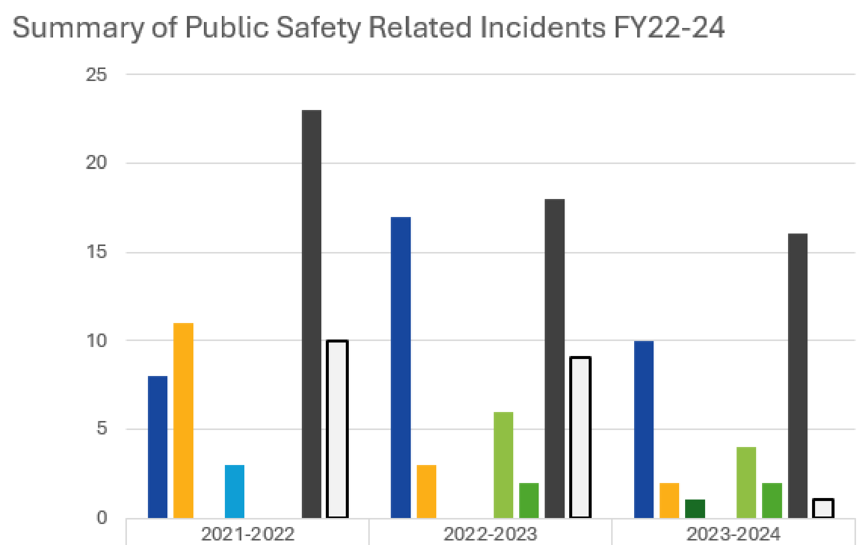
- The number of public information and education activities
- Annual certification to NZS7901:2014 for our Public Safety Management System - using Telarc as independent auditors
- Certification to ISO45001 Health and Safety Management Systems with Telarc has been completed, and we continue to operate a health and safety management system to conform with this
- Independent, third-party audits and reviews of compliance, risks, and crucial systems
- Monitoring mitigation of specific risks e.g., the removal of red tag poles from the network

6.2.3 Performance

The measurement of safety performance has traditionally focused on lost time injuries and incidents reported for our workers, but we have also measure a number of other leading and lagging indicators.

We also measure and monitor public incidents and accidents on our network, as shown in the table below:

Summary of public safety related incidents and accidents:



	2021-2022	2022-2023	2023-2024
Rural Activities	8	17	10
Construction Activities	11	3	2
Trades	0	0	1
Recreational	3	0	0
Customer Activities	0	6	4
Vandalism/Ignorance	0	2	2
Vehicles	23	18	16
Network Asset	10	9	1

Table 12 - Public Safety Performance Targets

Objective	Target	Performance
Unauthorised Network Access	0	0
Injuries to the Public from Network Operations	0	0
Significant damage from Network Operations	0	0

The figures show a decrease in the annual number of public incidents in FY23, likely due to our community safety messaging and advertisements. Most incidents still involve vehicle collisions with poles and other ground-mounted equipment. Overall, all incident classifications have seen a reduction. We will continue to monitor public safety areas closely to identify trends for potential intervention through awareness efforts, training, or targeted network improvements.

Continuous review of the input/output of information allows better tracking of potential issues and focus areas. A Health and Safety report is tabled and discussed at each monthly Board meeting, Health and Safety Committee meeting, management meetings and staff meetings. The report includes performance figures against our goals. This is to ensure all staff have good knowledge and understanding of our public safety responsibilities and how they contribute to meeting the success of our objectives.

6.3 Delivery of Customer Service

Our Strategy:

"to provide outstanding customer service by understanding and meeting our customers' reliability, security, and resilience needs from their electricity supply"

Using our Customer Service Level Strategy as a guide, we are using information from our customer journey process to re-engineer business processes and improve our use of digital systems and data. We want to enable customer self-service where possible or automate processes to deliver better outcomes.

6.3.1 New or changed connections

Our customers usually tell us when they intend to take a new load or generation connection (or alter an existing connection) by completing our online application form, coming into our office, or calling us on the phone. We aim to contact larger customers at least yearly to talk about their upcoming energy needs. This all sits with our *"Engage with our customers"* and *"Improve our business process and systems"* strategic priorities.

When we receive an application, we accept it immediately if capacity has been provisioned (for example, in a serviced subdivision). Otherwise, we contact the customer to confirm their needs and manage their expectations around our response timeframes.

We seek to minimise costs to our customers for new or altered connections by:

- Having a fair and transparent Capital Contributions Policy
- Investigating where non-network solutions may be appropriate to minimise congestion
- Offering the option of a controlled tariff for residential connections to minimise network impacts from hot water load, in return for a reduced daily charge (non-network solution)
- Modelling the impact of the new load on our network to understand any potential issues
- Using standard designs and equipment sizes where network upgrades are required

If we encounter delays - which may be due to weather, impaired site access, or equipment procurement - we do our best to keep our customers informed, and we prioritise this work once the cause of the delay is resolved.

Where connections are likely to have a significant impact on our network, we will:

- Communicate with our customer or their agent (e.g., electrician or consultant) to understand the technical and commercial requirements and timeframes for their proposed connection
- Model the impact of the proposed new load on our network, with the complexity of the modelling determined by the size of the potential impact. We will consult with other EDBs or engage external consultants as appropriate
- Add customer demand that has been signalled with reasonable certainty into our demand forecasting model

We manage the risk around uncertainty of the customer demand (or generation) timing by forecasting for three growth scenarios (low, expected, and high) at zone substation feeder level. For example, a planned customer development of 1 MVA between 2028 and 2031 may appear in the high demand scenario for 2028 and the expected scenario for 2031, and - depending on certainty - may or may not appear in the low scenario.

6.3.2 Customer Outage Notification

Our works delivery processes include notifying customers of planned outages within regulatory timeframes and in line with our strategic priority to "Engage with our customers". Before we arrange outages, we engage with priority customers to manage impacts. Once an outage is confirmed, we will notify customers directly. Communication is usually by text message and/or email, and we send letters to any customers we have been unable to contact electronically. Cancellations and postponements are advised by the same methods.

When there is a major unplanned outage, we notify customers through social media and on our website, advising which areas are affected by the outages, details of the fault and expected restoration timeframes. Priority customers are generally contacted directly. Details are also provided to our call centre operators to share with customers.

The implementation of improved Network Supervisory Control and Data Acquisition (SCADA), Outage Management Systems and Advanced Distribution Management Systems are on our roadmap, and will enhance our customer communications once implemented.

6.3.3 Customer Power Quality

We proactively check for power quality issues via our low voltage monitoring systems and have alerts configured for power quality issues. We may also be advised of power quality issues directly by customers or electricians.

When we become aware of an issue, we respond immediately if there is a safety risk, otherwise we will analyse the issue and develop solutions as part of our planning process.

As part of our plan to enhance or low voltage networks to enable customers to take up new technology, we are extending our network of monitors on low voltage feeders and looking at how we can best utilise data from customer smart meters. This will allow us to understand and fix power quality issues before a customer may be aware of them.

Our roadmap for this development is provided in Chapter 9.2.3 and is in line with our customer service level strategic priorities to *"Improve our business processes"* and *"Develop plans to close gaps".*

6.3.4 Other Customer Services

Some of our customer services were identified last year for redevelopment of processes and development of customer service KPIs. Work on these will continue over the next 12-18 months in line with our strategic priorities *"Engage with our customers"* and *"Improve business systems and processes".* Progress on these services includes:

- **Vegetation Management -** Our Vegetation Management Team have shifted from a reactive approach to vegetation management and are now supporting customers to manage vegetation before it becomes a hazard. We have automated our vegetation data system to enable tracking and reporting on progress and current status vegetation issues.

- **Private Service Line Management and Land Access -** The Network Waitaki Board has approved Network Waitaki Ltd to offer to take ownership of distribution services lines running through private land which, until recently, have been the landowners' responsibility. We are contacting landowners and providing them with an offer when we find a defect on the lines during inspection. Most landowners have responded positively and have signed an agreement for ownership by Network Waitaki.

- **Service Requests -** A new Customer Connections Database went live in April 2024. Customers can submit their connection applications, be it a new connection, distributed generation, change in capacity or a disconnection or decommission, via our website, which automatically adds them to the database and instantly delivers their service request to the right person. Applications can also be added manually by our team. The new database enables us to track progress on each request, how many customers are applying for new connections, whether they are residential, commercial, agricultural, or industrial, and change of capacity or distributed generation month on month. This information is reported to the Trust quarterly. We are developing ways to further automate the reporting and enhance customer KPIs. Once we are satisfied with this, we will look to adapt and apply it to other customer service requests received via the website.

- **New Outage Map -** A new outage map has been developed for the website which allows customers a clear illustration of exactly what properties are being affected by an outage. This enables customers to check themselves before needing to call us.

6.4 Customer Reliability Performance Monitoring

In line with our strategic priorities to "Develop plans to close gaps" and "Improve our business processes and systems," we are continuing to monitor customer reliability performance measures for customer groupings based on where they live or do business, rather than how the network assets are configured.

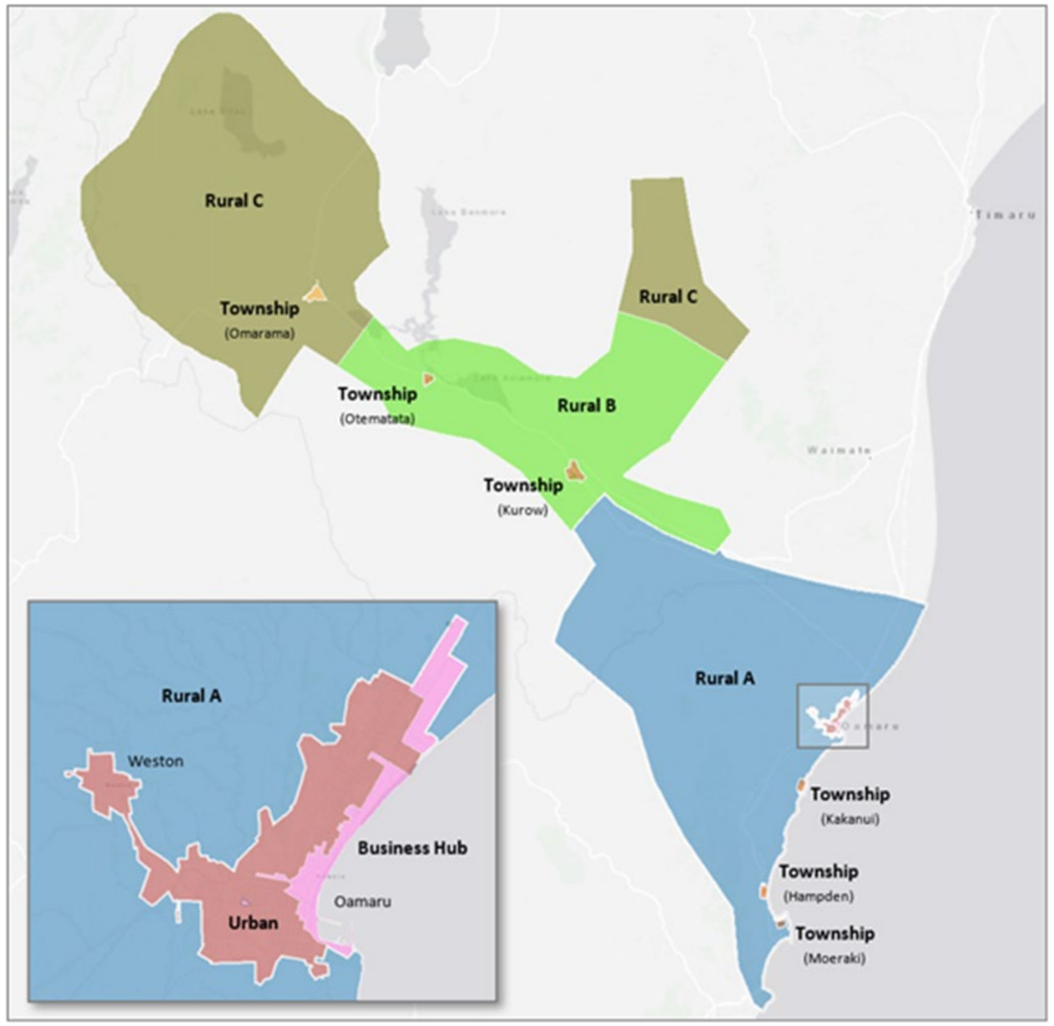


Figure ? – Customer reliability results groups

We currently use System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) as our network reliability targets (detailed in the next section) and intend to continue doing so. However, SAIDI and SAFI are based on averages across all customers and can mask issues that affect smaller groups of customers.

We will use the performance measures in Table 8 below as triggers to investigate how we are meeting the needs of our most affected customers. These measures will serve as prompts for further investigation, rather than as targets directly driving investment.

Our methodology will be refined as we progress, and results will drive further analysis into outage causes, conversations with customers, and may become a driver into our network planning process (see section 9.3).

Table 6 - Customer reliability targets

Customer Supply Group	Number of Customers in group	Target Annual Outage Duration (mins)		Annual Planned Interuptions		Annual Unplanned Interuptions	
		Target (hr)	Customers Exceding Target	Outage Target	Customers Exceeding target	Outage Target	Customers Exceeding Target
Business Hub	679	1	71	1	1	1	35
Urban	6,192	1	1,202	1	0	1	39
Township	1,907	3	392	2	0	2	1,277
Rural A	4,026	6	919	2	156	3	751
Rural B	428	8	22	2	34	4	9
Rural C	395	10	125	2	11	5	26
TOTAL	**13,627**						

6.4.1 Service level: Network reliability

Reliabilty of our network is important to us and our customers. Customer surveys have revealed that the most highly valued service attributes are "*keeping the power on*" and "*getting the power back on if it goes off*".

6.4.1.1 Objectives

One of our most important corporate objectives is to "operate a reliable and efficient distribution network". Reliability of supply is key for our customers, especially as the economy decarbonises and both business and residential users rely more on electricity. We aim to strike a balance between reliability and the cost to our customers of supplying this service.

At a network level, our investment plans for maintenance, replacement and development of the network aim to maintain or improve network reliability over time. We will utilise modern network design techniques and equipment to enhance reliability for customers where this is cost effective. Projects to improve reliability will be driven by performance against targets associated with reliability service levels as discussed in section 3.3.

6.4.1.2 Strategy

We will meet our reliability objectives by

- Designing and constructing new network assets to meet modern reliability standards, considering both the prevailing and changing environmental conditions
- Applying new technology where it can economically improve our reliability and customer service outcomes
- Monitoring the condition of our network assets using modern techniques to uncover risks to reliability and safety
- Proactively managing issues caused by vegetation around our assets
- Prioritising and rectifying defects in a timely manner, keeping in mind that minor defects can develop into more serious issues minor defects can develop into more serious issues over time
- Optimise, where economic, the use of automated and remotely controlled devices such as reclosers, sectionalisers, and tie-switches to reduce the impact of outages monitoring and analysing faults data to identify emerging trends and how to deal with them
- Monitoring and analysing faults data to identify emerging trends and how to deal with them
- Coordinating planned (and where possible, unplanned) work within a geographical area to minimise the impact of outages
- Examining network performance after major events such as snowstorms for insight into Asset Management changes that may improve performance.

6.4.1.3 Measures and targets

To ensure customers receive an appropriate level of service, we need to set performance targets, monitor our activity against those targets and adjust it where there is a signal to change. We use standardised measures to track network performance based on the average number of outages a customer will experience (SAIFI) and the average total outage time they will experience (SAIDI). These measures allow us to monitor our performance from year to year and against other EDBs.

For compliance reporting, SAIDI and SAIFI are normalised by applying compliance rules to adjust the measures under defined circumstances. For most of this chapter, however, analysis is presented as either Raw SAIDI or Raw SAIFI, which means they have not been normalised. We have used this approach for the analysis and improvement targets because raw values give a true view of the impact felt by customers from supply outages on the NWL network. Some previous targets were based on incomplete data and this is now reflected in current targets.

The targets for SAIDI and SAIFI, as published in our Statement of Corporate Intent, are shown in Table 7 below.

Table 7 - SAIDI and SAIFI targets

Network Non-Financial Performance Measures	2025-26	2026-27	2027-28
Unplanned SAIDI minutes	55	55	55
Planned SAIDI minutes	105	105	105
Total SAIDI minutes	**160**	**160**	**160**
Unplanned SAIFI	1.3	1.3	1.3
Planned SAIFI	0.5	0.5	0.5
Total SAIFI	**1.8**	**1.8**	**1.8**

While keeping safety paramount, we are committed to restoring power to our customers as soon as possible after an unplanned outage.

6.4.1.4 Network performance

Our historical SAIDI and SAIFI performance data is shown below in the figures below. The performance levels shown exclude the impact of Transpower outages.

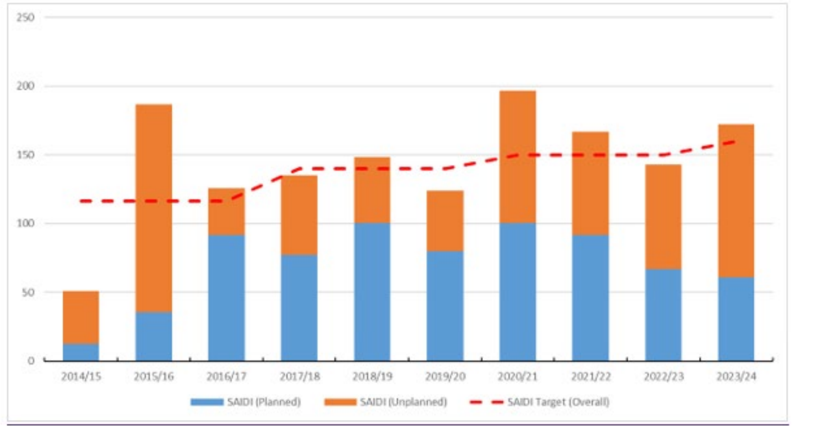


Figure 14 - Historical SAIDI performance compared to target

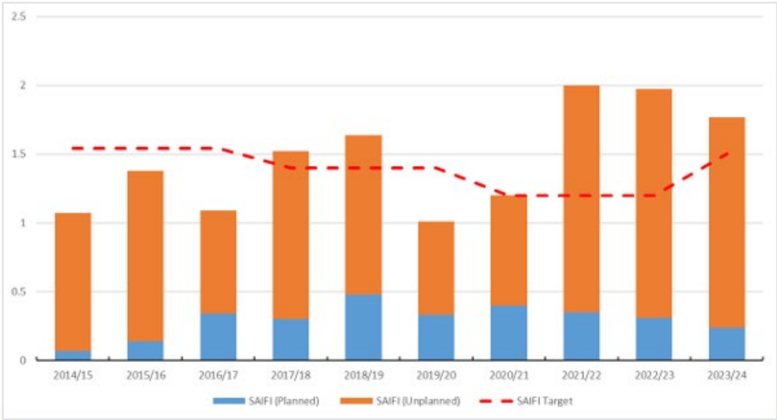


Figure 15 - Historical SAIFI performance compared to target

6.4.1.5 Planned and Unplanned Outages

The impact of planned outages has increased significantly since 2016 due to the implementation of a new risk framework for working with energised equipment.

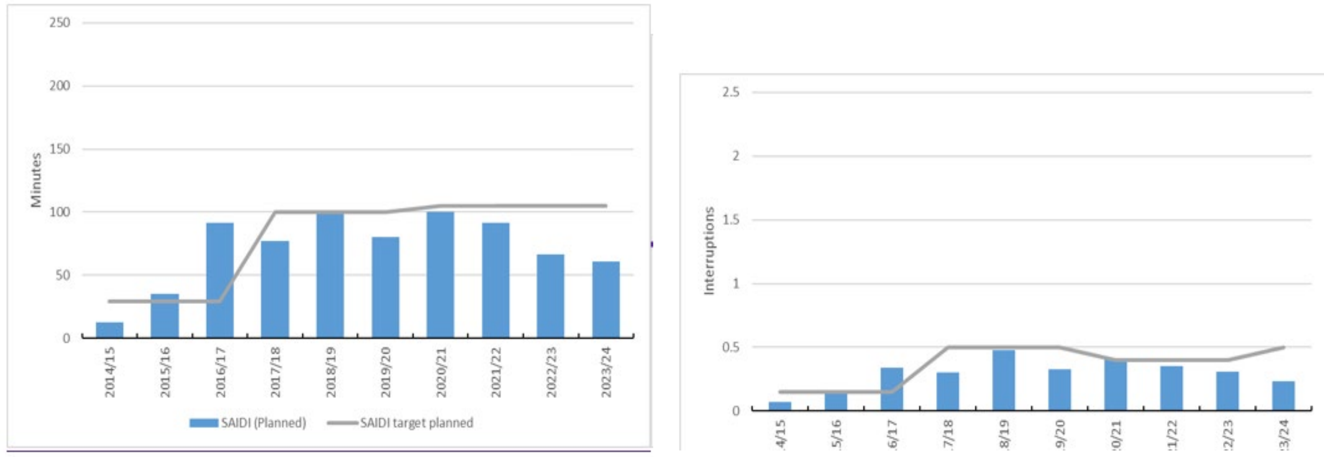


Figure 16 - Historical Planned SAIDI and SAIFI performance compared to target

We expect that performance since 2016 for planned outages will be maintained for the remainder of the planning period.

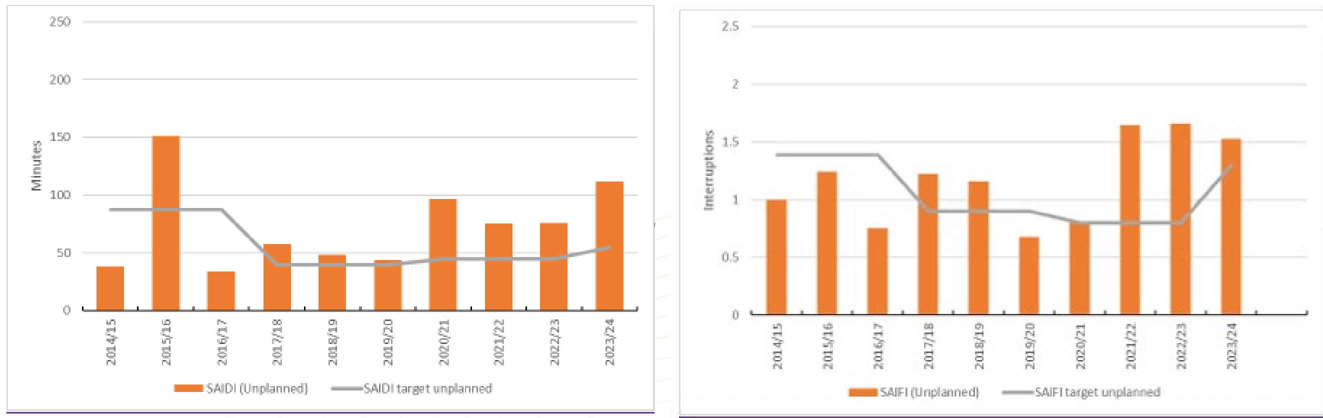


Figure 17 - Historical Unplanned SAIDI and SAIFI performance compared to target

Our performance for unplanned outages has exceeded targets in recent years. We have addressed this with projects completed in 2023 & 2024 to improve network reliability and protection system response, primarily in the subtransmission system, which impact the largest number of customers.

Projects to improve the performance of two of our main subtransmission networks have been completed in the last two years and the impact of these projects will start to be seen from 2025. Additional projects to further improve reliability are described in section 9.9.

We also monitor the service levels that individual customers experience compared with our service level targets.

We analyse these performance figures to look for evolving trends that may indicate a change in practices or a targeted replacement programme is called for. Analysis of unplanned outages for the previous year shows no trends requiring significant changes in Network operations.

6.4.1.6 Analysis of Issues causing Unplanned outages

We analyse causes of unplanned outages and their impact on our customers so we can continuously improve our asset management practices and minimise future impacts. We have recently found that while we are able to reduce the average fault per 100km to levels below the industry norm, we are not achieving the SAIDI/SAIFI targets we want for our customers. This is due to the impact that individual faults are having, i.e. a small number of faults are causing outages for large numbers of customers, and it is taking a comparatively long time to restore service. To address this, we have focused on developing more customer-centric reliability performance measures and are now identifying specific projects to close service gaps. Refer section 9.

6.4.2 Service Level: Economic Efficiency

As well as delivering a reliable supply, we need to supply customers efficiently and cost-effectively. We believe one of the best ways to verify that we are economically efficient is to compare our performance to that of similar EDBs. We therefore benchmark several measures against other network companies to understand whether our asset investment strategies are delivering cost effective outcomes to benefit our customers.

6.4.2.1 Objectives

We want to provide a safe and reliable electricity supply that is also sustainable. To do this, we need to make sure our service is economically efficient.

6.4.2.2 Strategy

To achieve our economic efficiency targets, we:

- Work with our customers to ensure their supplies are optimised to their requirements
- Consider the impact of losses when evaluating options for network upgrades and renewals
- Optimise loading between our GXPs to improve the efficiency of energy transmission to customers
- Actively manage capacity and asset utilisation, and balance equipment loadings where underuse or overuse becomes apparent
- Continually work to improve our works delivery model and processes
- Investigate new technologies where they can provide improved performance, and offer solutions from other providers where these are more economical

Measures and performance

We apply the following economic efficiency measures:

- Operational expenditure per connection point
- Operational expenditure per km of network

6.4.2.2 Total operational expenditure per connection point – measure and targets

This measure helps determine whether operating expenditures are appropriate given the operating parameters of our company. Adequate operational expenditure is required per connection point to provide sufficient maintenance to keep the system reliable.

We compare our forecast operational budgets against peer EDBs, including an allowance for inflation. This measure includes all operational costs involved in running the network, including support functions such as IT, finance, and health and safety. Tracking this measure links our asset management processes to customer and stakeholder preferences for supply reliability.

6.4.2.3 Total operational expenditure - performance

The measures associated with operational expenditure provide a view of whether the network operating expenditures (preventative maintenance, corrective maintenance, reactive maintenance, and vegetation management and business support functions) are appropriate for our network.

The figure below shows a comparison between the three-year average of our total operational expenditure (OPEX) per connection point and that of all other EDBs in New Zealand.

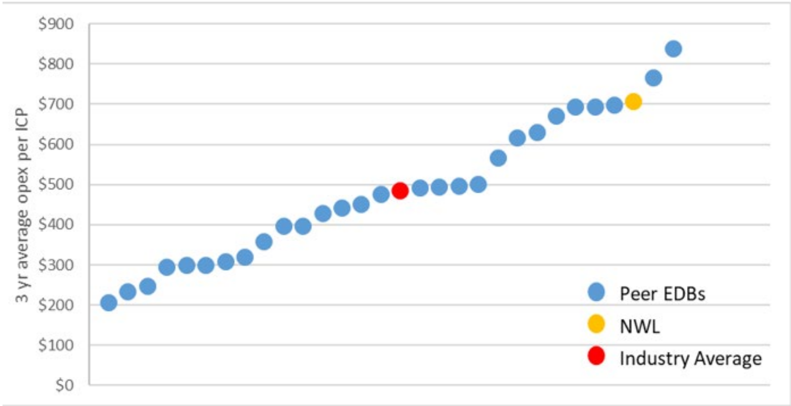


Figure 24 - 3-year average operational expenditure per connection point performance compared to all EDBs

In the context of the entire industry our operational costs are above average. This comparison includes large EDBs with densely populated networks, which skews the cost/ICP profile due to scale. We believe it is more appropriate to compare our operating costs to the networks in our peer group. The following graphs show operational cost comparisons within our peer group of EDBs for the average of the last three years.

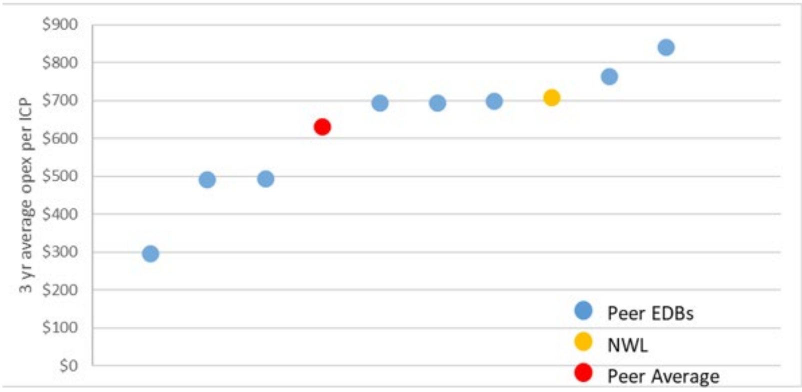


Figure 25 - 3-year average operational expenditure per connection point compared to peer

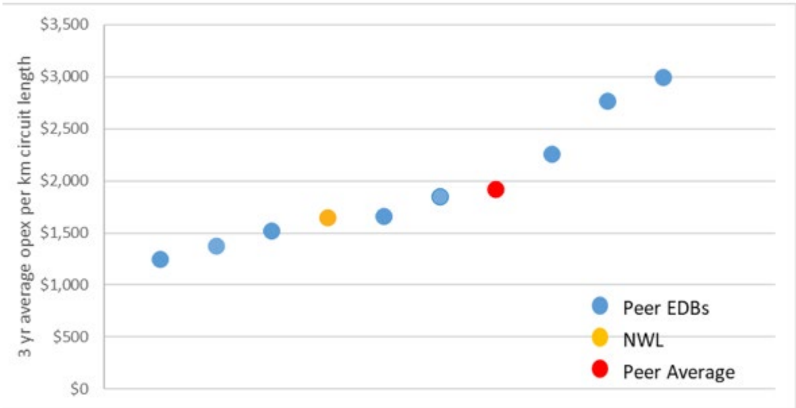


Figure 26 - 3-year average operational expenditure per km circuit compared to peer EDBs

Our total Opex/ICP and Opex/km are both close to our peer group average. We provide a relatively high reliability performance (shown in Figure 27 below). Our OPEX per ICP being around our peer group average, while our SAIDI and SAIFI performance is among the best in our peer group (refer to Figures 13 & 14). We will need to continue to focus on ensuring continue to focus on delivery of iniitatives to minimise/reduce ongoing costs to our customers while continuing to deliver customer expected network performance.

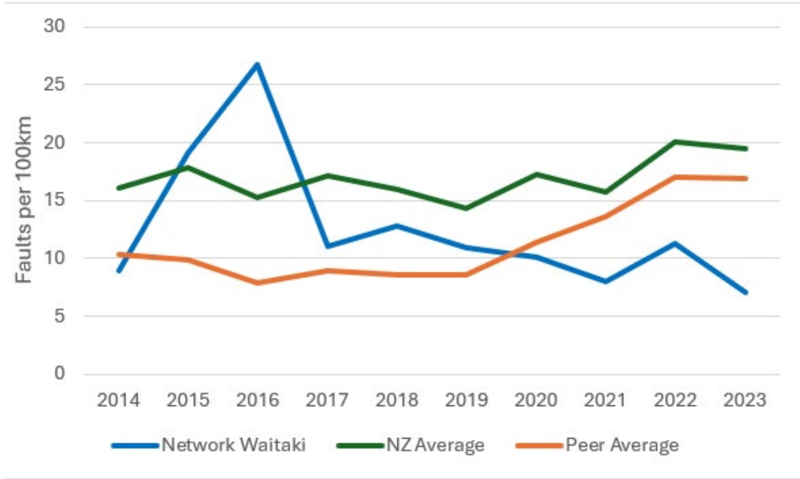


Figure 27 - Comparison of previous 10- years faults per km against peer EDBs and NZ Average

Whilst our reliability indicates good performance, we continue to understand the need to ensure appropriate and affordable asset management practices.

We will work on keeping our operational costs at an appropriate and economic level by:

- Ensuring proactive maintenance and repairs are completed efficiently to ensure fewer faults and asset failures occur
- Evaluating and making ‘replace versus repair’ decisions before undertaking large corrective maintenance projects
- Considering ongoing lifecycle operational costs in the selection of equipment and systems and selecting equipment that balances operational and capital expense

Approach to Asset Management

Approach to Asset Management

This chapter outlines our approach to managing our network assets. It provides an outline of the key parts of the planning and delivery areas of this discipline. This chapter is structured as follows:

Asset management process: An overview of how we view Asset Management as a process and detail of how key elements fit the process.

Asset lifecycle management: How we approach the lifecycle of our assets, including initial investment, ongoing maintenance, and refurbishment, and how we make decisions on asset investment.

Risk management framework: How we apply risk management to our business, especially around the treatment of assets.

Public Safety Management System, high impact low probability events and emergency response policies and contingency plans: These sections outline processes that we use to keep our network safe for the public, and how we stay prepared for major events.

Asset management maturity: How mature we believe our asset management processes are, specifically using the Commerce Commission's AMMAT system for analysis.

Improvement initiatives/continuous improvement: Outlines ways in which we are working to improve our asset management capability.

7.1 Asset Management Process

The process that we apply to planning our Asset Management is illustrated in Figure 19 below:

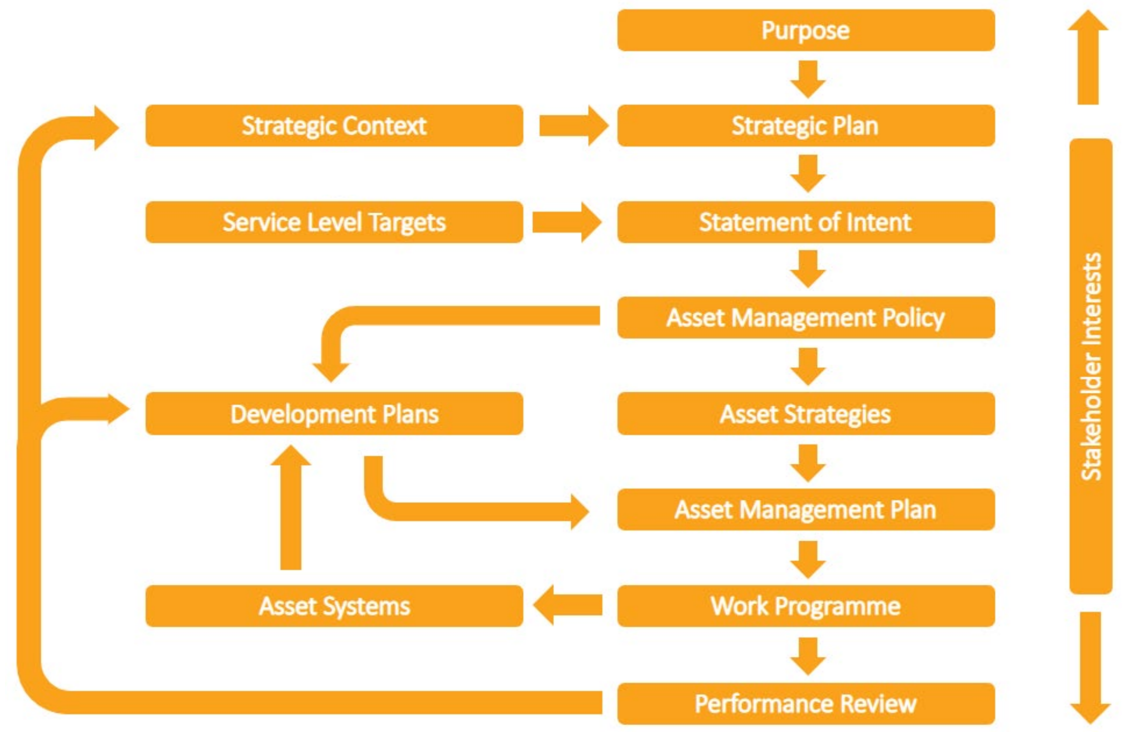
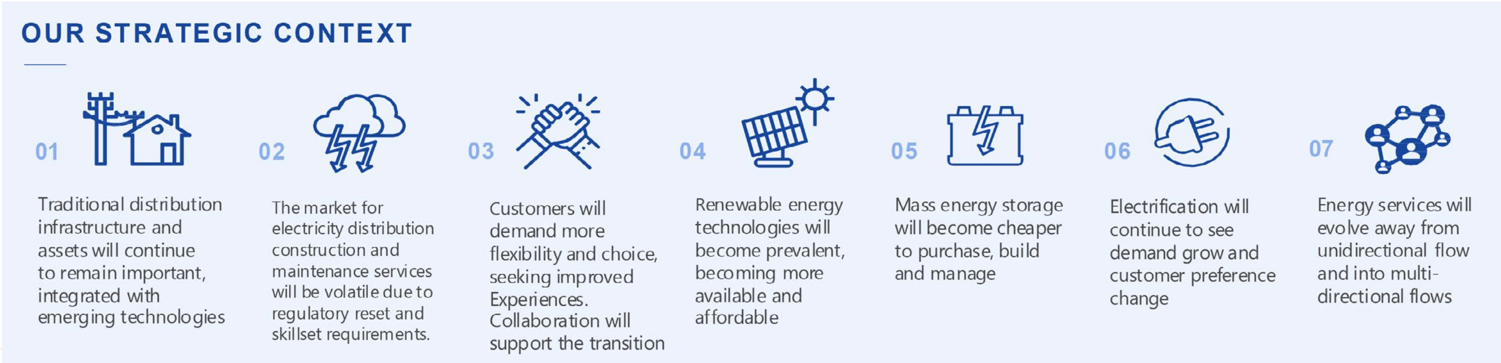


Figure 28 - Network Waitaki asset management process

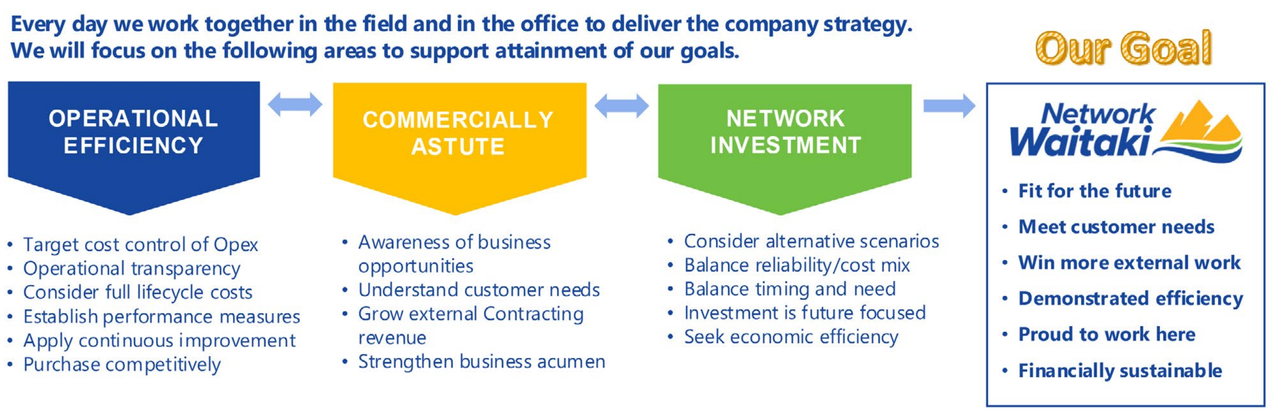
The planning process should be viewed as a continuous cycle rather than a hierarchy of documents. Some key components of this process are described on the following pages.

7.1.1 Company strategic plan

In 2025 we updated our strategic plan that will ensure alignment of the entire business to deliver on our vision of "Powering a vibrant Waitaki" and propel our strategy for the future of our business by "utilising our core assets, operating expertise, reputation and financial strength to develop growth opportunities for a sustainable future".



The key strategic priorities in delivering this Asset Management Plan are:



7.1.2 Asset management policy

The purpose of our Asset Management Policy is to ensure that our asset management activities occur within a structured and systematic framework. This framework focuses on delivering a safe, reliable, secure, resilient, and cost-effective supply of electricity that meets customers' performance expectations, while complying with relevant New Zealand laws, regulations, and codes of practice. Specifically, our Asset Management Policy states:

"It is NWL's policy that the electricity network is designed, constructed, operated, and maintained in a safe and efficient manner aligned to good industry practice, and follows the following principles:

1. Safety is the highest priority. We are committed to instilling a strong safety culture and capability throughout the company. We strive for zero harm to employees, contractors, and members of the public.

2. We will plan our activities to sustainability meet the price and service quality expectations of our customers. We will do this by engaging with our customers and stakeholders for consideration with other strategic, economic, and regulatory drivers.

3. Our investments will be clearly aligned with delivering our service level targets, effectively managing risk and optimising life cycle cost.

4. We will consider non-network and demand-side solutions, technology, innovation and investment and operational efficiency when we seek to optimise our investment.

5. We will continuously improve our Asset Management practices, to align with nationally and internationally recognised asset management standards. We will develop and retain talented, competent and motivated people to maintain and improve our asset management capability.

6. We will develop and retain talented, competent and motivated people to maintain and improve our asset management capability.

7. We will consult and manage our asset management practices in accordance with obligations related to the Treaty of Waitangi(Te Tiriti o Waitangi).

8. We will include emerging factors such as Decarbonisation, Climate Change, Sustainability, and Social Responsibility in our Asset Management activities.

9. We will comply with all environmental, security and other relevant statutory and regulatory requirements."

7.1.3 Asset management strategy

Our Asset Management Strategy is to ensure that our asset management practices continue to deliver agreed service levels as set out in this AMP at minimum long-term cost.

Our Asset Management strategy aligns with our Asset Management Policy and corporate objectives and encompasses the components listed below.

7.1.3.1 Asset configuration

The following strategies are applied to our consideration of asset configuration:

- We will take a long-term view of asset requirements, noting that customers ultimately benefit from well-planned investments
- When building new assets or rebuilding existing ones, we will ensure that the capability to meet future needs is built in; that is, we will purchase sufficient land to enable dual transformer substations to be built (where appropriate)
- We will consider using portable or semi-portable generators at distribution substations to help meet customer reliability levels during planned and unplanned outages. To enable this, when installing new or upgrading existing distribution boxes, consideration will be given to installing generator connection plugs to enable quick and easy connection of portable generators

7.1.3.2 Resourcing

The key strategies applied to resourcing for our company are:

- We will identify the required skill sets needed for effective asset management and have a well-developed recruitment and training plan in place
- We will ensure that our contracting business has a well-developed recruitment/training plan – an ageing workforce means we need to prepare workers to deliver on the strategy during the planning period
- We will continue to use external contractors to maintain our specialist systems such as communications and SCADA networks. We will continue to maintain our engineering skill set by hiring qualified engineers and supporting the growth of trained engineers through scholarships for local engineering students
- As technology and systems advance, we will actively identify gaps in skill sets so we use the best tools and train our staff or recruit to fill those deficiencies
- We will continue to engage suitable consultants for specialist work, including civil design, protection, and regulatory advice

Finding staff to fill technical roles is a challenge for our sector. Skilled immigrants is one pool of talent that all EDBs draw on and ongoing difficulties with immigration, combined with an ageing workforce, may make it harder to fill open positions. This has led to a greater focus on developing trainees and identifying work that can be done by less skilled staff without compromising quality or safety.

7.1.3.3 Materials

We recognise that choice of materials for construction projects can have long term implications for capital and operational expenditure. We apply the following principles to purchasing decisions:

- We will use only materials and equipment approved by our internal policies and standards, or by specific design where necessary
- In assessing offers to supply materials or equipment, we will consider the total life cycle costs of the offer. When bringing new equipment types onto the network, we will follow a rigorous procurement process that examines the risks associated with safety, longevity, maintainability, and operability of the equipment

Worldwide logistic issues have an impact on most of our suppliers. International freight disruptions have affected the price and availability of raw and finished materials, leading to uncertainty with supply arrangements. We anticipate that equipment will only be available on longer lead times and we will factor this in when purchasing major equipment for projects in the first few years of the works programme.

7.1.3.4 Delivery of works programme

Where practical, our engineering staff start designing major projects in the years before the works programme for which the project is scheduled. Budgets are developed to provide funds for this prework where possible. This smooths out the planning and delivery process and allows for consents, long lead-time procurement and resourcing scheduling.

It also provides opportunities to pre-order long lead-time material items so they arrive earlier in the financial year, providing more flexibility for works delivery and resulting in a smoother workflow. A project may be moved forwards or backwards in the plan to take advantage of an opportunity, provided this does not introduce undue risk.

Progress against the works programme is monitored by the management team throughout the year, with attention paid to resourcing and prioritisation of work. The timing of a job may be brought forward or deferred depending on the priority. For example, low priority maintenance such as painting an asset may be moved back to free up resource for safety-related work that has arisen through routine inspections since the original works programme was created.

7.1.3.5 Performance reporting for asset management

Asset management for our network should be implemented in an open and transparent manner. We employ the key formal reporting mechanisms shown below.

Reporting line	Reporting mechanisms and content
The Company to customers and stakeholders	The company website includes the AMP, Company Annual Report, and other disclosure documents. Company annual report includes Chairman and Chief Executive statements and audited accounts. Annual information disclosure.
The Board to the Trust	Quarterly presentation includes financial and operational performance.
Chief Executive to the Board	Monthly board report includes network performance updates, risk management activities, and progress on works programme delivery. Out-of-cycle reporting on significant developments.
Management Team to Chief Executive and the Board	Annual reports on budget and major projects. Monthly reports include network performance and progress against budget. Individual reports on major projects. Daily updates on areas of concern.

Table 9 - Key asset management reporting mechanisms

7.1.4 The Asset Management Plan

This Asset Management Plan (AMP) is intended to give stakeholders a view of our asset management practices and communicate our plans for the next 10 years of operation and development of the network.

In particular, the objectives of this AMP are to:

- Link the asset management processes to customer and stakeholder preferences for prices, supply reliability, and public safety
- Demonstrate that all asset lifecycle activities, plans, and associated costs are systematically planned with a long-term view towards minimising lifecycle costs, which promotes productivity and efficiency
- Demonstrate that physical, commercial, and regulatory risks are correctly managed throughout the life of our assets

7.2 Asset Lifecycle Management

An overview of the typical lifecycle of a network asset is shown in Figure 21:

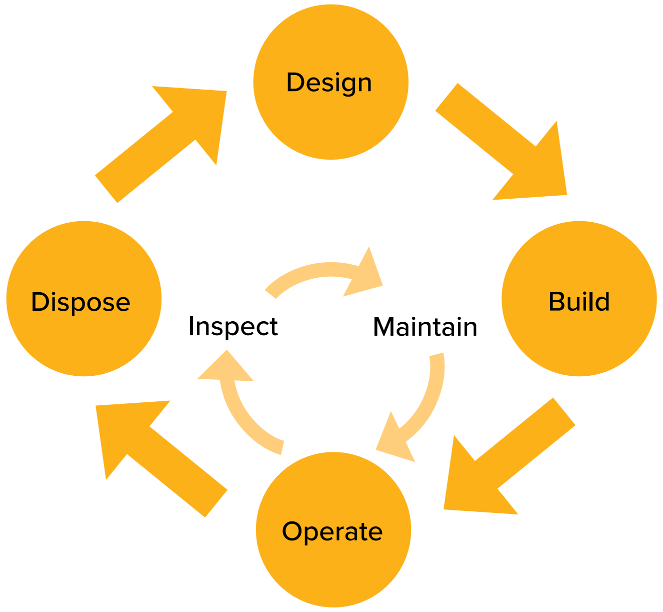


Figure 29 - Typical network asset lifecycle

7.2.1 Design and procurement

Design and procurement are where we begin to influence the service life of our assets. By following good design practice and standards and working with reputable suppliers, we control the quality of assets entering service on the network.

Having a well-developed Asset Management Plan and long-term works programme view ensures that materials are procured well in advance. This minimises logistical risks and ensures staff and other resources are available so that projects are delivered effectively and economically.

We follow a rigorous change management process to ensure new equipment can be safely installed, operated, and maintained on the network. This process also identifies any special tools or techniques that may be needed for installation and operation of a new asset, and helps us provide staff with the right training to safely install, operate and maintain the assets.

7.2.2 Installation and commissioning

Using correct techniques and equipment for installation and commissioning ensures that new assets are installed as per the manufacturer's intentions and are operated within design tolerances. Examples of this are specific handling methods for lifting concrete poles, and having trained staff use the correct tools for installing cable terminations.

7.2.3 Preventative Maintenance and Inspections

During their operational life, assets are regularly inspected for defects. Inspection intervals are determined by the type and criticality of the asset to make sure it still meets the required levels of service, and to meet legislative requirements for operation of the network.

Inspections include visual checks - such as a walk around a substation fence - and more in-depth condition-monitoring such as thermal inspection of a roadside distribution transformer or X-ray and seismic technology for inspections of wooden power pole. Inspections can also include non-intrusive testing such as earth resistance, oil sampling and partial discharge tests. The timing of inspections and tests is usually based on the criticality or consequence of the asset failing. The frequency of inspections is affected by asset type (high value assets are more closely monitored), location (highly public occupancy or fire risk areas) or significance in the system (if more customers lose supply on failure).

A vital consideration in our inspection regimes is asset safety for our workers and the public. The safety risk of an asset can be affected by external factors such as public activities in the neighbouring road or public spaces, or vegetation near overhead lines. To mitigate these factors, our inspections consider public safety based on where the asset is and what activities or external risks are present.

Trees and other vegetation can pose a significant risk to public safety through fire and electric shock, and can compromise the reliability of our network. Our Contracting team includes specialist Utility Arborists and we engage with the public in various ways to inform them of the risks of managing trees around overhead lines. Our vegetation management team complete scheduled patrols of our overhead network to manage risks to its safe and reliable operation. They work with tree owners to resolve problems within the Electricity (Hazards from Trees) Regulations 2003 and adhere to good practice.

Preventative maintenance to keep equipment in good condition is based on the results of condition assessments. Preventative maintenance includes activities such as greasing and checking the contacts on air brake switches, and maintaining on-load tap changers on power transformers. These activities can be scheduled based on time cycles (e.g., 3 yearly) or on operational activity (e.g., after three high current faults).

We are trialling real time monitoring on some assets to optimise our response to conditions such as overloading, and in some cases to potentially discover defect conditions much earlier.

7.2.4 Asset defects

Assets that do not meet a required service level are recorded in our defect management database. The defect process includes a risk assessment to identify potential risks to the public and our workers, and possible effects on the network. Defects with the potential to cause serious harm to members of the public, employees, or property, or which could have a significant impact on the reliability of the network, are prioritised and resolved rapidly.

Information to trigger renewals or maintenance can also come from analysis of fault reports, from observations by our staff or members of the public, or from wider industry advice of an issue with a particular asset type.

A defect may be due to the failure of an asset to meet a required level of service such as electrical capacity (e.g., an overload on a transformer), structural capacity (degradation of a power pole means it can no longer safely support conductors), or operational (the asset cannot be supported due to age and lack of spare parts). The outcome of the defect can range from a gradual reduction in useable life or capacity, to catastrophic failure.

7.2.5 Repair, renewal, or replacement decisions

When planning remedial work, the risk assessment is reviewed to determine the appropriate intervention strategy. Defects with a high safety, environmental or network operational risk attached – such as a damaged ground mount transformer – are dealt with urgently. Others may be scheduled for a future date, possibly during a planned shutdown. Occasionally the risk associated with a defect is so low that pre-emptive intervention is not considered economical and the asset may be left to run to failure, with appropriate monitoring.

Intervention can involve repairing an asset in place (return to pre-defect condition or capacity), renewing it on site (improving on pre-defect condition or capacity) or replacing it with a new asset. The age, condition, urgency of the defect and any known issues with the asset type are all considered when making this decision.

Sometimes a renewal programme will be triggered by the age and general condition of a group of assets, such as an overhead line of a particular type and age, or a type of switchgear that is known to fail prematurely, rather than individual defects. These planned renewals are undertaken to ensure network safety and reliability.

Renewal may also be carried out to ensure that an asset or system will continue to meet its performance requirements, such as capacity or speed of operation.

7.2.6 Standard life expectancy, asset age and health data

Our company has applied standard life expectancy figures across all categories of assets for many years. The values for these life figures are developed from industry-published figures and are used primarily for accounting purposes such as setting depreciation rates. In practice, the useful (and safe) life of our assets is usually higher than the standard life and may be highly dependent on location, treatment, and loading. For this reason, wherever possible we avoid using age as a proxy for condition and we base asset decisions on test results or observed data.

Asset health is primarily based on condition information, which can be further separated into objective (test results) and subjective (visual assessment) data. Where assets lack suitably robust condition data, then modelling is carried out using parameters such as type (make and model), location (environmental/pollutants) and age. Where a failure mode trend has been identified, the assets that have features in common with that trend may be replaced sooner.

Assets have varying degrees of obtainable data. Where there is evidence supporting a likely state (such as similar or adjacent equipment, or staff knowledge) then we will assess them accordingly. Otherwise, we take a conservative approach and place the assets in the lower health band for that type of asset.

7.2.7 Investment decision framework

Major investment in the network, such as new lines or zone substations, are often triggered by a constraint in the operation of the existing equipment. Before deciding on a major investment on our network, consideration is given to the following options:

1. Accept the risk

The risk may only exist for a few hours in a year or during a narrow set of circumstances, and we may decide to accept the risk of the constraint, especially if the remediation cost is high. This option is unlikely to be implemented permanently, but it may be used where longer-term solutions cannot meet the required timeframes or where the costs of other options significantly outweigh the benefits. The risks of operating in this mode must be quantified and assessed as acceptable to stakeholders.

2. Optimise the network

Examples of his option include altering the configuration of 11 kV feeders to shift load from a heavily loaded to a lightly loaded feeder, or installing a voltage regulator on a feeder to avoid a conductor upgrade.

Consequences such as increasing system losses or a reduction in security of supply will be included in the cost-benefit analysis.

3. Demand management

This option involves NWL and/or customers reducing demand while a constraint is present.

If new load is likely to exceed a constraint limit, conditions may be agreed that allow demand to be reduced during constraint periods. These conditions may be removed if the network is upgraded to remove the constraint.

Demand that may be controlled includes demand that is traditionally available for interruption, such as water heaters, and demand that is specified as controllable in our Security of Supply Standard (e.g., irrigation demand).

4. Non-network solutions

This option may be used to augment or even replace parts of our network. In some cases, a remote power system (typically a system combining solar and diesel generation with battery storage) may be more cost effective than a traditional power line. The comparative lifecycle costs of non-network solutions are examined where new lines, capacity upgrades or replacements are being considered. There is more detail on our approach to non-network solutions in **Section 9.3 - Our planning approach.**

5. Modify or re-rate existing assets

This option could involve a design review to increase conductor maximum temperatures or using dynamic rating on a line or cable to increase capacity. Cooling fans could be added to a transformer to increase capacity.

6. Install new assets

This involves either building new network or upgrading existing assets.

Increases in customer demand are often signalled at short notice (less than 12 months), which may require that we use options 1 to 3 in the short term, followed by a long-term response following detailed analysis of all appropriate options.

For low-cost projects, we use deterministic rules from our design and Security of Supply standards, which may result in evaluating only a subset of these options.

All options selected for detailed study are evaluated for cost and benefit (including costs of energy losses and value of lost load where appropriate) and considered for alignment with:

- Our strategic plan (which includes health and safety, environment, and sustainability requirements)
- Statutory requirements (e.g., voltage, power quality limits)
- NWL Security of Supply Standard
- Forecast network capacity requirements
- Customer reliability requirements.

Options are scored across these categories and ranked according to their scores. The option (or options) with the best score is submitted for expenditure approval.

7.2.8 Expenditure approvals

Following this initial prioritisation process, a Project Expenditure Approval is prepared for any budgeted individual project over $50,000; any individual project over $250,000 or major unbudgeted project requires a business case which will approved by the Chief Executive (>$250K) or the Board (>$1M).

The business case includes details of:

- The risks and issues that the project is designed to address
- Analysis of the options that have been considered
- Recommendations for solutions
- The rationale for the selected option or options
- Financial analysis of the options, including a risk-based assessment of the cost of lost load, if applicable
- Analysis of performance impacts with respect to SAIDI and SAIFI and any other service level targets
- Any other benefits that will accrue from this project in terms of security, quality, customer/community perception etc.

7.3 Risk Management Framework

Our business faces a wide range of risks. Some relate specifically to our network assets and the physical environment in which they are located, while others include more generic risks that all businesses face. Risk management is a fundamental part of good management practice and corporate governance, and effective stewardship of our assets.

Our approach to risk management strengthens our asset management decision making and practices. We apply risk management across all our business activities, including network planning, policy development, business planning and change management. We adopt a systematic risk management process based on the international standard *AS/NZS ISO 31000:2009 – Risk management – Principles and guidelines.*

Figure 22 below illustrates the systematic application of risk management according to the standard:

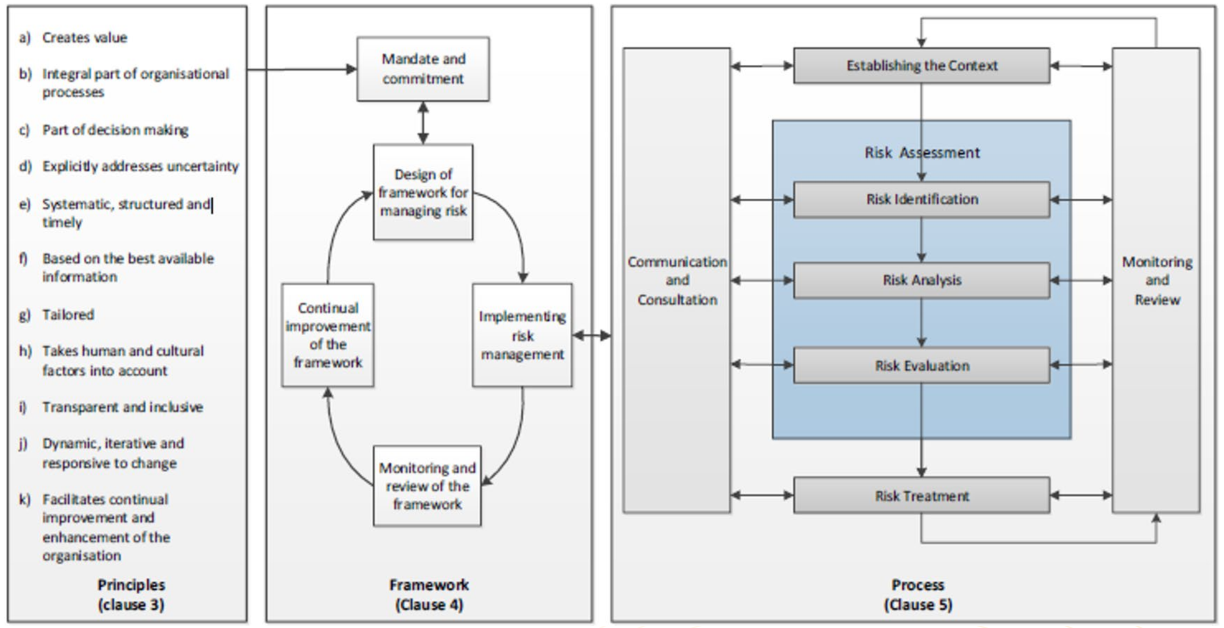


Figure 30 - From ISO31000:2009

Our risk management system consists of the following components:

- Risk management policy
- NWL risk management framework
- Risk management process
- Risk management plans
- Risk registers
- Risk reporting

7.3.1 Risk Management Policy

Our Risk Management Policy is updated regularly and applies to all business operations of Network Waitaki. It presents our risk management objectives, provides guidance for establishing risk appetite and lays out responsibilities of our staff. It is intended to support and drive:

- Protection of people, the community, our network, the environment, and the business through effective risk management
- A flexible and evolving risk management framework aligned to the AS/NZS ISO 31000 Risk Management Standard
- Effective systems and tools for managing risk
- Regular review of existing risks and assessment of emerging risks
- Understanding how robust risk management supports good decision making
- A culture of risk management awareness across all aspects of the business.

The policy includes a framework that ensures that risk management is integrated into all aspects of our business including governance, strategic planning, operational (day to day) planning, and reporting.

These activities are evaluated from the following aspects:

- Health and Safety (Public and Personnel)
- Environmental
- Legal and Regulatory Compliance
- Reputation and Stakeholder Confidence
- Customer Service Levels including Supply Reliability
- Financial
- Business Disruption

7.3.3 Risk management process

Our risk management process ensures risks are identified, understood, and managed consistently across all levels of our business. We assess and track risks are assessed and tracked on the basis of likelihood and consequence outcomes.

Our risk management process involves the following steps:

1. Establishing the context in which the risks exist. This involves understanding our business objectives and values, defining the internal and external environment in which we operate in, and setting the scope and risk criteria. We consider many factors such as, including accessibility of our assets by the public, asset age, and location.

2. Risk identification is identifying, recognising, and describing our risks, and their effects. Risks are identified through regular operational reviews, safety-in-design processes, and lessons learnt from other businesses. Risks are recorded in risk registers so we can track and monitor them and the effectiveness of our controls.

3. Risk analysis. Risks are analysed using qualitative and quantitative measures to identify the likelihood and potential consequences they present to the business.

4. Risk evaluation. All identified risks are evaluated against our risk criteria. This helps us ascertain which risks need treatment, the priority for implementing treatment, and the appropriate level of investment for the risk.

5. Risk treatment. We treat a risk depending on the outcome of the analysis and evaluation stage. Risk treatment involves selecting one or more options for modifying risks. Options may include:

- Avoiding the risk by not starting or continuing the activity
- Removing the risk source by doing the activity in a different way
- Changing the likelihood of the risk occurring
- Changing the consequences if the risk does eventuate
- Sharing the risk with another party or parties (e.g., contracts and insurance)
- Accepting the risk by informed decision

6. Post treatment risk evaluation. The risks are reassessed to verify that the post-treatment level of risk is known and accepted by the company.

7. Ongoing review of risks. Once a risk is recorded in the system it is regularly reviewed, as the likelihood and consequence of its occurring can change. Software risk registers are used to record and manage risks, including scheduling reviews and reporting on outstanding risks.

7.3.4 Risk management plans

For complex activities such as major projects or where a new type of work is being introduced, we develop complete risk management plans covering health and safety, financial, environmental, and operating risks for an activity. These plans are developed and approved by key stakeholders of the activity in question, such as engineers, managers, and field staff.

7.3.5 Risk registers

Information from the risk management process is recorded, reported, and monitored using our risk registers. These cover:

- Public Safety Management System
- Health and Safety risks
- Business risks
- Asset risks
- Individual project risks
- Physical risks for specific sites

It is important that all risks can be tracked and managed in one system to provide visibility of the total risk the business faces.

7.4 Public Safety Management System (PSMS)

As an electricity network operator, we strive to manage our assets in a way that reduces risk to our people, members of the public, and property to the lowest reasonably practical level. Under the Electricity (Safety) Regulations 2010, NWL must maintain a public safety management system to manage all known hazards and risks to the public or their property caused by the operation of our business. It records the actions to be taken (or that have been taken) to resolve those risks. Public safety risks are identified through operational processes such as documentation by field staff, and team and project meetings. This information is also reported to the Board monthly and in annual reports.

Our PSMS is certified to NZS7901 and is audited annually by an external auditor (Telarc). Internal auditors also work to provide assurance that the system is working effectively. In March 2024, we received confirmation that our PSMS again achieved certification to NZS7901:2008 and NZS7901:2014, and that the certification would be valid for another three years.

7.4.1 Risk reporting and monitoring

The risk register includes mechanisms for reporting and monitoring risks and their treatments. This includes automated reviews at set periods, dashboards to track the effectiveness of risk mitigation, and the risk profile of the business. We are confident that monitoring and reporting processes in this area are robust and complete, with monthly reporting on risks in this area going to the board.

Some lower-level risks, such as project level performance and commercial risks, are monitored by the staff managing the project. They are reported to management on an exception basis if the risk becomes a real threat.

7.4.2 Health and Safety Critical Risks

We maintain a special focus on what we consider to be critical risks associated with operating an electricity network. These risks have been identified and assessed in collaboration with staff through an ongoing workshop process, using bowtie analysis. The critical risks of focus include:

- Health and wellbeing (mental health and fatigue)
- Traffic management
- Asset integrity
- Electricity
- Mobile plant and equipment
- Driving
- Working at height
- Dropped objects

The treatment of these risks includes focus on training and the development of safe standard work practices, as well as regular monitoring of the risk profile and our performance in these areas.

7.5 Operational Resilience

Electricity distribution is a critical component of modern society. Businesses depend on electricity for production processes, IT operations and lighting. The general population depends on electricity for basic functions such as lighting, cooking and, increasingly, heating. Critical infrastructure such as water treatment and hospitals require electricity to function.

There are several events that could significantly disrupt our ability to deliver electricity. A major event could disrupt our ability to perform our core functions by damaging key components of our network, causing business systems to fail or to operate at reduced capacity, affecting the availability of resources to operate the network, or disrupting our supply chain. Examples include:

- A large earthquake on the South Island's alpine fault
- A large earthquake on a fault line in the Waitaki region
- A tsunami
- A pandemic
- A large snowstorm
- A large windstorm
- Flooding
- Sustained loss of supply from Transpower's transmission system
- Cyber attack
- Sabotage

Thankfully, the likelihood of many of these events is rare, with return periods ranging from decades to centuries. These sorts of events are often referred to as "high impact, low probability" (HILP) events.

As the provider of a lifeline utility, we have a duty to plan and prepare for HILP events. The Civil Defence Emergency Management Act 2002 requires Lifeline Utilities such as Network Waitaki to participate and plan for major events affecting the environment. It requires utilities to:

- Function to the fullest extent during and after an emergency
- Establish and maintain plans to enable this functioning
- Participate in CDEM planning at a regional and national level as required
- Provide technical advice and information to CDEM authorities where required

Due to our Network's location in the North Otago and South Canterbury regions, we are a member of both the Otago and Canterbury Lifeline groups. This provides us with information at regional and national levels into hazard and risk assessment, mitigation options, and business practices. It also establishes relationships with other lifeline utilities and agencies. We actively learn from other EDBs and communities that have been impacted by HILP events. This learning occurs through channels such as:

- Attending industry conferences such as EEA asset management forums
- Involvement in regional peer industry groups such as the Combined Network Operations Group (CNOG)
- Involvement in Civil Defence workshops and exercises
- Working with experienced consultants to carry out specific reviews of vulnerabilities in our assets and operations and develop remediation plans

In the 100 years our network has been operating, we have regularly been exposed to major flooding and snowstorms. The knowledge and experience gained from responding to these disruptions have informed our operational procedures, design standards and procurement standards to make our business more resilient.

We have also been working to improve our ability to ride through an abnormal event such as a large earthquake, and to operate effectively in the aftermath of such an event. This has included working with experts in different fields to ensure our electrical network and business infrastructure can perform as expected after a disruptive event. Our goal is to ensure that during and after a HILP event our network and business systems can:

- Provide a safe environment for staff, contractors, and the community
- Reduce potential damage to assets where this is economically viable
- Enable timely restoration of power supply as far as practicable
- Allow us to effectively communicate with the public, Civil Defence Emergency Management, our staff, and other stakeholders
- Return to "business as usual" as quickly and efficiently as practicable

The Covid 19 pandemic and the ongoing lockdowns proved an opportunity to trial the performance of many of our remote business systems and processes, with staff successfully working from home to keep our business as functional as possible under the restrictions at the time. We also carry out regular desk top exercises to test and tune our response plans and provide staff with experience in using them.

7.5.1 Resilience Management

Network Waitaki has adopted the “4 Rs” approach for managing resilience. These are Reduction, Readiness, Response and Recovery. These principles can be applied to a variety of events and can be scaled as appropriate.

Examples of Reduction can be found throughout the business. We have recently (2025) completed reinforcement of our zone substations to meet importance level 4 (IL4) building rating (or as high as economically effective). We have also anticipated more extreme climate events in our design standards using NIWA modelling forecasts to the year 2100 (the maximum practical life expectancy of assets currently being installed).

Readiness is evidenced by our Security of Supply Operation Plans, Strategic and Operational Spares holdings and participation in the Lifelines group and associated exercises.

The Lifelines group also allows us to respond to a variety of situations. Cooperation with other South Island EDBs regarding standardisation and materials along with escalation plans and mutual aid agreements facilitate the Response and Recovery aspects for larger events.

7.6 Asset Management Maturity

Since 2021 we have engaged an independent assessor to review our Asset Management practices against good practice, using the Commerce Commission’s Asset Management Maturity Assessment Tool (AMMAT). This tool is a series of self-assessment questions based on the principles of the ISO55000 suite of standards for Asset Management. The questions cover specific facets of good asset management practice and answers are scored from 0-4. The results reflect our organisation’s maturity and help identify gaps in our asset management systems. We are not currently seeking ISO55001[1] certification but will look to align our systems with the principles of those standards as part of the improvement plan following the review.

7.6.1 Summary of AMMAT assessment

The latest assessment of our asset management practices against the AMMAT is attached in the Appendices. We are applying many good practices in the asset management space and developing strengths in others, but we recognise that these initiatives have often been isolated and that our overall development strategy for asset management practices is not particularly mature.

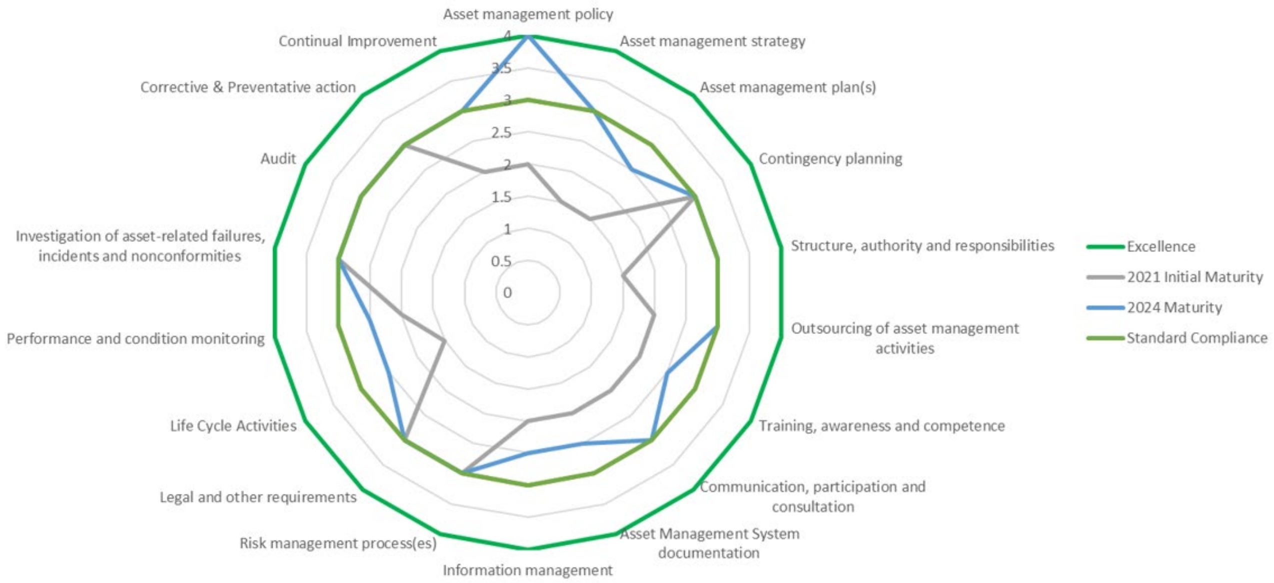


Figure 31 - AMMAT results summary including 2024 Progress Check

Our systems and processes are functional and have historically resulted in good network performance, but they are not particularly efficient and rely heavily on the knowledge of individual staff. We are still very reliant on manual data entry and processing. This reduces the efficiency of some of our activities, such as asset inspections, documenting project work and dealing with customer requests. It also reduces our ability to monitor and maintain oversight of our practices.

1 ISO 55001 – International Standard for Asset Management - Management Systems

Integration and coordination of data across our systems can also require considerable human intervention, as can analysis of that data to generate useful information. We are actively improving the efficiency and effectiveness of our systems by introducing field-based data capture systems and integrating data between software systems such as our GIS and our work management system.

7.6.2 Asset Management Maturity Development Plan

From this original AMMAT assessment point, we have been working on improving business focus areas such as our control room operations, field service delivery and GIS systems. The latest business strategic plan includes a goal to achieve substantial alignment with ISO55001 good practice within the next five years. One of the effects of the new strategic plan will be to align and integrate asset management strategy with the broader business strategy. In the shorter term we are targeting specific activities for improvement in some of the AMMAT assessment categories shown in **Figure 20.**

A key component for achieving ISO 55001 alignment and improving our asset management capability has been an independent expert review of our capabilities, strategies, systems, and processes. The outcome of this review enabled the creation of a strategic roadmap to guide development of our asset management practices and systems, and to identify initiatives for focus. These initiatives are summarised in Appendix C.

Lifecycle management of all assets are documented in Fleet Strategy Plans that record good practice activities for all our asset classes. These include Inspection and Maintenance schedules, long term renewal strategies and any type issue treatment plans.

Improvement of our resilience planning continues to be a focus. Assessing the impact of other major events on our critical components and developing our risk treatment plans is an ongoing process. The seismic upgrade programme for our substations based on the recent review is now almost complete.

Ongoing updates to our risk management processes have included adoption of better software tools for recording and analysing risk. Critical risks are undergoing bowtie analysis, and the integration of good practice risk management throughout the business is well underway.

A key strategic action in 2024 was improving our defects management system and integrating it with our works planning systems. Having a system that can record defects in the field, and that allows us to a track and follow up on the associated remedial work, provides more meaningful reporting. This can be used as a performance measure and provide insight for future Asset Management decisions.

In light of the relatively high inflationary environment, we are looking to improve the accuracy of project and work identification through to delivery, both in terms of cost and time. Our current initiatives focus on the continuous improvement of our existing management systems. However, we ultimately plan to invest in a suitable integrated asset management system, likely within the next 24–36 months (FY28). We will also ensure suitable experienced/independent reviews of higher risk projects.

7.6.2.1 Integration of asset management data

We operate several systems to manage asset data, including some that are paper based, and some on old software platforms that are becoming difficult to support. We realise this is inefficient, and ongoing work aims to integrate this data across our business in digital form. The scope of this work includes data in our GIS, works planning and management, fault recording, and defect management systems, as well as others. This will improve understanding and awareness of network and asset performance and risks and provide for more effective operation of the business.

Success with this project will allow staff to access asset data in the field, and to input information from the field directly into our asset records, rather than capturing on paper for later transcription into our systems. These systems have been trialled in the field with good success, and have been placed into production with the broader work force. The establishment of our in-house vegetation management crews in the last 12 months has been based on the use of field capture and reporting tools.

Our vegetation management process has successfully been put into production in an online, end-to-end digital system. This allows vegetation management crews to easily capture and share inspection and mitigation data on tree hazards on and near the Network. Moving from a paper-based system has improved visibility of performance and issues, the efficiency of planning work, and communication with tree owners and other stakeholders.

We are working closely with peer EDBs and other organisations with similar systems and requirements to share knowledge and learn good practice. The goal is to ensure a tightly integrated system across the following areas:

- Works planning
- Maintenance scheduling
- Condition monitoring and analysis
- Financial management
- Timesheet integration for plant and staff
- Defects recording and location
- Management of controlled documents such as standards and policies
- Fleet management of plant
- Asset registers, operational, financial, and regulatory
- Stores and procurement
- SCADA Data

7.6.2.2 Improvement of asset data

Many areas of our asset data are complete and accurate, but there are still some deficiencies. This workstream will be ongoing for the next few years and will involve the digitisation of old paper-based records, field surveys and using personal knowledge of the network to close any gaps. The improved systems integration outlined in section 10 will help in the discovery of these knowledge gaps.

The focus of this work will initially be assets classed as critical or with higher levels of public risk attached, as well as those where a particular knowledge hole has a high potential impact (e.g., the current rating power of a cable, the manufacturer of a circuit breaker or the age of a battery).

Certain classes of asset have traditionally been managed with the age of the asset used as a marker for replacement decisions. We are reviewing the collection and analysis of condition data for asset classes where there is a gap in condition information so we can establish measures and record data to build a future works programme based more on condition and risk factors and less on strict age-bound criteria.

An example of success in this area is the recent adoption of better inspection techniques and inspector training for pole condition assessment. These initiatives have improved the quality and reliability of pole condition data returned from inspections and allowed us to develop meaningful rates of renewal that provide better insight into future investment needs.

7.6.2.3 Understanding asset criticality

A focus of the early part of the planning period is the analysis of the true criticality of assets in the network. Although the criticality of some major components and sections of the network is well understood from an operational point of view, we lack a formal criticality analysis for all assets. Having this rating will assist in planning the most effective execution of work, and assist in improving network resilience, as we will be able to focus resources on the parts of the network where they will give the greatest benefit.

Our network controllers, engineers and planners are working with major customers and other stakeholders to complete risk assessments to identify critical assets that may have a disproportionate impact on customer experience and to ensure that these are dealt with appropriately. In the short term this is reflected in the ongoing review of contingency plans that will help us respond rapidly and effectively to critical emergency events, such as the loss of a major sub-transmission feeder.

7.6.2.4 Quantifying risk and obtaining value

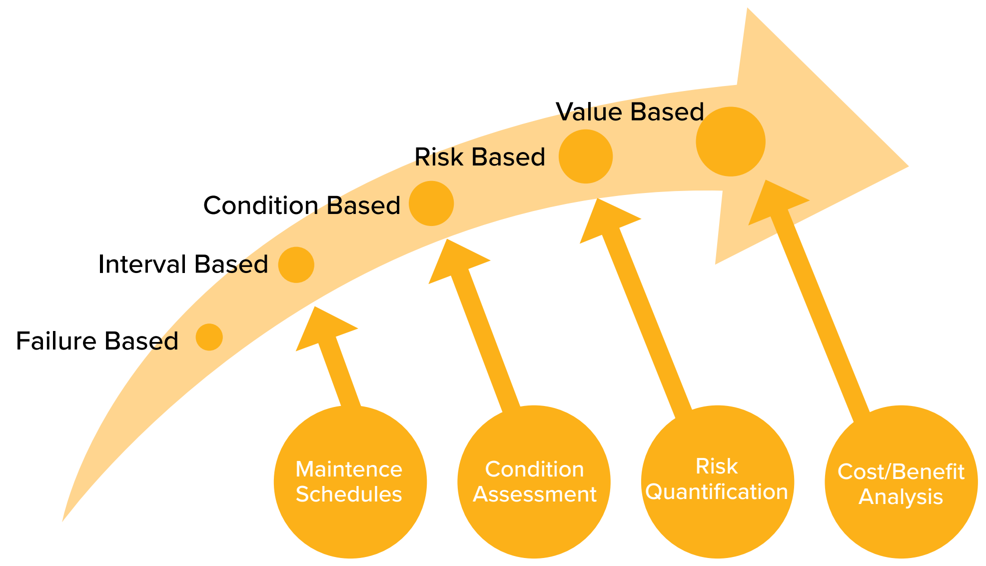
An Asset Owner who only replaces assets once they have failed is not an Asset Manager. The first step is developing a planned set of interventions such as inspection, testing and/or maintenance. This enables a better understanding of asset condition and rate of deterioration.

Once the Asset Condition is understood the level of intervention can be optimised, allowing more effective allocation of resources such as staff and funding, as well as reducing disruption and improving reliability.

Combining Asset Condition with Criticality through the lens of our Risk Framework allows us to understand the overall risk to be managed and lets us identify the highest risks across all asset classes and the wider business. However, simply prioritising our resources to the biggest specific risks is not necessarily the most effective form of management.

We must also understand the cost to mitigate any risk along with any risk that will remain once that mitigation is carried out. This results in value propositions that can be understood within the wider business sense.

7.6.2.5 Asset Management Development Path



Network Waitaki's assets are currently managed with varying degrees of maturity depending on their criticality and the cost/benefit of the relevant asset management regimen. Most assets are managed using condition as the basis for decisions, but Zone Substation equipment, poles and transformers use a risk-based approach informing their management strategy. More assets will have risk quantification applied in 2024.

Maintenance and Renewal

08

Maintenance and Renewal

In this section we have taken a consistent approach for each asset class:

- Describing the assets and their purpose within the system
- Profiling their age and current health
- Identifying and describing key risks associated with each class
- Detailing our processes for inspection and maintenance
- Describing our Renewal and Replacement criteria and plans

Asset description and purpose - We have typically grouped asset classes by function and their associated asset management processes and practices. This continues to be reviewed as our system information and the maturity of our processes develop.

Age and health - An age profile is provided but it is the health of an asset that is of prime consideration. The Health Index (HI) uses multiple factors including test and inspection results, type data and, to a limited extent, age. This Health index can correlate to Probability of Failure (PoF) of each individual asset. Health Index values are described below:

1. No longer fit for purpose, replace immediately
2. Near end of economic life, allow for replacement in plan
3. Fit for purpose but has signs of ageing/degradation
4. Normal in-service condition
5. As new

Asset Risks - We have evaluated the performance of the asset class in relation to its historical failure rates (faults per 100km or item) and contribution to SAIDI and SAIFI. The risks associated with failure modes of these assets are identified and described.

Inspection and maintenance - The failure causes and mitigation or control measures for any asset category help inform us of the appropriate inspection and maintenance regime. This, along with continually monitoring asset health, provides context for the asset condition, maintenance, and replacement plans. We provide the scheduled maintenance work plans that keep the asset serviceable and prevent deterioration or in-service failure.

Renewal and Refurbishment - These are major works that do not increase the asset's design capacity but restore, replace, or renew an existing asset to its original capacity or extend its expected service life. A summary of upcoming programmes and work is also included. Replacement expenditure forecasting is based on known historical replacement costs and projected replacement volumes.

8.1 Asset Summary

The assets that make up our network are summarised in the table below. The renewals and maintenance that we apply to these assets are the primary means by which we achieve the service levels laid out in Chapter 5 and retain the value of the assets for our owners.

Table 10 - Summary of network assets by category

Asset category	Section	Unit	Quantity
Concrete poles	8.7.2 & 8.8.3	No.	9,202
Wood poles	8.7.2 & 8.8.3	No.	12,557
Sub-transmission OH up to 66 kV conductor	8.7.1	km	249
Sub-transmission UG up to 66 kV (XLPE)	8.7.3	km	5
33 kV Switch (Pole Mounted)	8.7.4	No.	92
33 kV CB (Indoor)	8.6.3	No.	11
33 kV CB (Outdoor)	8.6.3	No.	55
11 kV CB (ground mounted)	8.6.3	No.	88
11 kV CB (pole mounted)	8.6.3	No.	4
Zone Substation Buildings	8.6.1	No.	20
Zone Substation Transformers	8.6.2	No.	25
Distribution OH Open Wire Conductor	8.8.1	km	1,266
Distribution UG XLPE or PVC	8.8.4	km	73
Distribution UG PILC	8.8.4	km	17
11 kV CB (pole mounted) - reclosers and sectionalisers	8.8.7	No.	58
11 kV Air Break Switches and Fuses (pole mounted)	8.8.7	No.	4,111
11 kV RMU (individual switches)	8.8.7	No.	152
Pole Mounted Transformer	8.8.8	No.	2,422
Ground Mounted Transformer	8.8.8	No.	588
Voltage regulators	8.8.8	No.	36
LV OH Conductor	8.8.2	km	222
LV UG Cable	8.8.5	km	108
LV Switchgear (Distribution Cabinets)	8.8.6	No.	313

8.2 Asset Categories

For the purposes of planning renewals and maintenance we group our network assets into the following functional areas:

- Zone substations
- Sub-transmission network
- Distribution network
- Secondary and support systems

Maintenance and renewal management plans for each of these groups are detailed in the following sections.

8.3 Maintenance Planning

Maintenance falls into four main categories:

- Preventative maintenance, which includes routine activities such as inspections, scheduled maintenance, and condition monitoring
- Corrective maintenance, which can include defect correction and renewals
- Reactive maintenance, which involves dealing with faults and service interruptions, and restoring supply to customers
- Vegetation maintenance, which is the inspection and management of trees and other vegetation around our assets, in accordance with the Electricity (Hazards from Trees) Regulations 2003 and good industry practice.

Our preventative maintenance programme is primarily time based. Assets are inspected and serviced at regular intervals, based on manufacturer's recommendations, industry good practice, or local experience. Intervals are set on asset and site specific risk criticality. The primary goal of these inspections is to verify that the assets continue to operate safely and correctly, provide a condition assessment of the assets, and to identify any defects or risks that may be present.

Preventative maintenance activities outlined in the following sections are based on the estimate of the number of assets that will fall due in a particular year, and the estimated cost per activity.

Our objective is to discover any non-compliance or defects and remedy the defect before it becomes a hazard, causes an outage, or damages the asset. The results of the routine inspections, fault reports and defect reports can trigger specific reactive maintenance or renewal activities on certain types of asset or in particular areas of the network. Other triggers for renewals or maintenance can also come from patterns of faults reports, which may reveal a developing problem, or from wider industry advice of an issue with a particular asset type.

Corrective maintenance activities in the following sections are based on estimates of defects that may be discovered in a particular year and the estimated costs of remedy. Where possible, this failure rate is based on empirical condition and failure rate data, although where this is not available, we will use historical expenditure trends, or industry failure rates, often based on the age profile of the asset type. Where we have used expected failure rates based on existing age and condition profiles, we have confidence in the first five years of the plan but expect that the accuracy of these estimates will reduce in the final five years of the plan.

NWL field staff carry out inspection and maintenance for most of our assets. We provide inspection staff with specialist training and tools such as thermal imaging cameras, partial discharge detectors and acoustic and x-ray imaging pole testing equipment. External contractors and laboratories are used to undertake certain detailed and technical assessments such as dissolved gas analysis (DGA) and partial discharge (PD) analysis of key assets such as substation transformers and cable terminations.

8.4 Renewals Planning

Planned renewals and replacements are undertaken to ensure network safety and reliability. The difference between renewal and maintenance actions is often around the scale of the work. The most common driver for the renewal programme is risks associated with asset condition, but availability of spares/replacements and compatibility with other assets are also recurring factors.

Renewal may also be carried out to ensure that an asset or system will continue to meet its performance requirements, such as capacity or speed of operation. Wherever possible we use asset condition when planning renewals, although if suitable condition data is not available, we may use asset age as a proxy for renewal or replacement triggers.

Economic analysis is also completed to decide whether an asset is renewed (i.e., substantially rebuilt or overhauled) or removed from service and replaced. If an asset is to be replaced the operational requirements throughout the expected life of its replacement are identified and specified. This includes aspects such as capacity (decarbonisation/demand changes), functionality (technology/customer expectations), strength (climate change/new standards) and end of life disposal (sustainability/safety).

8.5 Data Improvement

One of the key areas we are working on is improving the quality of asset data that we collect and base decisions on digitally. This includes fixed attributes such as manufacturer, model numbers and capacities, as well as operational data such as demand profiles, condition, location, and relationship with other assets on the network.

Some of this data, such as geographical location and relationship of one asset to the rest of the network, is available and reliable for almost all of our assets. Some asset types such as poles have good condition data available, but incomplete age data. Some asset types, such as distribution transformers, have good age data available, but incomplete information on demand profiles. We are working to identify and close these gaps based on the criticality of the information for asset management decision making.

Asset Health is primarily based on condition information. The condition information can be further separated into objective (test results) and subjective (visual assessment) data. Where assets lack suitably robust condition data, then modelling using parameters such as type (make and model), location (environmental/pollutants) and age is used.

Utilising field capture of key information will help in this improvement area. Many of our data capture activities are paper based, which leads to difficulty with data analysis and linking of data, and with the sharing of asset information between parts of the business.

8.6 Zone Substations

8.6.1 Overview of zone substations

Zone substations house the equipment that connects the bulk electricity supply at sub-transmission voltage to our customers for end use. Power transformers convert electricity from 33 kV, which allows transfer of large amounts of energy to 11 kV, allowing for the cost-effective connection of end user demand. Switchboards and other switchgear allow the safe and reliable connection of supply to multiple areas from a central point via 11 kV feeders that are monitored by protection relays to swiftly disconnect the supply in the event of a fault.

Our zone substations are summarised in the following table. We also own assets at two Transpower GXPs, which are functionally treated under the same regime as our zone substations for maintenance and renewals.

Table 11 - Summary of NWL zone substations

Zone Substation	GXP	Capacity (MVA)	Number of Customers	Security Level	Year Built	Number of Feeders	Transformer Year of Manufacture	Switchgear Year of Manufacture
Ohau	Twizel	3	178	N	2006	3	1959	1997
Omarama	Twizel	3	482	N	1984	3	1960 & 1963	1985
Ruataniwha	Twizel	2	18	N	2015	1	1971	None
Otematata	Waitaki	3	537	N	1973	2	1961	2017
Kurow	Waitaki	12.5	756	N-1	1991	5	1966 & 1979	2015
Eastern Road	Waitaki	7	124	N	2020	3	2005	2018
Duntroon	Waitaki	7	215	N	2010	3	2010	2024
Ngapara	Oamaru	7	358	N	1970	4	2005	1972
Papakaio	Oamaru	7	266	N	2006	4	2012	2006
Enfield	Oamaru	7	326	N	2006	3	2005	2006
Five Forks	Oamaru	7	174	N	2017	3	2005	2016
Parsons Road	Oamaru	10	1,119	N	1970	4	1966	2018
Weston	Oamaru	-	0	N-1	2005	-	-	2005
Pukeuri	Oamaru	12.5	445	N-1	1971	5	1966 & 1966	2017
Chelmer Street	Oamaru	28	4,133	N-1	1967	8	2009 & 2009	2009
Redcastle	Oamaru	15	2,390	N-1	1967	6	2014 & 2014	2008
Maheno	Oamaru	5	1,036	N	1967	4	1965	2019
Hampden	Oamaru	7	839	N	2010	2	2012	2023
Te Awamako	Oamaru	10	142	N	2024	2	2023	2023
Waitaki GXP	Waitaki	24	10	N	2013	1	2014	2013

Note: The security grade refers to the security of supply based on the equipment at the substation and does not factor in the ability for load to be switched to surrounding substations during an outage.

Management approach

Our zone substation assets are critical assets, as a component failure can have a significant impact on system reliability and many customers.

Our objectives for the maintenance of zone substations assets are:

- Keep our people and members of the public safe
- Maintain the reliable supply of electricity to our distribution network and minimise supply interruptions
- Ensure that zone substations are operable in a post disaster scenario
- Maintain the value of our investments and prevent negative effects on the neighbourhood.

8.6.1 Zone substation buildings, fences, switchyards, and grounds

Our zone substation buildings are specifically designed for their location and criticality. They are mostly constructed with reinforced, concrete-filled blocks. We continue to invest in strengthening them based on the experience gained by other infrastructure businesses.

8.6.1.1 Age profile and population data

We expect zone substation building to have an average life of 70 years. The age/health profile shown in the following graph is based on the establishment date of the substation. In several cases the buildings, switchyards and fences have been partially rebuilt in the intervening years.

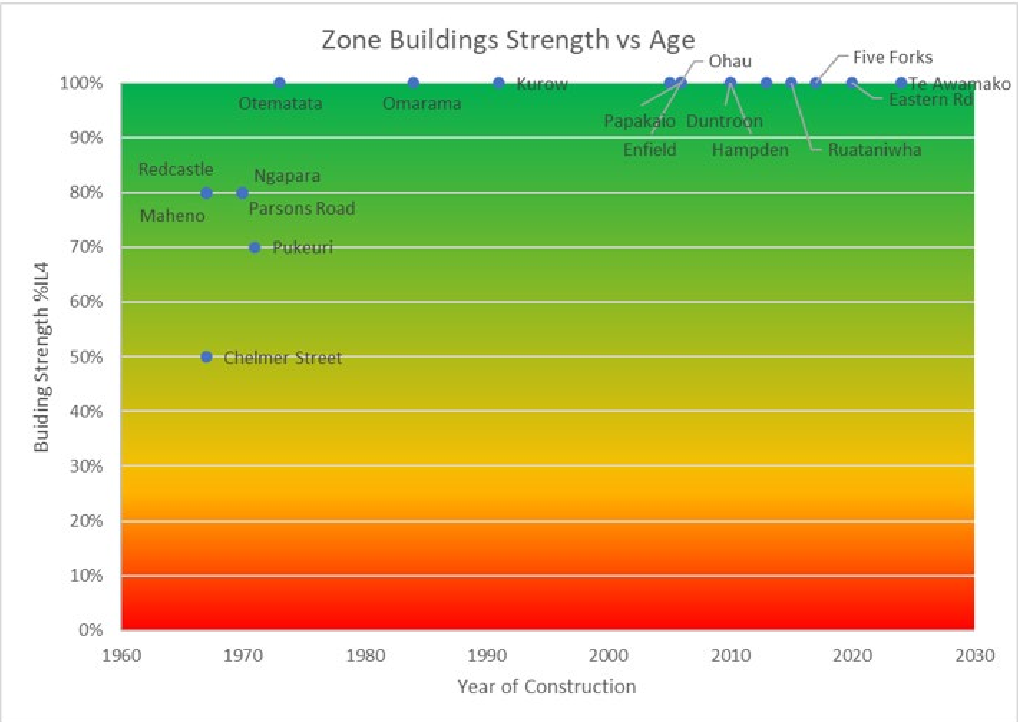


Figure 32 - Age and Strength profile for zone substation buildings

8.6.1.2 Asset risks

Specific risks and issues associated with this asset group include:

- Security breach due to fence condition, failure of locks, etc
- Damage due to animal ingress into yard (e.g., possums) or into switch room equipment (e.g., mice)
- Water/weather ingress into switch room
- Work hazards due to condition of switchyard surfaces, including surface levelling, weeds, etc
- Failure of lighting, heaters, and other secondary equipment
- Electrical hazards from rubbish, straw, and other foreign materials inside switchyards
- Condition of firefighting equipment, oil spill equipment, etc.

8.6.1.3 Inspection and maintenance programme

Activity	Summary	Frequency
Routine visual inspections	All equipment at substation. Check for defects, weeds, issues with weather tightness, housekeeping, pest control, etc. Special attention to site security, fences, etc.	3 months
Detailed inspection	Detailed condition assessment of fencing, building envelope, bus structures, etc.	5 yearly
Earthing system test	Specialist test of the performance of the substation earth mat	5 yearly

8.6.1.4 Renewal and refurbishment programme

In line with our commitments to prepare for HILP events (see section 3), our substations need to be able to operate immediately after an earthquake or other disaster and are therefore required to meet importance level 4 (IL4) under the New Zealand Building Code. In 2019 we assessed the seismic capacity of our substations against the new building standard for IL4 (% NBS IL4). A remediation plan was developed, and remedial work began in 2020. The following table shows the work completed since then.

Substation	% NBS IL4	Risk level	Structural work	Non- structural work	Land remediation	Target date
Waitaki GXP	100%	Low	N/A	N/A	no	Complete
Kurow	100%	Low	N/A	Minor	minor	Complete
Twizel	100%	Low	N/A	N/A	no	Complete
Ruataniwha	100%	Low	N/A	N/A	no	Complete
Ohau	100%	Low	N/A	N/A	no	Complete
Omarama	100%	Low	N/A	N/A	no	Complete
Otematata	100%	Low	N/A	Significant	no	Complete
Pukeuri	70%	Medium	Required	N/A	no	Complete
Five Forks	100%	Low	Required	Minor	no	Complete
Hampden	100%	Low	Required	Minor	no	Complete
Papakaio	100%	Low	Required	Minor	no	Complete
Duntroon	100%	Low	Required	Minor	no	Complete
Enfield	100%	Low	Required	Minor	yes	Complete
Redcastle	80%	Medium	Required	Significant	no	Complete
Maheno	80%	Medium	N/A	N/A	no	Complete
Parsons	80%	Medium	Required	Minor	no	Complete
Ngapara	80%	Medium	N/A	Minor	minor	Complete
Weston switch room	100%	Medium	N/A	N/A	no	Complete
Chelmer St	50%	Medium	Required	Minor	minor	Complete

Table 12 - Zone substation building strength against IL4

The work ranged from spot strengthening actions at some substations through to the addition of significant internal steel reinforcing frames in others. All strengthening work is now finished with the recent completion of Chelmer Street strengthening at the end of 2024. Although Chelmer Street is rated at approximately 50%NBS(IL4), there is a very low probability of collapse due to the inherent ductility of the structure. Similar buildings in Christchurch did not collapse, and in general performed better than expected.

Other refurbishment and renewal programmes include repair, upgrade or replacement of fencing and security systems based on condition assessment, and how effective they are compared with current security standards. Other defects such as damage to buildings are remedied as they are found.

The transformer bunds at Otematata and Omarama substations will also be upgraded as part of scheduled transformer replacements at those sites.

8.6.2 Zone substation transformers

Power transformers are installed at zone substations to transform sub-transmission voltages to a distribution voltage of 11kV. They are fitted with on-load tap changers and electronic management systems to maintain the required delivery voltage on the network.

8.6.2.1 Age profiles and health data

We expect power transformers to have an average service life of 60 years. The age used in the following graph is the date of manufacture of the transformers and the health index is based on the Electricity Engineers Association Asset Health Indicator Guide.

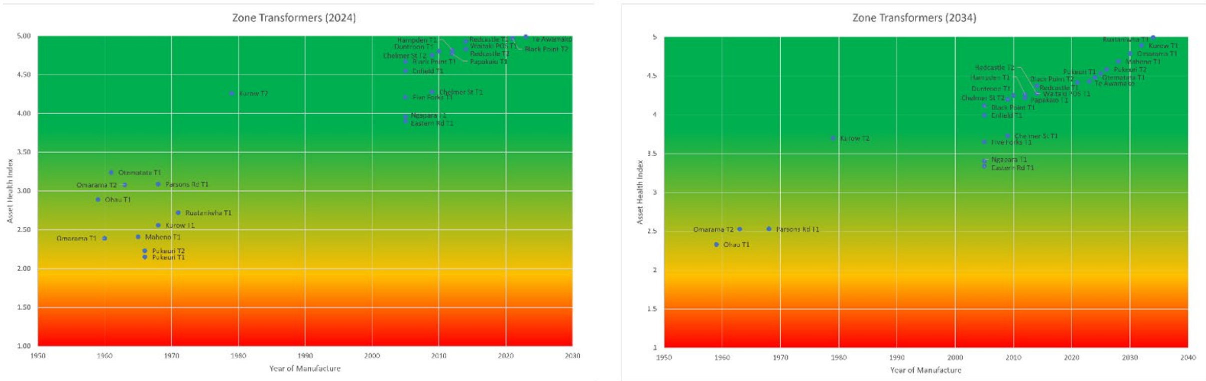


Figure 33 - Zone transformers age and health profile 2023 and 2033 (forecast)

8.6.2.2 Asset Risks

Risks and issues commonly associated with zone substation transformers include:

- Degradation of paper insulation resulting in damage during faults
- Reduction in life due to oil degradation
- Catastrophic failure due to internal electrical fault
- Online tap changer failure
- Reduction in capacity due to cooling system (radiators and fans) failure
- Environmental damage due to oil leaks
- Electrical failure due to cracked or damaged bushings
- Moisture ingress into transformer due to dehydrating breather system malfunction
- Reduction in life due to corrosion
- Damage in an earthquake due to failure of seismic hold-down equipment

8.6.2.3 Inspection and maintenance programme

Activity	Summary	Frequency
Routine visual inspection	As part of regular sub inspections.	3 months
Partial discharge tests	As part of substation PD testing.	12 months
Transformer detailed inspection	Detailed inspection. Includes expert inspection, thermal imagery, DGA and oil testing.	12 months
Transformer tap changer maintenance	Servicing of tap changer and associated equipment. SFRA and other offline testing carried out during work.	Oil filled 3 yearly, or 10,000 operations
		Vacuum 7 yearly, or 300,000 operations

8.6.2.4 Renewal and refurbishment programme

Zone substation transformers are a long lead time item, in that procurement of replacements can take 12 months or more. For this reason, we aim to maintain these assets in good condition, and to predict end of life with sufficient notice to secure replacements. In the case of an unforeseen failure, contingency arrangements are in place for all transformers based on the criticality of the site and utilising a hierarchy of controls, including:

- Energised spare on site (N-1)
- Transferral of load to adjacent sites (N-1 Switched)
- De-energised spare on site
- Compatible energised spares at other sites

Transformer on-load tap changers are refurbished every three years, or 10,000 operations, whichever comes first. Analysis of our historical refurbishment work indicated a historical under-budgeting in this area, so the forecast for this programme has received an uplift in this plan.

Maintenance activities such as oil treatment or streamlining are triggered by trends detected during DGA testing.

Minor defects such as a damaged breather or cracked bushing are remedied soon after they are detected, as the repair work is relatively simple. Major refurbishment of transformers is based initially on age (mid-life) and then condition and operation characteristics (late-life). An older transformer that shows good results for oil and paper condition in routine testing (such as DGA tests) can be a good candidate for late-life refurbishment, which will generally involve core de-tanking for dry out and tightening, as well as refurbishment of the tank, replacement of fans, radiators and auxiliary systems as required.

Replacement decisions for transformers are based on the assessment of factors such as having outdated major systems (e.g., tap changers) that cannot be adequately supported, incompatible vector group for normal operation or the condition of insulating paper as determined by DGA testing.

We follow international good practice to ensure that our transformer condition assessment processes are delivering good outcomes. As can be seen from the age profile, several of our transformers will reach or surpass the standard asset life within the planning period, with nine units currently more than 50 years old. Annual DGA and inspections indicate that most of our fleet are in good condition for their age and are likely to continue to operate safely and reliably. We will look to extend the life of these transformers if it is economic to maintain them in operation, or until reinforcement or capacity upgrades force their retirement.

Capacity upgrades at some substations as part of the network development plan (see chapter 6) will influence this replacement programme, as this work may free up newer transformers that can replace older units or be stored as emergency spares.

8.6.3 Zone substation switchgear

Zone substation switchgear allows the control of the individual high voltage circuits that radiate out from the substations. The switchgear provides a safe and convenient way to energise and de-energise sections of the sub-transmission and distribution networks for clearance of faults, or to carry out work.

8.6.3.1 Age profile and asset data

We expect zone substation outdoor switchgear to have an average service life of 40 years, and indoor switchgear 45 years.

The health profiles in the following graphs are based on the Electricity Engineers Association Asset Health Indicator Guide. The units with the lowest health ratings are in Duntroon, Hampden and Ngapara substations and are all scheduled for replacement in the next 3 years.

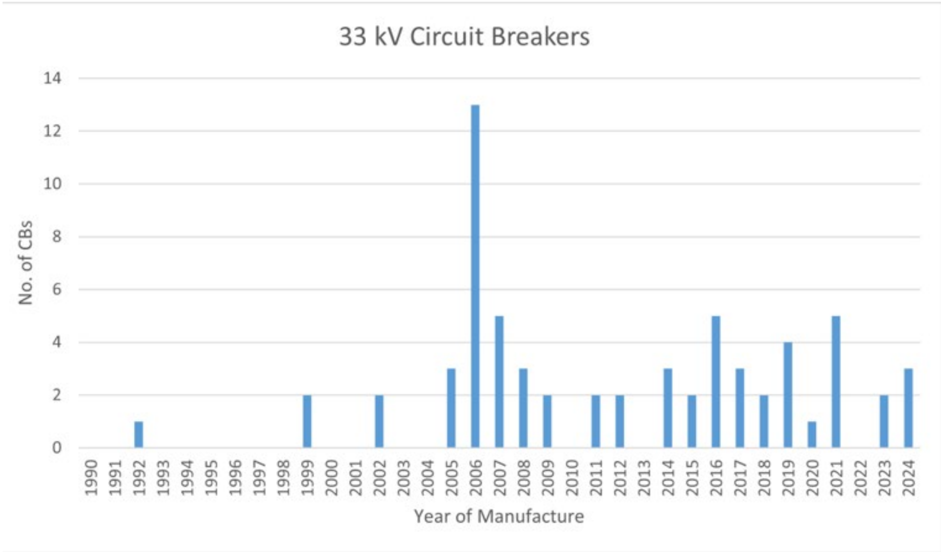


Figure 34 - 33 kV circuit breaker age profile

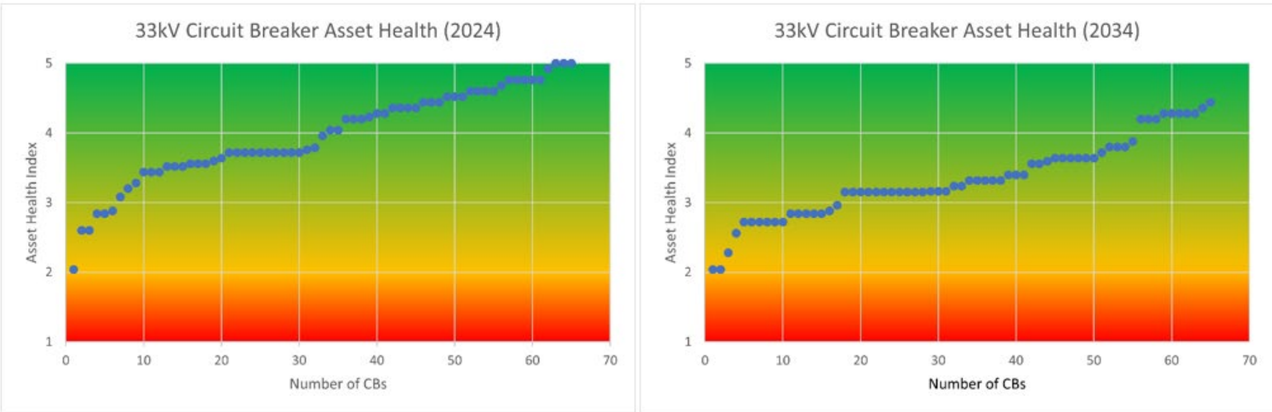


Figure 35 - 33 kV circuit breaker Asset Health 2024 (Current) and 20 34 (Forecast)

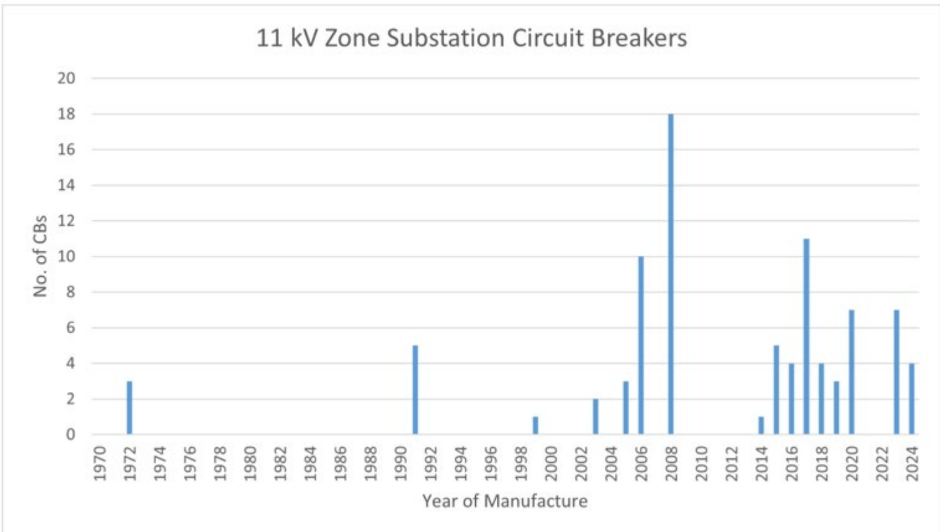


Figure 36 - 11 kV Zone Substation circuit breaker age profile

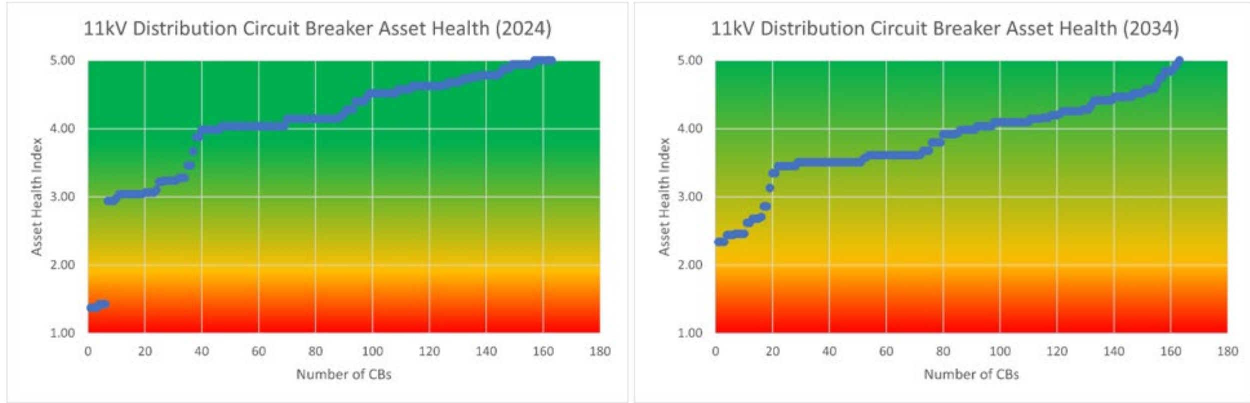


Figure 37 - 11 kV Distribution circuit breaker Asset Health 2024 (Current) and 2034 (Forecast)

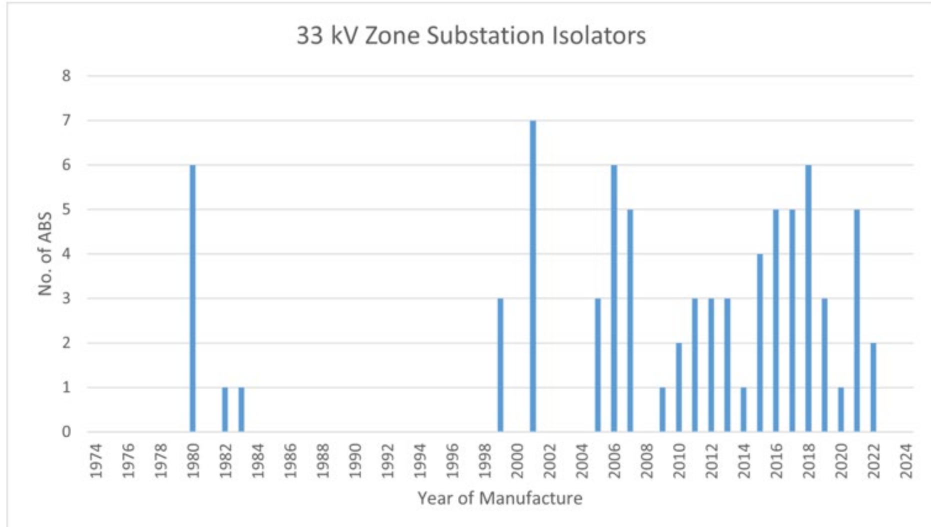


Figure 38 - Zone Substation Isolator Age Profile

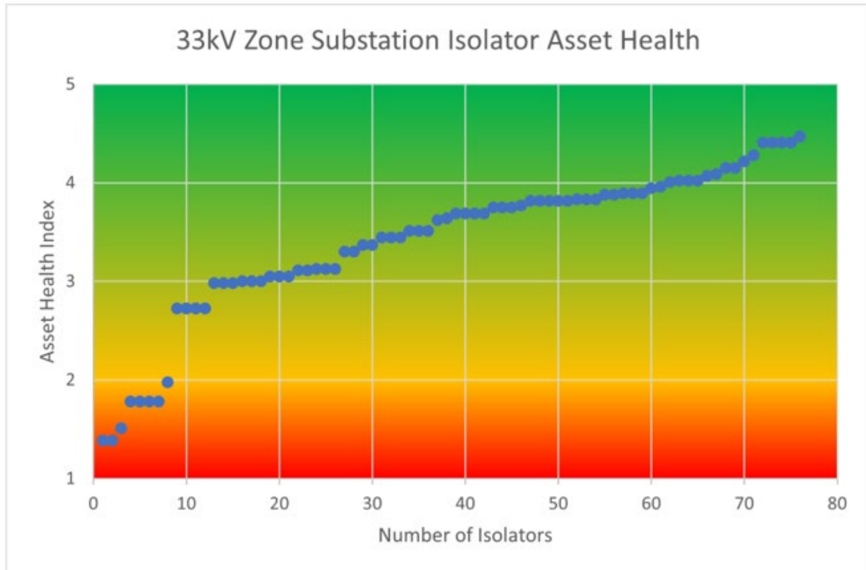


Figure 39 - Zone Substation Isolator Asset Health

8.6.3.2 Asset risks

Common issues and risks associated with this asset group include:

- Degradation of oil insulation in older switchgear
- Mechanisms binding and slowing down
- Overheating conductors (busbar, joints, terminations)
- Partial discharge (cable terminations, busbar chambers)
- Arc flash hazard to operators due to switchgear design and type
- Isolator contact damage
- Cracking porcelain insulators

8.6.3.3 Inspection and Maintenance Programme

Activity	Summary	Frequency
Visual external inspections	As part of regular inspection	3 monthly
Detailed switchboard inspection (non-invasive)	Partial discharge testing, thermal imaging of boards, CBs, cable terminations etc.	12 months
110kV or 33kV gas insulated CB maintenance	Insulation, contact resistance and operational tests.	5 yearly
33kV or 11kV vacuum insulated CB switchboard maintenance	Insulation, contact resistance and operational tests.	5 yearly
11kV oil filled CB switchboard maintenance	Service of oil CBs. Insulation, contact resistance and operational tests.	3 yearly/3 high current fault operations

8.6.3.4 Renewal and refurbishment programme

A programme is underway to replace older (pre-1990) oil insulated switchboards with modern, arc-fault-rated switchboards fitted with vacuum-insulated circuit breakers. Three switchboards remain to be replaced, at Ngapara, Duntroon and Omarama zone substations; all are scheduled for replacement in the planning period. Drivers for replacement include the age and obsolescence of equipment making maintenance and repairs difficult, minor age-related failures causing reliability problems, and the poor safety performance of the type of switchgear in the event of an arc flash fault.

We are retrofitting arc-fault-rated doors and arc flash detection systems to the more modern switchgear in our zone substations. Installations are scheduled based on fault level and other work that is being completed on switchgear.

Outdoor switchgear (33 kV and 11 kV vacuum/gas-insulated circuit breakers and air break switches) are replaced based on condition assessment or as they become obsolete and the management of spares becomes problematic. We expect to replace two examples of this switchgear in the planning period.

There is a known problem with a particular brand of 33 kV air break switch where the porcelain insulators crack and fail. We carry out detailed inspection of these ABS at twice yearly intervals to check on signs of cracking and will be replacing all of this type of insulator during the early part of the planning period.

Substation cables are replaced or re-terminated based on the results of condition assessment (such as PD inspection) or based on age and type (e.g., old paper lead insulated cables) when replacement of associated equipment occurs, such as switchgear or power transformers.

8.6.4 Zone substation DC systems

DC systems at substations include the battery chargers and batteries. These systems are considered critical to the network, as they enable the operation of network equipment such as protection relays and circuit breakers in the event of the loss of mains power.

8.6.6.1 Age profile and population data

We expect zone substation DC supplies to have an average service life of 20 years, with the batteries having an expected serviceable life of 10 years. A profile showing the asset age of the main DC systems is below.

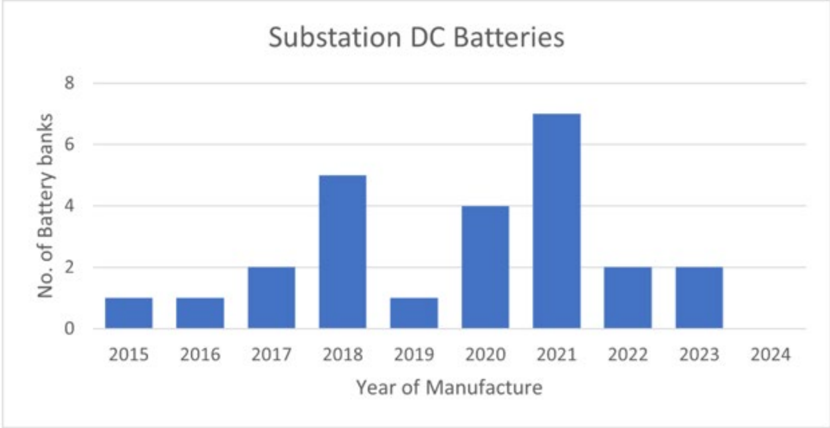


Figure 40 - Age profile data for zone substation battery banks

8.6.4.2 Asset Risks

Specific risks in this asset group include:

- Corrosion on battery terminals
- Loss of battery capacity
- Internal failure of batteries
- Failure of battery charger
- Damage to equipment during seismic event

8.6.4.3 Inspection and maintenance programme

Activity	Summary	Frequency
Visual inspection	As part of regular sub inspections	3 months
Battery testing	Routine testing of battery bank	12 months
Discharge testing	Discharge testing of battery banks	2 yearly

8.6.4.4 Renewal and refurbishment programme

Substation batteries are critical to the ongoing operation of the network. We currently plan to replace complete battery banks after no more than 10 years of life, to ensure that they will be fully capable of operating when required. Individual cells or entire banks may be replaced depending on the results of discharge testing before then. We will be monitoring the performance of more modern batteries to see whether modern charging management is increasing this useful life. We expect to replace up to five battery banks per annum. A stocktake and review of existing systems was completed in FY21 to close the information gaps around the age of some of the battery banks.

Battery chargers and associated switchgear are replaced based on age (if obsolescent) and operating performance. These systems are generally up to date and in good condition. As we replace older systems, we are installing smart chargers that provide detailed operational information through the SCADA system and will review DC system functionality and capacity during any upgrades.

8.6.5 Zone substation protection relays

Protection relays detect faults on the network and signal the circuit breakers to open and remove the supply to the affected assets. The key attributes of this equipment are that it is sensitive and reliable, so that public safety and network performance is maintained.

All the protection systems at our substations are of the modern digital type and are reasonably up to date and performing satisfactorily. All our substation protection relays are connected to our SCADA systems and are remotely controllable.

8.6.5.1 Age profile and population data

We expect protection relays to have an average service life of 40 years, although technological development and changing operational requirements often mean that the relays are superseded before this. A profile showing the asset age of the relays is below.

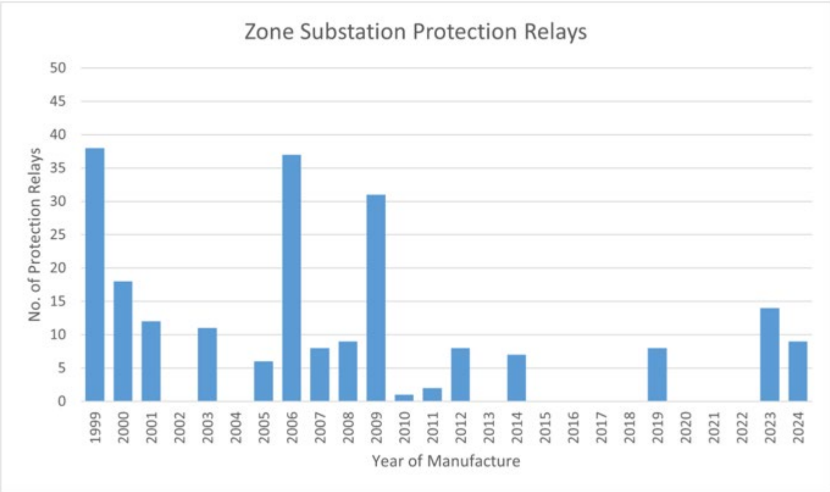


Figure 41 - Age profile data for protection relays

8.6.5.2 Asset risks

Specific risks in this asset group include:

- Failure of a protection device to operate, putting staff or the public in danger.
- Obsolescence of protection device leading to improper operation in the network.

8.6.5.3 Inspection and maintenance programme

Modern (post 1995) relays are microprocessor based and have inbuilt self-monitoring checks and alarms. These are linked to the Network Waitaki Operations Centre via the communications network. Additional direct monitoring and testing is described in the table below.

Activity	Summary	Frequency
Visual inspection	As part of regular sub inspections	3 months
Detailed protection relay assessment	Confirm settings and test operation, check, and replace onboard batteries, check terminals and wiring.	5 yearly

8.6.5.4 Renewal and refurbishment programme

We are working through a programme to replace some early microprocessor based protection relays (SEL 551 type) with more advanced designs that offer better operational flexibility.

We also take opportunities to improve the quality of our protection relay network when we can, as with the commissioning of differential protection on sections of our 33 kV sub-transmission network. These projects are generally carried out as part of wider project work, such as replacement of a switchboard or transformer.

There are no other specific condition-based replacement plans for protection relays currently, and neither are there obsolescence issues with the current fleet of relays. However, we have allowed an ongoing budget for replacement of protection relays that have been in operation for more than 20 years , as it is likely that we will begin to get some failures in the population from that point.

8.6.6 Zone substation Ripple Control transmitters

Our Load Management (Ripple) System controls electrical loads predominantly by injecting frequency signals over the electricity network. The primary purpose is to defer energy consumption and minimise peak load. This is achieved in two ways: 1) Customer demand management load reduction and/or generation; and 2) by distributor-controlled load management through hot-water cylinders and other interruptible loads. A secondary purpose of the system is to allow coordinated management of common load types such as streetlighting.

NWL owns and operates Landis & Gyr solid state 33 kV Ripple Injection Plants at Oamaru and Twizel GXPs. An indoor Landis & Gyr solid state 11 kV injection unit is installed at the Kurow Zone Substation and services the demand connected to the Waitaki GXP. We own the ripple control relays installed at customers' premises.

5.6.6.1 Age profile and population data

We expect ripple transmitters and their associated equipment to have an average service life of 40 years. Transmitters are located at the following sites:

Zone substation	GXP(s) served	Year Installed
Kurow	Waitaki	1999
Twizel	Twizel	2005
Parsons Rd	Oamaru	2013

Table 13 - Ripple control transmitters by installation date

8.6.6.2 Asset risks

Specific risks for ripple control transmitters include:

- Failure of power electronics in transmitter
- Failure of coupling cell component

8.6.6.3 Inspection and maintenance programme

Activity	Summary	Frequency
Visual inspection	As part of regular substation inspections	3 months
Detailed ripple control plant inspection	Check operating signals, test coupling cell components	Annually

Further monitoring, testing and maintenance of the SCADA System is part of a support contract with the SCADA system provider.

8.6.6.4 Renewal and refurbishment programme

Our ripple control transmitters are still within their expected lifespan, but they are a highly critical piece of equipment, and the system configuration does not allow for mutual support between all units in the event of the failure of one. For this reason, we hold critical spares for these plants.

We expect that ripple control will be rendered obsolete by 2035 due to displacement by new smarter technology or the next generation of smart meters. As a result, we are not forecasting any replacement of ripple plant in the planning period.

We will maintain a watching brief on this situation and adjust this programme accordingly. We intend to maintain our ripple control capability until alternatives are established and proven and have increased our holding of critical spares for these assets in the interim.

8.6.7 Total zone substation expenditure forecast

Zone Substations ($000)	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
Service Interruptions & Emergencies	0	0	0	0	0	0	0	0	0	0
Routine & Corrective Maintenance and Inspections	368	351	351	351	351	351	351	351	351	351
Replacement & Renewal (Pukeuri Transformer 1)	2,284	0	0	0	0	0	0	0	0	0
Replacement & Renewal (Pukeuri Transformer 2)	2,290	0	0	0	0	0	0	0	0	0
Replacement & Renewal (Omarama Transformer 1)	0	0	113	2,268	130	0	0	0	0	0
Replacement & Renewal (Kurow Transformer 1)	0	0	0	0	113	2,268	130	0	0	0
Replacement & Renewal (Maheno Transformer)	0	0	0	0	0	0	113	2,268	130	0
Replacement & Renewal (Ruataniwha Transformer)	0	0	0	0	0	0	0	0	113	2,268
Replacement & Renewal (Ngapara Switchgear)	499	0	0	0	0	0	0	0	0	0
Replacement & Renewal (Pukeuri Alliance Switchgear)	0	2,387	227	0	0	0	0	0	0	0
Replacement & Renewal (Other)	596	529	581	484	484	536	484	484	484	484
Total	6,037	3,267	1,272	3,103	1,078	3,155	1,078	3,103	1,078	3,103

8.7 Sub-Transmission Network

8.7.1 Overview of the sub-transmission network

The sub-transmission network connects the supply of electricity from Transpower grid exit points (GXPs) to our zone substations. The zone substations connect to our distribution network to supply the local community.

Supplies to zone substations are generally configured so they have an alternative supply from another sub-transmission circuit. This also makes the sub-transmission assets relatively easy to remove from service in order to carry out inspections, maintenance and repairs.

Our sub-transmission system currently operates at 33 kV only. New and rebuilt sections are designed to operate at 110kV to provide optionality for the future.

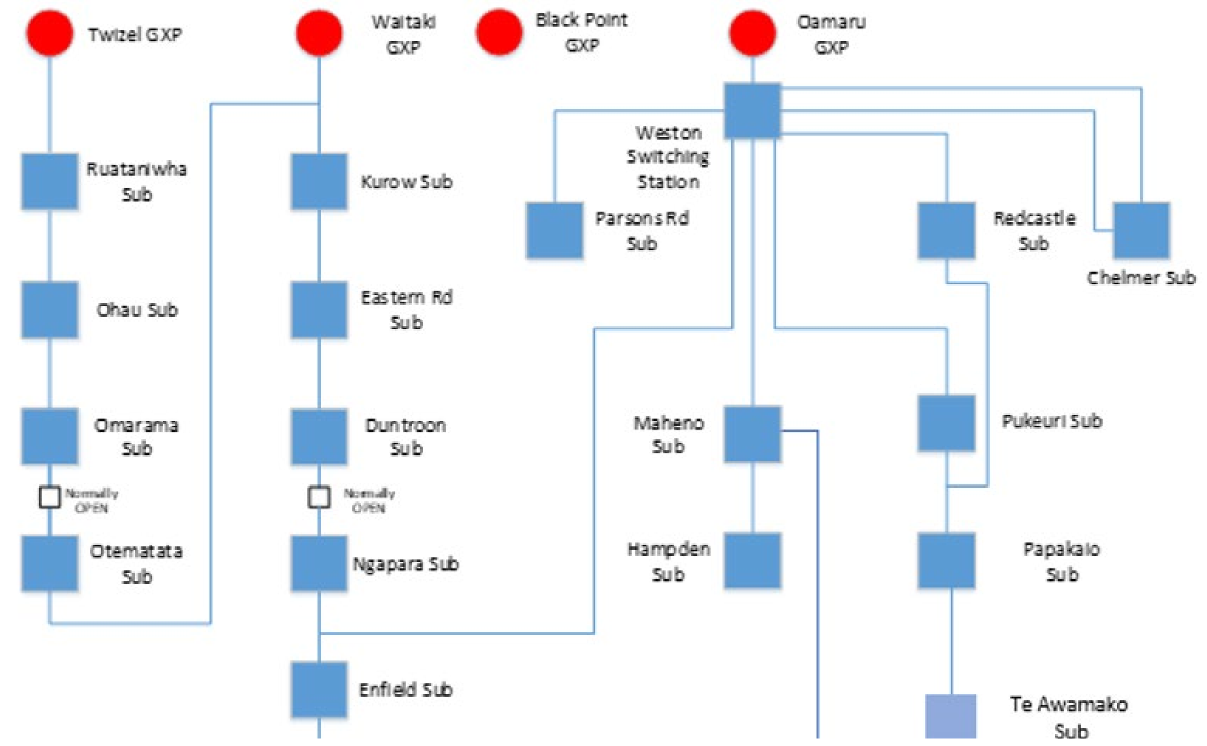


Figure 42 - Sub-transmission system configuration

Management approach

The 33 kV sub-transmission network is mostly overhead construction, apart from some short lengths of cable, generally between the feeder CBs and line terminations, and on the Redcastle to Pukeuri feeder.

Our objectives for the maintenance of our sub-transmission assets are to:

- Keep members of the public safe.
- Maintain the reliable supply of electricity to our zone substations and minimise supply interruptions.

A failure on the sub-transmission system can affect several zone substations, and hence many customers. The construction maintenance and inspection requirements for these high criticality assets is accordingly to a higher standard than the general distribution system.

8.7.1 Sub-transmission lines

Our sub-transmission overhead circuits total 249km in length and are a mixture of ACSR, AAC and AAAC conductors.

ACSR is a stranded aluminium conductor reinforced with steel strands at its core. It is chosen for its high strength and reasonable conductivity. It performs well under snow, wind and ice but can be vulnerable to corrosion in coastal and other areas with high air pollution.

AAC is a stranded All Aluminium Conductor. It has historically been chosen for its good conductivity and corrosion resistance, but it lacks the mechanical properties of ACSR. It performs well in coastal environments and in urban areas where its limited strength is not a liability, as the spans between poles are shorter.

AAAC is a stranded All Aluminium Alloy Conductor. It has good conductivity and corrosion resistance and better strength characteristics than AAC, though not quite as good as ACSR. It performs well in all environments and is the default conductor of choice on the sub-transmission network unless local conditions (e.g., higher altitude) require the use of ACSR.

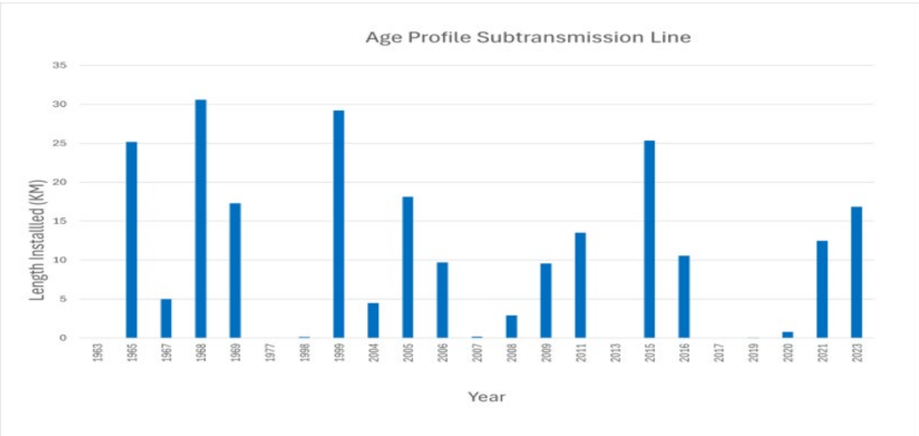
A summary of the line conductor types on our sub-transmission system is in the table below.

Conductor type	Length
ACSR	106 km
AAC	77 km
AAAC	66 km

Table 14 - summary of sub-transmission line types

8.7.1.1 Age and health profile data

The average life expectancy we apply to our sub-transmission lines is 60 years and an age profile for them is shown below:



The health profile of these assets is shown below. Sub-transmission lines are often installed and replaced in large sections with the same material subject to similar environmental conditions. This is reflected in the "stepped" nature of the profile.

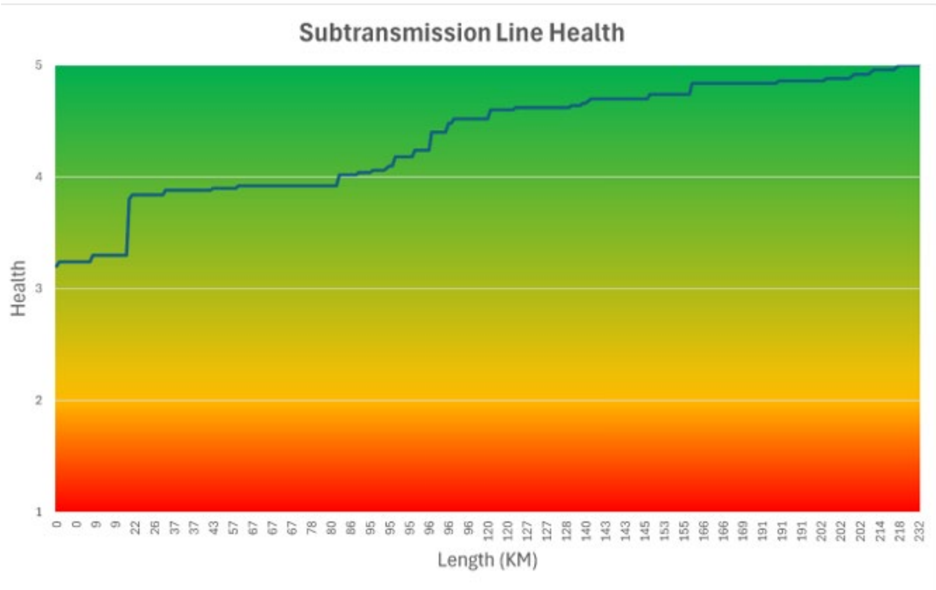


Figure 43 – Asset Health profile of sub-transmission overhead conductor

8.7.1.2 Asset risks

Major risks to the sub-transmission lines include:

- Extreme weather events such as heavy snow or high winds resulting in contact with trees or windborne debris
- External equipment – pivot irrigators moving into, spraying, or contacting lines
- Degradation of strength due to age-related issues such as corrosion
- Thermal fatigue or damage to connections due to cyclic loading or through fault currents.

8.7.1.3 Inspection and maintenance programme

Activity	Summary	Frequency
Ground patrol	Ground based visual inspection for clearances, uneven sagging and damage such as broken strands Thermal inspection of joints and terminations Vegetation-related defects are recorded to be managed in accordance with the Electricity (Hazards from Trees) Regulations 2003	Annual
Climbing patrol	Standard ground inspection plus pole top accessed via ladder or EPV in order to tighten fittings, repair loose binders, examine conductor condition etc.	At least 5 yearly
Conductor sample testing	Special targeted testing of conductor to check for issues on older lines	As required
Aerial inspection	Inspection of overhead lines and equipment using either helicopters or drones – may include visual inspection, Corona camera inspection, thermal imaging, and LiDAR data capture.	As required

8.7.3.4 Renewal and refurbishment programme

Sometimes the overall age and condition of a particular stretch of overhead line will require a complete rebuild. Some sub-transmission circuits that were installed in the 1960s are scheduled for rebuilding during the planning period. In the planning period we expect to rebuild the Weston to Maheno 33kV circuit due to conductor condition caused by vibration over time.

During renewals we may also improve the reliability of the sub-transmission network by replacing overhead circuits with underground, or by physically separating circuits to increase route diversity, when it is economic to do so.

8.7.2 Sub-transmission support structures

The sub-transmission lines are supported by 2881 poles. They are a mixture of wooden (Hardwood and Softwood) and concrete (Pre-stressed and Mass Reinforced).

Hardwood poles are usually sourced from Australia. They are suitable in all conditions and can be used under all loading conditions.

Softwood poles are usually locally sourced. They are suitable in all conditions and can be used under all loading conditions but have a lower strength to size ratio compared with hardwood poles and they age faster. An issue has been identified where some have been designed using the same criteria as hardwood poles. A project to replace those most at risk is planned for FY25 and accelerated replacement of the remainder has been allowed for within the normal renewal programme.

Pre-stressed poles are usually locally sourced. They are suitable in most conditions but are vulnerable in low temperature and age faster in high pollution environments. Their shape (width to breadth ratio) means that they are not suited to all loading situations. They are lighter than wood and mass reinforced concrete poles for a given strength but are vulnerable to shock loads such as from contact machinery and vehicles.

Mass reinforced poles were usually locally sourced but are no longer available. They are suitable in most conditions but are vulnerable in low temperature and age faster in high pollution environments. Their shape (width to breadth ratio) means that they are not suited to all loading situations, but they are less vulnerable to shock loads than prestressed poles.

A summary of the different pole types in use on the sub-transmission system is in the table below:

Asset type	Number
Hardwood Poles	1937
Softwood Poles	486
Pre-stressed Concrete	238
Mass Reinforced Concrete	220

Table 15 – Pole types in use on the sub-transmission system

8.7.2.1 Age and health profile data

The average life expectancy we apply to our poles is 40 years for softwood poles and 60 years for all other types. An age profile for them is shown below. Softwood poles have been installed on sub-transmission lines only since 2000.

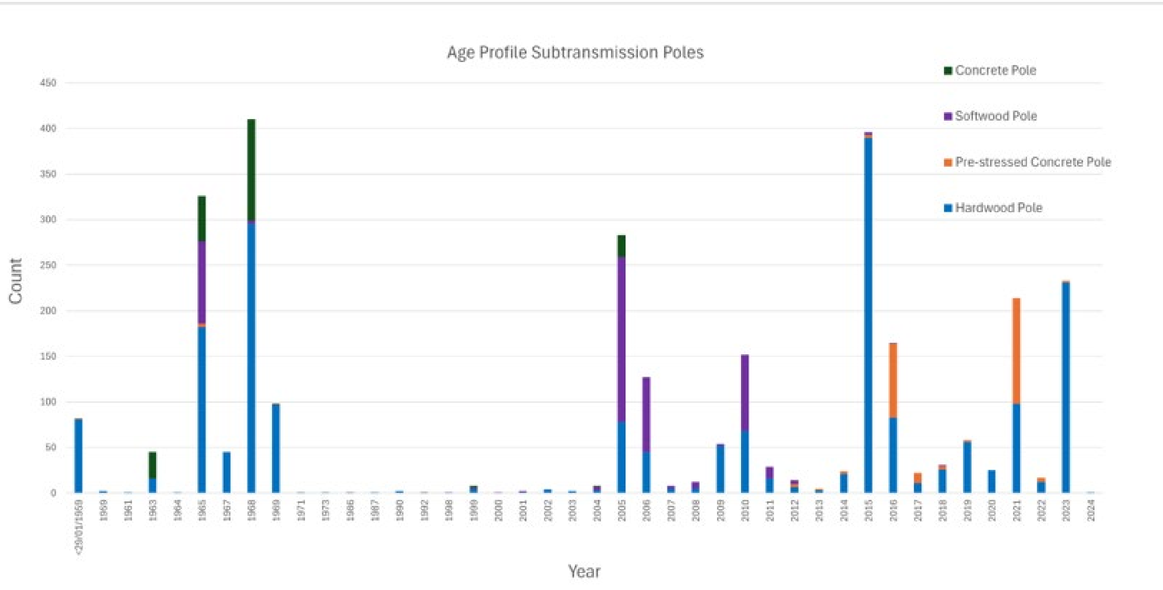
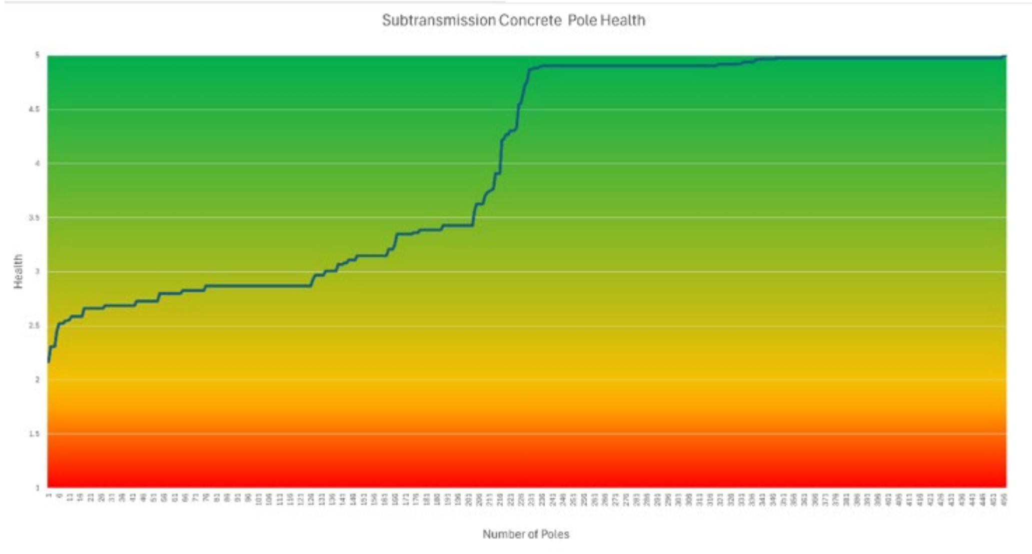
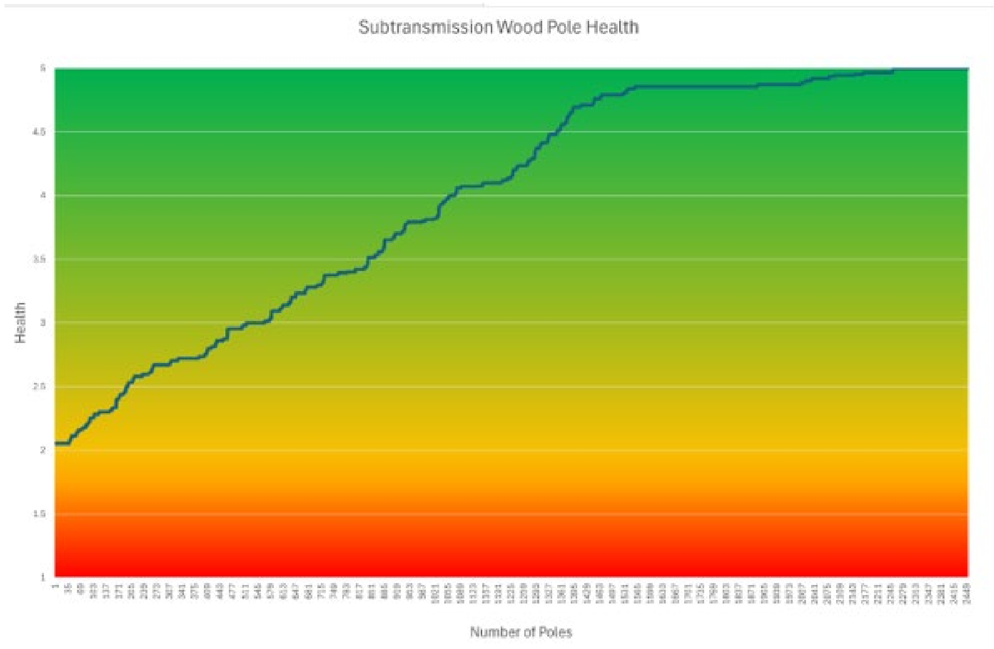


Figure 44 - Age profile for sub-transmission poles

Concrete and wood poles have different condition assessment criteria but are graded using a common index. The asset health of the concrete and wood pole fleets are shown below.





8.7.2.2 Asset risks

Major risks to the sub-transmission poles include:

- Vehicle impact – much of the network is built adjacent to public roads
- Erosion of land around foundations
- Extreme weather events such as high winds or heavy snow
- Degradation of structural strength due to age related issues such as pole decay.

8.7.2.3 Inspection and maintenance programme

Activity	Summary	Frequency
Ground patrol	Ground based visual inspection of pole top, cross arms, and pole top hardware Testing of pole structural condition Thermal inspection of joints and cable terminations Vegetation related defects are recorded to be managed in accordance with the Electricity (Hazards from Trees) Regulations 2003.	Annual
Climbing patrol	Standard ground inspection plus pole top accessed via ladder or EPV to tighten fittings, repair loose binders, examine conductor condition, etc.	5 Yearly
Aerial inspection	Inspection of overhead lines and equipment using helicopters or drones – may include visual inspection, Corona camera inspection, thermal imaging, and LiDAR data capture.	As required

8.7.2.4 Renewal and refurbishment programme

Renewals in the sub-transmission network are largely repairs and replacements to structures based on the results of line patrols. Individual poles are generally earmarked for removal due to condition and changed in a suitable shutdown period. The renewal budget for pole and hardware replacement is based on defect rates developed from recent analysis of line patrols.

Sometimes the overall age and condition of a particular stretch of overhead line will require a complete rebuild. Some sub-transmission circuits installed in the 1960s are forecast for such rebuilding during the planning period. In the planning period we expect to rebuild the Weston to Maheno 33kV circuit due to conductor condition caused by age and vibration.

During renewals we may also improve the reliability of the sub-transmission network by replacing overhead circuits with underground, or by physically separating circuits to increase route diversity, when it is economic to do so. Condition based pole replacements required on the Chelmer St substation No.2 33 kV circuit are in difficult to reach locations, and the opportunity is being taken to replace the affected section of line with a new cable, at the same time locating in a more diverse route from the other 33 kV feeder. This will increase the resilience of the substation.

8.7.3 Sub-transmission cables

We have a small length (4km) of underground cable on our sub-transmission network, all of it modern (post 1985) XLPE type.

XLPE (Cross Linked Polyethylene) enhances the temperature properties of the insulation, allowing strength and chemical stability to be maintained at higher operating temperatures (and loads). Impact and tensile strength, scratch resistance, and resistance to brittle fracture are also enhanced over other insulation types.

8.7.3.1 Age and health profile data

The average life expectancy we apply to our modern XLPE cables is 55 years. An age profile for the various sections is shown below:

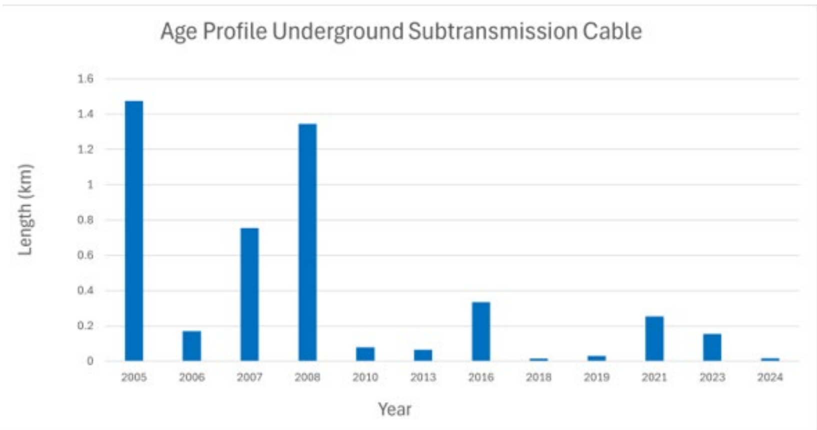


Figure 45 - Age profile of sub-transmission underground cables

8.7.3.2 Asset risks

Major risks to the sub-transmission cables include:

- Earthquake and other land movement around cables
- Damage by excavation and other works in the vicinity
- Material degradation of the insulation.

8.7.3.3 Inspection and maintenance programme

Activity	Summary	Frequency
Ground patrol	Patrol of cable routes to identify land damage and any excavation work in the vicinity	Annual
Partial Discharge Monitoring	Sub-transmission cable terminations as part of zone substation partial discharge monitoring	Annual

8.7.3.4 Renewal and refurbishment programme

Given the asset type, age and condition, there are no renewal or refurbishment plans for Network Waitaki's sub-transmission cables within the planning period.

8.7.4 Sub-transmission switchgear

Sub-transmission switchgear is used to control and redirect the flow of electricity between our zone substations. They are differentiated by function into subcategories (Circuit Breakers, Reclosers, Sectionalisers and Isolators).

Circuit Breakers are designed to operate and safely interrupt supply even under fault conditions where there are significant amounts of energy to be contained. They are normally located within zone substations.

Reclosers perform a similar function to Circuit Breakers but are usually rated to lower energy levels. Reclosers will automatically restore supply (re-close) in a transient fault situation. Often the only difference between a Circuit Breaker and a Recloser is its control mechanism and operational configuration.

Sectionalisers are used to isolate (sometimes automatically) sections of the network and can be operated under load, but not when a fault is present.

Isolators (Air Break Switches) are like Sectionalisers but can only be operated when there is no load flowing through them.

We utilise Vacuum and SF6 insulated switchgear Circuit Breakers, Reclosers and Sectionalisers in our sub-transmission network. Isolators are air insulated. Most of this equipment is of recent manufacture, although there are a handful of older items.

8.7.4.1 Age and health profile data

The average life expectancy we apply to our sub-transmission switchgear is 45 years and age profiles for the various types are shown below.

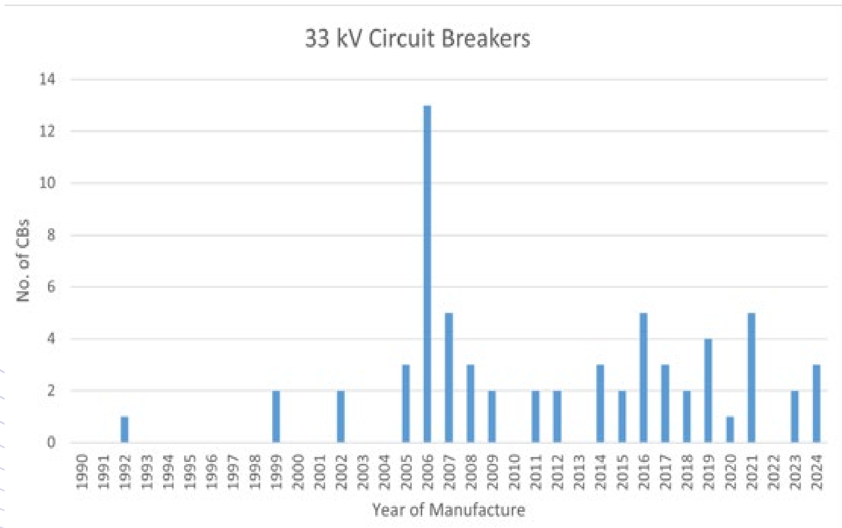


Figure 46 – Age profile of sub-transmission circuit breakers

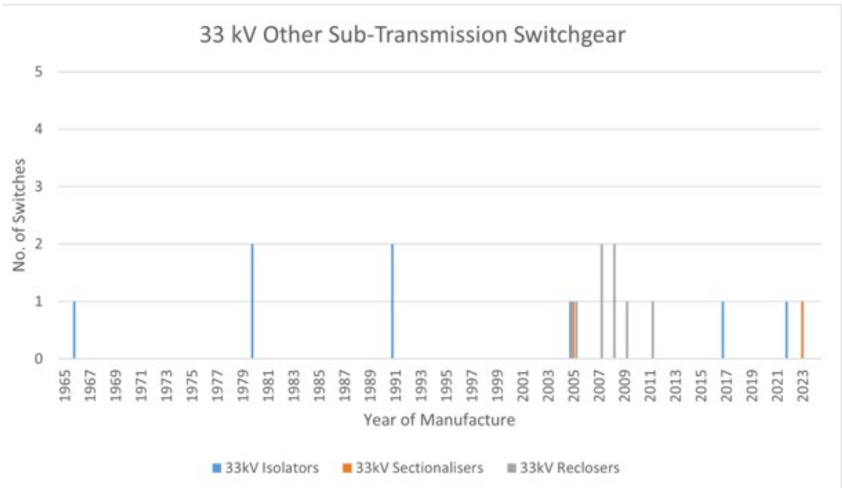


Figure 47 – Age profile of other sub-transmission switchgear

The practicable life of Circuit Breakers and Reclosers is often determined by other factors such as operational functional requirements, number of operations and magnitude of fault interruption. Asset Condition is therefore a more accurate indicator of remaining life than age.

The asset health of 33kV Circuit Breakers (including Reclosers and Sectionalisers) and Isolators are shown below:

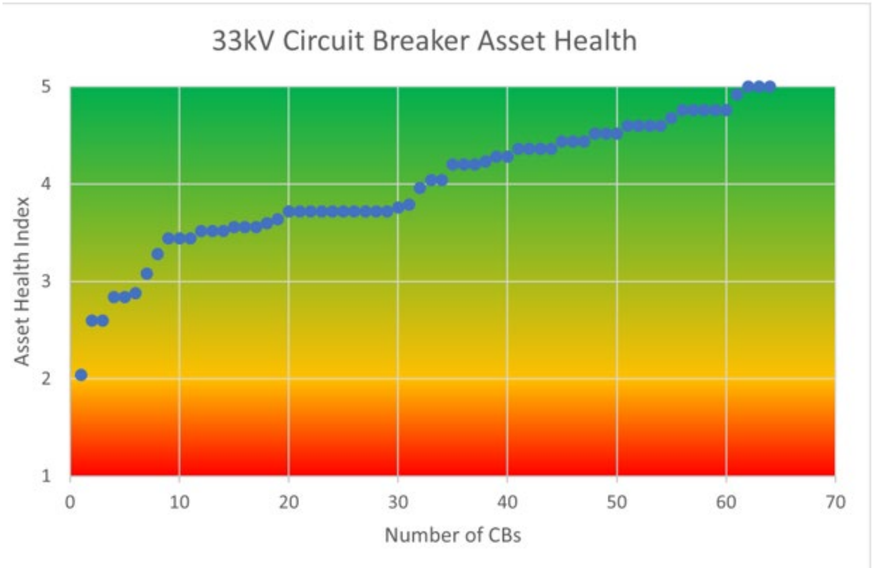


Figure 48 – Asset Health profile of sub-transmission Circuit Breakers , Reclosers and Sectionalisers

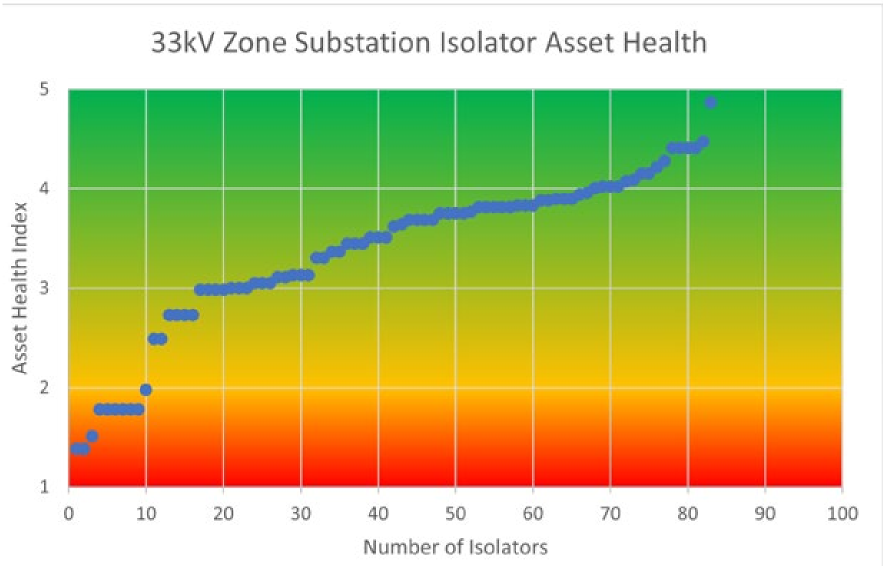


Figure 49 – Asset Health profile of sub-transmission Isolators

8.7.4.2 Asset risks

Risks commonly associated with our sub-transmission switchgear include:

- Loss of insulating gas or vacuum
- Failure of porcelain insulator through cracking or age
- Failure due to terminations overheating.

8.7.4.3 Inspection and maintenance programme

Activity	Summary	Frequency
Ground patrol	Thermal inspection of switchgear and terminations	Annual
Climbing patrol	Physical check of terminations, fittings etc.	5 yearly
Operational checks	Verification of settings and trip testing. Battery replacement	5 yearly

8.7.6.4 Renewal and refurbishment programme

Switchgear in this category is replaced based on condition assessment or as it becomes obsolete and the management of spares becomes problematic. We expect to replace two reclosers in this planning period for these reasons.

There is a known problem with a particular brand of 33 kV air break switch where the porcelain insulators crack and fail. We will be replacing all examples of this type of ABS in the early years of the planning period.

8.7.7 Sub-transmission network maintenance and renewal expenditure

Sub-transmission ($000)	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
Service Interruptions & Emergencies	16	16	16	16	16	16	16	16	16	16
Routine & Corrective Maintenance and Inspections	218	218	218	218	218	218	218	218	218	218
Asset Replacement & Renewal (Omarama-Twizel, Duntroon-Te Awamako)	0	61	0	0	0	0	0	0	0	0
Asset Replacement & Renewal (Weston-Maheno)	306	311	0	0	0	0	0	0	0	0
Asset Replacement & Renewal (Other)	353	353	353	353	353	353	353	353	353	353
Asset Relocations	0	0	0	0	0	0	0	0	0	0
Total	893	959	587	587	587	587	587	587	587	587

8.8 Distribution Network

Overview of the distribution network

Our distribution network operates at 11 kV. The distribution network reaches out from our zone substations to supply the majority of our customers using distribution transformers to convert the 11 kV supply down to 400/230 V for connection to customer loads.

There are fifty-five 11 kV distribution feeder lines supplied from our 33/11 kV zone substations. Supply restoration in the event of an outage is often possible by connecting neighbouring feeders. To assist in quicker supply restoration, we are installing automated open points on 11 kV interconnection between substations.

There are 1,247 km of overhead lines and 90 km of 11 kV cables on our distribution network.

Management approach

We maintain our distribution network with the aims of keeping it safe for our workers and the public, and minimising outages. Our approach is predominately mainly driven from defects found during regular inspection cycles, or generated from other work such as customer connections, or attendance at faults. When a part of the network is particularly affected by a major event (e.g., a snowstorm) we will instigate a special line patrol post event.

Where 11 kV feeders interconnect, they are normally configured as open points using remote controlled switches. This allows us to swiftly reconfigure the network to support load in the event of an outage. NWL's loadings are such that security provisions are generally focussed on switching to restore supply quickly rather than targeting zero interruptions.

This approach, which is backed by a fairly well interconnected distribution network, means that outage figures are kept below our targets without over investment on the distribution network.

Our distribution network covers a large area, with assets in diverse locations ranging from busy urban streets to isolated mountainsides. Individual components connect fewer and fewer customers the closer they are to the load, down to the level of an individual installation. Accordingly, we aim to balance our maintenance and renewals with the risk and service level associated with each asset.

Key objectives for management of our distribution network include:

- Keeping the public safe
- Keeping our workers safe
- Maintaining the reliability of our network
- No unassisted failures of poles and conductors in normal operating conditions
- Reduce the number of third-party contact incidents on our distribution network
- No incidents of unauthorised access to our ground mounted distribution assets
- Maintain the visual condition of our assets in neighbourhood areas.

8.8.1 Distribution lines

Our distribution lines connect the zone substation to distribution transformers, which are usually next to public roads or within the property they service. Any failures can be disruptive to our customers and the public at large, as most of the equipment is located in publicly accessible areas. They operate at 11kV and total 1,247km in length and are a mixture of HD Cu, GS, ACSR, AAC and AAAC conductors.

HD Cu is a stranded Copper conductor treated to ensure it retains its shape over time. It performs well under all environmental conditions and has excellent electrical properties. The cost increases in the late 1960s mean that it is now rarely used in new builds.

GS (Galvanised Steel) has been used where mechanical strength needs to dominate over electrical requirements. This conductor has extremely high strength but poor reasonable conductivity. It performs well under snow, wind and ice but can be vulnerable to corrosion in coastal and other areas with high air pollution.

ACSR is a stranded Aluminium conductor reinforced with steel strands at its core. It is chosen for its high strength and reasonable conductivity. It performs well under snow, wind and ice but can be vulnerable to corrosion in coastal and other areas with high air pollution.

AAC is a stranded All Aluminium Conductor. It has historically been chosen for its good conductivity and corrosion resistance, but it lacks the mechanical properties of ACSR. It performs well in coastal environments and in urban areas where its limited strength is not a liability, as the spans between poles are shorter.

AAAC is a stranded All Aluminium Alloy Conductor. It has good conductivity and corrosion resistance and better strength characteristics than AAC, though not quite as good as ACSR. It performs well in all environments and is the conductor of choice on the sub-transmission network unless local conditions (e.g., higher altitude) require the use of ACSR.

A summary of the line conductor types on our 11kV distributions system is in the table below.

Conductor type	Length
HD Cu	92 km
GS	70 km
ACSR	942 km
AAC	105 km
AAAC	42 km
Unknown	15 km

Table 16 - summary of distribution line types

8.8.1.1 Age and health profile data

The average life expectancy we apply to our distribution lines is 55 years and an age profile for them is shown below:

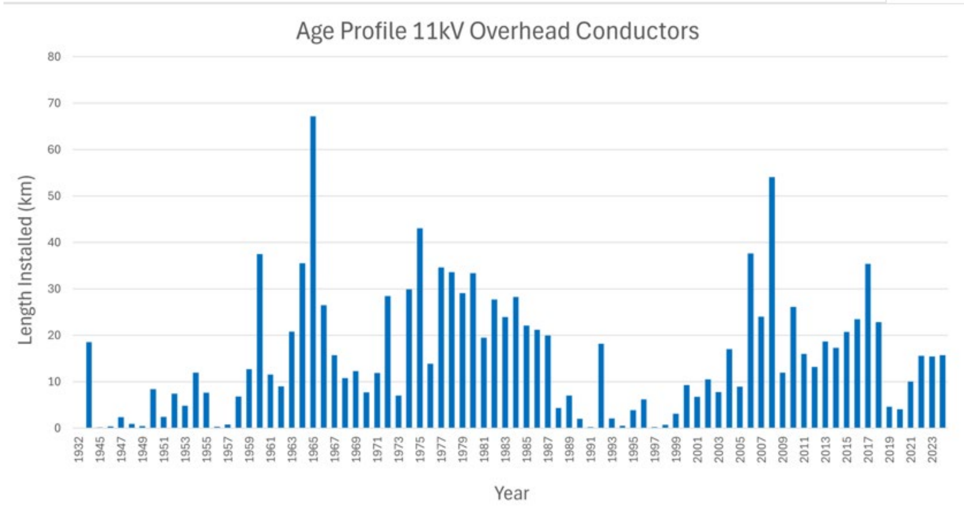


Figure 50 - Age profile of 11 kV overhead lines

The asset health profile of these assets is shown below.

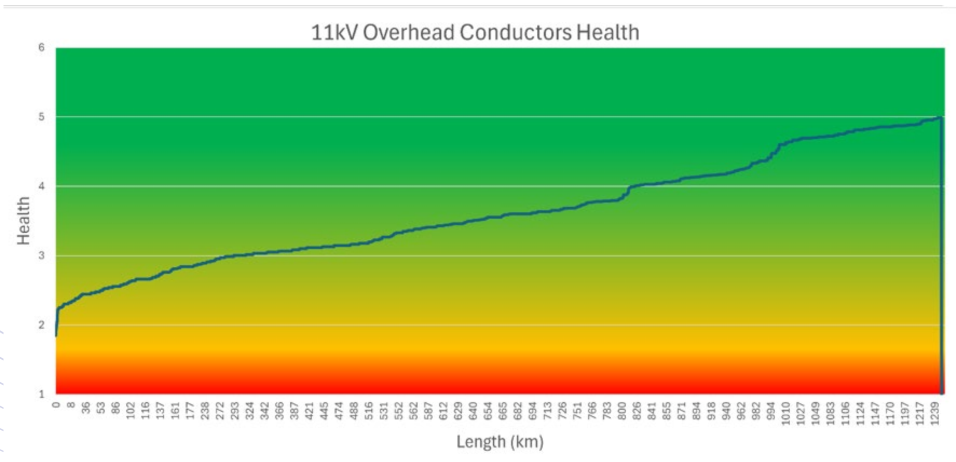


Figure 51 - Health profile of 11 kV overhead lines

8.8.1.2 Asset risks

Major risks to the distribution lines include:

- Extreme weather events such as heavy snow or high winds, resulting in contact with trees or windborne debris
- External equipment – pivot irrigators moving into, spraying, or contacting lines
- Degradation of strength due to age-related issues such as corrosion
- Thermal fatigue or damage to connections due to cyclic loading or through fault currents

8.8.3.3 Inspection and maintenance programme

Activity	Summary	Frequency
Ground patrol	Ground based visual inspection for clearances, uneven sagging and damage such as broken strands Thermal inspection of joints and terminations Vegetation-related defects are recorded to be managed in accordance with the Electricity (Hazards from Trees) Regulations 2003.	5 yearly
Vegetation Patrols	Overhead lines on main feeder routes are inspected annually by our specialist vegetation team to maintain safety and reliability.	5 Yearly
Climbing patrol	Standard ground inspection plus pole top accessed via ladder or EPV in order to tighten fittings, repair loose binders, examine conductor condition etc.	15 yearly
Conductor sample testing	Special targeted testing of conductor to check for issues on older lines.	As required
Aerial inspection	Inspection of overhead lines and equipment using either helicopters or drones – may include visual inspection, Corona camera inspection, thermal imaging, and LiDAR data capture.	As required

8.8.1.4 Renewal and refurbishment programme

Conductor replacements are primarily determined with condition as the highest weighted factor, followed by maintainability and age if required. Sometimes localised load increases will mean a conductor is replaced for capacity or voltage support reasons before it reaches the end of its practical life. In that case, the replacement will be included in the Network Development programme (Section 6). Using Asset Health modelling, the conductor fleet will be replaced using the following priorities:

- All single wire steel conductors will be replaced in the financial year following their next scheduled inspection (i.e. FYE 2026-2029).
- All other steel wired conductors that are within the enmeshed network or supplying more than two transformers on a radial branch will be replaced in the financial year following their next scheduled inspection (i.e. FYE 2026-2029).
- All other steel wired conductors that supply two or fewer transformers on a radial branch will be replaced in the year following their scheduled inspections in FYE 2029-2033.
- All 7/.064 Copper conductors that are within the enmeshed network or supplying more than two transformers on a radial branch will be replaced in the financial year following their next scheduled inspection (i.e. FYE 2026-2029).
- All 7/.064 Copper wired conductors that supply two or fewer transformers on a radial branch and any remaining 7 stranded Copper Conductors will be replaced in the year following their scheduled inspections in FYE 2030-2034.

This will result in the removal of all Steel conductors from the network by 2033 and the replacement of all 7 stranded Copper conductors on the network by 2035.

8.8.2 LV lines

Our LV lines connect distribution transformers which are usually next to the local street to customers' properties. They operate at 400V, total 222km in length and are a mixture of bare and covered HD Cu and AAC conductors.

HD Cu is a stranded Copper conductor treated to ensure it retains its shape over time. It performs well under all environmental conditions and has excellent electrical properties. The cost increases in the late 1960s mean that it is now rarely used in new builds.

AAC is a stranded All Aluminium Conductor. It has historically been chosen for its good conductivity and corrosion resistance, but it lacks the mechanical properties of ACSR. It performs well in coastal environments and in urban areas where its limited strength is not a liability as the spans between poles are shorter.

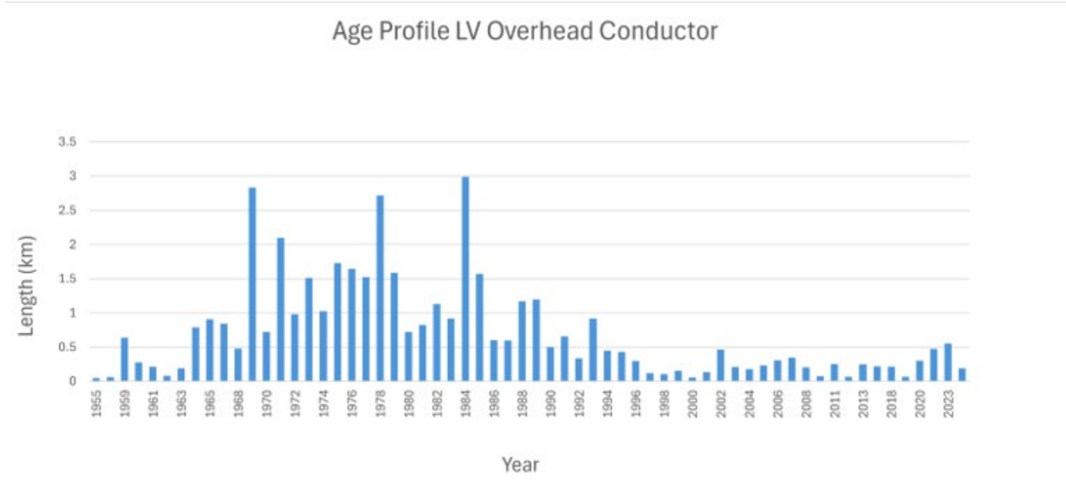


Figure 52 - Age profile of LV lines

The asset health profile of these assets is shown in the following chart:

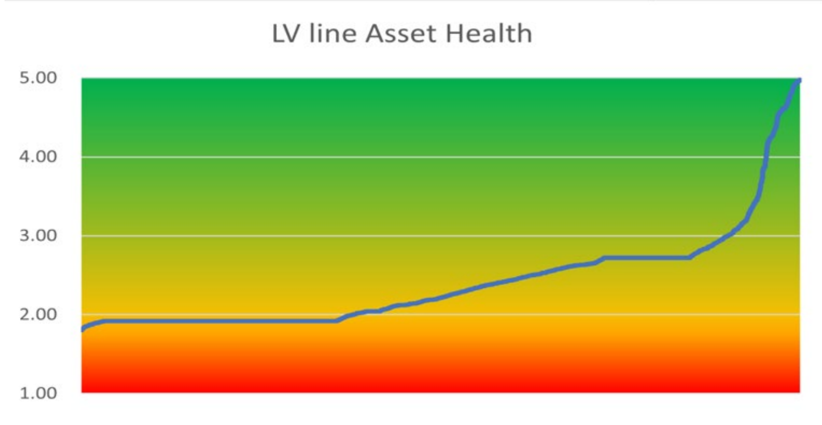


Figure 53 - Health profile of LV overhead lines

8.8.2.2 Asset risks

Major risks to the LV lines include:

- Extreme weather events such as heavy snow or high winds, resulting in contact with trees or windborne debris
- External equipment – farming equipment and irrigators moving into, spraying, or contacting lines
- Degradation of strength due to age-related issues such as corrosion
- Insufficient clearance above ground or between the conductors and structures

8.8.2.3 Inspection and maintenance programme

Activity	Summary	Frequency
Ground patrol	Ground based visual inspection for clearances, uneven sagging and damage such as broken strands Thermal inspection of joints and terminations Vegetation-related defects are recorded to be managed in accordance with the Electricity (Hazards from Trees) Regulations 2003.	5 yearly
Conductor sample testing	Special targeted testing of conductor to check for issues on older lines.	As required
Aerial inspection	Inspection of overhead lines and equipment using either helicopters or drones – may include visual inspection, Corona camera inspection, thermal imaging, and LiDAR data capture.	As required

8.8.2.4 Renewal and refurbishment programme

Conductor replacements are primarily determined with condition as the highest weighted factor, followed by maintainability and age if required. Sometimes localised load increases will mean a conductor is replaced for capacity or voltage support reasons before it reaches the end of its practical life. In that case, the replacement will be included in the Network Development programme (Section 6). There are no type issues with this asset class so replacement will continue to be based on condition or load requirements only.

8.8.3 Distribution support structures

Distribution lines are supported by 19,171 poles of which 2884 support LV lines only, with the balance supporting 11kV lines or a combination of both voltages. They are a mixture of wooden (Hardwood and Softwood) and concrete (Pre-stressed and Mass Reinforced). Some distribution lines are co-located on poles owned by other asset owners. There are about 2000 poles supporting HV Distribution Lines that supply customers on private property. Network Waitaki will be engaging with the property owners and end customers to agree to a solution for the ongoing management of these lines and supports in the long term.

Hardwood poles are usually sourced from Australia. They are suitable in all conditions and can be used under all loading conditions.

Softwood poles are usually locally sourced. They are suitable in all conditions and can be used under all loading conditions but have a lower strength-to-size ratio than hardwood poles and they also age faster.

Pre-stressed poles are usually locally sourced. They are suitable in most conditions but are vulnerable in low temperature and age faster in high pollution environments. Their shape (width to breadth ratio) means that they are not suited to all loading situations. They are lighter than wood and mass reinforced concrete poles for a given strength but are vulnerable to shock loads such as from contact machinery and vehicles.

Mass reinforced poles were usually locally sourced but are no longer available. They are suitable in most conditions but are vulnerable in low temperatures and age faster in high pollution environments. Their shape (width to breadth ratio) means they are not suited to all loading situations, but they are less vulnerable to shock loads than pre-stressed poles.

A summary of the different pole types in use on the distribution system is in the table below:

Asset type	All Distribution	LV Only
Hardwood Poles	7150	1252
Softwood Poles	2733	392
Pre-stressed Concrete	1499	261
Mass Reinforced Concrete	7200	982

Table 17 – Pole types in use on the distribution system

8.8.3.1 Age profiles and population data

The average life expectancy we apply to our poles is 40 years for softwood poles and 60 years for all other types. An age profile for them is shown below.

Of the nearly 22,000 poles on our network, about 40% are of unknown or uncertain age. Data collection using the new field collection platform will provide estimated ages as part of the inspection process, supported by condition data for each pole. This should close this age information gap within five years.

For this reason, we have been enhancing our inspection techniques to ensure that our condition-based replacement regime is not degraded by the unknown age data.

Any probable installation dates that are developed during this exercise will also be verified against the details of nearby assets using our GIS systems. In this way, we expect to improve our confidence in the age profile of our network poles.

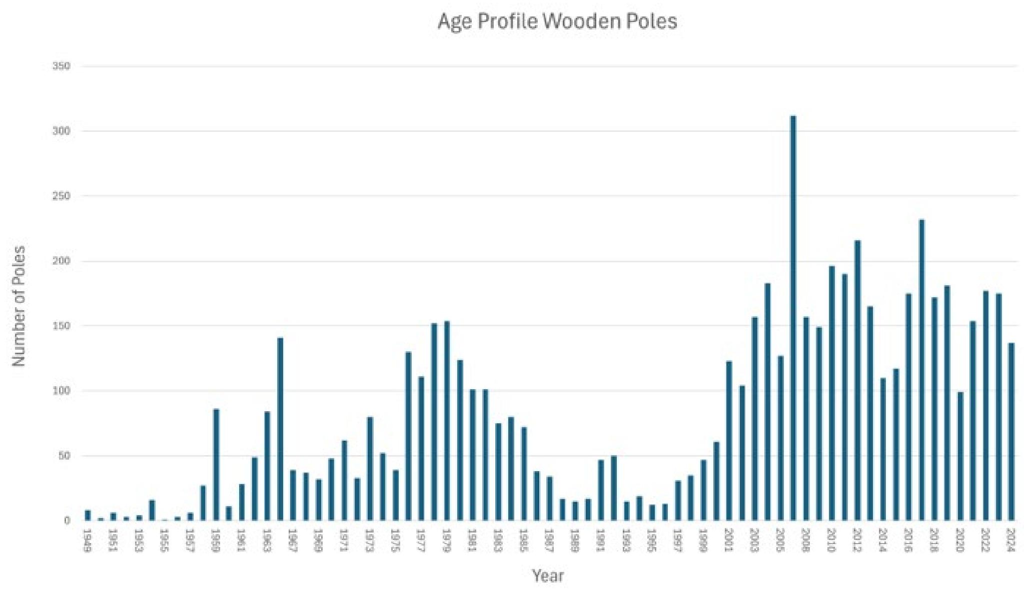


Figure 54 - Age profile of wooden poles

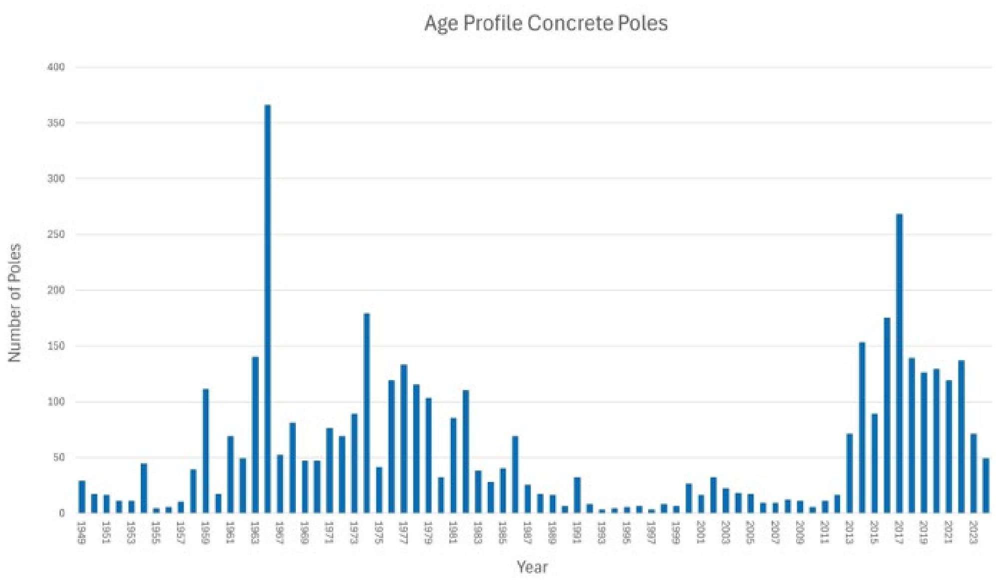
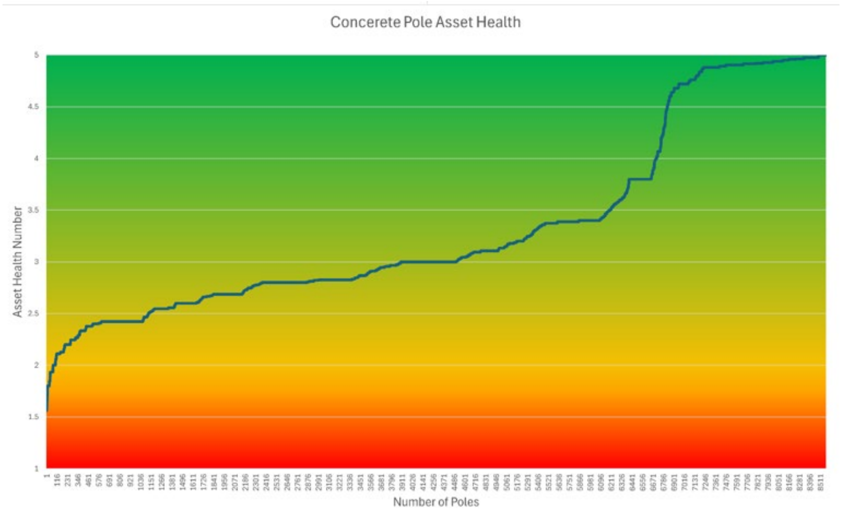
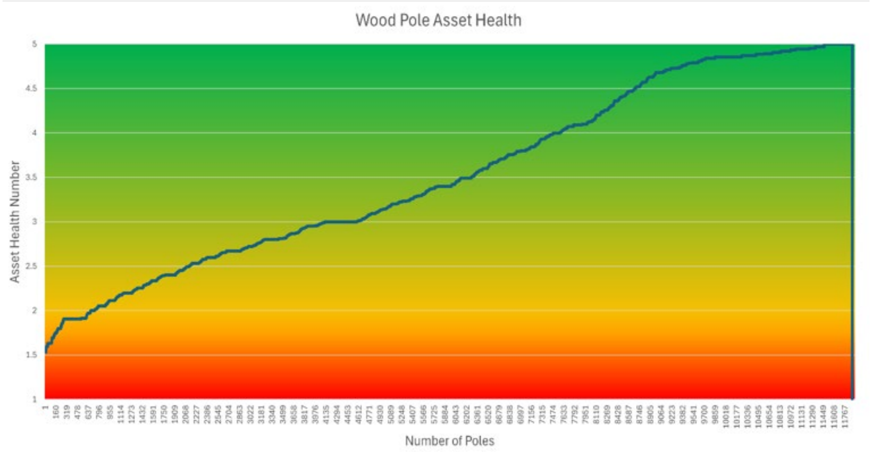
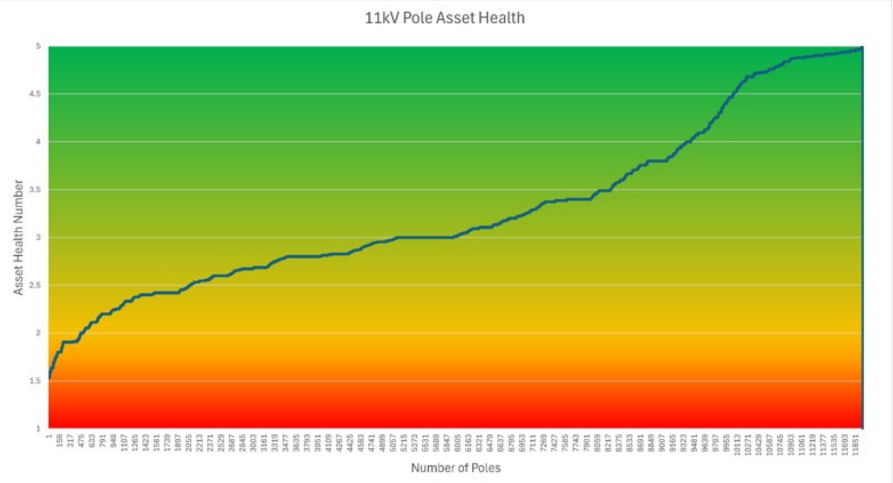


Figure 55 - Age profile of concrete poles

Concrete and wood poles have different condition assessment criteria but are graded using a common index. The asset health of the distribution poles by type are shown below.







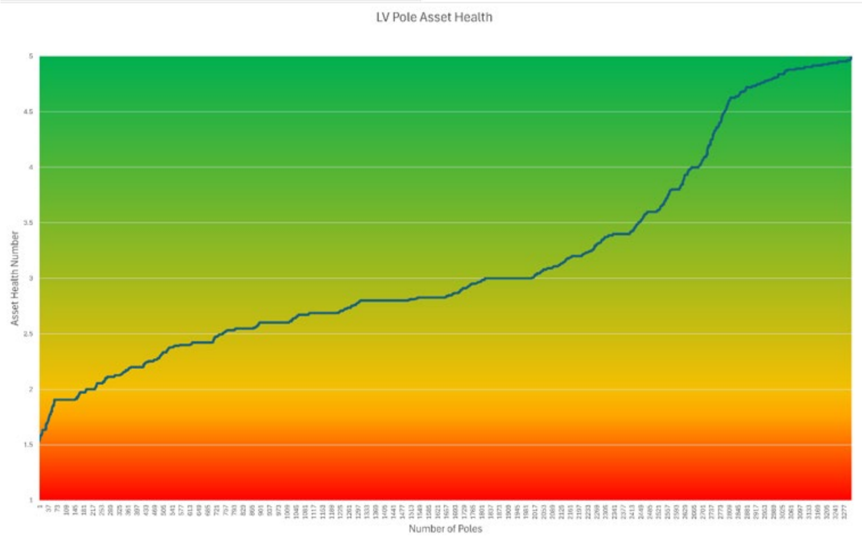


Figure 56 – Asset Health profiles for distribution poles

8.8.3.2 Asset risks

Major risks to the distribution poles include

- Vehicle impact – much of the network is built adjacent to public roads
- Erosion of land around foundations
- Extreme weather events such as high winds or heavy snow
- Degradation of structural strength due to age-related issues such as pole decay.

Applying criticality factors with our Asset Health indices can identify the total risk associated with each structure. Likelihood of Failure correlates with Asset Health and Consequence of Failure correlates with Asset Criticality. Likelihood of Failure correlates with Asset Health and Consequence of Failure correlates with Asset Criticality.

8.8.3.3 Inspection and maintenance programme

Activity	Summary	Frequency
Ground patrol	Ground based visual inspection of pole top, cross arms, and pole top hardware Testing of pole structural condition Thermal inspection of joints and cable terminations Vegetation-related defects are recorded to be managed in accordance with the Electricity (Hazards from Trees) Regulations 2003	5 Yearly
Vegetation Patrols	Overhead sub-transmission lines are inspected by our specialist vegetation team to maintain safety and reliability	5 Yearly
Aerial inspection	Inspection of overhead lines and equipment using either helicopters or drones – may include visual inspection, Corona camera inspection, thermal imaging, and LiDAR data capture	As required

8.8.3.4 Renewal and refurbishment programme

Renewals in the distribution network are largely repairs and replacements to structures based on the results of line patrols. Individual poles are generally earmarked for removal due to condition and changed in a suitable shutdown period. The renewal budget for pole and hardware replacement is based on defect rates developed from recent analysis of line patrols. Sometimes the overall age and condition of a particular stretch of overhead line will require a complete rebuild.

During renewals we may also improve the reliability of the network by replacing overhead circuits with underground, or by physically separating circuits to increase route diversity, when it is economic to do so.

8.8.4 Distribution cables

Distribution cables perform the same function as distribution lines in that they connect the zone substation to distribution transformers. They are usually along public roads or within the property they service and are mainly installed in urban areas. Any failures can be disruptive to our customers and the public as most of the equipment is in publicly accessible areas. They operate at 11kV and total 90 km in length and are a mixture of Copper and Aluminium conductors insulated with PILC or XLPE.

PILC – Paper Insulated Lead Covered cables are manufactured by using layers of paper impregnated with a compound mineral oil as insulating medium, both as individual core and overall insulation. They are a long lasting and proven technology with some cables remaining in service for over 100 years. They offer less flexibility during installation and usually allow a lower load rating for any given size than XLPE, as they have a lower maximum operating temperature. Jointing and connecting them usually requires a higher skillset.

XLPE (Cross Linked Polyethylene) enhances the temperature properties of the insulation, allowing strength and chemical stability to be maintained at higher operating temperatures (and loads). Impact and tensile strength, scratch resistance, and resistance to brittle fracture are also enhanced over other insulation types. Early production (pre-1985) XLPE cables were found to be vulnerable to "treeing", which results in accelerated breakdown of the insulation.

A summary of the cable types on our 11kV distribution system is in the table below.

Conductor type	Length
Cu PILC	9 km
Cu XLPE	1 km
Al PILC	8 km
Al XLPE	67 km
Unknown	5 km

Table 18 - summary of 11kV distribution cable types

8.8.4.1 Age profiles and population data

The average life expectancy we apply to PILC cables is 70 years, modern XLPE cables is 55 years, while first generation XLPE is 45 years. An age profile for the various sections is shown below.

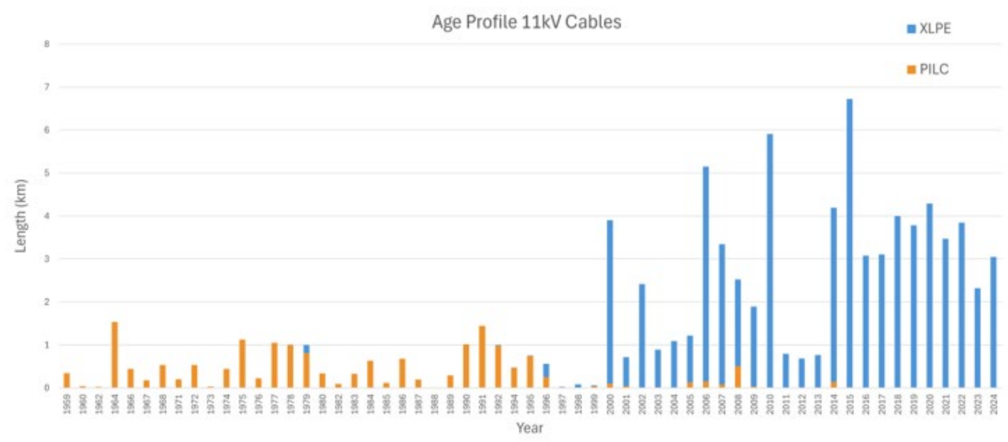


Figure 57 - Age profile of 11 kV cables

The asset health profile of these assets is shown below.

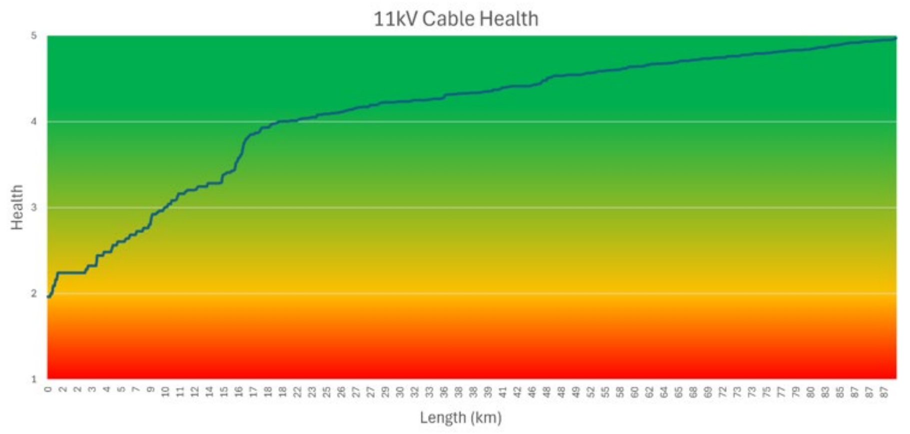


Figure 58 - Health profile of 11 kV cables

8.8.64.2 Asset risks

Major risks to the distribution cables include:

- Earthquake and other land movement around cables
- Damage by excavation and other works in the vicinity
- Material degradation of the insulation
- Sudden failure of pitch filled terminations

8.8.4.3 Inspection and maintenance programme

Activity	Summary	Frequency
Partial Discharge Monitoring	Distribution cable terminations as part of substation partial discharge monitoring	Annual

8.8.4.4 Renewal and refurbishment programme

Given the asset type, age and condition, there are no renewal or refurbishment plans for Network Waitaki's distribution cables within the planning period unless they are part of a greater project.

The 29 remaining outdoor pitch-filled terminations are scheduled for replacement during the planning period.

8.8.5 LV cables

Our LV cables connect distribution transformers which are usually next to public roads and along local streets to customers' properties. They operate at 400V, total 107km in length and are a mix of Copper and Aluminium conductors predominantly within urban areas.

A summary of the cable types on our LV system is in the table below.

Conductor type	Length
Copper	21 km
Aluminium	45 km
Unknown	28 km

Table 19 - Summary of LV line types

Copper cables are generally used to supply smaller groups of customers (fewer than 10) and are usually installed in short sections along accessways or across roads.

Aluminium cables are used for the main sections of the 400V distribution network and are usually installed along public roads, along the frontage of the properties they service.

8.8.7.1 Age profiles and population data

The average life expectancy we apply to LV cables is 70 years. An age profile for the various sections is shown below.

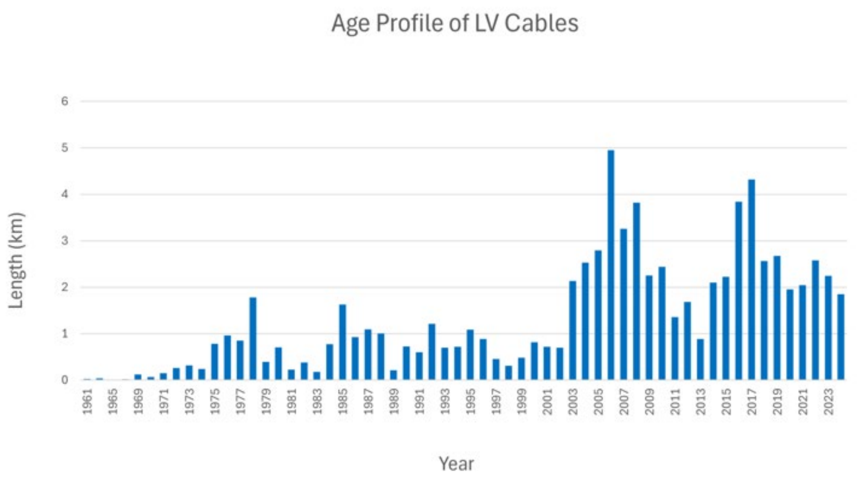


Figure 59 - Age profile of LV cables

The asset health profile of these assets is shown below:

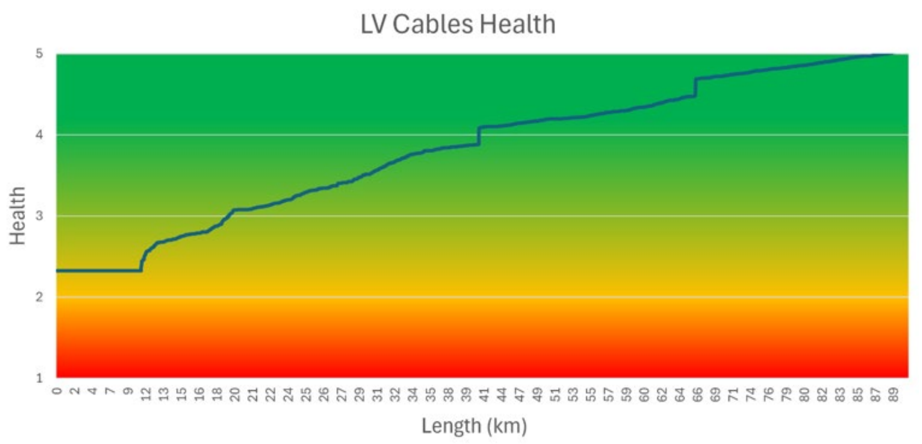


Figure 60 - Health profile of LV Cables

8.8.5.2 Asset risks

Major risks to the LV cables include:

- Earthquake and other land movement around cables
- Damage by excavation and other works in the vicinity
- Material degradation of the insulation
- Overheating of joints and terminations

8.8.5.3 Inspection and maintenance programme

Activity	Summary	Frequency
Ground patrol	Ground based visual inspection for any damage, such as broken strands Thermal inspection of joints and terminations Part of the Distribution transformer inspection programme	Annual
Partial Discharge Monitoring	Distribution cable terminations as part of distribution substation partial discharge monitoring	Annual

8.8.5.4 Renewal and refurbishment programme

Given the asset type, age, and condition, there are no renewal or refurbishment plans for Network Waitaki's distribution cables within the planning period unless they are part of a greater project.

8.8.6 Distribution cable enclosures

We have 2826 distribution cable enclosures that allow staff access to key parts of the cabling system, including fusing and isolation points, while preventing the public from accessing energised network equipment. They are differentiated by purpose with 1) Distribution Cabinets that house network switching equipment and isolating points, and 2) Service Fuse Boxes that house the equipment that isolates customer's installations from the network. The enclosures are made from coated steel, concrete, polymer plastics or polycarbonates.

A summary of the enclosure types on our LV system is in the table below.

Enclosure Material	Total
Coated Steel	1737
Polymer	1600
Polycarbonate	310
Unrecorded	179

Table 20 - Summary of LV box types

Distribution cabinets allow the system to be reconfigured if each radial feeder is capable of supplying or can be supplied from the feeder next to it. There are two material types used for this sort of enclosure -steel and polycarbonate.

Service fuse boxes are generally installed on alternate boundaries on both sides of the street. Several types of distribution box are in service, with most having a steel cover on a steel base frame. Modern types are entirely made from an insulated polymeric material with additives that reduce UV degradation.

Coated Steel enclosures were the default type of enclosure on the network until 2008. They are structurally strong but are vulnerable to corrosion due to ground water acidity/alkalinity and can be conductive if a fault occurs with the equipment inside them.

Polymer enclosures are the most used modern type of Service Fuse Box. They are not as structurally strong as steel but are not vulnerable to corrosion from ground water acidity/alkalinity. They are made of an insulated material which cannot conduct electricity if a fault occurs, but as they are less heat resistant than steel they can be damaged from the heating effect of an internal equipment fault.

Polycarbonate enclosures are the most used modern type of Distribution Cabinet. They are not as strong as steel but are stronger than Polymer enclosures though more vulnerable to impact. They are not vulnerable to corrosion due to ground water acidity/alkalinity like polymers and are made of an insulated material which can't conduct electricity if a fault occurs. They are less heat resistant than steel but more resistant than polymer enclosures.

About 10% of assets do not have an identified material type. This issue will be resolved as our new inspection programme captures this and other information.

8.8.6.1 Age profiles and population data

The average life expectancy we apply to enclosures is 45 years. The age and health profiles of the assets is shown below.

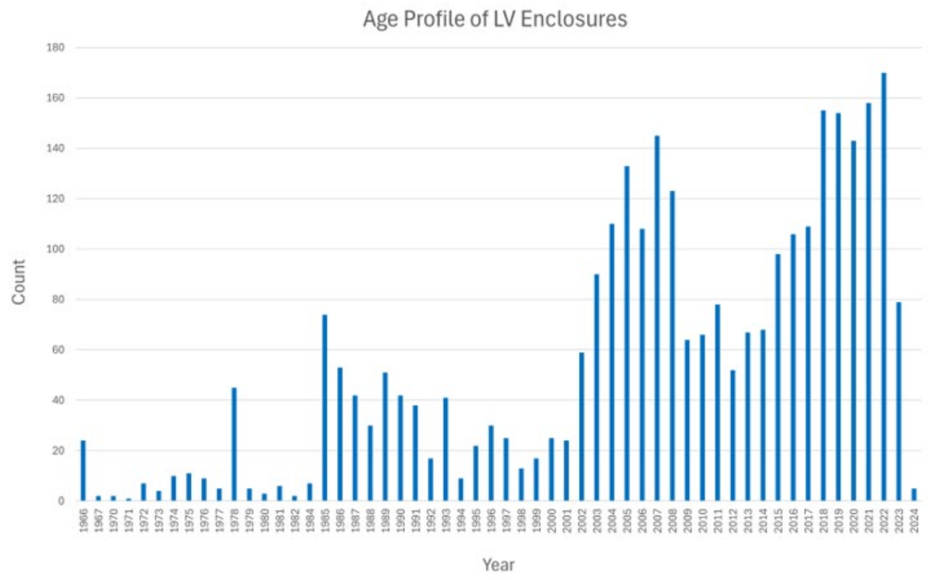


Figure 61 - Age profile of enclosures

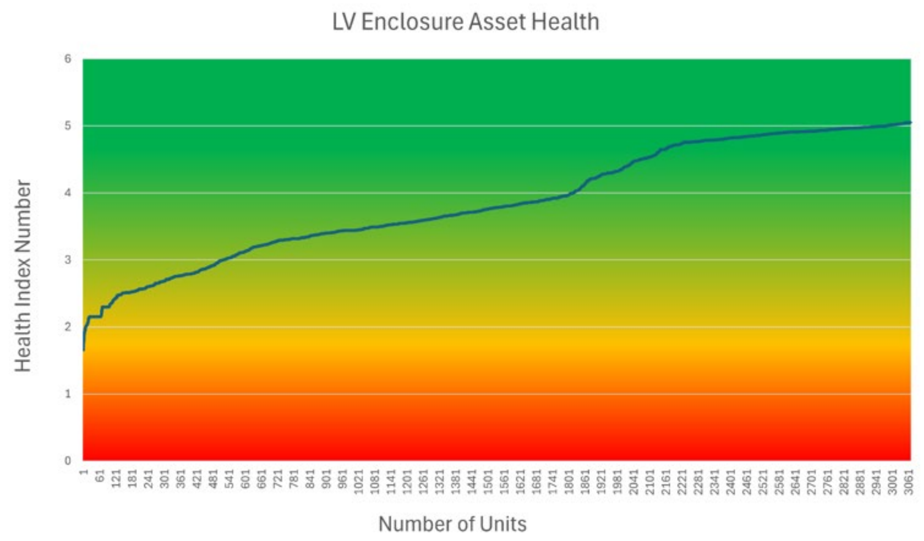


Figure 62 - Health profile of enclosures

8.8.6.2 Asset risks

Major risks to the cable enclosures include

- Vehicle impact – many enclosures are built adjacent to public roads and private accessways
- Erosion of land around foundations
- Material degradation of the asset such as corrosion or UV damage
- Overheating of joints and terminations

8.8.6.3 Inspection and maintenance practices

Activity	Summary	Frequency
Condition and security checks	Visual inspection of enclosures to identify any public safety risks	5 yearly
Partial Discharge Testing	Cable terminations as part of visual inspection	5 yearly

8.8.8.4 Renewal and refurbishment programme

Our policy is to replace enclosures when they cannot remain in service until the next scheduled inspection. We believe this is the correct approach for managing the end of life of enclosures, as it reduces risk by not leaving them in service if they are in a marginal condition.

8.8.7 Distribution switchgear

We use 11 kV reclosers and sectionalisers extensively in rural areas to automatically clear transient faults, and to minimise the areas affected by fault outages. Most of these devices are linked to the SCADA system and can be remotely monitored and operated.

11 kV oil-filled ground mount switchgear (individual fused switches and ring main units) have been commonly installed since 1990, as part of the major urban undergrounding programmes that began then, and the more recent network reinforcement programmes.

Distribution spur lines and individual 11 kV service lines to customer premises are often connected to the main feeder via drop out type fuses or manually operated air break switches. These provide a control point for disconnecting the spur during a fault or planned outage, and the fuses provide a level of discrimination for faults on the fringes of our network, minimising the effect of faults on remote parts of the network. Other such switches are used as manual sectionalising points during fault response or to minimise outages during planned work.

LV switchgear is classified into two groups:

- *Enclosed* switchgear includes vertical, fully shrouded switchgear, such as the Weber Verti-group unit. These have been installed from the early 1990s until now. There are 160 of these on the network.
- *J-Type* switchgear has a variety of types. These were installed on our network between 1964 and 1997. There are 100 of these units on the network.

8.8.7.1 Age and health profiles

Life expectancy for these assets is 35 years for High Voltage overhead equipment, 40 years for High Voltage ground sited equipment and 45 years for LV switchgear. Age profiles for the various sub-types are below.

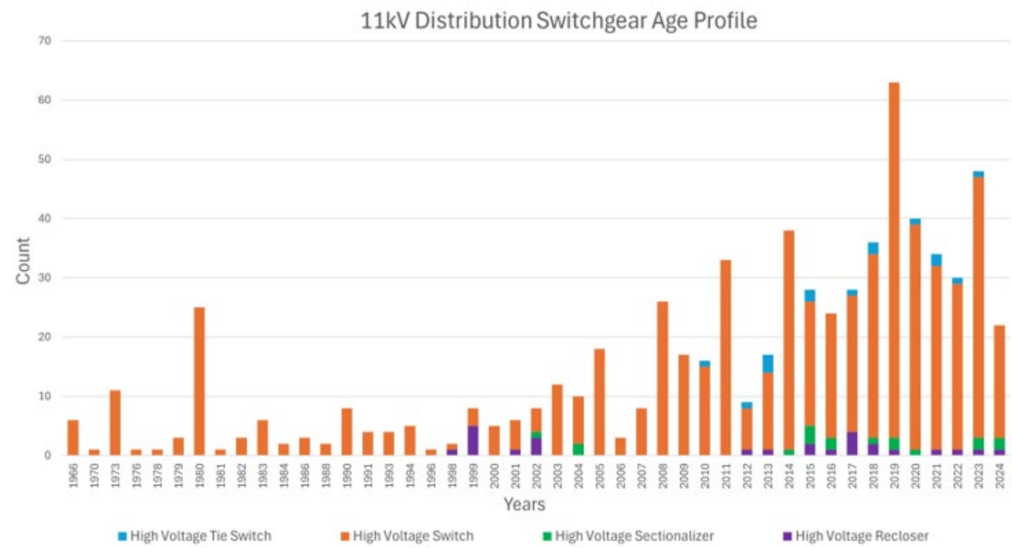


Figure 63 - Age profile of Feeder tie switches, HV switches, sectionalisers, and reclosers

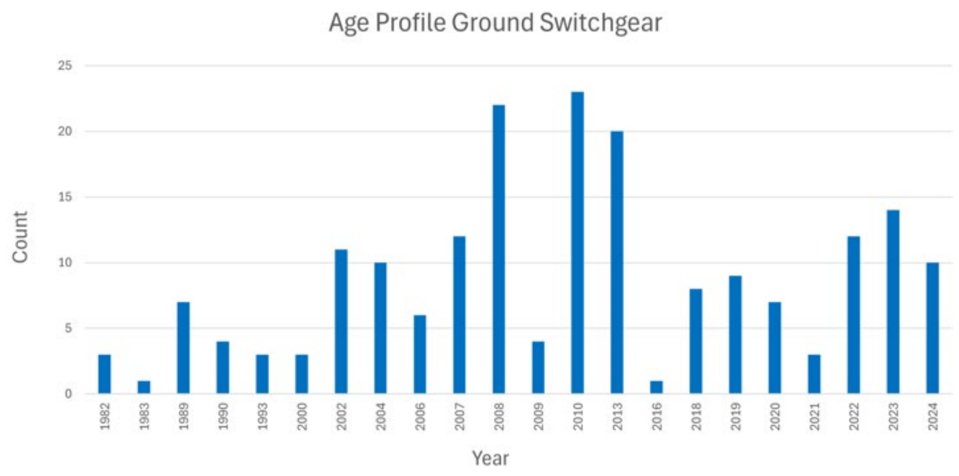


Figure 64 - Age profile of ground sited switchgear (including RMUs)

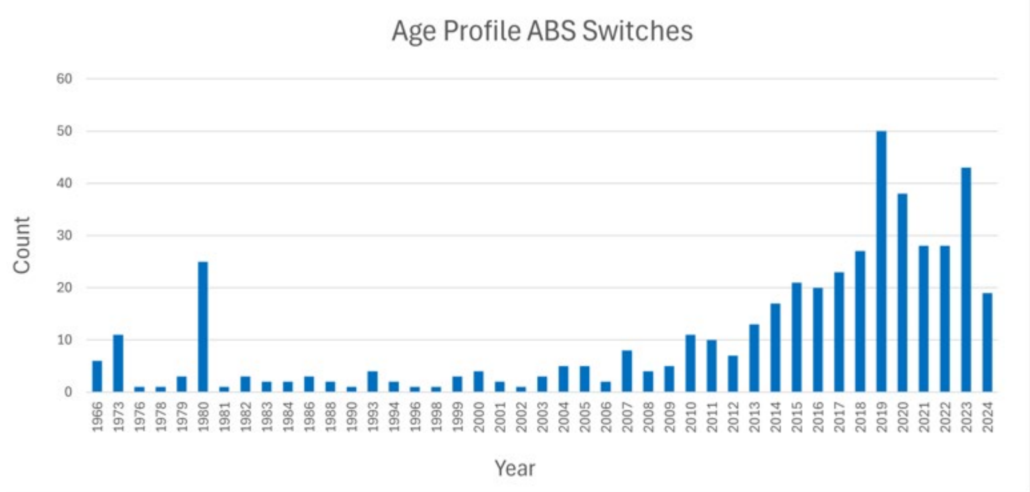


Figure 65 - Age profile of Air Break Switches

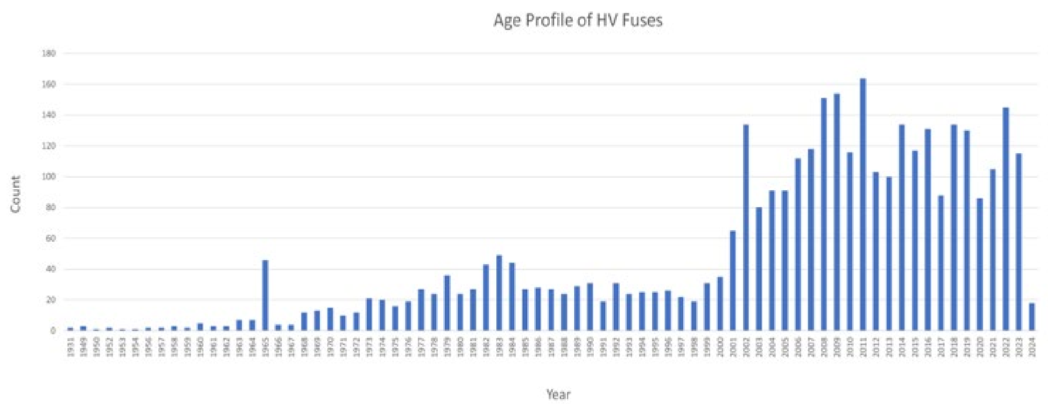


Figure 66 - Age profile of HV fuses

We will often manage distribution switchgear based on the design or age of the equipment, as common failure points become obvious in a particular design. The health profiles of 11 kV distribution switchgear are shown in the following figures:

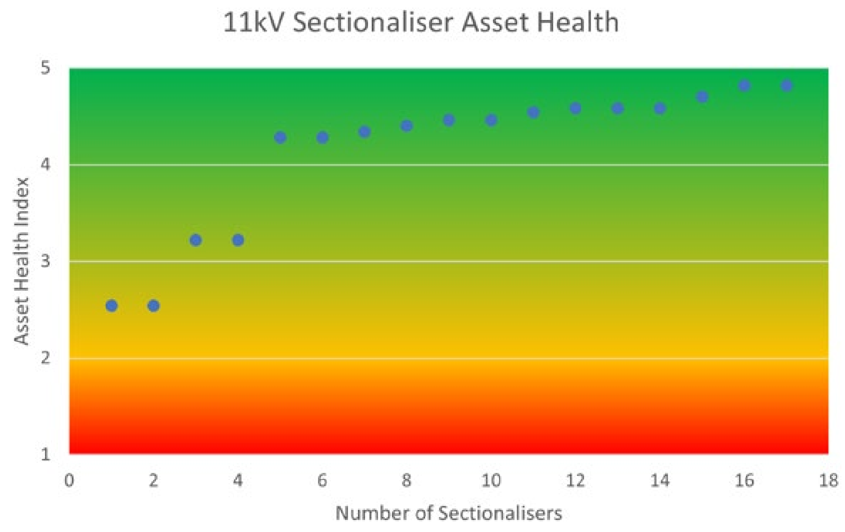


Figure 67 - Health profile of distribution sectionalisers

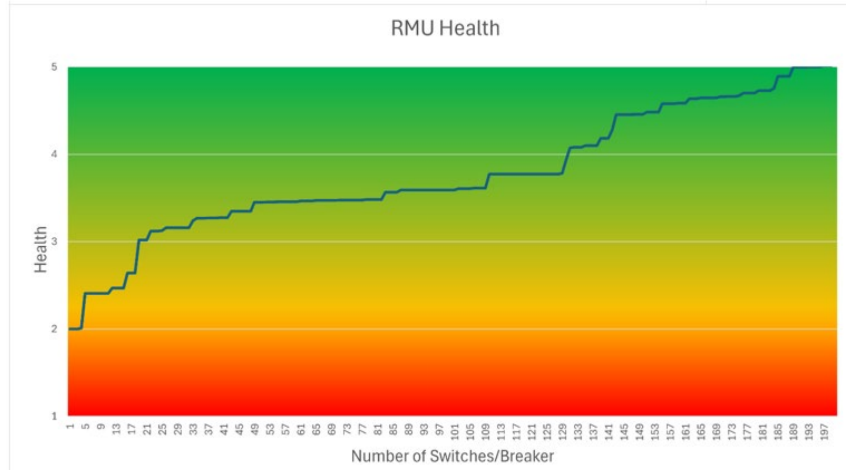


Figure 68 - Health profile of ground mounted distribution switchgear

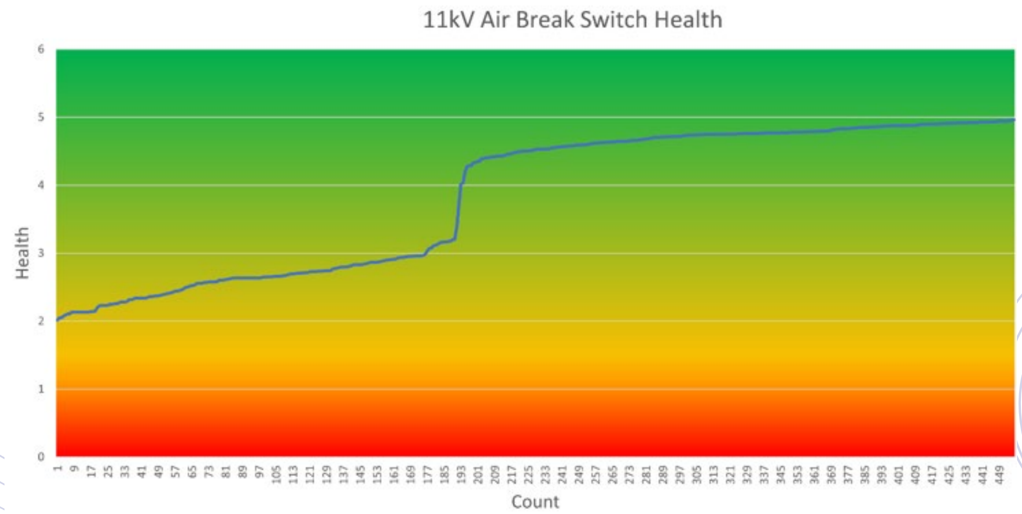


Figure 69 - Health Profile of Pole Mounted Air Break Switches

8.8.7.2 Asset risks

Major risks for the asset class include:

Pole mounted ABSs, reclosers, sectionalisers, pole mounted fuses:

- Lightning – although surge arresters are widely used, a direct strike may be destructive
- Animal contacts, such as possums and birds
- Cracking of porcelain insulators during operation
- Overheating and failure of older fuse gear during service

Ground mounted switchgear:

- Cabinets and casings degrading or becoming unsecure
- Vehicle incidents, as many are located in the road reserve
- Failure due to dirty insulating oil
- Failure of cable terminations on the unit
- Failure of mechanism during switching

The operational risk associated with the failure of distribution switchgear depends on location and use. In-service failure of a sectionaliser or recloser on a major feeder could either lead to the loss of more customers than necessary during a fault (because upstream protection must clear the fault) or prevent a planned alternate feed being used to restore lost load during an outage. By comparison, an ABS or fuse on a spur line or a low voltage fuse supplying one house has lower operational risk.

Safety-related risks are generally lower for pole mounted equipment but can be more important for ground mounted equipment, where operators are standing nearby during switching.

Recent experience in New Zealand and overseas has shown that older oil-filled switchgear can fail during operation in a way that is dangerous to the operator. Following this, we have stopped manual operation of these units and instead use a remote actuator. In practice, these operational restrictions are increasing switching complexity and outage times on the network. We have reviewed and changed our maintenance practices to reduce this risk.

The majority of the oil filled ring main units on our network are Andelect/ABB SD types. These units are no longer manufactured and in some cases are not supported by the manufacturer. We are replacing them at a rate of around three per year with modern vacuum switch ring main units, often with remote SCADA operation. These will be installed in locations selected to enhance our resilience to faults. This will support future "smart grid" features, such as ring feeders with automatic fault isolation and detection. Removal of the oil filled switchgear will provide an ongoing stock of spares for the remaining units in service.

8.8.7.3 Inspection and maintenance practices

Activity	Summary	Frequency
Line patrol	Visual and thermal inspection of high voltage and low voltage switchgear and terminations, ground mount and pole mount	5 yearly
Condition and security checks	Visual inspection of ground mounted high voltage equipment in high traffic urban areas to identify any public safety risks	Annual
Partial Discharge Testing	11kV Distribution switchgear discharge testing	5 yearly
RMU Maintenance	Cleaning, oil testing, operational testing	5 yearly
Air break switch maintenance	Cleaning, lubrication, checking operation	5 yearly
Recloser and sectionaliser operational checks	Operational tests and checks. Replace batteries	5 yearly

8.8.7.4 Renewal and refurbishment programme

The renewal and refurbishment programme for the planning period includes:

- Replace some air break switches with sectionalisers in rural feeders to minimise outage areas during faults
- Replacement of all 11 kV ABSs are based on condition assessment, or ABS has signs of damaged, cracked or chipped insulators.
- Replace other switchgear based on condition assessment from scheduled inspections
- Continue to replace oil filled ring main based on assessment with SCADA operable RMUs of the vacuum circuit breaker type to improve operational performance of the network
- Continuing to replace older J-type low voltage switchgear with more modern enclosed switchgear that is safer to operate

8.8.8 Distribution transformers

The 11 kV distribution network supplies 3009 distribution transformers, of which about 823 have a capacity in excess of 100 kVA. All new transformers 200 kVA or over are ground mount "mini-sub" configured, irrespective of whether they are installed in an underground or overhead reticulated area. LV reticulation in urban areas is typically supplied by 200-500 kVA distribution substations that are located to accommodate three to four LV feeders. Transformer capacity is normally based on an average After Diversity Maximum Demand (ADMD) of about 5.6 kW for a residential customer.

An LV distribution switchboard is normally housed in or near the transformer cabinet, with each feeder independently fused. The LV switchboard is mounted independently of the transformer cabinet and is fitted with an incomer switch to facilitate the isolation and removal of the transformer independent of the LV board. In overhead reticulated areas, transformers are protected by pole mounted expulsion fuses and, in underground reticulated areas, with ground mounted fused oil or vacuum switches. In urban areas, the LV system is run in open rings with tie points brought into ground-mounted distribution boxes or jumper cuts in the overhead reticulated system. Earths for ground-mounted transformers in urban areas incorporate an equipotential earth loop to control step and touch voltages.

Transformers are arranged in a mesh layout such that neighbouring units can support an outage via LV interconnection. Transformers and cables are designed with sufficient spare capacity for this purpose. Maximum Demand Indicators (MDIs) are fitted to determine the need for capacity upgrade and phase balancing. Larger customer supplies may have dedicated LV cables back to the LV distribution frame and/or a dedicated transformer on their own site. Rural supplies tend to have smaller dedicated pole mounted transformers.

Voltage regulators are a special type of transformer installed on the 11 kV distribution network to improve voltage regulation of feeders, especially where there is demand growth due to dairy conversions and irrigation. They are often used as an interim measure until the demand growth warrants reinforcement of the supply. We have 14 installations of voltage regulators in service.

8.8.8.1 Age profiles and population data

The average life expectancy that we apply is 45 years for distribution transformers and 25 years for voltage regulators. The age profile of our ground and pole mounted transformers is shown below.

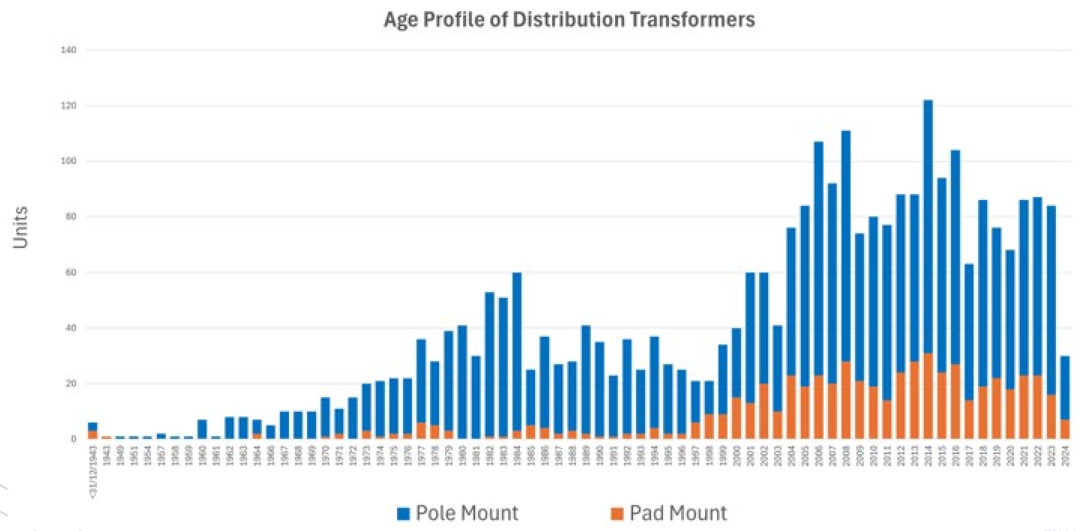
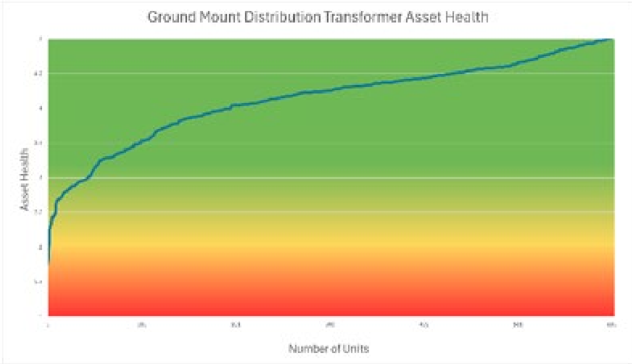
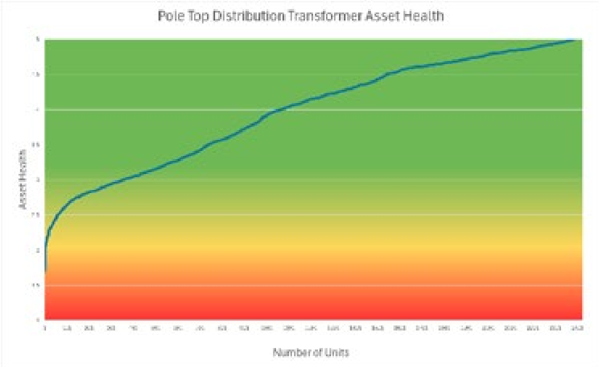


Figure 70 - Age profile of distribution transformers

Health profiles for Distribution transformers are shown below.





8.8.8.2 Asset risks

The main risks to this equipment class include:

- Oil leaks into the environment
- For pole mount transformers – animal contacts, such as possums and rats
- For ground mount transformers – vehicle incidents, as many are located in the road reserve
- Overloading of CBD transformers due to offloading of adjacent transformers during faults or planned outages
- Corrosion that may cause issues with security of cabinets and doors.

8.8.8.3 Inspection and maintenance practices

Activity	Summary	Frequency
Line patrol	Visual and thermal inspection of transformers	5 yearly
Condition and security checks	Visual inspection of transformers in high traffic urban areas to identify any public safety risks	2 Yearly
Earth testing	Test earth continuity and values	5 yearly

8.8.8.4 Renewal and refurbishment programme

The renewal and refurbishment programme for the planning period includes:

- General condition-based refurbishment work such as painting cabinets, fixing doors, or any safety-related issues
- Condition based replacements, based on overall condition, or where a transformer is particularly old and is showing signs of end-of-life conditions
- Overhaul regulator transformers based on manufacturer's recommendations.

Our distribution transformer fleet is generally reliable and robust. We aim to maximise the utilisation of our transformers without overloading them during normal operation, although we will apply a managed approach to short term overloading in the event of a fault.

MDI readings are used to monitor the loading on large transformers. We have completed a small trial of distribution transformer monitoring (DTM) units in some of our larger urban transformers and have seen benefits for our asset management processes compared with the traditional maximum demand indicators, which are manually recorded at longer intervals. A DTM system provides remote monitoring of transformer loading and voltages (actual and historical), allowing much greater information on how our assets are being used, and gives visibility of any overloaded transformers, so we can reduce loading before the transformer life is compromised.

The value of being able to remotely check loading on a distribution transformer has been shown when planning the reconfiguration of open points to ensure that customer load can be met. Rather than a simple maximum, transformer loadings can be understood in the context of the duration of the overload, and the cool-down time that follows. These lessons are being factored into ongoing work to develop a low voltage monitoring system, mentioned in section 9.2.3 – Workstream 3 – Enhanced low voltage management. In addition to the ongoing rollout of the low voltage monitoring system, when a distribution transformer is being replaced we will take the opportunity to include monitoring equipment where it suits the operational needs of the network.

Both pole and ground mount transformers have proven to be reliable and robust, with few equipment failures in general. We are planning a steady number of transformer replacements throughout the planning period to maintain the average age of the fleet at a reasonable figure. Replacements will often naturally synchronise with other works such as capacity or configuration upgrades.

8.8.11 Distribution network expenditure forecast

Distribution ($000)	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
Service Interruptions & Emergencies	529	519	519	519	519	519	519	519	519	519
Routine & Corrective Maintenance and Inspections	763	822	858	822	858	822	858	822	858	822
Asset Replacement & Renewal (Single Wire Steel Conductors)	361	55	42	0	0	0	0	0	0	0
Asset Replacement & Renewal (Other Steel Conductors)	57	1476	1044	1287	946	1231	964	0	0	0
Asset Replacement & Renewal (7/.064 Copper Conductors)	1267	178	670	468	811	525	793	1756	1756	1756
Asset Replacement & Renewal (Poles)	1612	1612	1612	1612	1612	1612	1612	1612	1612	1612
Asset Replacement & Renewal (Other Assets)	2333	2236	2335	2265	2307	2316	2465	2514	2620	2620
Asset Relocations	0	0	0	0	0	0	0	0	0	0
Vegetation Management	807	807	807	807	807	807	807	807	807	807
Total	7729	7706	7888	7780	7860	7832	8018	8030	8172	8135

8.9 Secondary and Support Systems

8.9.1 Overview of secondary and support systems

We use various technologies to enhance the safety and efficient use of the primary Network assets. The associated hardware for these systems is generally co-sited with the assets themselves, but the core elements are centrally located.

8.9.2 Management approach

These systems are managed with the active assistance of manufacturers and suppliers, as we do not have the expertise in house to carry out the higher-level maintenance functions for this equipment.

We have undertaken a strategic review of our communications equipment, including SCADA system and radios. This review highlighted that the systems are at limited risk of cyberattack or other failure, and we expect further improvement with major upgrades over the next three years.

8.9.1 SCADA

Our Supervisory Control and Data Acquisition (SCADA) is a digital model of our sub-transmission, zone substation and high voltage distribution network and supports a range of activities related to the operation, planning and configuration of the electricity network. It directly supports key safety and reliability measures by enabling remote control and management of our electricity network from our Operations Centre and Remote Terminal Units (RTUs). These are connected to field devices when we identify telemetry and control benefits with them.

We operate an Abbey Systems Powerlink SCADA system. The SCADA system is connected to all of our zone substations via Abbey Systems RTUs and provides remote control, indication, logging, and alarm status information for key operating assets. In addition, most reclosers and sectionalisers are connected to the SCADA system and can be remotely controlled.

8.9.1.1 Age profiles and population data

Our SCADA system is about 15 years old, which is the typical life expectancy we allow for this asset. The current system continues to be supported by the Supplier but there is no development path. We expect that the SCADA will no longer be able to meet our requirements after 2028 and are planning to have a replacement system operational before then.

8.9.1.2 Asset risks

Failure of the SCADA would significantly impact the effectiveness of the control room. A less efficient level of network operation could continue in the field using other means of communication, as well as directing operation at substations and field devices.

The major risk to our SCADA system is hardware failure, as the system operates on specialised PCs. This is mitigated by a master and backup computer. In 2020 a complete offsite control room was commissioned to act as an offsite backup for the main control room. The commitment to ongoing support from the Supplier means that any software firmware issues are not considered a risk for now.

Field RTUs can also fail but, since they are modular and configurable, can be easily replaced with spare units held by Network Waitaki.

8.9.1.3 Inspection and maintenance practices

Monitoring, Testing and Maintenance of the SCADA System is part of a support contract with the SCADA system provider.

8.9.1.4 Renewal and refurbishment programme

Our SCADA system is about 15 years old, which is the typical life expectancy we allow for this asset. We have been investigating options (maintain/upgrade/replace) including our long-term requirements. A final decision is expected in 2025 with a view to implementing and putting into effect any changes early in 2026.

RTUs are replaced on failure. Network Waitaki carries a quantity of spares based on historical failure rates. At this stage there is no indication of an increasing trend in failure rates.

8.9.2 Communications

Our communication network is made up of different voice and data systems that provide an essential ancillary service assisting with the operation of our distribution network. These systems provide contact between our Control Room and operating staff and provide remote indication and control of network equipment. Our communication systems enable us to operate our network and deploy our people effectively, reducing the impact of faults on customers.

VHF analogue radio: installed in vehicles and handheld portable units. These operate via linked VHF hilltop radio repeaters.

UHF radio data communicates information from remote network devices, indicating the state of the network to our Control Centre.

Public cellular networks are used for mobile voice and data communications for non-operational communication and as a backup for the VHF radio system.

Owned or leased dark Fibre Optic cables that connect to automation devices at our Zone Substation

Radio repeaters are sited at Cape Wanbrow, Station Peak and Cloud Hill. They are shared between the UHF Data and the VHF radio telephone system.

8.9.2.1 Age profiles and population data

The typical life expectancy we allow for these assets is 15 years.

5.9.2.2 Asset risks

The failure of our primary communications systems would significantly reduce the effectiveness of the control room. Network operation could continue in the field using the other means of communication we have, along with manual operation at substations and by way of field devices. These alternative communication systems are owned and managed by other providers.

The major risks to the radio network are:

- Extreme weather events - the remote locations of our repeater sites can make them difficult to access and repair during snow and other major weather events.

8.9.2.3 Inspection and maintenance programme

Maintenance of the Communication Systems involves an annual radio equipment site check.

8.9.2.4 Renewal and refurbishment programme

Items in the communication system are to be replaced upon failure, and spares are carried for this purpose.

8.9.3 Power quality monitoring

We have recently installed 400V monitoring equipment on selected distribution transformers to aid our understanding of customer behaviours and network responsiveness. We have 90 units monitoring 212 low voltage feeders with a target of 200 units to be installed by the end of FY25. The units are installed at ground mount locations in LV distribution switchboards inside transformer cabinets or inside distribution box cabinets, or to pole mount locations. The units measure voltage and current over three phases and up to six LV feeders per unit. The measured data is sent via mobile network to an online hosting service, and is then used to calculate current imbalance, neutral current, congestion, total harmonic distortion, and PV injection.

The ground mount unit housing is made from polycarbonate, and the pole mount unit housing is made of a UV stable polycarbonate for use in outdoor environments. The units are IP 65 rated and are compact enough to fit into smaller DB cabinets.

A summary of the installation location types on our LV system is in the table below:

Installation Location	Total
Ground Mount – Transformer cabinet	48
Ground Mount – DB cabinet	30
Pole Mount	2

Table 21 – Installation types of LV monitors

8.9.3.1 Age profiles and population data

The typical life expectancy of this equipment is 15 years.

All units were installed in 2023 and 2024.

8.9.3.2 Asset risks

- Vehicle impact – most units will be located in or on assets adjacent to public roads
- Overheating or failure of electrical components and communication components
- Water/weather ingress in transformer or DB cabinet
- Corrosion on fuse terminals
- Failure of power leads, Rogowski coils and other secondary equipment

8.9.3.3 Inspection and maintenance practices

Continuous monitoring of the LV monitoring units is undertaken by the vendor under a support agreement. Any abnormalities automatically trigger an alarm and are reported back to Network Waitaki.

LV monitors and secondary equipment are to be replaced upon failure and are to be tested in house before being returned to the vendor.

The LV monitor can be visually assessed for physical condition during distribution transformer inspections.

8.9.3.4 Renewal and refurbishment programme

Given the asset type, age and condition there are no renewal or refurbishment plans for Network Waitaki's LV monitoring units within the planning period.

8.9.4 Load management system relays

Our Load Management (Ripple) System controls electrical loads predominantly by injecting frequency signals over the electricity network. The primary purpose is to defer energy consumption and minimise peak load. This is achieved in two ways: 1) Customer demand management load reduction and/or generation; and 2) by distributor-controlled load management through hot-water cylinders and other interruptible loads. A secondary purpose of the system is to allow coordinated management of common load types such as streetlighting.

The system is made up of various electrical plant and hardware/software platforms supplied by Landis & Gyr. A centralised plant injects a carrier frequency (283Hz) with a digital signal into the power network. That signal is acted upon by relays installed at the customer's connection point. Further information on the central plant can be found in section 5.6.8.

We use Decabit ripple control relays at customer premises to control demand to minimise line charge costs and to control network demand below certain constraints. The ripple relays are typically owned by Network Waitaki, apart from the approximately 200 owned by Waitaki District Council and used for controlling streetlights. Alternative signal means are also used to prepare and initiate some major customer load management.

8.9.4.1 Age profiles and population data

The typical life expectancy of this equipment is shown in the table below.

Asset Description	Standard life expectancy (years)
SCADA System	15
Radios	15

8.9.4.2 Asset risks

Failure of the relays would significantly impact customers in the following ways:

- Hot water systems failing to be energised
- Streetlight remaining on or off
- Other customer-controlled equipment failing to be energised

Relays are modular and configurable so can easily be replaced with spare units held by Network Waitaki Ltd.

8.9.4.3 Inspection and maintenance practices

Relays and receivers are replaced on failure. There is no active inspection or maintenance regime.

8.9.4.4 Renewal and refurbishment programme

Relays and receivers are replaced on failure. Network Waitaki carries a quantity of spares based on historical failure rates. At this stage there is no indication of an increasing trend in failure rates.

8.9.7 Secondary and support system asset expenditure forecast

Distribution ($000)	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
Service Interruptions & Emergencies	41	45	45	45	45	45	45	45	45	45
Routine & Corrective Maintenance and Inspections	252	545	545	545	545	545	545	545	545	545
Asset Replacement & Renewal	1,310	200	-	-	-	-	-	-	-	-
Total	1,602	791	591	591	591	591	591	591	591	591

8.10 Non-Network Assets

The lifecycle management of non-network assets follows the estimated useful life in keeping with the company's accounting policies, most recently set out in the Annual Report. The estimated useful lives are shown below:

Asset Description	Standard life expectancy (years)
Information and Technology Systems	2-105
Office Buildings and Workshops	40-100
Office Furniture and Equipment	10
Motor Vehicles	5-15
Tools Plant and Machinery	2-10

Table 22 - Life expectancy of other fixed network assets

8.10.1 Information and Technology Systems

8.10.1.1 Asset Risks

- Hardware with a moderate to high risk of failure due to age or environmental conditions
- Hardware no longer capable of running latest software
- Software no longer supported or loses functionality

8.10.1.2 Inspection and maintenance practices

Servers, storage devices, and network devices are continuously monitored for availability and errors with alarms. Other hardware is repaired/replaced on failure.

Software vendors automatically notify if new versions are available and provide notioce when current versions will cease being supported.

8.10.1.3 Renewal and refurbishment programme

Servers and workstations are usually replaced after 3 but before 4 years of service. Smartphones and tablets are usually replaced after 2 but before 3 years of service. Network equipment, such as switches, are usually replaced after 5 but before 6 years of service.

Software is kept updated to the latest version as soon as practicable. No software will be more than one significant update behind the latest release. Where versions are no longer supported it is either upgraded or replaced prior to the end of the support period.

8.10.2 Office buildings and workshops

8.10.2.1 Asset risks

- Structural damage or failure due to age or environmental based conditions
- Structural damage or due to seismic event

8.10.2.2 Inspection maintenance practices

To ensure Network Waitaki remains compliant with building warrant of fitness requirements, maintenance contracts are in place with third parties. These contracts cover scheduled and reactive maintenance activities on both grounds and buildings, including air-conditioning units, fire alarms and security systems.

8.10.2.3 Renewal and refurbishment programme

The renewal of property assets is primarily on an 'as required' basis. The organisation's property requirements are reviewed frequently at both a strategic and tactical level. The review identifies any changes which may be necessary to ensure the continued efficient operation of the business.

8.10.3 Office furniture and equipment

8.10.3.1 Asset risks

- Harm to staff due to condition or incorrect application

8.10.3.2 Inspection maintenance practices

Annual inspections are carried out to identify hazardous equipment and usage. There is no active monitoring programme.

8.10.3.3 Renewal and refurbishment programme

Office furniture and equipment is repaired or replaced on disclosure of damage.

8.10.4 8.10.4 Motor Vehicles

8.10.4.1 Asset risks

- Harm to staff or public due to condition or incorrect application

8.10.4.2 Inspection maintenance practices

Vehicles are maintained and serviced in accordance with the Manufacturers recommendations. This is monitored using QuipCheck which is updated whenever a vehicle is used or during the weekly vehicle checks.

8.10.4.3 Renewal and refurbishment programme

Vehicle replacements follow WP0580 Motor Vehicle Policy which is summarised below.

Vehicle Type	Renewal Policy	Average per Annum
Cars & Pool Utes	4 years or 150,000km	6
Light Trade Vehicles	5 years or, 200,000km	3
Heavy Trucks	15 years	1
EWPs	15 years	0.5
Trailers		1

8.10.5 Tools Plant and Machinery

8.10.4.1 Asset risks

- Harm to staff due to age or incorrect application

8.10.4.2 Inspection maintenance practices

Annual inspections are carried out to identify hazardous equipment and usage. There is no active monitoring programme.

8.10.4.3 Renewal and refurbishment programme

Tools and plant are repaired or replaced on disclosure of damage.

Total maintenance & renewal expenditure summary

Forecast expenditure for renewals and maintenance are summarised by asset category in the table below.

$000s	Asset Class	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33
Asset Relocations	Zone Substations	0	0	0	0	0	0	0	0	0	0
	Sub-transmission	0	0	0	0	0	0	0	0	0	0
	Distribution	0	0	0	0	0	0	0	0	0	0
	Secondary & Support	0	0	0	0	0	0	0	0	0	0
Replacement & Renewal	Zone Substations	5,669	2,916	921	2,752	727	2,804	727	2,752	727	2,752
	Sub-transmission	659	725	353	353	353	353	353	353	353	353
	Distribution	5630	5557	5703	5632	5676	5684	5834	5882	5988	5988
	Secondary & Support	1,310	200	0	0	0	0	0	0	0	0
Total	Capex	3,001	9,110	7,083	8,827	6,846	8,659	6,731	8,804	6,886	8,910
Service Interruptions & Emergencies	Zone Substations	0	0	0	0	0	0	0	0	0	0
	Sub-transmission	16	16	16	16	16	16	16	16	16	16
	Distribution	529	519	519	519	519	519	519	519	519	519
	Secondary & Support	41	45	45	45	45	45	45	45	45	45
	Vegetation	54	54	54	54	54	54	54	54	54	54
Routine & Corrective Maintenance	Zone Substations	368	351	351	351	351	351	351	351	351	351
	Sub-transmission	218	218	218	218	218	218	218	218	218	218
	Distribution	763	822	858	822	858	822	858	822	858	822
	Secondary & Support	252	545	545	545	545	545	545	545	545	545
	Vegetation	807	807	807	807	807	807	807	807	807	807
Total	Opex	2408	2743	2779	2743	2779	2743	2779	2743	2779	2743
Grand Total		15409	11853	9862	11570	9625	11402	9510	11547	9665	11653

Table 23 – Maintenance and Renewal expenditure forecast by category and asset type

09

Our Future Network Plan

09

Our Future Network Plan

This chapter sets out our Future Network Plan

9.1 Introduction

In Chapter 4 – *Supporting our customers' energy transition*, we present our future energy scenarios and high-level plans for how we intend to meet our customers' future energy needs at each level of our network. In this section we will provide further detail on our:

- Plans to transform our network to support our customers' future energy requirements
- Future energy scenarios and detailed planning assumptions
- Capacity and security analysis
- Proposed development projects for the "Balanced scenario"

We base our development plans on traditional network solutions due to our comprehensive understanding of costs and benefits. Before confirming a project for delivery, we assess whether non-traditional solutions such as solar, batteries, or the procurement of non-traditional services are operationally viable and can provide better value for our customers over the lifecycle of the solution.

For example, we recently collaborated with Transpower to implement a temporary Special Protection Scheme on the transmission circuits supplying Ōamaru GXP. This non-traditional solution increased capacity for a low cost by extending the capacity of existing assets.

We value collaboration and standardisation between Electricity Distribution Businesses and are active members of the following industry groups:

- **Electricity Networks Aotearoa (ENA) Future Networks Forum (Steering Group)** Developing strategy and aligned solutions across the industry
- **ENA Regulatory Working Group** – Working with regulators to develop sound legislation and fair rules
- **South Island Chief Executives** – Direction setting to enable collaboration between EDBs
- **ENA Communications and Engagement Forum** – Providing strategic direction and collaboration opportunities
- **EEA Flex Talk Project -** Investigating communications protocols between EDBs and flex providers

9.2 Transforming Our Network

This section builds on Chapter 4 – Supporting our customers' energy transition and aligns with the ENA Network Transformation Roadmap (NTR).

While our traditional methods remain important, advancements in technology and evolving customer expectations make it important to transform how we understand our customers, operate our networks, and engage with stakeholders. This transformation will allow us to capitalise on new opportunities, manage emerging risks, and deliver optimal value to our customers.

Below is a summary of key initiatives currently underway:

Refining our future energy scenarios

In 2023, the ENA engaged Sapere Consulting to create national peak electricity demand scenarios out to 2050. Sapere created three scenarios for different uptake rates and usage of Consumer Energy Resources (CER) such as electric vehicles (EVs) and hot water demand. These scenarios were developed to meet the Climate Change Commission's 2050 targets.

We worked with Deta Consulting to peer review our future energy scenario inputs and methodology, with an emphasis on transport electrification, water heating, and space heating. Deta adapted the ENA/Sapere 2050 transport scenarios to fit our region, accounting for a delayed uptake due to significantly lower average household incomes in our area.

This methodology has enabled us to refine our future energy scenarios and investment plans. Our investment plan is based on the balanced scenario however our development plans are built to provide a no regrets pathway to cater for all scenarios. We will continue to refine this over the next year in collaboration with the Future Networks Forum to standardise scenario development methodologies across New Zealand's Electricity Distribution Businesses (EDBs).

Understanding our low voltage networks

Our goal is to understand more about our low voltage networks so we can benchmark existing performance, monitor trends, and model future energy scenarios. This will allow us to anticipate issues and use data to develop optimal solutions in advance of our customers' needs.

Two key projects are underway to achieve this:

1. **Low Voltage Feeder Monitoring:** Launched in 2022, this project now provides real-time monitoring for 150 transformers and 340 low voltage feeders, covering 70% of residential Ōamaru customers. We plan to extend coverage to 90% of Ōamaru residential customers over the next two years.

   We have used data from this system to assess hosting capacity per customer relative to measured demand for a sample group of transformers and LV feeders. We have modelled the impact of our future energy scenarios, developed and costed solutions, and applied the results to the entire asset fleet to create preliminary investment plans up to 2050. The graph below illustrates hosting capacity analysis for a sample of 22 residential distribution transformers. We will refine our methodology over the upcoming year.

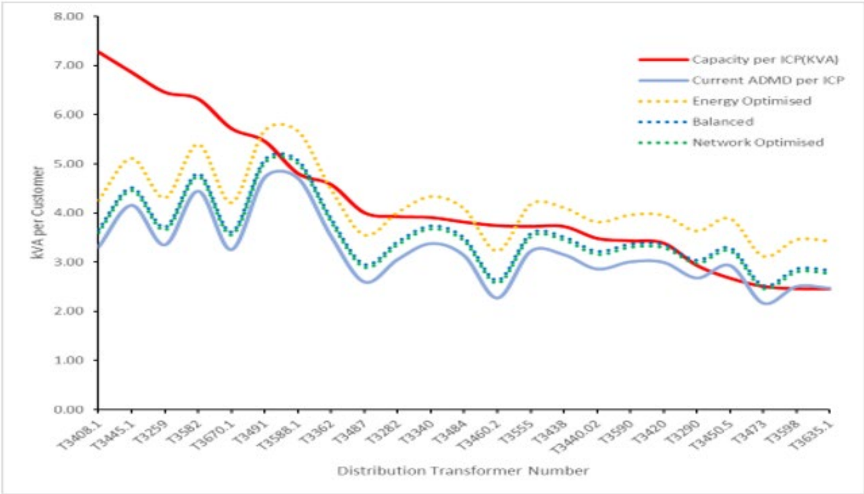


Figure 71 - Distribution transformer hosting capacity vs. scenarios

2. **Smart Meter Data Trial:** We have obtained MEP smart meter data for 1,000 customers and are currently conducting a trial with a smart meter analytics provider. This initiative aims to integrate this dataset with our low voltage monitoring system data so we can evaluate benefits and develop use cases to leverage smart meter data.

Enhancing our network model

In 2022, we created a load flow model of our network to distribution substation level so we could perform network studies and analyse hosting capacity. Over the next year, we will develop a process to regularly synchronise this model with our GIS system and demand forecasting tool, which will increase the accuracy of our model and allow us to produce hosting capacity maps regularly.

Delivering hosting capacity maps

Hosting capacity maps offer customers a visual representation of available capacity on our networks for new generation or load, without necessitating significant infrastructure upgrades. This initiative is a crucial step towards enabling customer self-service.

We have published distributed generation hosting capacity maps for our entire high voltage feeder network and zone substations. We acknowledge Powerco, who generously shared their methodology and standards with us. In 2025, we will publish hosting capacity maps for available load capacity and extend these to cover our subtransmission network.

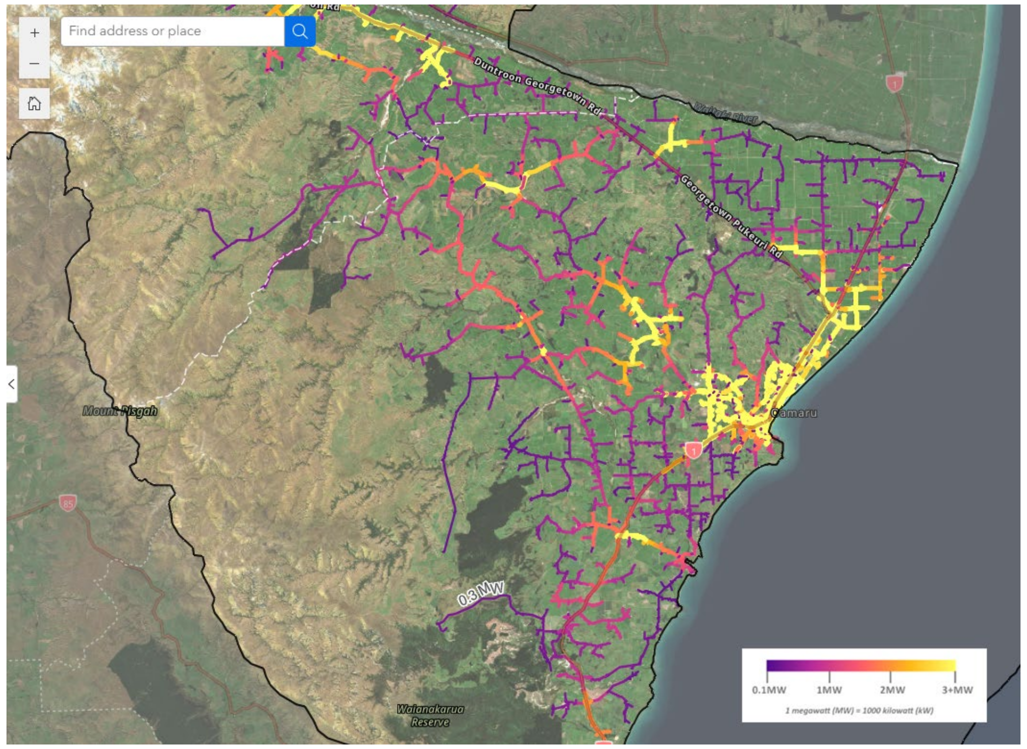


Figure 72 - Generation hosting capacity maps

Aligning our standards and processes

We are actively working to continuously improve our standards and processes to align with best-practice national EDBs. So far, we have aligned our distributed generation standards and processes with Powerco and Northpower. We led a group of peer EDBs to develop a common overhead line design standard and are now developing a common underground cable standard. During the next year, we will continue to align customer facing documentation across EDBs. Standardisation offers many benefits, creating a consistent experience for our customers, increasing buying power, reducing spare holdings, and making it easier to assist our neighbouring EDBs during major events.

Supporting the ENA Future Networks Forum

We are committed members of the ENA Future Networks Forum (FNF), actively participating on the steering group. We support the FNF's objective to "harness the collective power of the distribution sector to help Aotearoa reach its climate change goals."

Current initiatives include:

- Development of a standard load control protocol between retailers and Electricity Distribution Businesses (EDBs)
- Defining future system roles and functions
- Understanding our customer segments
- Mapping customer connection journeys to identify areas for improving customer experiences, especially when interacting with multiple EDBs
- Refreshing the Network Transformation Roadmap

Additionally, the FNF regularly holds Innovation Forums and has developed Communities of Practice to facilitate further sharing and collaboration among EDBs.

ENA Network Transformation Roadmap (NTR) alignment

In 2019, the Smart Technology Working Group created the Network Transformation Roadmap to guide New Zealand EDBs in preparing for the new energy future. Our plan aligns with the NTR, and we have assessed progress using the five stages outlined in the 2022 NTR update: Initial, Emergent, Developing, Mature, and Leading.

Foundational actions are the highest priority and support downstream workstreams.

Dependent actions rely on foundational actions being completed first.

Independent actions are standalone and not dependent on other actions.

Red items have improved since last year's evaluation.

Category	NTR Actions	Stage	Our Comments
Information	Access to smart meter data	Developing	We are conducting a trial with a data analytics company and have agreements in place for a trial NODS data from a MEP
	LV monitoring	Developing	We are now monitoring 320 low voltage feeders and 135 transformers in real-time and developing plans to further integrate data into our business
	Understand DER deployment	Emergent	We currently have low penetrations of DER in our network. We are trialling identification of EVs and DGs from our data analytics trial.
	Network stability	Developing	We have a working network model to distribution transformer level and have conducted EV hosting capacity studies on sample LV networks.
	Provision of network information	Developing	We provide network information in our Asset Management Plan and have published interactive generation hosting capacity maps and will extend these maps for load hosting capacity in early 2025
	Network understanding	Developing	We use LV data from our LV monitoring system to model impacts of future energy scenarios to LV feeder level and develop 2050 investment plans.
Procurement	Demand response framework	Developing	We developed a demand response and energy management strategy and will continue to work with our peers to refine our assumptions.
	Develop contracting for network support	Emergent	We have access to processes and guidance from our peers who have contracted for network support
	Third party flexibility services for network support	Initial	We will develop our action plan once we have established the foundational actions and as markets develop.
	Enable distribution network trading	Initial	We will develop our action plan once we have established the foundational actions and as markets develop.
	Off-grid power supplies	Developing	We have access to processes and guidance from our peers who have successfully installed OGPS and have evaluated an OGPS as an option instead of a remote line rebuild. OGPS is an option we consider when we need to build or renew assets in remote areas.
Standardisation	Understand new distributed generation	Developing	We have a good understanding of existing DG and have aligned our standards with best practice EDBs to improve consistency of approaches.
	DER connection codes	Developing	We have aligned our DG connection standards and congestion policy with best practice EDBs.
	Appliance/DER connection standards	Initial	We will contribute to working groups as appropriate and adopt new standards as they are developed.
	Cybersecurity for DERs	Initial	We will contribute to working groups as appropriate and adopt new standards as they are developed.
Consumer Driven	Understand new loads	Developing	We have a good understanding of process heat electrification opportunities and have aligned peer reviewed EV and hot water growth projections with national best practice.
Asset Management	Network engineering	Developing	We have developed a combined overhead line standard among peer EDBs and are now working on a underground cable standard. We have aligned DG standards with best-practice EDBs.
	Asset management practice	Developing	See section 6.6 Asset Management Maturity.

9.3 Our Planning Approach

Our planning process

The main drivers for network development projects are:

- Customer demand growth
- Customer reliability
- Security of supply
- Network transformation
- Power quality and thermal constraints

Where we identify immediate drivers (customer growth, power quality or thermal constraints) we look to deliver projects in time to meet customer needs. When studies indicate future drivers, we will signal the potential investment in our Future Networks Plan.

Before confirming significant projects for delivery we:

- Review capacity and security gaps, value of risk, and develop a case for change
- Develop a long-list of options (including non-traditional solutions)
- Evaluate options for ability to reduce risk and create a shortlist of options
- Perform economic lifecycle analysis of shortlist options and evaluate risk improvement
- Develop a business case for the preferred option

Once a business case is approved, we schedule a project for delivery.

Once a project is completed, we review to check that it delivered the expected benefits.

Our planning criteria

Safety

We prioritise safety for our people and the public during planning, design, and construction stages. We conduct Safety in Design reviews to ensure new designs are safe before construction.

Energy efficiency

Our network is configured to minimize voltage drop and maximize efficiency. Although we pass network loss costs to customers, we aim to reduce their total electricity costs by considering energy losses in our business case calculations.

Voltage quality and constraints

The Electricity (Safety) Regulations 2010 require us to maintain a supply voltage of 230 V +/- 6% at customer points. Our customer requirements are detailed in our connection standard and network harmonics standard.

We currently monitor power quality for low voltage feeders covering 60% of our urban Ōamaru customers. When we identify a power quality issue, either from our low voltage feeder monitors, or raised directly from customers, we will investigate the issue and evaluate viable solutions. The best value solution will be selected in line with our planning process above and affected customers will be kept up to date with progress.

Customers are advised of any planned work to remedy voltage quality and constraints through our usual customer work planning process.

Environmental and sustainability

When analysing options for a solution, lifecycle environmental impact and sustainability are considered. For example, vacuum-type switchgear is chosen instead of Sulphur Hexafluoride (SF6) type where possible, due to SF6 being a potent greenhouse gas.

Equipment rating and selection

Where available, equipment ratings are taken from nameplate data or manufacturers' published data. When this information is unavailable, ratings are calculated from first principles or estimated from similar equipment. Conductors and switchgear are selected to meet the highest demand scenario, provided that the incremental cost of upsizing is less than the future cost of upgrading the equipment. The first stage in the design process is to check for existing standard designs or find one developed by others. Network assets are designed using standard sizes and models to minimise spares, maximise interchangeability, and reduce stock levels. Standard equipment sizes are specified in design standards.

Collaboration with peer South Island EDBs is ongoing to develop an overhead line design standard and standard pole constructions. Membership in the Southern Buyers' Group aims to standardise equipment and materials among members and leverage increased purchasing power.

Security of supply and reliability

Security of supply refers to the network's ability to meet customer demand for energy delivery without interruption. Deterministic security criteria are used to check for security gaps. When a gap is identified, a more detailed probabilistic analysis may be conducted to understand the risk exposure and estimate its cost so that we can ensure the cost of solutions is appropriate. Failure rates for specific classes of equipment are derived from internal statistics when available. In cases of insufficient data, industry guidelines such as the EEA Guide for Security of Supply and IEEE standard 493 are consulted.

Security of Supply notes

- Switching time: Time taken to reconfigure the network for backup supply.
- Repair time: Time taken to repair faulted assets, including locating and isolating the fault.
- Individual security levels may be negotiated with large or non-standard customers.
- The security criteria are based on the ability to interrupt irrigation demand for up to 48 hours per event.
- Restoration targets are based on percentage of customer numbers (excluding contracted N-security customers)
- Customer Supply Group for GXP, Zone Substations and subtransmission assets will be based on highest connected customer group
- Distribution feeders, substations and LV feeders will be broken into segments for analysis based on connected customer types

Table 25 - NWL Security of supply standard - deterministic criteria

Class	Description	Examples	First Outage (restoration target)	Second Outage (restoration target)	Bus/switchgear failure (restoration target)
Grid Exit Points (GXPs)					
A1	Business hub/ urban	Oamaru GXP North Otago GXP	No interruption (except N security demand)	50% in switching time 50% in repair time	50% in switching time 50% in 2 hrs
A2	Urban		75% in switching time 15% in 8 hrs 10% in repair time	100% in repair time	50% in switching time remainder in repair time
A3	Township	Waitaki GXP Twizel GXP	50% in switching time 40% in 12 hrs, 10% in repair time	100% in repair time	100% in repair time
Zone substations and sub-transmission feeders					
B1	Business hub	Chelmer Redcastle	No interruption (except N security customers)	100% in repair time	No interruption - 50% 50% in switching time
B2	Urban	Parsons	No interruption (except N security customers)	100% in repair time	-
B3	Township	Maheno, Hampden, Pukeuri, Otematata, Omarama, Duntroon, Kurow	100% - switching time	100% in repair time	-
B4	Rural A and B	Papakaio, Te Awamako, Eastern Rd, Five Forks, Enfield, Ngapara	100% - switching time	100% in repair time	-
B5	Rural C	Ohau	100% - switching time	100% in repair time	-
Distribution feeders, distribution substations, LV feeders					
C1	Business hub		100% - switching time (except faulted segment which is repair time)	100% in repair time	-
C2	Urban		100% - switching time (except faulted segment which is repair time)	100% in repair time	-
C3	Township		100% - switching time (except faulted segment which is repair time)	100% in repair time	-
C4	Rural A		50% in switching time remainder in repair time 100% in repair time	100% in repair time	-
C4	Rural B		50% in switching time remainder in re pair time 100% in repair time	100% in repair time	-
C5	Rural C		50% in switching time remainder in re pair time 100% in repair time	100% in repair time	-
Spur lines (HV and LV) and customer substations					
D1	All		100% in repair time	100% in repair time	-

9.4 Our Planning Assumptions

Introduction

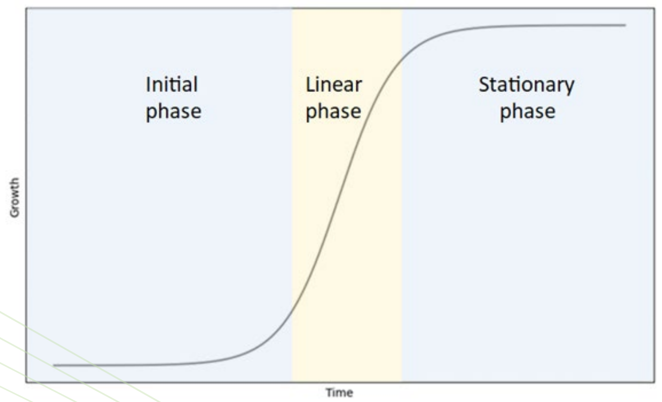
In Chapter 4, we presented our Future Energy Scenarios, focusing on supporting our customers' energy transition. We will now look at each customer segment in more detail, examining growth stages, confidence behind our assumptions, and the materiality of assumptions to our investment plan.

Planning data

We collect historical data from our SCADA system to analyse past demand and trends on our GXPs, subtransmission, zone substations, and high voltage feeders, and compare this with constraints using our system model. We also gather historical data per phase of each low voltage feeder for 60% of urban Ōamaru customers and are exploring the potential benefits of augmenting this with smart meter data.

Growth Stage

We use a Sigmoid (S-curve) model to describe the growth phase for each customer group. An S-curve graphically represents growth that commences slowly, accelerates during the mid-phase, and levels off upon reaching maturity. This model is frequently used to depict growth cycles, illustrating how new technologies first experience slow adoption, followed by rapid growth, and eventually stabilize as the market becomes saturated.



For instance, in our region, dairy shed growth is in the stationary phase of the S-curve, with most dairy conversions already completed. Conversely, electric vehicle (EV) growth is in the initial phase, where uptake is currently low, making it challenging to predict when we will enter the linear phase.

Confidence Levels

We evaluate our assumptions based on the following confidence levels:

- **Low Confidence:** Assumptions involving new or emerging technologies with no historical precedent, or customer projects that are currently at early enquiry stage.
- **Medium Confidence:** Assumptions derived from historical data, but still subject to some variability, or related to customer projects at the feasibility stage.
- **High Confidence:** Assumptions associated with well-established trends supported by robust data, or customer projects that are committed, or where customers have indicated a high likelihood of proceeding.

Materiality

We rate the materiality of our assumptions based on the potential to affect our investment plan during the AMP period as per our company risk framework.

- **Low:** Low impact on investment plan (less than $0.25m)
- **Medium:** Medium impact on investment plan (less than $1m)
- **High:** Significant impact on investment plan (above $1m)

Residential growth assumptions

Base housing growth

Our residential growth projections fall between the Waitaki District Council's 2043 Long Term Plan, which anticipates an average annual housing stock growth of 0.31%, and Statistics NZ's high scenario of 0.45%.

Given the absence of clear constraints on regional housing development, we assess the growth rates as being in the linear and stable phase of the growth S-curve.

The materiality is considered medium, as growth occurs in relatively small and predictable increments. We do not foresee a significant rise in housing development or an increase in housing density.

- S-Curve phase - linear
- Confidence level – medium
- Materiality - medium

Efficiency

As customers transition to LED lighting, improved building insulation, and more energy efficient appliances and motors, we expect a slight reduction in demand due to efficiency improvements.

We model a 0.5% decrease in residential and commercial demand from energy efficiency across all scenarios. However, typically this is offset by increased usage as more energy efficient appliance manufacturing lowers costs, leading to more appliances per household and negating operational efficiency gains.

Although the impact of energy efficiency is challenging to quantify and our confidence in this projection is low, it does not significantly affect overall demand.

- S-Curve phase - unknown
- Confidence level – low
- Materiality - low

Solid fuels/gas phase out

In our supply area, many homes use wood burners for heating. Without strict clean-air rules, we don't foresee a significant shift from wood burners to heat pumps soon. However, new homes are expected to prefer heat pumps, and older units will likely be replaced with modern, energy efficient inverters.

This gradual transition will reduce reliance on wood, gas, and less energy efficient electric heating, increasing peak demand by 0.6 to 1.2 MW over ten years across all GXPs.

- S-Curve phase - unknown
- Confidence level – Low
- Materiality - Low

Commercial and industrial growth assumptions

Base growth

Over the past decade, connected capacity has grown at an average annual rate of 1.2%, decreasing to 0.9% over the last five years. Our model predicts a base growth rate (excluding process heat electrification) of 0.9%, with a potential increase to 1.2% under the energy-optimised scenario.

Our confidence level is medium based on historical growth patterns; however, the materiality for this group is higher than for residential growth due to the larger potential load steps. For instance, a new factory in the district could require a significant electricity supply. We do not speculate on unforeseen large loads in our demand forecasts; instead, we allocate capacity once an application has been submitted.

- S-Curve phase - linear
- Confidence level – Medium
- Materiality - Medium

Electrical intensity

We are not aware of any factors that will increase electrical intensity across commercial and industrial customers, (except for known process heat conversions which are included in the next section)

We are currently talking with a customer who intends to significantly increase electrical intensity at their factory and have included this in our demand forecasts.

To manage uncertainty around this, we regularly catch up with key customers to discuss their future energy plans.

- S-Curve phase - unknown
- Confidence level – low
- Materiality - medium

Process heat electrification

We collaborated with Deta Consulting to identify material process heat electrification opportunities in our region and to assess the feasibility of choosing electricity as a replacement fuel source instead of biomass.

In FY24, we provided new electricity connections for three customers previously using coal and diesel, resulting in a total new demand of 4.5 MVA.

Among the remaining identified opportunities, we may see up to 6 MVA additional electricity demand depending on whether a meat processing plant elects to use electricity to decarbonise their process heat needs. We will continue working with this customer to understand their needs.

- S-Curve phase – linear
- Confidence level – medium
- Materiality - high

Agricultural growth assumptions

Dairy sheds

Following extensive dairy shed expansion over the past two decades, we have not received any new requests for dairy shed connections in the last three years. Farmers have indicated that they do not to see significant dairy shed conversions in the future.

- S-Curve phase – stationary
- Confidence level – high
- Materiality - medium

Irrigation

Over the past 10 years, connected capacity grew at an average annual rate of 3.2%, slowing to 1.8% in the last three years and 0.5% in the past year, indicating reduced irrigation expansion.

We are confident that these irrigation projects will connect to the Ōamaru GXP within three years:

- An irrigation company expects customers in Lower Waitaki to switch 2,300 hectares from gravity to spray irrigation by 2027, adding up to 1.7 MVA of demand.
- An irrigation company plans to add 0.4 MVA capacity at their pump stations by 2027.

Once completed, irrigation growth will stall in the region as most viable land will be irrigated.

- S-Curve phase – top end of linear
- Confidence level – high
- Materiality - high

Transport growth assumptions

Light vehicles

The current penetration of light electric vehicles (battery and plug-in hybrid) in our district stands at 1.0% compared to 2.5% across New Zealand.

We have based our projections for the growth in uptake of light and commercial electric vehicles on the ENA/Sapere 2050 scenarios model. We adjusted these projections to reflect the specific conditions of our region, where household incomes are 24% lower than the national average, and there is a regional preference for traditional vehicles commonly used in farming, trades, and recreational activities.

These scenarios suggest minimal impact from electric vehicles over the planning period, confirming that we are still in the initial phase of S-Curve growth, with a significant increase in electric vehicle demand anticipated within the following decade.

- S-Curve phase – Initial
- Confidence level – Low
- Materiality - high

Public chargers

The utilisation of public electric vehicle (EV) charging stations continues to see substantial growth, particularly along state highways. We anticipate ongoing expansion in both the number and capacity of these charging stations within our region.

In collaboration with Deta Consulting, we have developed a projection of demand for public EV chargers extending through to 2050.

We expect flexibility associated with public EV charging infrastructure will be minimal, as it is unlikely that customers will significantly alter their charging behaviour while travelling based on pricing or incentives.

- S-Curve phase – Initial
- Confidence level – low
- Materiality - high

Public transport

Public transport availability in our area is limited, and significant effects from public fleet electrification are not anticipated. If autonomous vehicles become widespread, they might be used for public transport, potentially replacing existing private vehicles, resulting in minimal net impact.

- S-Curve phase – unknown
- Confidence level – low
- Materiality - low

Heavy vehicles

The national electrification of heavy vehicles may increase the load on the network at critical points along state highways where charging stations are required. The local adoption is expected to progress gradually during the planning period due to evolving technology and potential alternatives such as hydrogen.

Over the next year, we will work with with local heavy vehicle fleet customers and national fleet users to refine our strategies in this area.

- S-Curve phase – initial
- Confidence level – low
- Materiality - high

Distributed generation assumptions

Rooftop solar

Most Distributed Generation (DG) in our region is provided by small-scale photovoltaic (PV) panels, and this continues to grow. There are currently 290 DG connections on our network, representing 1.8% of all connections or 2.9 MW, with an average residential size of 4.7 kW.

Our growth scenarios are aligned with the 2022 Boston Consulting Group report, “Climate Change in New Zealand: The Future is Electric”. We estimate the firm reduction in network demand from solar generation to be approximately 5% of the DG rated power. This estimate is based on statistical analysis of solar performance under full cloud cover during evening peak demand. Our presently installed 2.9 MW of solar DG results in a firm reduction in demand of 150 kVA.

- S-Curve phase – Initial
- Confidence level – low
- Materiality - medium

Utility-scale distributed generation

Numerous large-scale solar generation projects are planned in New Zealand. These large-scale schemes would connect to our network at high voltage levels and will be evaluated as applications are received.

Our large-scale DG connection standard and congestion policy are aligned with best-practice EDBS to provide a consistent experience for national operators and manage risk to connected customers.

Consumer energy resource assumptions

Batteries

Currently, there are 50 customer battery installations connected to our network. All of these are associated with solar installations, with a total installed capacity of 550 kWh (equivalent to 10 average electric vehicles).

As battery costs decrease and value streams for battery flexibility services develop, an increase in distributed battery capacity connected to our network is anticipated. This will enhance the ability to align solar distributed generation with network peaks.

Due to the low number of batteries and uncertainty about their impact on the network, these are not currently modelled in demand forecasts but are planned to be included next year.

- S-Curve phase – Initial
- Confidence level – low
- Materiality - medium

Vehicle to grid

We do not currently model impacts from vehicle-to-grid technology, whether behind the meter or true vehicle-to-grid. This could be a major opportunity for short-term storage if it becomes feasible in the future. By 2050, with near 100% electrification of light vehicles and more vehicles on the road, energy storage in cars will surpass other sources and even exceed daily electricity demand.

We don't expect significant benefits from V2G during the planning period but will prioritize incorporating V2G into our demand scenarios next year.

- S-Curve phase – Initial
- Confidence level – low
- Materiality - medium

Hot water

We currently purchase hot water flexibility services from our customers and shift 2.5 MW of hot water heating demand from network peaks into the 11pm to 7am period, with an additional 1 MVA that we can control if necessary.

Retailers and aggregators have shown increased interest in sharing control of this demand, and we will collaborate with these groups to ensure optimal outcomes for our customers. We will continue to provide emergency control of these resources via our ripple control system.

- S-Curve phase – Initial
- Confidence level – low
- Materiality - Medium

9.5 Transmission and GXP summary[1]

Capacity and security

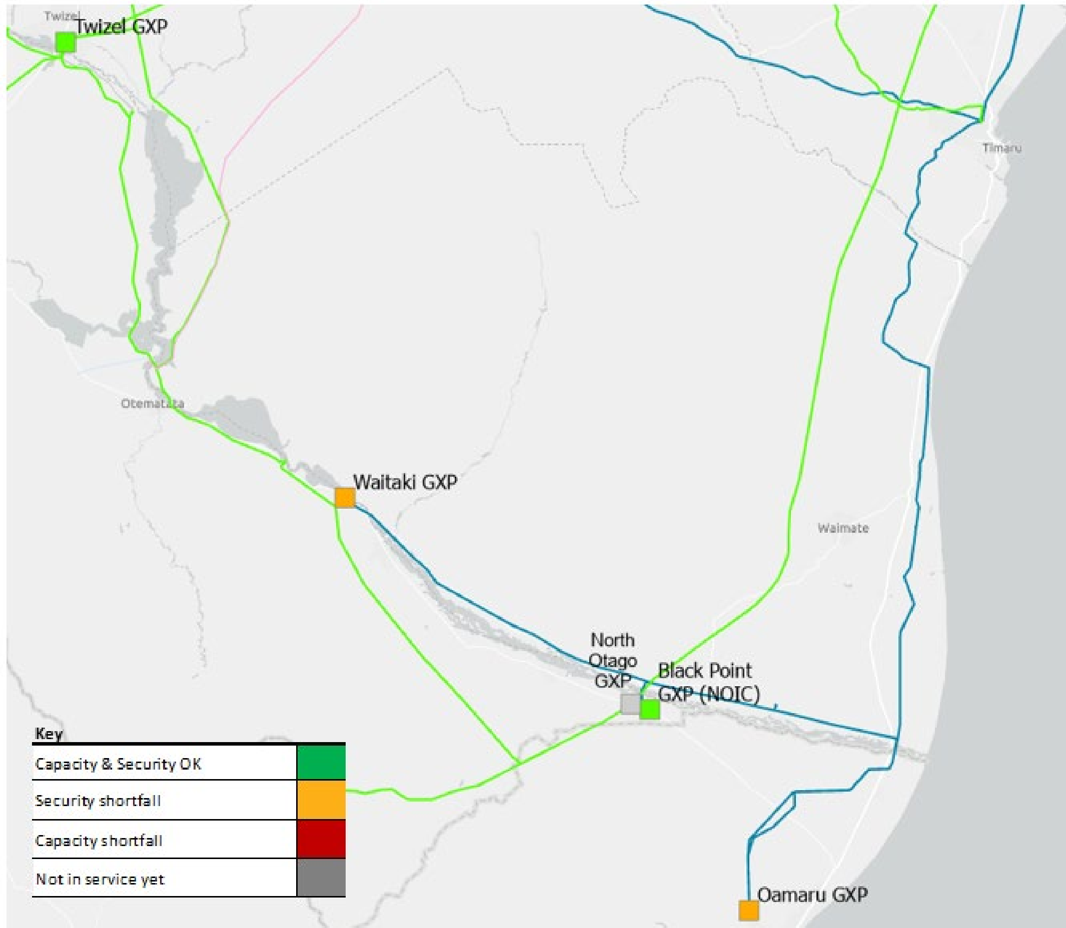


Figure 73 - Network Waitaki GXP locations and Transpower transmission network

GXP	Capacity and security summary								
	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Ōamaru	1								
North Otago			2						
Waitaki	3								
Twizel	4								
Black Point	4								

Comments

1. Our expected customer demand, largely driven by process heat electrification will result in Ōamaru GXP reaching the capacity limit by FY28.
2. We are working with Transpower to deliver a new "North Otago GXP" by FY28. Until the new GXP is operational, Transpower has allowed us to use a temporary Special Protection Scheme to allow us to continue to supply new customer demand. Until FY28, we may need to connect new large-load customers at (n) level GXP security.
3. Backup security at Waitaki GXP will decrease as demand increases at Ōamaru GXP. There is a risk of a shortfall of backup security for parts of FY26 and FY27 until the new North Otago GXP is in service. If an outage occurs during a shortfall, we will manage with rolling irrigation demand outages of up to 48 hours and by hiring diesel generators for longer outages.
4. There are no capacity or security constraints expected at Twizel or Black Point GXPs over the planning period.

1 - Note: detailed planning information and related projects can be found in Appendix C – Transmission/GXP capacity and security analysis and Appendix E – Future network plan – Projects.

9.6 Sub-transmission and substation summary[1]

Ōamaru GXP Supply Area

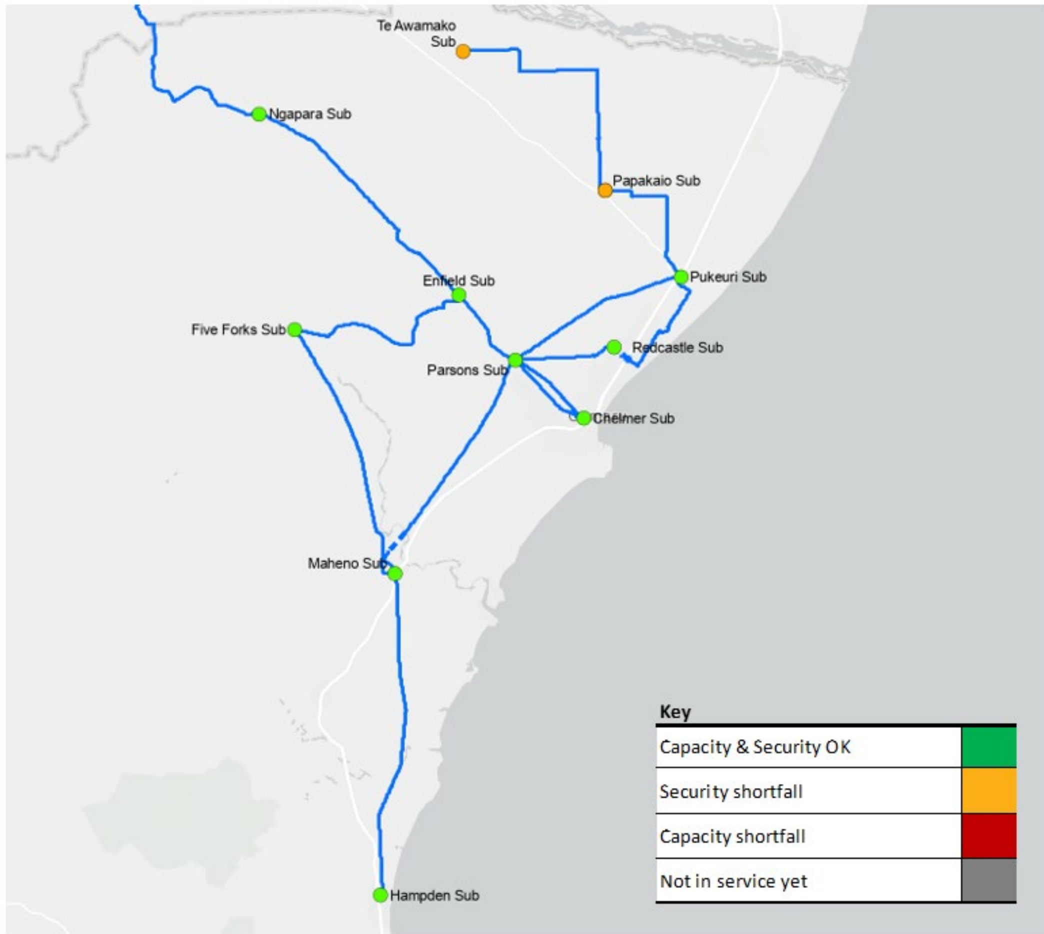


Figure 74 - Ōamaru GXP sub-transmission and substations

Table 24 - Ōamaru GXP substations - capacity and security summary

Zone Substation	Capacity and security summary								
	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Te Awamako	1								
Chelmer									
Enfield									
Five Forks									
Hampden									
Maheno									
Ngapara				2					
Papakaio	1								
Redcastle									
Parsons									
Pukeuri									

Comments

1. Te Awamako and Papakaio Zone Sub security constraints are present until FY28 when the North Otago GXP and subtransmission ring is in service. (For part of the year, irrigation load on these substations may need to be shed for repair time for a failure on the overhead sub-transmission line between Pukeuri and Papakaio).
2. We plan to transfer Ngapara Zone Sub to the North Otago GXP in FY29.

1 - Note: detailed planning information and related projects can be found in Appendix D – Subtransmission/Zone Sub capacity and security analysis and Appendix E – Future network plan – projects.

Waitaki GXP Supply Area

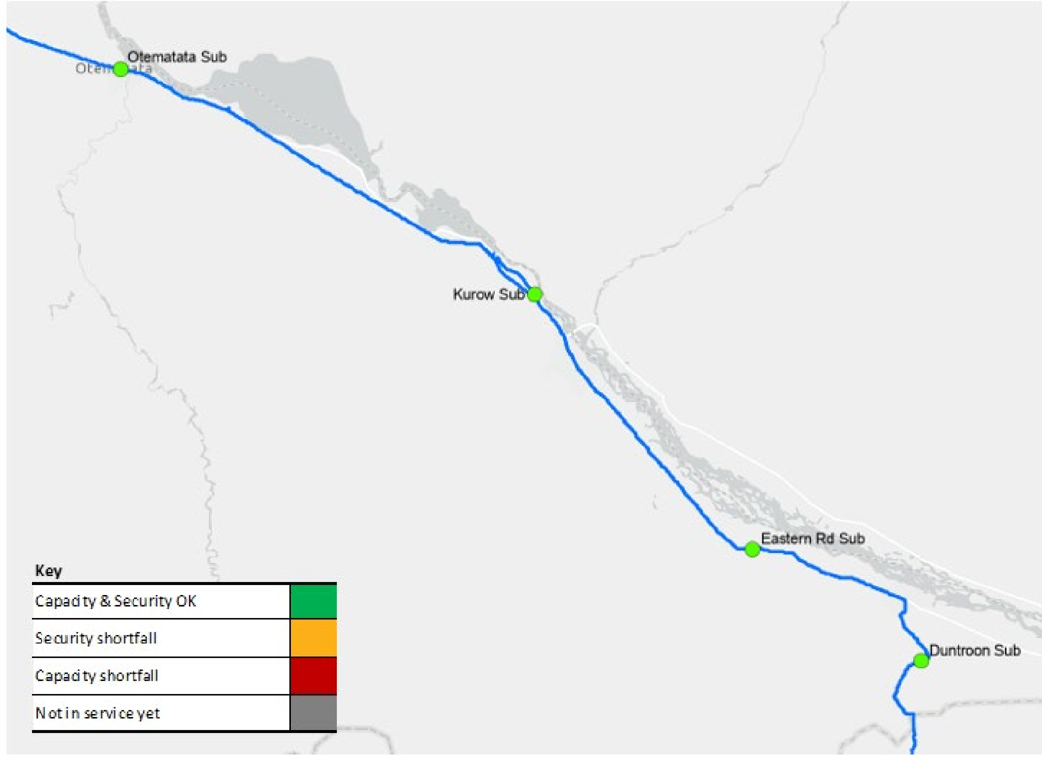


Figure 75 -Waitaki GXP sub-transmission and substations FY23
Table 25 - Zone substation capacity and security summary

Zone Substation	Capacity and security summary								
	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Duntroon				1					
Eastern									
Kurow									
Otematata									

Comments
(See Section 6.8 Network Development Projects for detail on projects and appendices for detailed zone substation analysis).

1. In FY29, Duntroon Zone Substation will be transferred to the new North Otago GXP.

Twizel GXP Supply Area

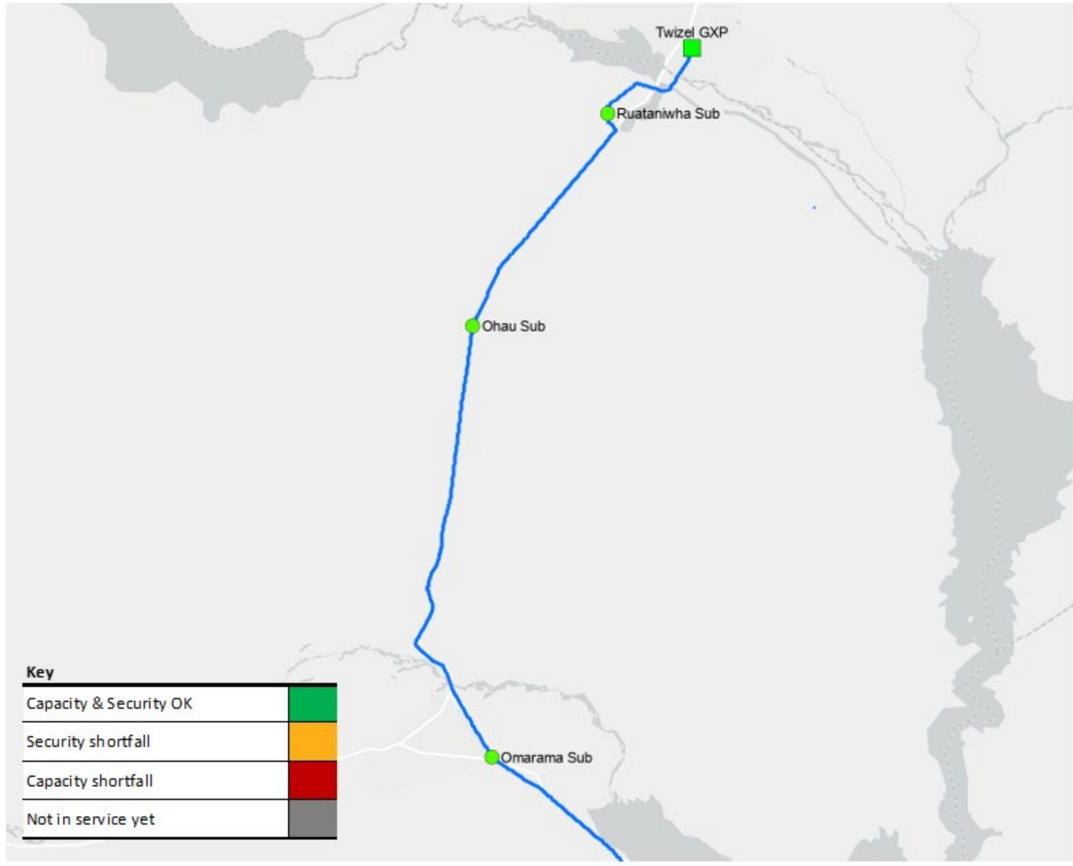


Figure 76 - Twizel GXP sub-transmission and substations FY24
Table 26 - Zone substation capacity and security summary

Zone Substation	Capacity and security summary								
	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Ōhau									
Ōmārama									
Ruataniwha									

Comments
No capacity or security constraints are expected in the planning period.

North Otago GXP Supply Area (FY28)

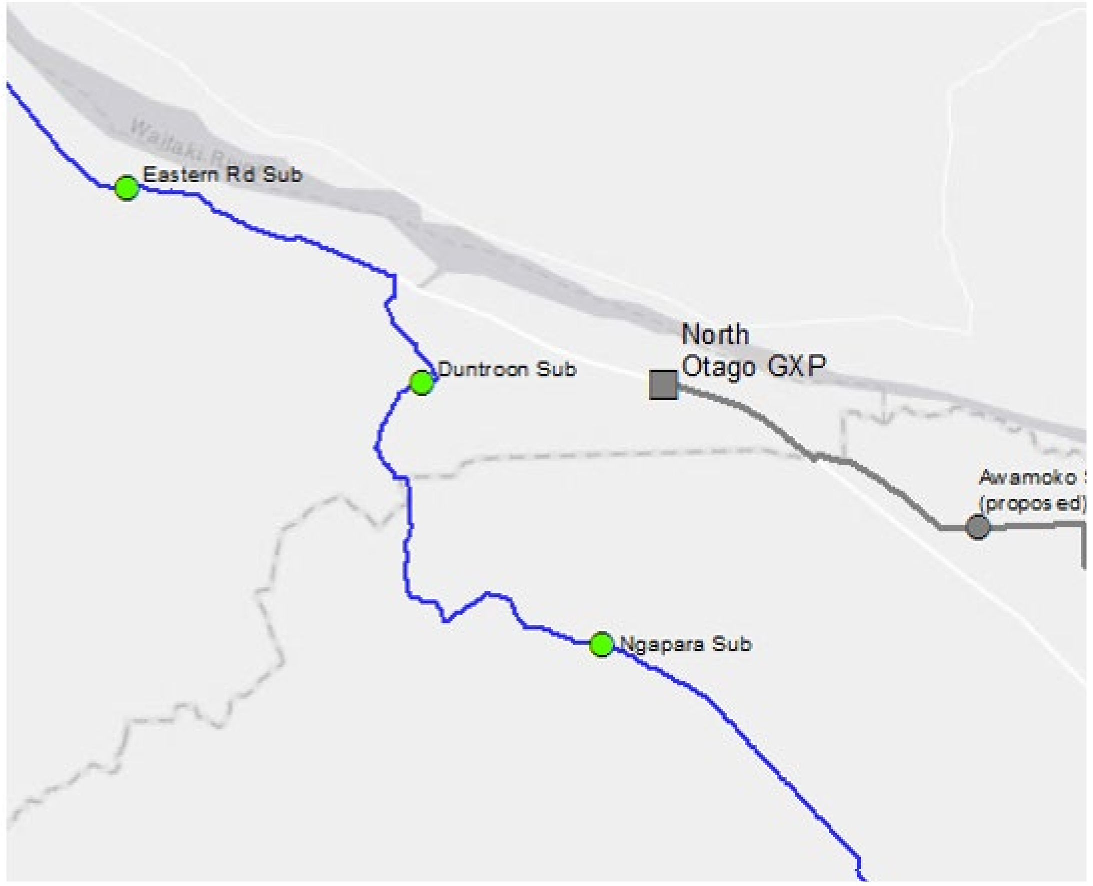


Figure 77 - North Otago GXP sub-transmission and substations

Table 27- Zone substation capacity and security summary

Zone Substation	Capacity and security summary								
	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Te Awamako			1						
Ngapara				2					
Papakaio			1						
Duntroon				2					

Comments

No capacity or security constraints are expected before FY35.

1. Te Awamako and Papakaio zone subs will be transferred from Ōamaru GXP in FY28.
2. Ngapara, and Duntroon zone subs will be transferred from Ōamaru GXP in FY29

9.7 Distribution Network Summary

We have completed capacity and security studies for customer groups on our high voltage feeders.

In these studies, we examined previous reliability levels and security levels for these customer groups. From these studies we have identified the following gaps.

Further details on these projects are presented in Appendix E – Future network plan - projects

Table 28 - Distribution high voltage feeder capacity and security summary

Customer Area	Zone Substation	Proposed Project Number	Capacity (MVA)	Security Service Level
Te Awamako	Te Awamako	9		
Moeraki	Hampden	11		
South Hill	Chelmer	12		
Ōmārama	Ōmārama	13		
Otematata	Otematata	14		
Weston	Parsons	15		
Kurow	Kurow	16		
Ardgowan	Parsons	17		
Horse Gully	Parsons	18		
Ōhau	Ōhau	19		
Waitaki Bridge	Papakaio	20		
Teaneraki	Enfield	21		
Hampden	Hampden	22		
North Otago Business Park	Redcastle	23		
Observatory Village	Chelmer	24		

Further details of projects and rationale behind these can be found in Appendix E – Future network plan - projects

9.8 Ten Year Development Programme

Project No.	System level	Description	FY26 $(00)	FY27 $(000)	FY28 $(000)	FY29 $(000)	FY30 $(000)	FY231 $(000)	FY32 $(000)	FY33 $(000)	FY34 $(000)	FY35 $(000)	Total ($000)
Subtransmission													
1	System growth	North Otago GXP - Site establishment	950										**950**
	System growth	North Otago GXP - 110 kV switchyard	1,500	11,541									**13,041**
2	RSEQ	Weston Switching Station security improvements	1,050										**1,050**
3	System growth	New subtrans - North Otago GXP to Awamoko	5,968										**5,968**
4	System growth	New subtrans - North Otago GXP to Ngapara		210	6,061								**6,271**
5	System growth	New subtrans - Ngapara to Oamaru									300	12,285	**12,585**
6	System growth	Weston/Redcastle ring protection upgrade	600	300									**900**
7	System growth	110/33 kV conversion stations					500						**500**
Zone Substations													
8	System growth	Convert Ruataniwha to Zone Substation				462							**462**
9	System growth	Automated open points into Te Awamako Sub	105										**105**
10	System growth	Omarama Zone Sub security/resilience improvement				126							**126**
Distribution													
11	System growth	Moeraki security/ resilience improvement	221										**221**
12	RSEQ	South Hill HV security/resilience improvement	200										**200**
13	System growth	Omarama township security/resilience improvement		473									**473**
14	System growth	Otematata township security/resilience improvement	300	189									**489**
15	System growth	Weston security/ resilience improvement			431								**431**
16	System growth	Kurow township security/resilience improvement			315								**315**
17	RSEQ	Ardgowan Road security/resilience improvement	74										**74**
18	RSEQ	Horse Gully Road feeder automation					100						**100**
19	RSEQ	Ōhau feeder automated open point					100						**100**
20	RSEQ	Waitaki Bridge security/resilience improvements						100					**100**
21	RSEQ	Teaneraki security/ resilience improvements							270				**270**
22	RSEQ	Hampden security/ resilience improvements										30	**30**
23	System growth	North Otago Business park security/resilience improvements			200								**200**
24	System growth	Observatory village security/resilience improvements			200								**200**
25	System growth	Provisional DTx and LV reinforcement	300	300	300	400	1,500	1,500	1,500	1,500	1,500	1,500	**10,300**
26	System growth	Provisional HV reinforcement	200	200	200	200	200	200	200	200	200	200	**2,000**
27	System growth	Provisional network enhancement projects					300	400	230	400	400	400	**2,130**
Communications and Monitoring													
28	System Growth	Low voltage monitoring	335	290	250								**875**
29	System Growth	Fibre - Station Peak to Kurow	360										**360**
30	System Growth	Fibre (Kurow to Eastern Rd) 17km		440									**440**
31	System Growth	Fibre (Eastern Rd to North Otago GXP) 22km			550								**550**
32	System Growth	Radio link upgrade	100	100	100	100	100	100	100	100	100	100	**1,000**
33	System Growth	Communications upgrades	100	100	100	100	100	100	100	100	100	100	**1,000**
34	System Growth	Purchase Transpower Station Peak site	200										**200**
Consumer Connection													
35	Consumer Connection	New LV Service Connections	583	583	583	583	583	583	583	583	583	583	**5,826**
36	Consumer Connection	Install Distribution Transformers - Customers	404	404	404	404	404	404	404	404	404	404	**4,042**
37	Consumer Connection	New 11kV Network Extensions	497	497	497	497	497	497	497	497	497	497	**4,968**
38	Consumer Connection	Residential Subdivisions	228	228	228	228	228	228	228	228	228	228	**2,276**
		Grand total	**14,273**	**15,854**	**10,417**	**3,099**	**4,611**	**4,111**	**4,111**	**4,011**	**4,311**	**16,326**	**81,125**

Summary by category	FY26 ($000)	FY27 ($000)	FY28 ($000)	FY29 ($000)	FY30 ($000)	FY31 ($000)	FY32 ($000)	FY33 ($000)	FY34 ($000)	FY35 ($000)	Total ($000)
System Growth	11,239	14,143	8,706	1,388	2,700	2,300	2,130	2,300	2,600	14,585	**62,090**
RSEQ	1,323				200	100	270			30	**1,923**
Consumer Connection	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	**17,112**
Grand total	**14,273**	**15,854**	**10,417**	**3,099**	**4,611**	**4,111**	**4,111**	**4,011**	**4,311**	**16,326**	**81,125**

Non-Network Investment Plan

10

Non-Network Investment Plan

This chapter sets out our Non-Network Investment Plan.

10.1 Asset Categories

The delivery of our asset management plan strategies requires supporting infrastructure, equipment and systems. At Network Waitaki these are categorised as:

- Vehicles and plant to construct and maintain the assets
- Buildings and depots to store equipment and spares
- Systems and data to inform operations and other asset management activities
- Other business systems and support

10.2 Vehicles and plant

Asset Summary

Network Waitaki primarily utilises its own contracting business to deliver the Asset Management Plan. To provide confidence in the delivery process a high level summary of the various plant and equipment is below.

Vehicle Type	Total	Average Age
Cars & Pool Utes	23	3 Years
Light Trade Vehicles	17	3 Years
Heavy Trucks	14	9 Years
EWPs	7	7 Years
Trailers	31	19 Years

Maintenance Planning

Vehicles are maintained and serviced in accordance with the Manufacturers recommendations. This is monitored using QuipCheck which is updated whenever a vehicle is used or during the weekly vehicle checks.

Renewals Planning

Vehicle replacements follow WP0580 Motor Vehicle Policy which is summarised below.

Vehicle Type	Renewal Policy	Average per Annum
Cars & Pool Utes	4 years or 150,000km	6
Light Trade Vehicles	5 years or, 200,000km	3
Heavy Trucks	15 years	1
EWPs	15 years	0.5
Trailers		1

Develoment Planning

There are no material changes or development plans proposed for the vehicle and plant fleet.

10.3 Property

Asset Summary

Aside from the Zone Substations covered in Section 7. Network Waitaki has properties in Oamaru (Main Office, Depot, Workshops and Store), Weston (backup Office, Depot, Workshops, Store and Training facilities) and Otematata (Depot and Emergency Store).

Maintenance Planning

To ensure Network Waitaki remains compliant with building warrant of fitness requirements, maintenance contracts are in place with third parties. These contracts cover scheduled and reactive maintenance activities on both grounds and buildings, including air-conditioning units, fire alarms and security systems

Renewals Planning

The renewal of property assets is primarily on an 'as required' basis. The organisation's property requirements are reviewed frequently at both a strategic and tactical level. The review identifies any changes which may be necessary to ensure the continued efficient operation of the business.

Development Planning

Of note in the Property component of our non-network capex expenditure forecast is the redevelopment of our Chelmer Street site (our primary administration and operations site) between FY26 and FY28. This project will increase the resilience of our operations and involves redevelopment of our yard and construction of a new earthquake rated (IL4) operations building and control room.

10.4 System operations and network support

Operating the network safely and efficiently requires robust systems and data. We also anticipate the necessity to be more agile and responsive to our customers' changing expectations and this requires us to continually review and look at our systems, processes, and capabilities. Network Waitaki needs to become data-centric to ensure our operations are performing as effectively as possible.

A key area of focus for us is ensure continual investment in and development of our key systems and processes to extend our use of data and digitisation to deepen our understanding of how customers are using our network. These insights will help us to optimise our business processes, inform system and platform development and engage in new ways with our customers.

To make the most of new systems and processes, we are developing our business capability by investing in both our systems and our people. This is required to enable us to deliver on the expected future state in a new world of flexible de-carbonised energy resources.

Asset Summary

The system operations and network support activity area covers the teams managing our network, and includes:

- Network development responsible for the overall direction and management of our network infrastructure. It is responsible for strategic and engineering planning for our electricity distribution network;
- Our customer service activity delivering excellent customer engagement, service and support;
- Infrastructure stewardship, developing appropriate whole of life strategies for our network assets;
- The daily operation of the network, delivery of AMP work programmes, and other delivery and engineering related services.
- Network Data Management that includes geospatial information and asset information systems that extend out to field mobility solutions.

Function	Current	Future
Load Modelling	Digsilent Power Factory	Digsilent Power Factory
Geospatial Information	Esri ArcGIS Pro	Esri ArcGIS Pro
System Operations	Abbey	TBA (2026)
Outage Management	Revman	TBA (2027)
Customer Interaction	Microsoft	TBA (2028)
Distributed Energy Management	N/A	TBA (2029)
Asset Lifecycle Management	Microsoft	TBA (2030)
Real Time Event Response	N/A	TBA (2031)

Digsilent Power Factory is a widely used power system analysis software application that analyses generation, transmission, distribution and industrial systems. It covers a range of functionality including distributed generation, real-time simulation and performance monitoring and is used for Network Planning, analysis of new connections and constraint identification.

Esri ArcGIS Pro is a full-featured professional desktop GIS application from Esri. It is widely used in NZ particularly by Local Authorities which simplifies sharing of information. It is used to store records of network assets both by location and electrical connectivity.

Abbey Systems is an established SCADA (Supervisory Control And Data Acquisition) system designed for water and wastewater utilities, power and gas distribution networks. The SCADA enables control and operation of the network includes managing and communicating with assets in the field along with tools to enable operators to make informed decisions based on the current network status enabling faster fault detection and supply restoration.

Revman is software widely used within Network Waitaki. It integrates activities within various parts of the business including Outage Management (Planning, Recording, Notifications), Retailer Billing (incl. detailed disclosure reporting), ICP Management (in sync with Electricity Authority Registry), and Metering Works Management.

Maintenance Planning

All systems are fully licensed and supported by the vendor.

Renewals Planning

Servers, storage devices, and network devices are continuously monitored for availability and errors with alarms. Other hardware is repaired/replaced on failure.

Software vendors automatically notify if new versions are available and provide notice when they will stop support. Network Waitaki has a policy to remain on supported versions of software and replace hardware at the end of the vendor-provided warranty period.

Development Planning

Network Waitaki looks to cooperate and coordinate with similar organisations to reduce the cost, complexity and risk associated with new systems. This often means that the development and implementation of new systems does not always follow our own plan.

Discussions are underway with several other EDBs to establish a common approach for the System Operations, Outage Management and Customer Interaction support systems. These are at varying states of progress and are still commercially sensitive.

10.5 Business systems and support

The business support activity area manages the support systems, processes, that supports the network business to deliver its strategic plans. This includes:

- Delivery of systems of management of quality, health and safety management systems;
- Risk and compliance management frameworks;
- People and culture support services;
- Financial Management and business support;
- Support for delivery of field services and corporate support infrastructure, including business information technology services;
- Corporate and strategic governance.

The table below outlines the IT application landscape and shows the major business functions supported by the material applications in use at Network Waitaki, and how this is planned to change over time.

Function	Current	Future
Works Management	Business Central	Business Central
Finance	Business Central	Business Central
Inventory	Business Central	Business Central
Payroll	iPayroll	iPayroll
Safety	Vault	Vault
Risk Management	Quantate	Quantate
Retailer Billing	Revman	TBA (2025)
Vehicle and Plant Management	QuipCheck	QuipCheck
Business Productivity	Microsoft O365	Microsoft O365
Business Integration	FME	FME

Microsoft Dynamics 365 Business Central is used in over 160 countries by SMEs to manage their entire business from finances to customer service, using a single, integrated platform. It is primarily an ERP (Enterprise Resource Planning) system, it also incorporates CRM (Customer Relationship Management) functionalities. Business Central is Network Waitaki's Financial Management System (FMS) and incorporates the asset register for all financially material assets. The asset data that Business Central masters is linked to other systems such as GIS through a Microsoft Power App known as MAPA (Master Asset Power Application). As part of its materials management role (inventory and purchasing) Business Central masters the location of network assets prior to installation and utilisation.

iPayroll is a cloud-based payroll solution developed in 2001 for New Zealand businesses. It is the leading online PAYE Intermediary (PI) with Inland Revenue, processing gross payrolls of over $4.5 billion per year.

Vault is a Safety Management Software widely used in Australia and New Zealand. Vault catalogues Network Waitaki's Health and Safety information including audits and compliance documentation

Quantate is Risk Management software that is designed to support risk and assurance frameworks consistent with best practice and standards such as ISO 31000. Quantate records Network Waitaki's quantified business and major asset risks and their associated treatment plans.

Revman is software widely used within Network Waitaki. It integrates activities within various parts of the business including Outage Management (Planning, Recording, Notifications), Retailer Billing (incl. detailed disclosure reporting), ICP Management (in sync with Electricity Authority Registry), and Metering Works Management.

QuipCheck is used to monitor plant and vehicle condition and compliance. It records any maintenance or repair activities and any requests for them.

Microsoft 0365 is the system used to track, manage, and store documents while keeping a record of the various versions created and modified by different users. SharePoint 2016 houses all of Network Waitaki's controlled documents including standards.

Maintenance Planning

All systems are fully licensed and supported by the vendor.

Renewals Planning

Servers, storage devices, and network devices are continuously monitored for availability and errors with alarms. Other hardware is repaired/replaced on failure.

Software vendors automatically notify if new versions are available and provide notice when they will stop support. Network Waitaki has a policy to remain on supported versions of software and replace hardware at the end of the vendor-provided warranty period.

Development Planning

The Retailer Billing system is currently in a tendering and price assessment process with implementation planned for 2025.

A summary of planned material, capital, and maintenance expenditure in respect of these assets is also provided below.

Summary of Expenditure Forecasts

11

11

Summary of Expenditure Forecasts

The summary of our forecast expenditure for the planning period is presented on the following pages

These forecasts are expected costs based on known measures and values for the first five years of the planning period, with the figures being indicative beyond that point. Many of our investment, maintenance and renewal decisions will be highly dependent on the outcomes of inspections in the first five years, on customer growth, and other issues that are out of our control, such as the development of the Transpower transmission network.

Note: The forecasts are presented in constant dollars. Deliverability of the proposed expenditures will be subject to inflationary pressures and these are considered in business forecast modelling.

Network Capital Expenditure	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
System Growth	11,239	14,143	8,706	1,388	2,700	2,300	2,130	2,300	2,600	14,585
Reliability, Safety & Environment - Quality of Supply	1,323	-	-	-	200	100	270	-	-	30
Reliability, Safety & Environment - Legislative & Regulatory	-	-	-	-	-	-	-	-	-	-
Asset Replacement & Renewal	13,001	9,110	7,083	8,827	6,846	8,659	6,731	8,804	6,886	8,910
Consumer Connection	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711
Asset Relocations	-	-	-	-	-	-	-	-	-	-
Total Network Capital Expenditure	**27,274**	**24,964**	**17,500**	**11,927**	**11,457**	**12,770**	**10,843**	**12,816**	**11,197**	**25,236**
Network Operational Expenditure										
Asset Replacement & Renewal	296	267	267	222	222	222	222	222	222	222
Routine & Corrective Maintenance and Inspections	1,602	1,998	1,973	1,936	1,973	1,936	1,973	1,936	1,973	1,936
Vegetation Management	807	807	807	807	807	807	807	807	807	807
Service Interuptions & Emergencies	735	723	723	723	723	723	723	723	723	723
System Operations and Network Support	78	78	78	78	78	78	78	78	78	78
Total Network Operational Expenditure	**3,238**	**3,364**	**3,333**	**3,368**	**3,287**	**3,322**	**3,287**	**3,322**	**3,287**	**3,287**
Total Network Expenditure	**30,791**	**28,837**	**21,349**	**15,693**	**15,260**	**16,536**	**14,646**	**16,582**	**15,000**	**29,003**

Table 29 - Summary of expenditure forecasts

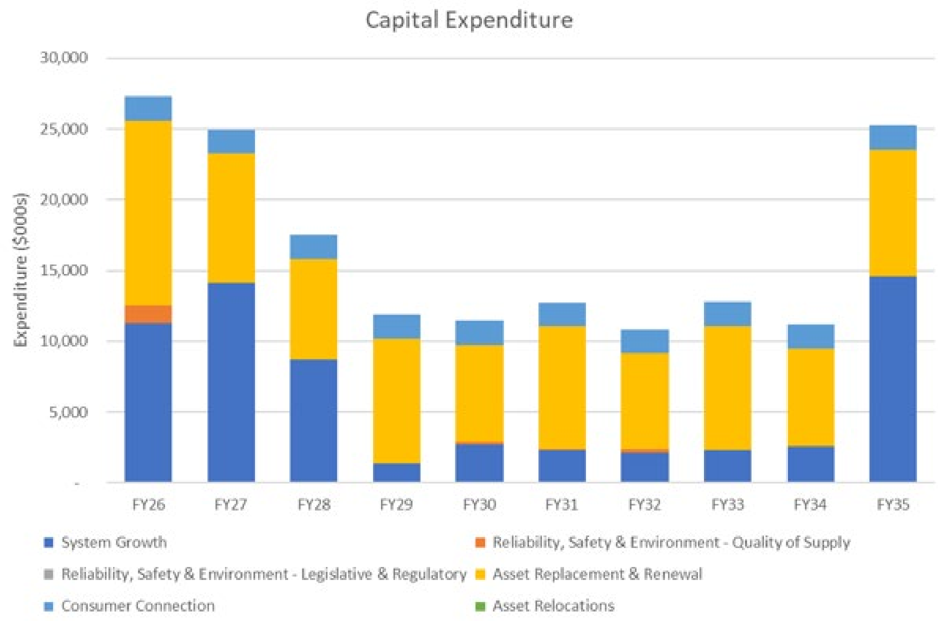


Figure 78 - Annual capital expenditure forecast by category

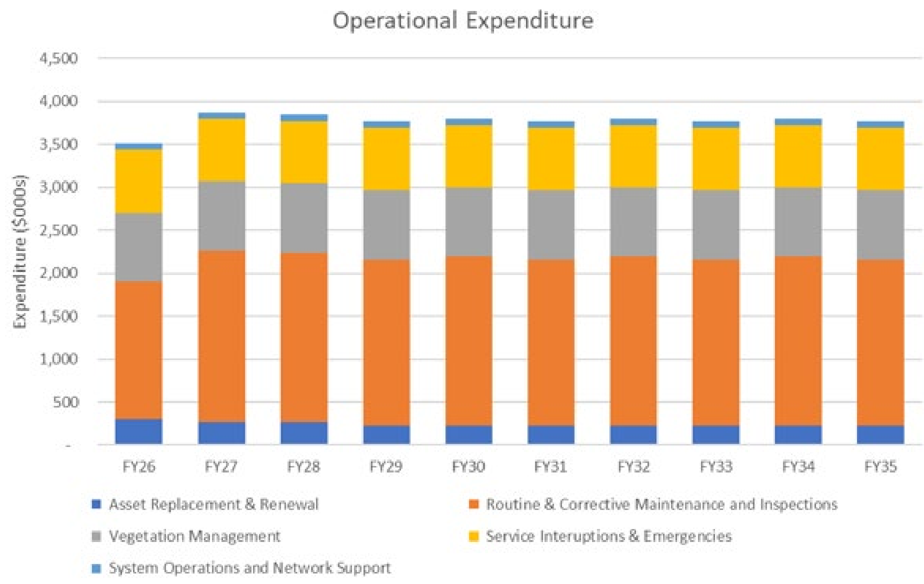


Figure 79 - Annual operational expenditure forecast by category

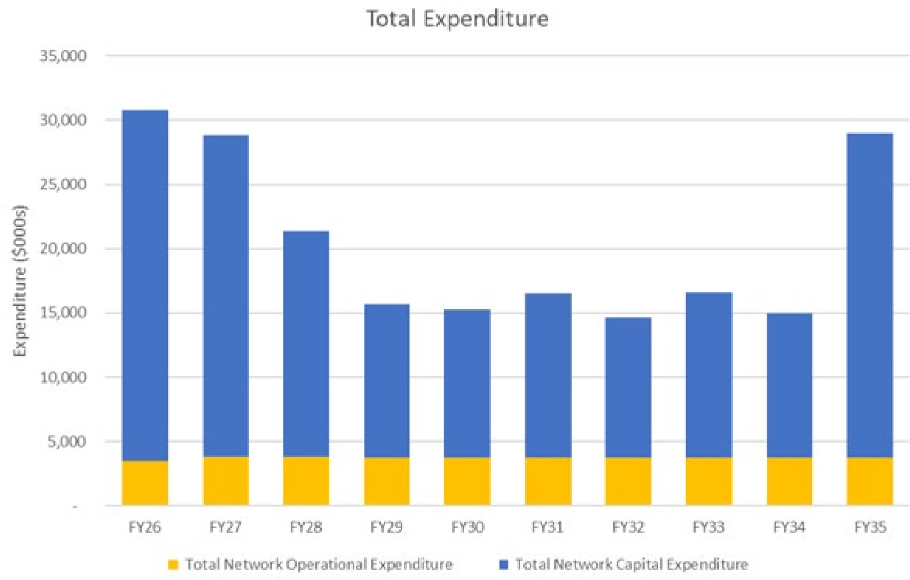


Figure 80 - Summary of total network expenditure forecast across planning period

Appendices

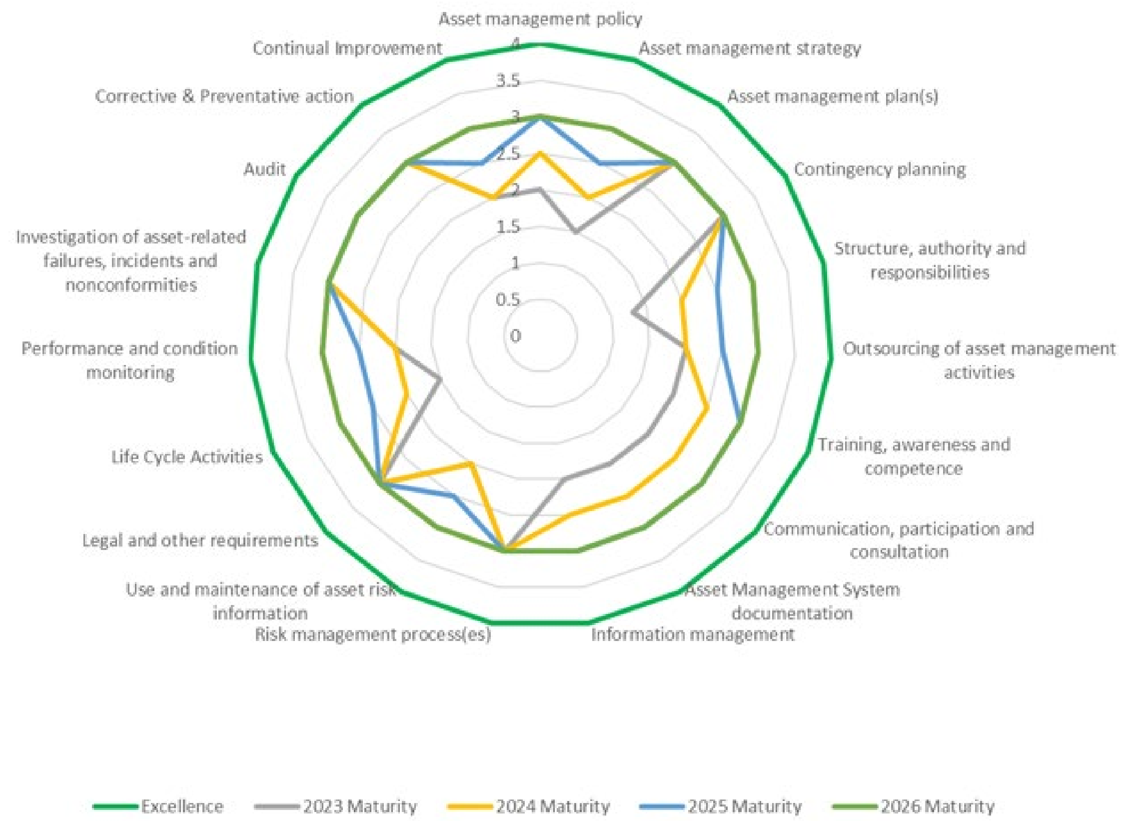
Appendix A - Asset Management Maturity Development Plan

As described in section 4.6, Network Waitaki is developing its asset management practices to align with ISO55001 and has identified a range of improvements to enable this. The proposed improvements and their timing are summarised in the table below:

Improvement	Priority	Status	Target Year
Review the asset management policy to ensure that it represents Network Waitaki's current requirements	1	Complete	2023
Review roles, accountabilities, and key result areas to ensure alignment with the organisation's asset management policy and strategy	1	Complete	2023
Complete the asset information review	1	Underway	2023 (now 2025)
Develop a strategic asset management improvement plan with initiatives framed and sequenced	1	Complete	2023
Develop a high-level asset management strategy defining Network Waitaki's approach to planning network investment	1	Underway	2024
Review roles and responsibilities for development, monitoring, management, and implementation of the asset management plan and work programme	1	Complete	2024
Document required asset management related competencies	1	Underway	2024
Develop a formalised stakeholder communication plan	1	Complete	2024
Implement a portfolio management function	1	Complete	2024
Review asset maintenance standards and their implementation	1	Underway	2024
Review asset inspection standards and data management systems to enable the recording of asset condition for use in future modelling	1	Complete	2024
Include condition or health indicator profiles as part of asset renewal justifications in the AMP	1	Complete	2024
Ensure that the contents of the policy are communicated to relevant stakeholders and that its contents are implemented	2	Complete	2024
Develop a resourcing strategy and plan to proactively identify the organisation's current and projected future requirements	2	Underway	2024
Develop a more comprehensive asset information strategy that links asset information systems to corporate and asset management objectives	2	Not Started	2024
Develop asset fleet plans for core asset classes defining Network Waitaki's lifecycle management strategies for each fleet from procurement to disposal	2	Complete	2025
Assign accountability and develop a system for planning the overall portfolio of work including performance measures and resource forecasting	2	Not Started	2025
Identify system elements for which improvement will provide cost effective benefits and include in an asset management improvement plan	2	Underway	2025
Review the current design standard and develop a forward work plan to progressively improve the level of specification that it includes	2	Not Started	2025
Review the approach to procurement of major plant items, ideally aligning with design standard choices and fleet asset strategies	2	Underway	2025
Develop an overall asset information roadmap that can be used for planning for resourcing and implementation	3	Not Started	2025
Develop a Pricing Book to assist with budgeting and performance measurement	2	Not Started	2026
Complete the development of the document framework that is currently underway and issue as a formal document	2	Underway	2026

Improvement	Priority	Status	Target Year
Expand the stakeholder engagement plan to include assigning an accountable manager to each stakeholder relationship, and the channel(s) and frequency for engagement	3	Not Started	2026
Develop methods for assessing value for money for work completed internally	3	Not Started	2026
Review specialist activities that are currently outsourced to identify if internal capabilities are sufficient to effectively specify and control these activities	3	Not Started	2026
Implement a more formal documented contractor management process for external contracts to include criteria for qualification, selection, management, and compliance	3	Not Started	2027
Fully implement the critical spares policy to ensure that spares are available	3	Not Started	2027
Implement an internal audit plan to periodically review the asset management system.	3	Not Started	2027
Implement a computerised maintenance management system for planning and scheduling maintenance and recording and reporting history	2	Not Started	2028

These improvements will ensure compliance with the standard at minimum by 2027 and expected progress is illustrated below.



Appendix B -
Compliance Schedule to Information Disclosure Requirements 2015

Electricity Distribution Information Disclosure, Amendment Determination 2022	AMP Section
3 The AMP must include the following -	
3.11 An overview of systems and information management data	Throughout document
3.12 A statement covering any limitations in the availability or completeness of asset management data and disclose any initiatives intended to improve the quality of this data	4.6.2
3.13 A description of the processes used within the EDB for-	
3.13.1 managing routine asset inspections and network maintenance	4.2.3, 5.3
3.13.2 planning and implementing network development projects	4.2.7, 6.3
3.13.3 measuring network performance.	Section 3
3.14 An overview of asset management documentation, controls and review processes	4.6
3.15 An overview of communication and participation processes	2.5
3.16 The AMP must present all financial values in constant price New Zealand dollars except where specified otherwise;	Throughout AMP
3.17 The AMP must be structured and presented in a way that the EDB considers will support the purposes of AMP disclosure set out in clause 2.6.2 of the determination.	Throughout AMP
Assets covered	
4 The AMP must provide details of the assets covered, including-	
4.1 a high-level description of the service areas covered by the EDB and the degree to which these are interlinked, including-	1.1.1, 2.7
4.1.1 the region(s) covered	2.5.1
4.1.2 identification of large consumers that have a significant impact on network operations or asset management priorities	Throughout section 6
4.1.3 description of the load characteristics for different parts of the network	2.6.2
4.1.4 peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	
4.2 a description of the network configuration, including-	2.6
4.2.1 identifying bulk electricity supply points and any distributed generation with a capacity greater than 1 MW. State the existing firm supply capacity and current peak load of each bulk electricity supply point;	5.6, 5.7
4.2.2 a description of the sub-transmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the sub-transmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x sub-transmission security or by providing alternative security class ratings;	5.8
4.2.3 a description of the distribution system, including the extent to which it is underground;	5.8
4.2.4 a brief description of the network's distribution substation arrangements;	5.8
4.2.5 a description of the low voltage network including the extent to which it is underground; and	8.8
4.2.6 an overview of secondary assets such as protection relays, ripple injection systems, SCADA and telecommunications systems.	5
4.3 If sub-networks exist, the network configuration information referred to in subclause 4.2 must be disclosed for each sub-network.	N/A

Electricity Distribution Information Disclosure, Amendment Determination 2022	AMP Section
Network assets by category	
4.4 The AMP must describe the network assets by providing the following information for each asset category-	
4.4.1 voltage levels;	5
4.4.2 description and quantity of assets;	5
4.4.3 age profiles; and	5
4.4.4 a discussion of the condition of the assets, further broken down into more detailed categories as considered appropriate. Systemic issues leading to the premature replacement of assets or parts of assets should be discussed.	5
4.5 The asset categories discussed in subclause 4.4 should include at least the following-	
4.5.1 The categories listed in the Report on Forecast Capital Expenditure in Schedule 11a (iii)	5, 6
4.5.2 Assets owned by the EDB but installed at bulk electricity supply points owned by others	5, 6
4.5.3 EDB owned mobile substations and generators whose function is to increase supply reliability or reduce peak demand	5, 6
4.5.4 Other generation owned by the EDB.	N/A
Service levels	
5 The AMP must clearly identify or define a set of performance indicators for which annual performance targets have been defined. The annual performance targets must be consistent with business strategies and asset management objectives and be provided for each year of the AMP planning period. The targets should reflect what is practically achievable given the current network configuration, condition and planned expenditure levels. The targets should be disclosed for each year of the AMP planning period.	3
6 Performance indicators for which targets have been defined in clause 5 must include SAIDI values and SAIFI values for the next 5 disclosure years.	Information disclosures in appendix
7 Performance indicators for which targets have been defined in clause 5 above should also include-	
7.1 Consumer oriented indicators that preferably differentiate between different consumer types;	3, 6.2, 6.3
7.2 Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	3.4
8 The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholders' requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	3
9 Targets should be compared to historic values where available to provide context and scale to the reader.	3
10 Where forecast expenditure is expected to materially affect performance against a target defined in clause 5, the target should be consistent with the expected change in the level of performance.	5, 6
Network Development Planning	
11 AMPs must provide a detailed description of network development plans, including—	
11.1 A description of the planning criteria and assumptions for network development;	9.3
11.2 Planning criteria for network developments should be described logically and succinctly. Where probabilistic or scenario-based planning techniques are used, this should be indicated and the methodology briefly described;	9.3
11.3 A description of strategies or processes (if any) used by the EDB that promote cost efficiency including through the use of standardised assets and designs;	T9.3

Electricity Distribution Information Disclosure, Amendment Determination 2022	AMP Section
11.4 The use of standardised designs may lead to improved cost efficiencies. This section should discuss- 11.4.1 the categories of assets and designs that are standardised; 11.4.2 the approach used to identify standard designs.	9.3
11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network.	9.3
11.6 A description of the criteria used to determine the capacity of equipment for different types of assets or different parts of the network.	6.3
11.7 A description of the process and criteria used to prioritise network development projects and how these processes and criteria align with the overall corporate goals and vision.	9.3
11.8 Details of demand forecasts, the basis on which they are derived, and the specific network locations where constraints are expected due to forecast increases in demand; 11.8.1 explain the load forecasting methodology and indicate all the factors used in preparing the load estimates; 11.8.2 provide separate forecasts to at least the zone substation level covering at least a minimum five-year forecast period. Discuss how uncertain but substantial individual projects/developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts;	9.4 - 9.8 Appendices C-E
11.8.3 identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period; and	9.4 - 9.8 Appendices C-E
11.8.4 discuss the impact on the load forecasts of any anticipated levels of distributed generation in a network, and the projected impact of any demand management initiatives.	9.4
11.9 Analysis of the significant network level development options identified and details of the decisions made to satisfy and meet target levels of service, including- 11.9.1 the reasons for choosing a selected option for projects where decisions have been made; 11.9.2 the alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described;	Appendix E
11.9.3 consideration of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment.	Throughout AMP
11.10 A description and identification of the network development programme including distributed generation and non-network solutions and actions to be taken, including associated expenditure projections. The network development plan must include- 11.10.1 a detailed description of the material projects and a summary description of the non-material projects currently underway or planned to start within the next 12 months;	Appendix E
11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and 11.10.3 an overview of the material projects being considered for the remainder of the AMP planning period.	9.9 Appendix E
11.11 A description of the EDB's policies on distributed generation, including the policies for connecting distributed generation. The impact of such generation on network development plans must also be stated.	9.4
11.12 A description of the EDB's policies on non-network solutions, including- 11.12.1 economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation; and	9.3

Electricity Distribution Information Disclosure, Amendment Determination 2022	AMP Section
11.12.2 the potential for non-network solutions to address network problems or constraints.	9.3
Lifecycle Asset Management Planning (Maintenance and Renewal)	
12 The AMP must provide a detailed description of the lifecycle asset management processes, including—	
12.1 The key drivers for maintenance planning and assumptions;	5.3
12.2 Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include-	5
12.2.1 the approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring carried out and the intervals at which this is done;	5
12.2.2 any systemic problems identified with any particular asset types and the proposed actions to address these problems; and	5
12.2.3 budgets for maintenance activities broken down by asset category for the AMP planning period.	5
12.3 Identification of asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include- 12.3.1 the processes used to decide when and whether an asset is replaced or refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets;	5
12.3.2 a description of innovations that have deferred asset replacements;	5
12.3.3 a description of the projects currently underway or planned for the next 12 months;	5
12.3.4 a summary of the projects planned for the following four years (where known); and	5
12.3.5 an overview of other work being considered for the remainder of the AMP planning period.	5
12.4 The asset categories discussed in clauses 12.2 and 12.3 should include at least the categories in subclause 4.5.	5
Non-Network Development, Maintenance and Renewal	
13 AMPs must provide a summary description of material non-network development, maintenance and renewal plans, including—	
13.1 a description of non-network assets;	7
13.2 development, maintenance and renewal policies that cover them;	7
13.3 a description of material capital expenditure projects (where known) planned for the next five years;	7
13.4 a description of material maintenance and renewal projects (where known) planned for the next five years.	7
Risk Management	
14 AMPs must provide details of risk policies, assessment, and mitigation, including—	4.3
14.1 Methods, details and conclusions of risk analysis;	4.3
14.2 Strategies used to identify areas of the network that are vulnerable to high impact low probability events and a description of the resilience of the network and asset management systems to such events;	4.5
14.3 A description of the policies to mitigate or manage the risks of events identified in clause 14.2;	4.5
14.4 Details of emergency response and contingency plans.	4.5
Evaluation of performance	
15 AMPs must provide details of performance measurement, evaluation, and improvement, including—	
15.1 A review of progress against plan, both physical and financial;	3

Electricity Distribution Information Disclosure, Amendment Determination 2022	AMP Section
15.2 An evaluation and comparison of actual service level performance against targeted performance;	3
15.3 An evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 against relevant objectives of the EDB's asset management and planning processes.	4.6
15.4 An analysis of gaps identified in clauses 15.2 and 15.3. Where significant gaps exist (not caused by one-off factors), the AMP must describe any planned initiatives to address the situation.	4.6
Capability to deliver	
16 AMPs must describe the processes used by the EDB to ensure that-	
16.1 The AMP is realistic and the objectives set out in the plan can be achieved;	4.2, 4.1.3.4
16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	2.1.4
Voltage Quality and Constraints	
17.2 a description of the EDB's practices for: monitoring voltage, including:: 17.2.1 monitoring voltage, including: (a) the EDB's practices for monitoring voltage quality on its low voltage network; (b) work the EDB is doing on its low voltage network to address any known non-compliance with the applicable voltage requirements of the Electricity (Safety) Regulations 2010; (c) how the EDB responds to and reports on voltage quality issues when the EDB identifies them, or when they are raised by a stakeholder; (d) how the EDB communicates with affected consumers regarding the voltage quality work it is carrying out on its low voltage network; and (e) any plans for improvements to any of the practices outlined at clauses (a)-(d) above;	Section 9.2 – Our planning criteria - Voltage Quality and Constraints
17.2.2 monitoring load and injection constraints, including: (a) any challenges, and progress, towards collecting or procuring data required to inform the EDB of current and forecast constraints on its low voltage network, including historical consumption data; and(e) (b) any analysis and modelling (including any assumptions and limitations) the EDB undertakes, or intends to undertake, with the data described in clause 17.2.2(a).	Section 9.4 – Our planning assumptions – Planning data
Customer service practices - There may be a degree of overlap between the information required under this clause and the information required in respect of customer charters under clause 2.5.3. For the avoidance of doubt, if there is overlap, EDBs should disclose the information in both places. 17.3 a description of the EDB's customer service practices, including: 17.3.1 the EDB's customer engagement protocols and customer service measures – including customer satisfaction with the EDB's supply of electricity distribution services; 17.3.2 the EDB's approach to planning and managing customer complaint resolution;	Section 5 – Customer needs and engagement

Electricity Distribution Information Disclosure, Amendment Determination 2022	AMP Section
Practices for connecting new consumers and altering existing connections	
17.4 a description of the EDB's practices for connecting consumers, including:	
17.4.1 the EDB's approach to planning and management of-Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024	6.3
(a) connecting new consumers (offtake and injection connections), and overcoming commonly encountered issues; and	
(b) alterations to existing connections (offtake and injection connections);	
17.4.2 how the EDB is seeking to minimise the cost to consumers of new or altered connections;	6.3
17.4.3 the EDB's approach to planning and managing communication with	6.3
consumers about new or altered connections; and	
17.4.4 commonly encountered delays and potential timeframes for different connections	6.3
17.4.5 the EDB's approach to sharing information on current and forecast constraints (both load and injection) with potential new consumers. This must include any information on low voltage network constraints, including the constraint information the EDB derives from the data specified under clause 17.2.2(a) of Attachment A .	4.3
New connections likely to have a significant impact on network operations or asset management priorities The following requirements focus on the EDB's capability and risk management regarding demand, generation, or storage capacity that the EDB considers are likely to have a significant impact on its network operations or asset management priorities. The EDB may consider voltage, network location, or other factors in making this assessment. 17.5 A description of the following: 17.5.1 how the EDB assesses the impact that new demand, generation, or storage capacity will have on the EDB's network, including: (a) how the EDB measures the scale and impact of new demand, generation, or storage capacity; (b) how the EDB takes the timing and uncertainty of new demand, generation, or storage capacity into account; (c) how the EDB takes other factors into account, e.g., the network location of new demand, generation, or storage capacity; and 17.5.2 how the EDB assesses and manages the risk to the network posed by uncertainty regarding new demand, generation, or storage capacity;	Section 9.4 – Our planning assumptions
Innovation practices 17.6 a description of the following: 17.6.1 any innovation practices the EDB has planned or undertaken since the last AMP or AMP update was publicly disclosed, including case studies and trials; 17.6.2 the EDB's desired outcomes of any innovation practices, and how they may improve outcomes for consumers; 17.6.3 how the EDB measures success and makes decisions regarding any innovation practices, including how the EDB decides whether to commence, commercially adopt, or discontinue these practices; 17.6.4 how the EDB's decision-making and innovation practices depend on the work of other companies, including other EDBs and providers of non-network solutions; and 17.6.5 the types of information the EDB uses to inform or enable any innovation practices, and the EDB's approach to seeking that information.	Chapter 4.3 – Enabling our customers future energy needs

Appendix C - Transmission/GXP capacity and security analysis

GXP Summary

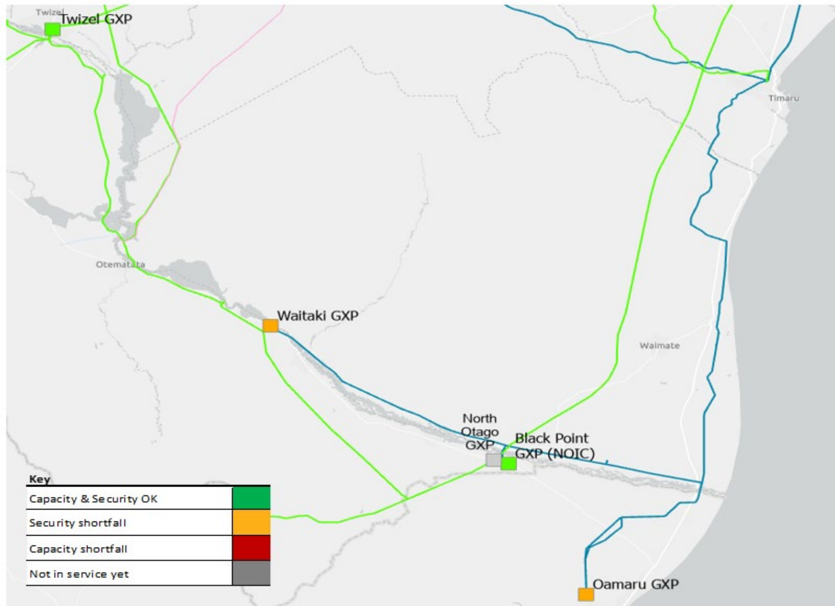


Table 30 - GXP details

Grid Exit Point	Voltage	Supply Configuration	Capacity	Max demand FY24 (Non-Coincident)	FY24 Zone Substations supplied
Ōamaru GXP	33 kV	(n-1) (n)	45 MVA 53 MVA	44 MVA	11
Twizel GXP	33 kV	(n-1)	27 MVA	4 MVA	3
Waitaki GXP	11 kV 33 kV	(n) (n-1) switched	24 MVA 13.5 MVA	13 MVA	4
Black Point GXP	110 kV	(n)	25 MVA	17 MVA	0
North Otago GXP (proposed)	33 kV (FY27) 110 kV (FY33)	(n-1) (n-1)	27 MVA 120 MVA	-	-

Oamaru GXP

Configuration – Dual 60 MVA power transformers, Dual 45 MVA transmission circuits

GXP security rating – 45 MVA (n-1), 53 MVA (n)

Most demand growth to FY35 is from process heat conversion followed by irrigation conversion and EV journey chargers, all of which have low flexibility in terms of demand response. During the latter part of the planning period, we start to see an increase in demand from residential and commercial EV uptake.

Capacity (MVA)	Security class	Security service level for first sub-transmission or zone substation outage	Capacity and security summary									
			FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
45 (n-1) 53 MVA (n)	A3	No interruption										

Table 31 - Ōamaru GXP capacity and security summary

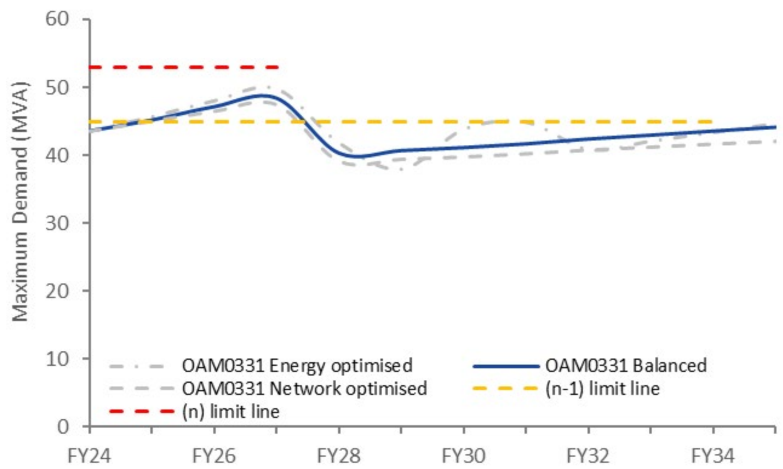


Figure 81 - Ōamaru GXP demand growth (Balanced scenario)

Marker	Period	Description
1	FY27	• 5 MVA customer process heat electrification project
2	FY28	• North Otago GXP in service • Te Awamako Sub (3.2 MVA) and Papakaio Sub (5.3 MVA) transferred from Ōamaru GXP to North Otago GXP
3	FY29	• Ngapara Sub (3.2 MVA) transferred from Ōamaru GXP to North Otago GXP
4	FY35	• Enfield Sub (3.2 MVA) transferred - Ōamaru GXP to North Otago GXP

Note: triggers for the transfers of load to the new GXP will happen at different times for Energy Optimised and Network Optimised scenarios resulting in different demand forecast curves.

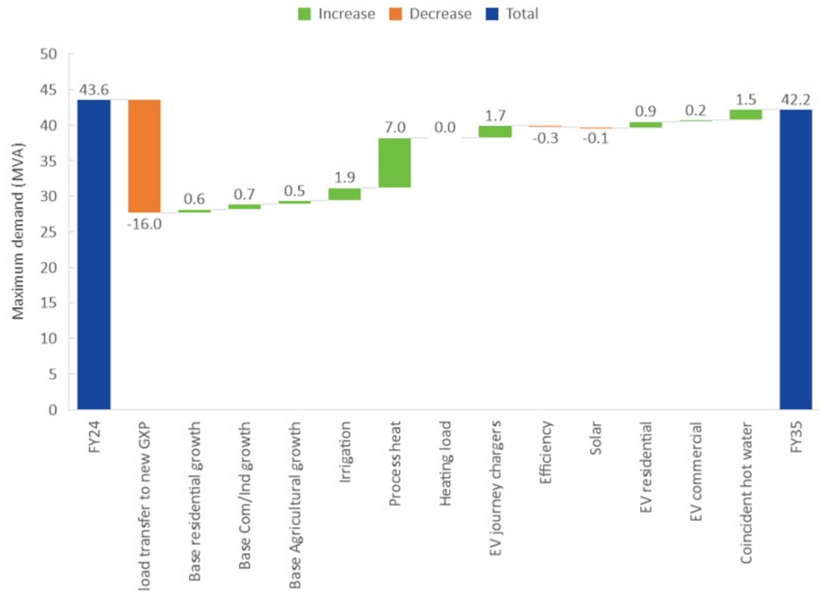


Figure 82 - Ōamaru GXP demand growth components – Balanced scenario

Notes:

- Most demand growth to FY35 is from process heat conversion followed by irrigation conversion and EV journey chargers, all of which have low flexibility in terms of demand response. During the latter part of the planning period, we start to see an increase in demand from residential and commercial EV uptake.
- Until the new GXP is operational and the temporary Special Protection Scheme is retired in FY28 demand between 45 MVA and 53 MVA will be subject to (n) security of supply. Until FY28, we may need to connect new large-load customers at (n) level GXP security.
- Since 2022, all new subtransmission lines have been constructed at 110 kV standard and initially operated at 33 kV. Once demand approaches the capacity of the 33 kV network, the system can be upgraded to 110 kV.
- Connecting Ōamaru GXP to this 110 kV subtransmission ring would free up significant capacity on Transpower's Waitaki-Glenavy 110 kV system. Under our balanced demand scenario, we do not expect this upgrade will be required within the planning period.

We provide further details on these projects in Appendix E – Future Network Plan - projects.

Waitaki GXP

Configuration – One 25 MVA power transformer (NWL owned) and one 5.5 MVA power transformer (Transpower owned)

GXP security rating – 13.5 MVA (n-1 switched), 25 MVA (n)

Most demand growth to FY35 is from process heat conversion followed by irrigation conversion and EV journey chargers, all of which have low flexibility in terms of demand response. During the latter part of the planning period, we start to see an increase in demand from residential and commercial EV uptake.

Capacity (MVA)	Security class	Security service level for first sub-transmission or zone substation outage	Capacity and security summary									
			FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
24	A3	50% in switching time 40% within 12 hours 10% in repair time										

Table 32 - Waitaki GXP capacity and security summary

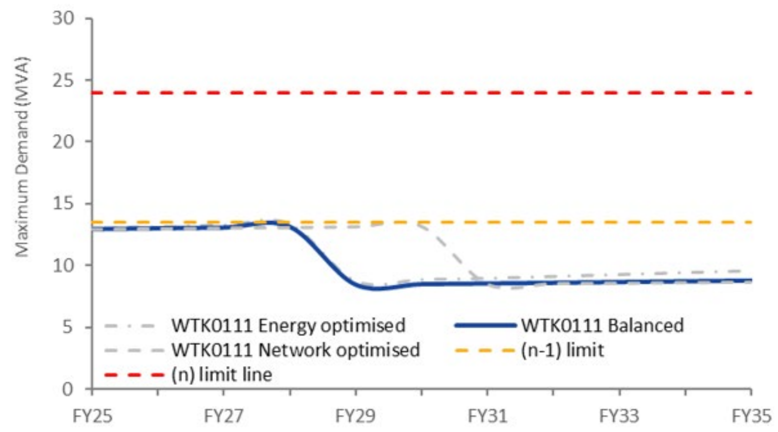


Figure 84 - Waitaki GXP demand growth scenarios

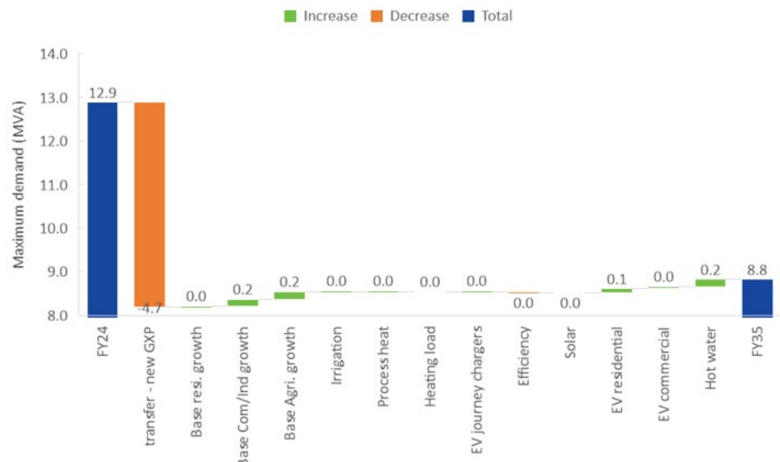


Figure 85 -Demand growth components – expected scenario

We expect reasonably low demand growth for the Waitaki GXP and do not expect any capacity constraints during the planning period.

Currently, 13.5 MVA of backup security is provided from:

- 5.5 MVA from Waitaki GXP backup transformer,
- 3 MVA from Twizel GXP
- 5 MVA from Oamaru GXP

As demand increases at Oamaru GXP, backup security will decrease. There will be a potential security shortfall during parts of FY26 and FY27 until the new North Otago GXP is in service. We would manage this by rolling irrigation demand control for outages of up to 48 hours and by hiring diesel generators for longer outages.

Twizel GXP

Configuration – Two 27 MVA power transformers

GXP security rating – (n-1)

Twizel GXP supplies Network Waitaki, Alpine Energy, and Meridian. At present, our demand is about 50% of the total GXP demand.

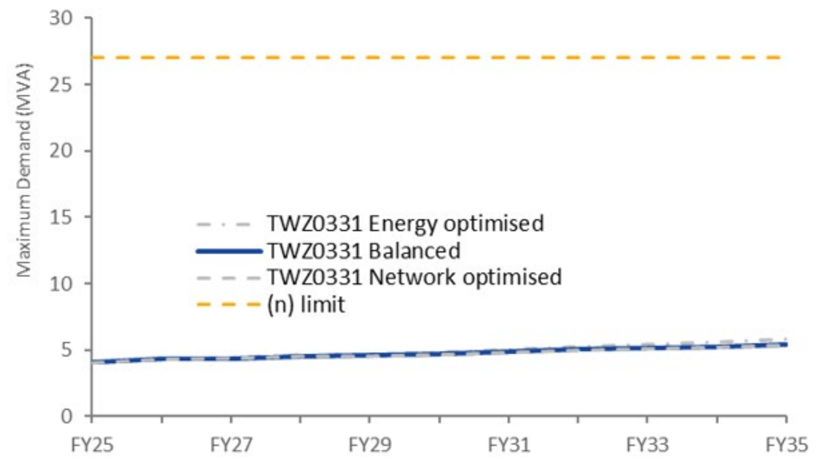


Figure 86 – Twizel GXP demand growth scenarios

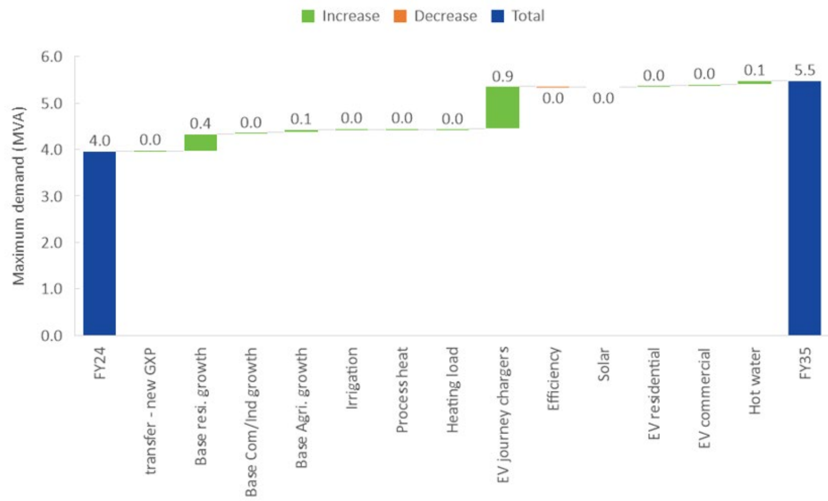


Figure 87 - Demand growth components – expected scenario

We expect low demand growth over the planning period, with the main component being EV journey chargers in the Ōmārama area.

Capacity (MVA)	Security class	Security service level for first sub-transmission or zone substation outage	Capacity and security summary									
			FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
27	(n-1)	No interruption										

Table 88 - Twizel GXP capacity and security summary

There are no capacity or security constraints expected in the planning period.

Black Point GXP

Configuration – Single 25 MVA power transformer

GXP security rating – (n) level security - customer substation

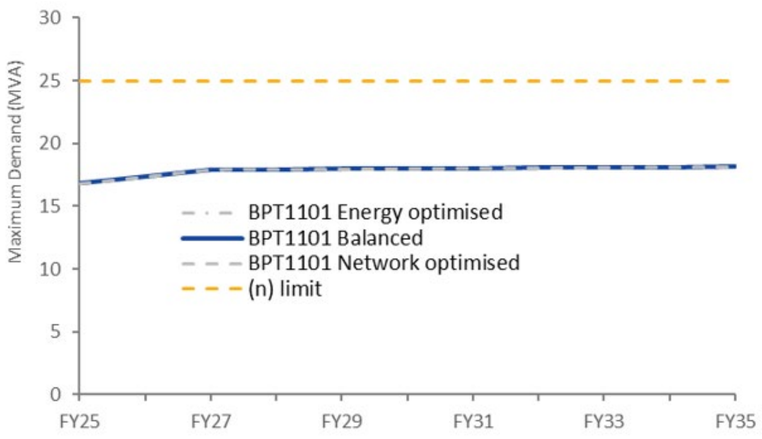


Figure 89 - Black Point GXP demand scenarios

NOIC are in the process of selling the remaining shares in their irrigation scheme, which will increase demand for water supply from the scheme. As a result, we expect maximum demand to increase to 18 MVA by FY27.

Capacity (MVA)	Security class	Security service level for first sub-transmission or zone substation outage	Capacity and security summary									
			FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
25	(n)	Supply restored in repair time										

Table 33 - Black Point GXP capacity and security summary

No capacity or security constraints are expected in the planning period.

Note: This GXP is subject to a Transpower special protection (demand control) scheme. In the event of a fault on the Waitaki-Bells Pond-Ōamaru 110 kV line during a constrained period, the special protection scheme may reduce NOIC pumping demand below the constraint.

North Otago GXP (proposed FY28)

Configuration – Dual 27 MVA 110/33 kV power transformers

GXP security rating – (n-1) level security

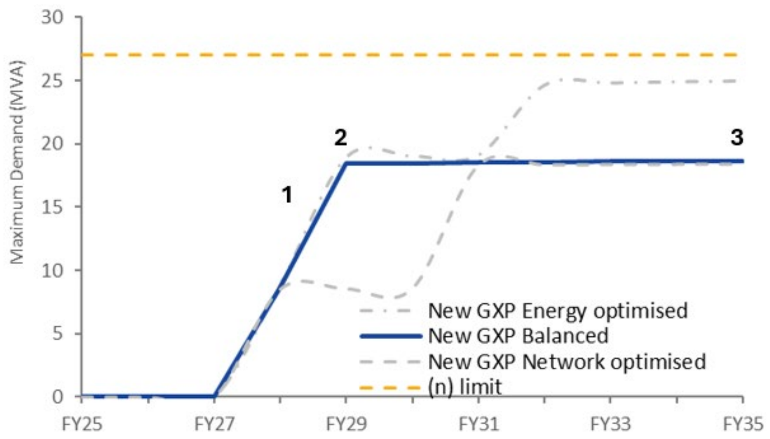


Figure 90 - North Otago GXP demand scenarios

Marker	Period	Description
1	FY28	• North Otago GXP in service at 33 kV • Te Awamako Sub (3.2 MVA) transferred - Ōamaru GXP to North Otago GXP • Papakaio Sub (5.3 MVA) transferred - Ōamaru GXP to North Otago GXP
2	FY29	• Ngapara Sub (3.2 MVA) transferred - Ōamaru GXP to North Otago GXP • Enfield Sub (3.2 MVA) transferred - Ōamaru GXP to North Otago GXP • Duntroon Sub (4.7 MVA) transferred - Waitaki GXP to North Otago GXP
3	FY35	• Construct subtransmission line from Ngapara to Enfield (Enfield and Five Forks Subs to be supplied from new GXP in FY36)

Table 34 - Key events in demand scenarios

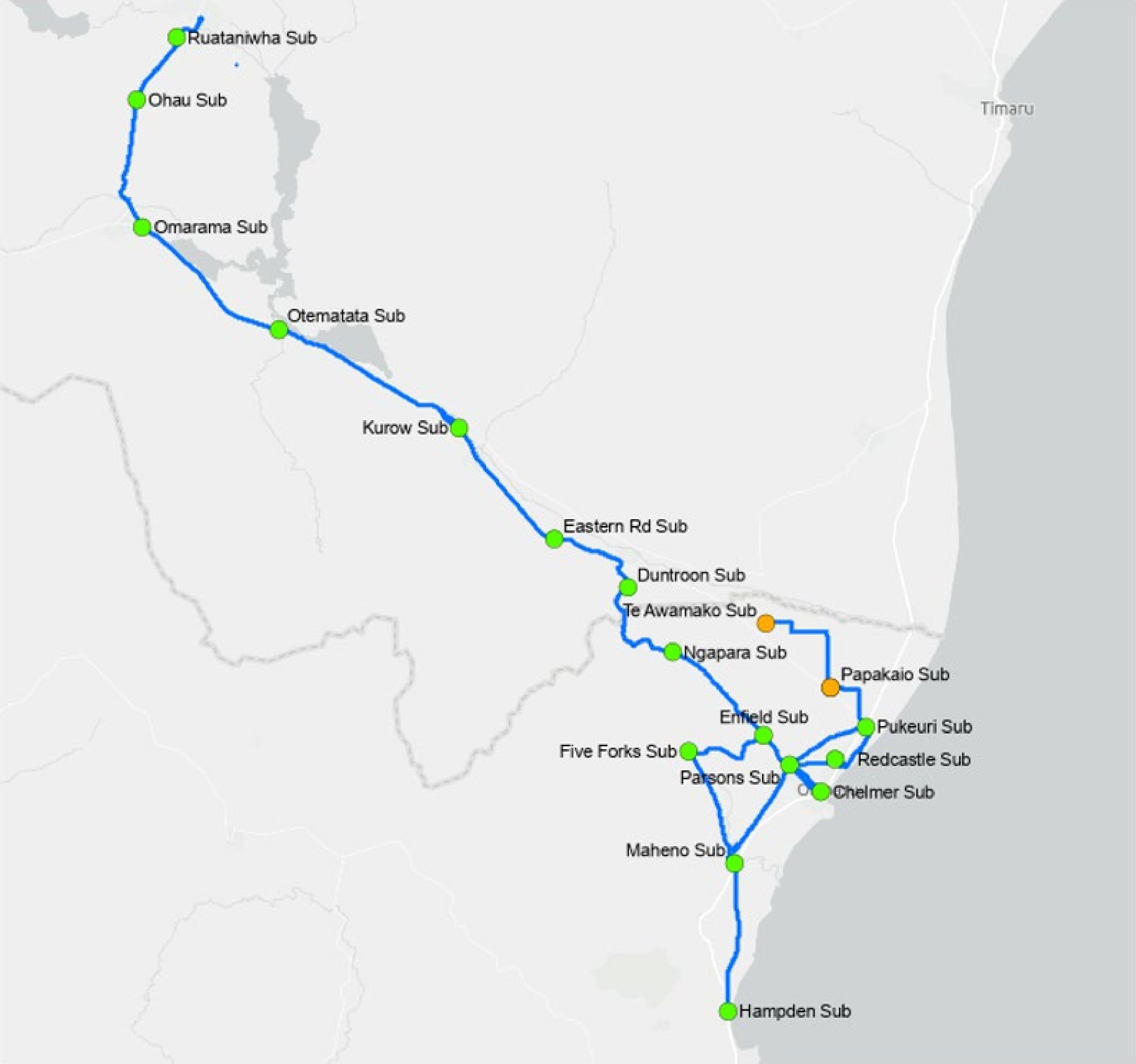
Note: load transfers will be made at different times for Energy Optimised and Network Optimised scenarios resulting in different demand forecast curves.

Capacity (MVA)	Security class	Security service level for first sub-transmission or zone substation outage	Capacity and security summary									
			FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34	FY35
23	(n-1)	No interruption										

Table 35 - North Otago GXP capacity and security summary

There are no capacity or security constraints expected in the planning period.

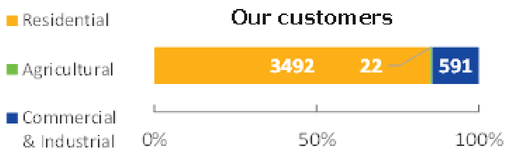
Appendix D - Subtransmission/Zone sub capacity and security analysis



Chelmer Zone Substation

Configuration – Dual 28 MVA power transformers

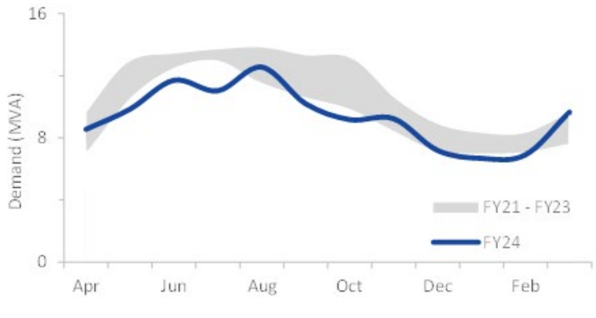
Security rating – B1 Business hub



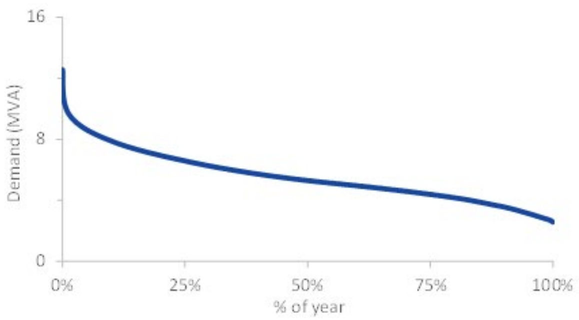
FY24 customer reliability performance

Customer supply group	Number of customers	Average interruption duration	Average number of interruptions	Max interuptions for any customer
Business hub	559			
Urban	3400			
Rural A	136			

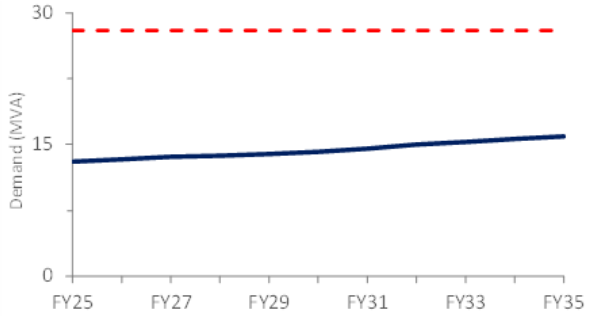
FY24 demand profile



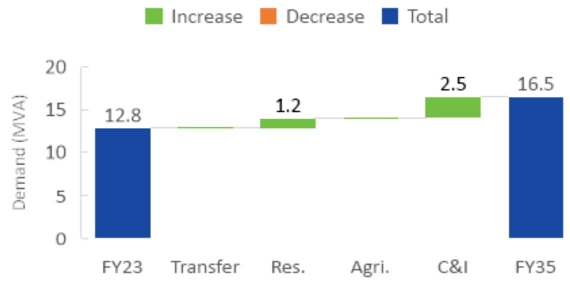
FY24 demand duration curve



10 year demand forecast



New demand breakdown



Customer security of supply summary

Customer supply group	Sub-transmission/Zone substation			Distribution feeder		
	FY26	FY30	FY35	FY26	FY30	FY35
Business hub						
Urban						
Rural A						

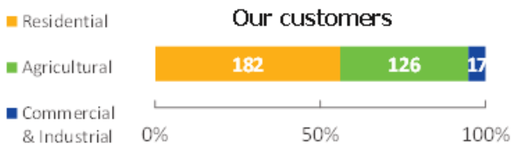
Commentary:

Chelmer Zone Substation has sufficient capacity to meet all demand scenarios and will meet our security of supply standard for the expected scenario over the planning period. Named project South Hill FY26 will fix security shortfall.

Enfield Zone Substation

Configuration – Single 7 MVA power transformer

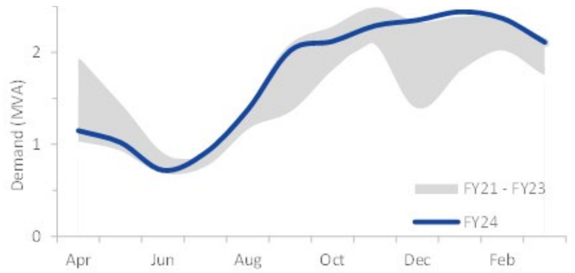
Security rating – B4 rural zone substation



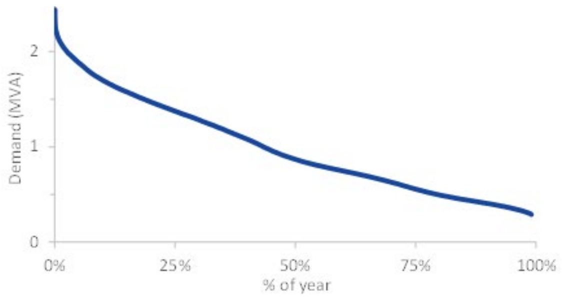
FY24 customer reliability performance

Customer supply group	Number of customers	Average interruption duration	Average number of interruptions	Max interuptions for any customer
Rural A	325			

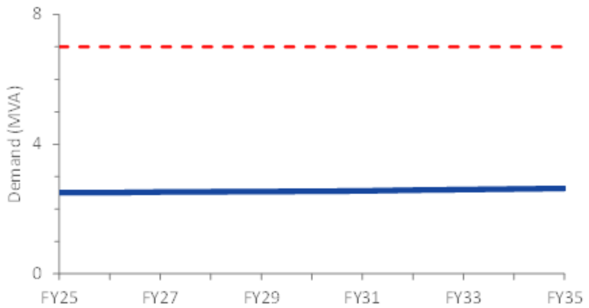
FY24 demand profile



FY24 demand duration curve



10 year demand forecast



New demand breakdown

Customer security of supply summary

Customer supply group	Sub-transmission/Zone substation			Distribution feeder		
	FY26	FY30	FY35	FY26	FY30	FY35
Rural A						

Commentary:

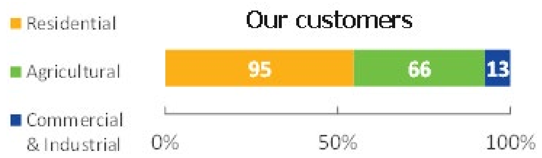
Enfield Zone Substation has sufficient capacity to meet all demand scenarios and will meet our security of supply standard for the expected scenario over the planning period.

Reliability at this substation was impacted by a storm in October 2023.

Five Forks Zone Substation

Configuration – Single 7 MVA power transformer

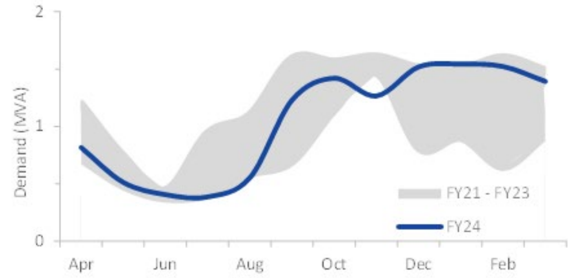
Security rating – B4 rural zone substation



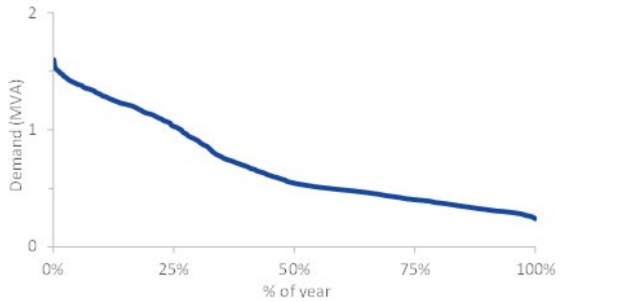
FY24 customer reliability performance

Customer supply group	Number of customers	Average interruption duration	Average number of interruptions	Max interuptions for any customer
Rural A	174			

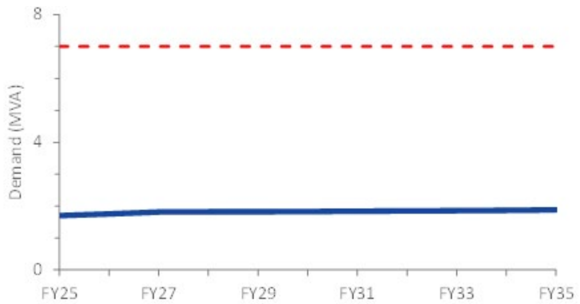
FY24 demand profile



FY24 demand duration curve



10 year demand forecast



New demand breakdown

Customer security of supply summary

Customer supply group	Sub-transmission/Zone substation			Distribution feeder		
	FY26	FY30	FY35	FY26	FY30	FY35
Rural A						

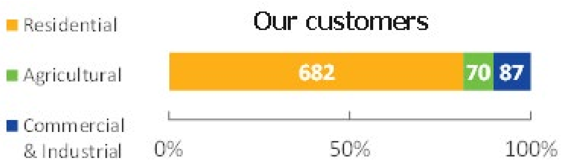
Commentary:

Five Forks Zone Substation has sufficient capacity to meet all demand scenarios and will meet our security of supply standard for all scenarios over the planning period.

Hampden Zone Substation

Configuration – Single 7 MVA power transformer

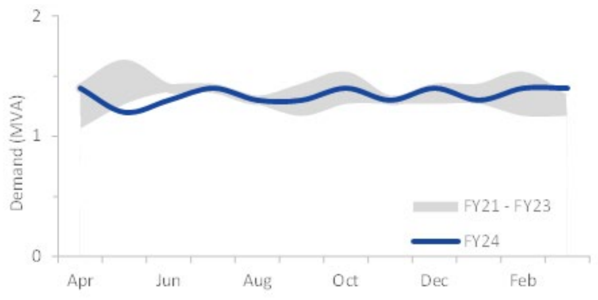
Security rating – B5 township zone substation



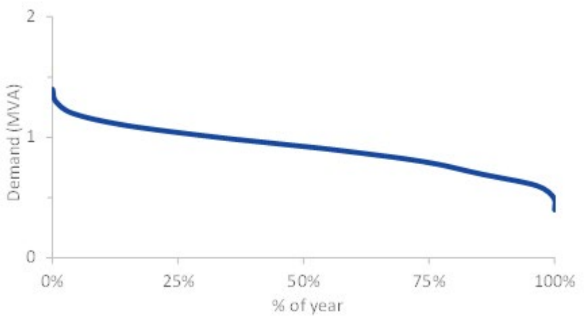
FY24 customer reliability performance

Customer supply group	Number of customers	Average interruption duration	Average number of interruptions	Max interuptions for any customer
Township - Hampden	275			
Township - Moeraki	189			
Rural A	375			

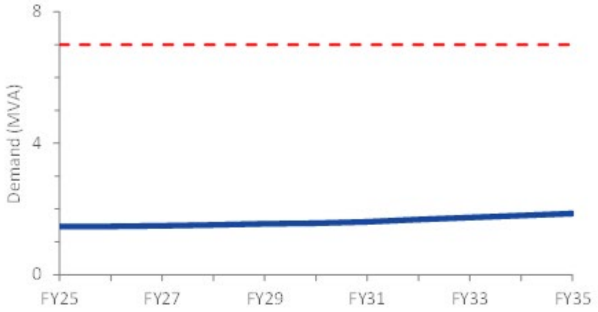
FY24 demand profile



FY24 demand duration curve



10 year demand forecast



New demand breakdown

Customer service levels and security summary

Customer supply group	Sub-transmission/Zone substation			Distribution feeder		
	FY26	FY30	FY35	FY26	FY30	FY35
Township - Hampden						
Township - Moeraki						
Rural A						

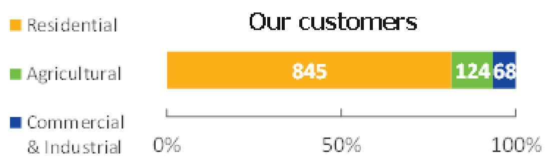
Commentary:

Storms in May and October resulted in poor reliability performance.
Hampden Zone Substation has sufficient capacity to meet all demand scenarios.
There is a security shortfall for Moeraki township customers – we cannot resupply 50% of customers within switching time for a distribution feeder outage. The Moeraki township security and resilience improvement project will address this security shortfall and improve reliability for future storm events.

Maheno Zone Substation

Configuration – Single 5 MVA power transformer

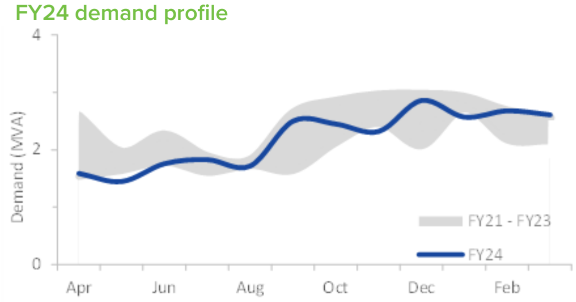
Security rating – B3 township zone substation



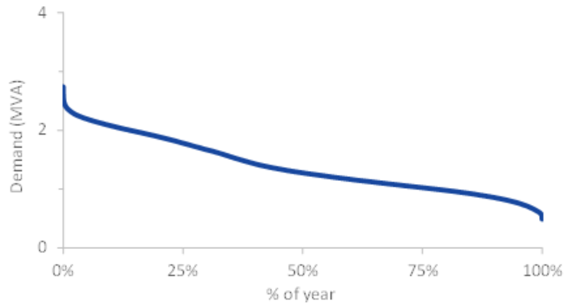
FY24 customer reliability performance

Customer supply group	Number of customers	Average interruption duration	Average number of interruptions	Max interuptions for any customer
Township - Kakanui	340			
Rural A	697			

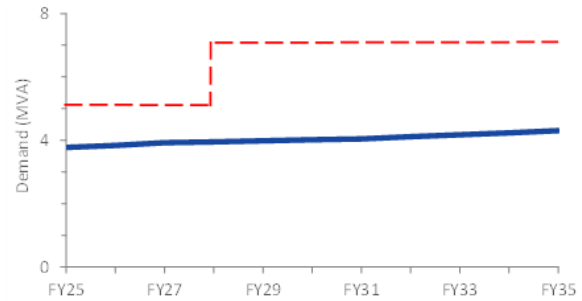
FY24 demand profile



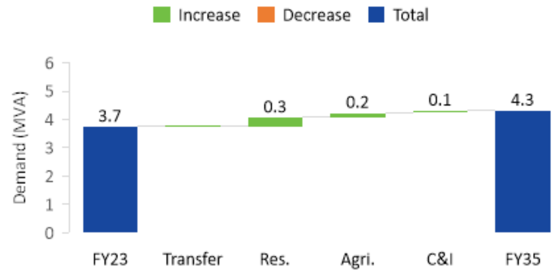
FY24 demand duration curve



10 year demand forecast



New demand breakdown



Customer security of supply summary

Customer supply group	Sub-transmission/Zone substation			Distribution feeder		
	FY26	FY30	FY35	FY26	FY30	FY35
Township - Kakanui						
Rural A						

Commentary:

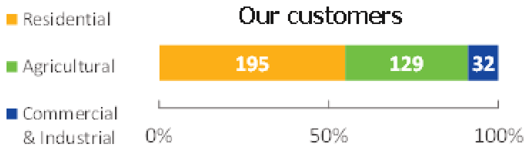
Maheno Zone Substation has sufficient capacity to meet all demand scenarios and will meet our security of supply standard for the balanced scenario over the planning period. Reliability at this substation was impacted by a storm in October 2023.

Maheno transformer is scheduled for end of life replacement in FY28 and will be replaced with a larger standard sized unit.

Ngapara Zone Substation

Configuration – Single 7 MVA power transformer

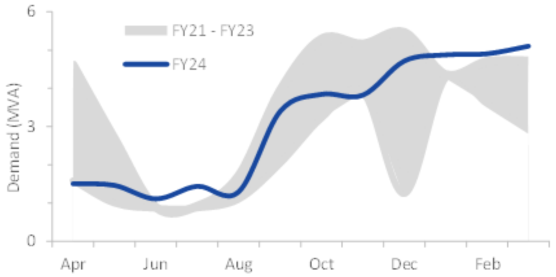
Security rating – B4 rural zone substation



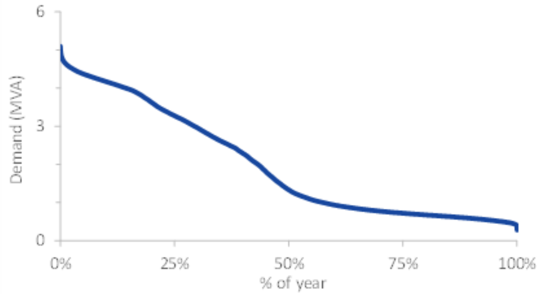
FY24 customer reliability performance

Customer supply group	Number of customers	Average interruption duration	Average number of interruptions	Max interuptions for any customer
Rural A	356			

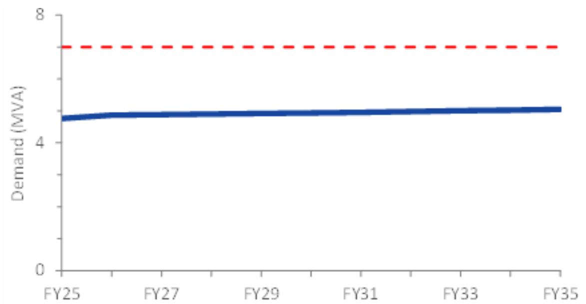
FY24 demand profile



FY24 demand duration curve



10 year demand forecast



New demand breakdown

Customer security of supply summary

Customer supply group	Sub-transmission/Zone substation			Distribution feeder		
	FY26	FY30	FY35	FY26	FY30	FY35
Rural A						

Commentary:

Ngapara Zone Substation has sufficient capacity to meet all demand scenarios and will meet our security of supply standard for the expected scenario over the planning period.

Reliability at this substation was impacted by a storm in October 2023.

Papakaio Zone Substation

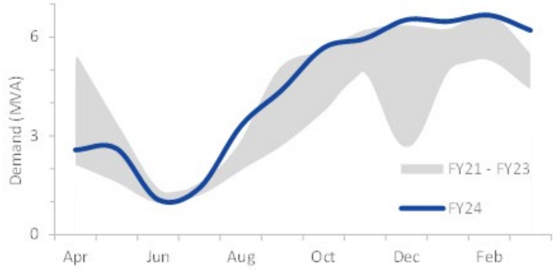
Configuration – Single 7 MVA power transformer

Security rating – B4 rural zone substation

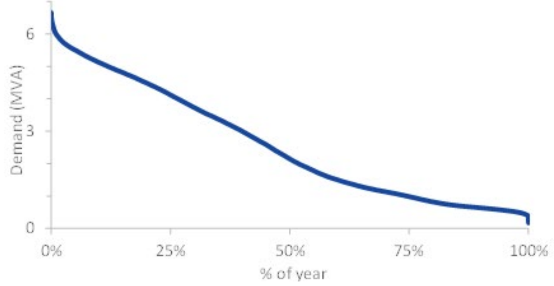
FY24 customer reliability performance

Customer supply group	Number of customers	Average interruption duration	Average number of interruptions	Max interuptions for any customer
Rural A	266			

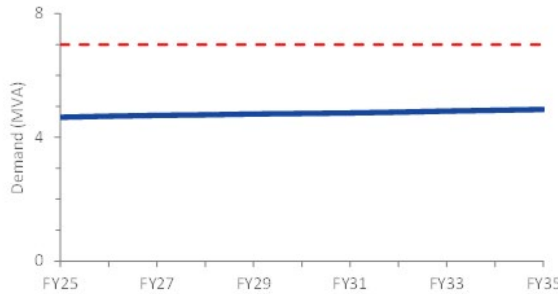
FY24 demand profile



FY24 demand duration curve



10 year demand forecast



New demand breakdown

Customer security of supply summary

Customer supply group	Sub-transmission/Zone substation			Distribution feeder		
	FY26	FY30	FY35	FY26	FY30	FY35
Rural A						

Commentary:

Papakaio Zone Substation has sufficient capacity to meet all demand scenarios.

There is a security constraint for a subtransmission outage between Pukeuri and Papakaio Zone Subs. This constraint will be alleviated in FY28, when the new North Otago GXP is in service.

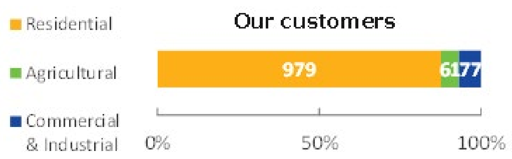
10 year demand forecast has reduced due to recent load transfer to new Te Awamako zone substation.

Reliability at this substation was impacted by a storm in October 2023.

Parsons Road Zone Substation

Configuration – Single 12 MVA power transformer

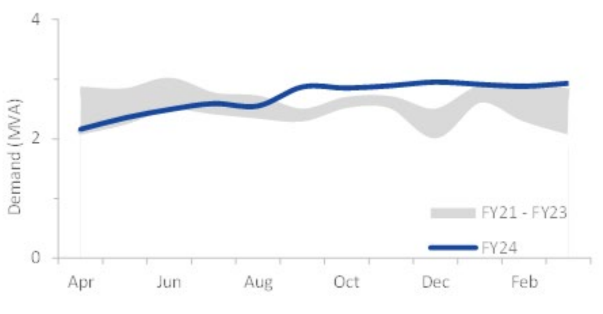
Security rating – B2 urban zone substation



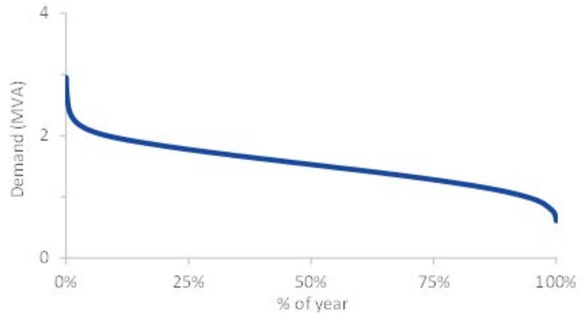
FY24 customer reliability performance

Customer supply group	Number of customers	Average interruption duration	Average number of interruptions	Max interuptions for any customer
Urban	523			
Rural A	594			

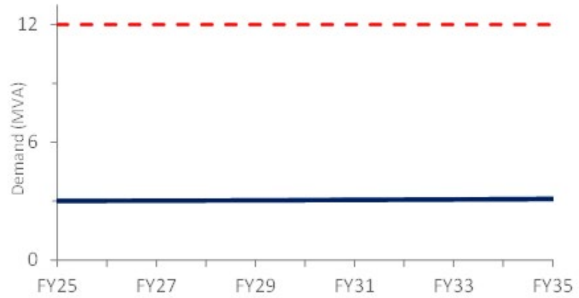
FY24 demand profile



FY24 demand duration curve



10 year demand forecast



New demand breakdown

Customer security of supply summary

Customer supply group	Sub-transmission/Zone substation			Distribution feeder		
	FY26	FY30	FY35	FY26	FY30	FY35
Urban						
Rural A						

Commentary:

Reliability performance at this substation was impacted by a storm in October 2023.

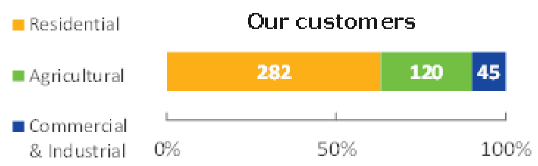
Parsons Zone Substation has sufficient capacity to meet all demand scenarios and will meet our security of supply standard for the balanced scenario. Horse Gully feeder has a security constraint, where we cannot supply 50% of customers in switching time. We have a project scheduled in FY29 to address this issue.

Ardgowan Distribution feeder security of supply constraint will be alleviated in FY26 by Ardgowan Road security/resilience improvement project.

Pukeuri Zone Substation

Configuration – Dual 12 MVA power transformer

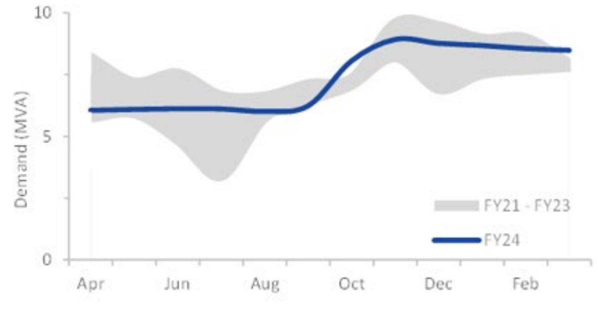
Security rating – B1 Business Hub/urban



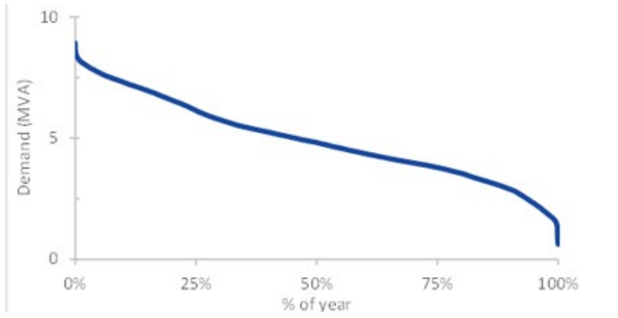
FY24 customer reliability performance

Customer supply group	Number of customers	Average interruption duration	Average number of interruptions	Max interuptions for any customer
Business	10			
Rural A	437			

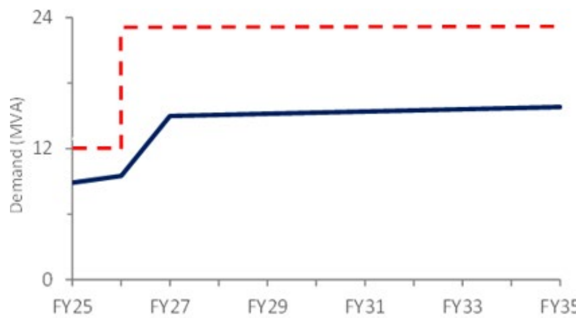
FY24 demand profile



FY24 demand duration curve



10 year demand forecast



New demand breakdown

Customer security of supply summary

Customer supply group	Sub-transmission/Zone substation			Distribution feeder		
	FY26	FY30	FY35	FY26	FY30	FY35
Business hub/ urban						
Rural A						

Commentary:

Reliability performance at this substation was impacted by a storm in October 2023.

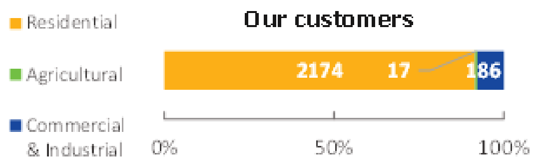
Pukeuri Zone Substation has sufficient capacity to meet all demand scenarios and will meet our security of supply standard for the balanced scenario.

The two power transformers are scheduled for condition-based replacement in FY26 and will be replaced with our standard sized large transformer type, increasing capacity at this site.

Redcastle Zone Substation

Configuration – Dual 12 MVA power transformer

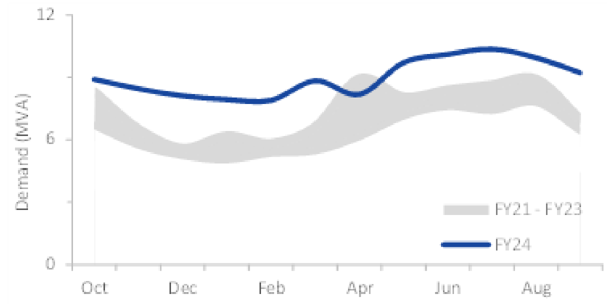
Security rating – B1 Business Hub/urban



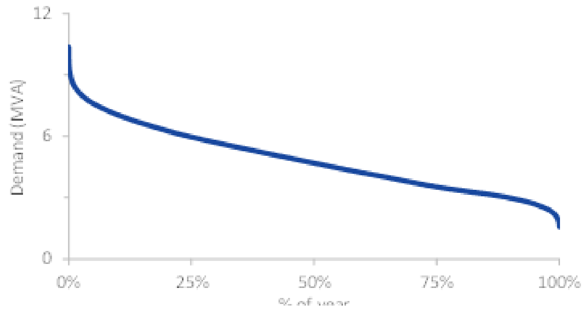
FY24 customer reliability performance

Customer supply group	Number of customers	Average interruption duration	Average number of interruptions	Max interuptions for any customer
Business	186			
Urban	2156			
Rural A	35			

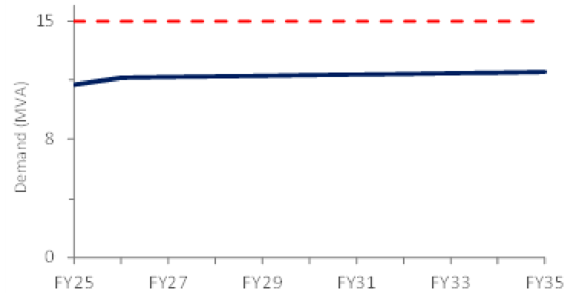
FY24 demand profile



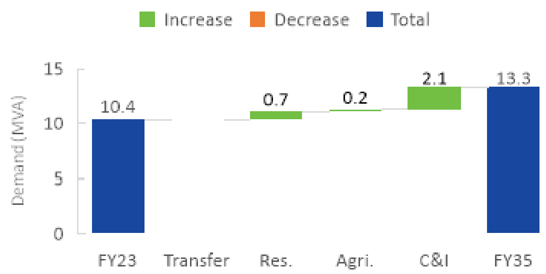
FY24 demand duration curve



10 year demand forecast



New demand breakdown



Customer security of supply summary

Customer supply group	Sub-transmission/Zone substation										Distribution feeder									
	FY26				FY30					FY35	FY26				FY30					FY35
Business																				
Urban																				
Rural A																				

Commentary:

Reliability performance at this substation was impacted by a storm in October 2023.

Redcastle Zone Substation has sufficient capacity to meet all demand scenarios and will meet our security of supply standard for the expected scenario over the planning period.

We cannot meet security switching time requirements for business hub customers. This will be improved with the North Otago Business Park security/resilience improvements project scheduled for FY28.

Te Awamako Zone Substation

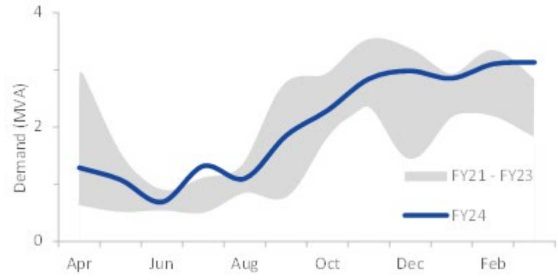
Configuration – Single 10 MVA power transformer

Security rating – B4 rural zone substation

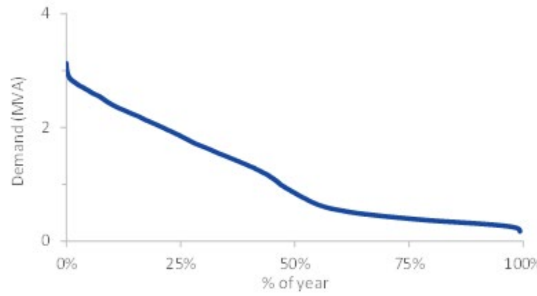
FY24 customer reliability performance

Customer supply group	Number of customers	Average interruption duration	Average number of interruptions	Max interuptions for any customer
Rural A	143			

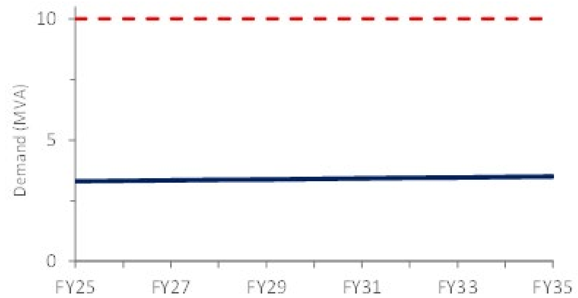
FY24 demand profile



FY24 demand duration curve



10 year demand forecast



New demand breakdown

Customer security of supply summary

Customer supply group	Sub-transmission/Zone substation										Distribution feeder									
	FY26				FY30					FY35	FY26				FY30					FY35
Rural A																				

Commentary:

Te Awamako Zone Substation was commissioned in FY25. Demand profile and duration curves are derived from feeders that have been transferred from Ngapara and Papakaio Zone Substations.

There is a security constraint for a subtransmission outage between Pukeuri and Papakaio Zone Subs which will be alleviated in FY28, when the new North Otago GXP is in service.

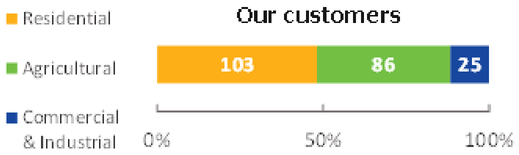
There is a feeder security constraint related to switching time, which will be alleviated in FY27 with the automated open points into Awamoko Sub project

No further capacity or security constraints are expected in the planning period.

Duntroon Zone Substation

Configuration – Single 7 MVA power transformer

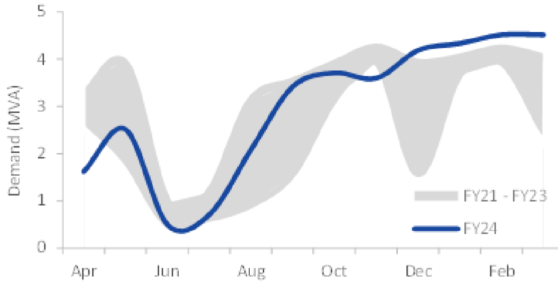
Security rating – B4 rural zone substation



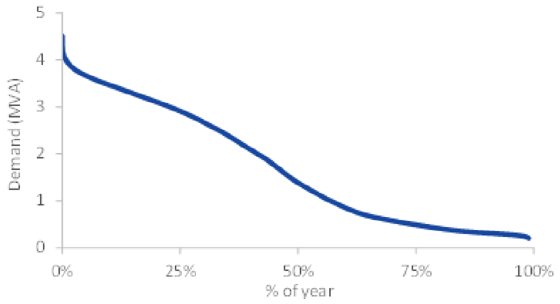
FY24 customer reliability performance

Customer supply group	Number of customers	Average interruption duration	Average number of interruptions	Max interuptions for any customer
Rural A	214			

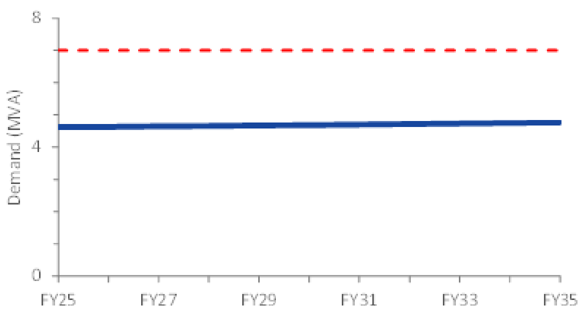
FY24 demand profile



FY24 demand duration curve



10 year demand forecast



New demand breakdown

Customer security of supply summary

Customer supply group	Sub-transmission/Zone substation			Distribution feeder		
	FY26	FY30	FY35	FY26	FY30	FY35
Rural A						

Commentary:

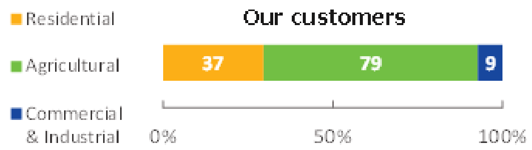
Duntroon Zone Substation has sufficient capacity to meet all demand scenarios.

We may have insufficient subtransmission backup security from Ōamaru GXP for parts of FY27. In the event of an outage, irrigation demand would be subject to rolling outages. This will be alleviated by the new North Otago GXP.

Eastern Road Zone Substation

Configuration – Single 7 MVA power transformer

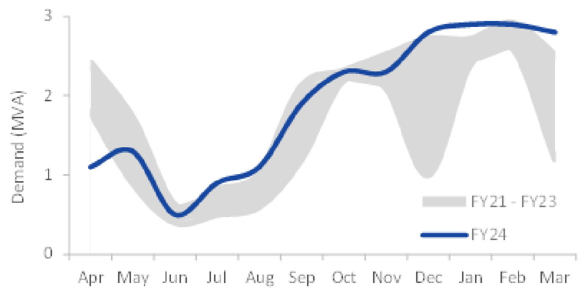
Security rating – B4 rural zone substation



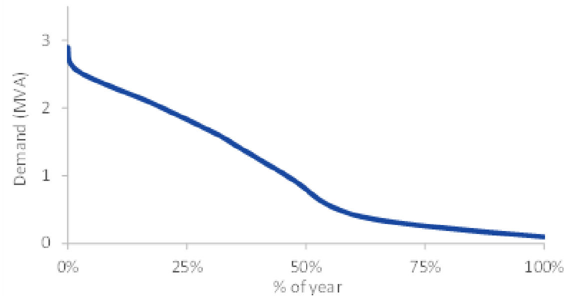
FY24 customer reliability performance

Customer supply group	Number of customers	Average interruption duration	Average number of interruptions	Max interuptions for any customer
Rural A	125			

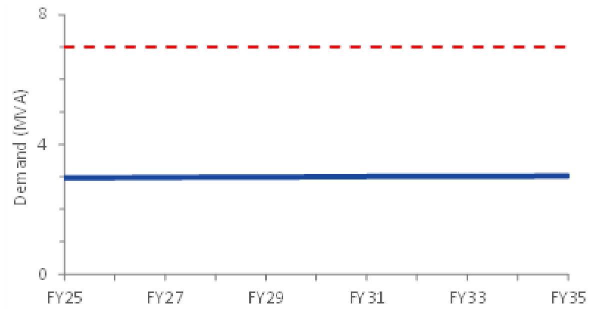
FY24 demand profile



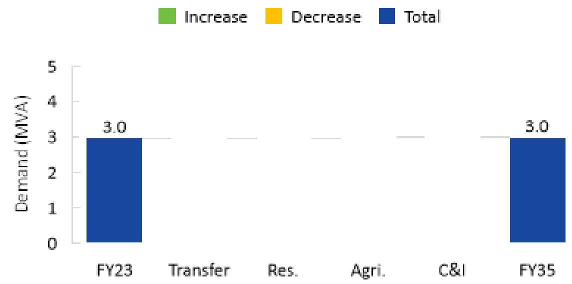
FY24 demand duration curve



10 year demand forecast



New demand breakdown



Customer security of supply summary

Customer supply group	Sub-transmission/Zone substation			Distribution feeder		
	FY26	FY30	FY35	FY26	FY30	FY35
Rural A						

Commentary:

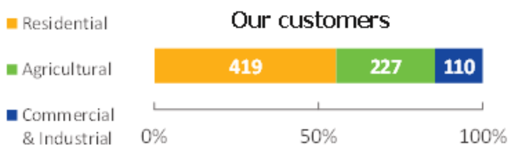
Eastern Road Zone Substation has sufficient capacity to meet all demand scenarios and will meet our security of supply standard for the expected scenario over the planning period.

Reliability performance at this substation was impacted by a storm in October 2023.

Kurow Zone Substation

Configuration – 12 & 15 MVA power transformers

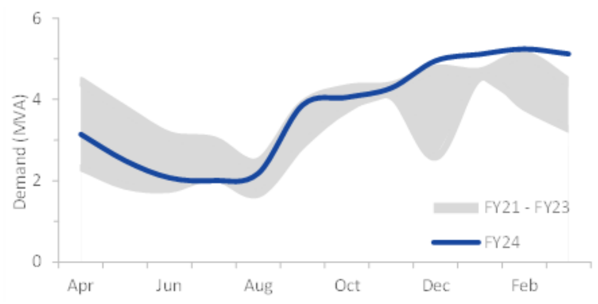
Security rating – B3 township zone substation



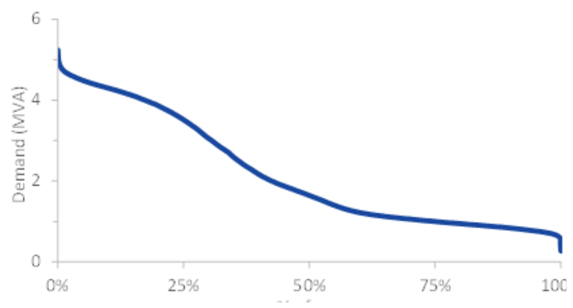
FY24 customer reliability performance

Customer supply group	Number of customers	Average interruption duration	Average number of interruptions	Max interuptions for any customer
Township - Kurow	270			
Rural A	65			
Rural B	366			
Rural C	55			

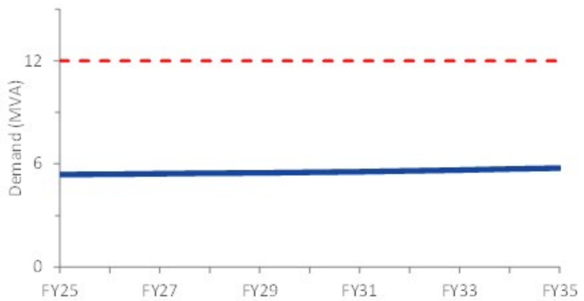
FY24 demand profile



FY24 demand duration curve



10 year demand forecast



New demand breakdown

Customer security of supply summary

Customer supply group	Sub-transmission/Zone substation										Distribution feeder									
	FY26				FY30					FY35	FY26				FY30					FY35
Township - Kurow																				
Rural A																				
Rural B																				
Rural C																				

Commentary:

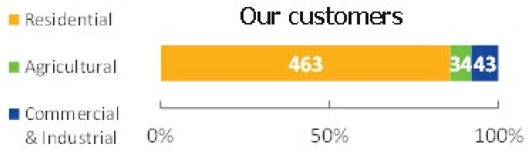
Kurow Zone Substation has sufficient capacity to meet all demand scenarios.

Distribution feeder security of supply constraint alleviated in FY28 by *Kurow township security/resilience improvement project.*

Otematata Zone Substation

Configuration – Single 3 MVA power transformer

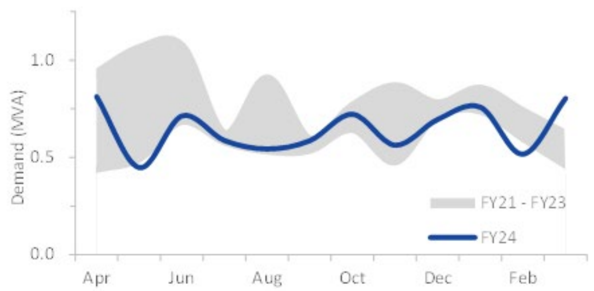
Security rating – B3 township zone substation



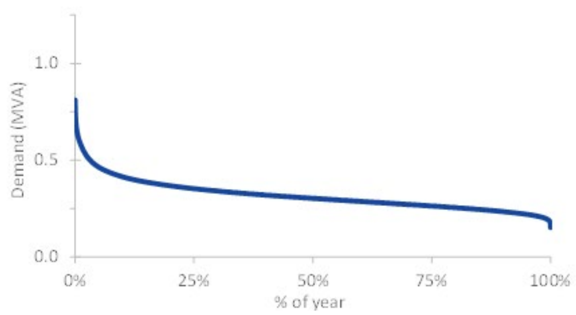
FY24 customer reliability performance

Customer supply group	Number of customers	Average interruption duration	Average number of interruptions	Max interuptions for any customer
Township - Otematata	495			
Rural B	45			

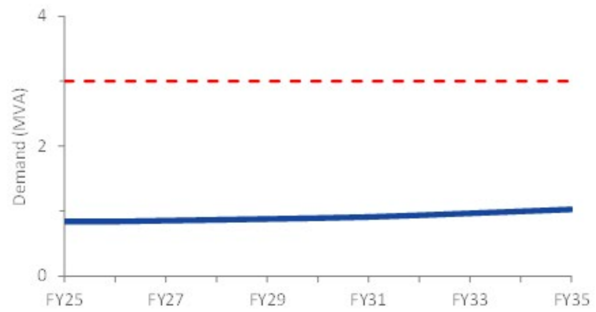
FY24 demand profile



FY24 demand duration curve



10 year demand forecast



New demand breakdown

Customer security of supply summary

Customer supply group	Sub-transmission/Zone substation										Distribution feeder									
	FY26				FY30					FY35	FY26				FY30					FY35
Township - Otematata																				
Rural B																				

Commentary:

Otematata zone substation has sufficient capacity to supply forecast demand for the remainder of the planning period.

There is a security shortfall for a zone substation outage, which will be alleviated in FY26 when a second transformer is planned to be installed. There is also a security shortfall on the Benmore and Otematata feeders which will be alleviated in FY26/27 by *Otematata township security/resilience improvement project.*

Ōhau Zone Substation

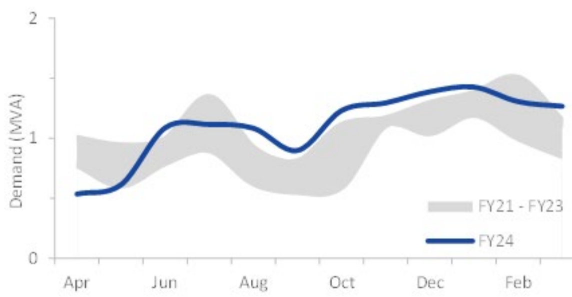
Configuration – Single 3 MVA power transformer

Security rating – B5 rural zone substation

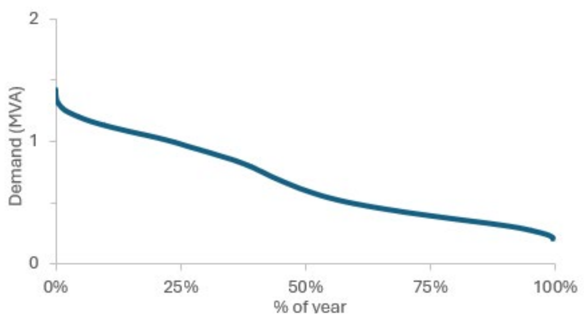
FY24 customer reliability performance

Customer supply group	Number of customers	Average interruption duration	Average number of interruptions	Max interuptions for any customer
Rural C	176			

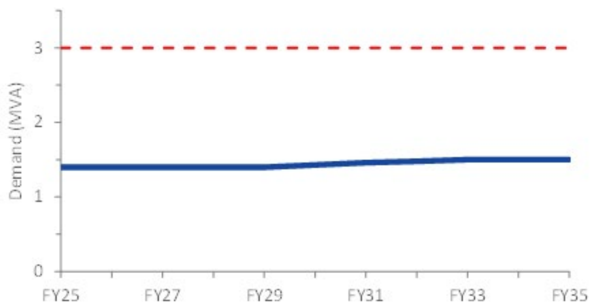
FY24 demand profile



FY24 demand duration curve



10 year demand forecast



New demand breakdown

Customer security of supply summary

Customer supply group	Sub-transmission/Zone substation			Distribution feeder		
	FY26	**FY30**	**FY35**	**FY26**	**FY30**	**FY35**
Rural B						

Commentary:

FY24 reliability exceeded targets because of a subtransmission line failure during severe winds. This line has since been hardened against future failures of this type.

Ōhau zone substation has sufficient capacity to meet all demand scenarios.

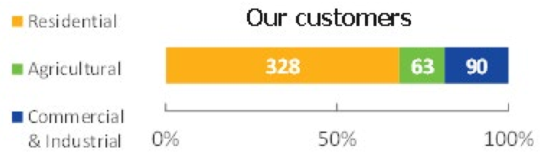
Ōhau feeder does not meet our security standard, we cannot restore 50% of customers within switching time for a feeder outage.

It is currently uneconomic to provide a backup supply into this area, however we have hardened this distribution feeder to reduce susceptibility to faults.

Ōmārama Zone Substation

Configuration – Dual 3 MVA power transformer

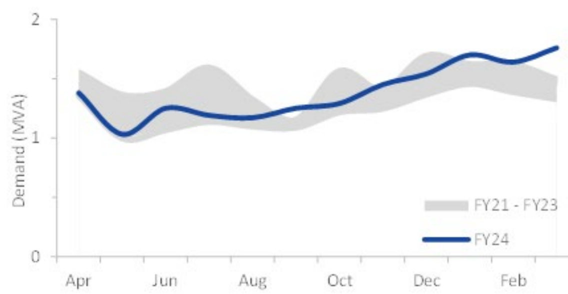
Security rating – B3 township zone substation



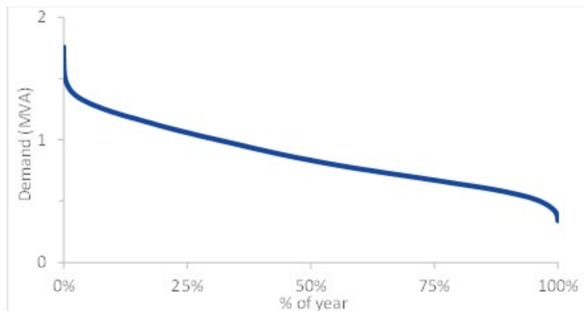
FY24 customer reliability performance

Customer supply group	Number of customers	Average interruption duration	Average number of interruptions	Max interuptions for any customer
Township - Ōmārama	345			
Rural C	136			

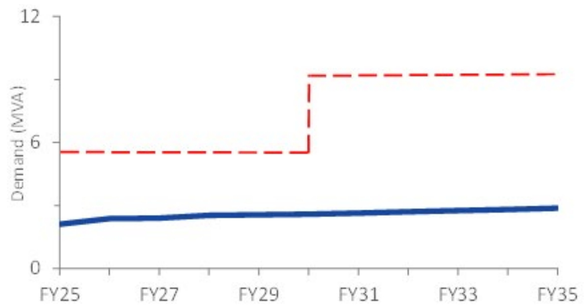
FY24 demand profile



FY24 demand duration curve



10 year demand forecast



New demand breakdown

Customer security of supply summary

Customer supply group	Sub-transmission/Zone substation			Distribution feeder		
	FY26	**FY30**	**FY35**	**FY26**	**FY30**	**FY35**
Township – Ōmārama						
Rural C						

Commentary:

Ōmārama zone substation has sufficient capacity to meet all demand scenarios and will meet our security of supply standard for the expected scenario over the planning period.

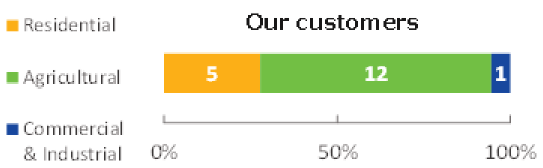
Distribution feeder security of supply constraint alleviated in FY27 by *Ōmārama township security/resilience improvement project*.

Subtransmission & Zone substation security of supply constraint alleviated in FY29 when two automated switches are installed (in conjunction with transformers end of life renewal).

Ruataniwha Zone Substation

Configuration – Single 2 MVA power transformer

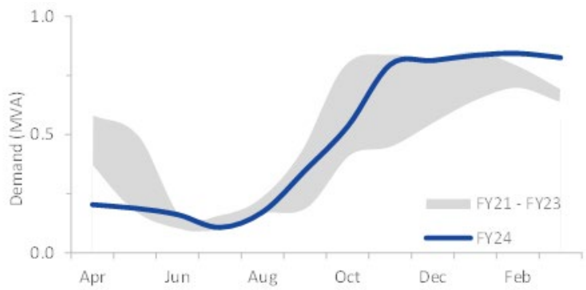
Security rating – (n) security customer substation



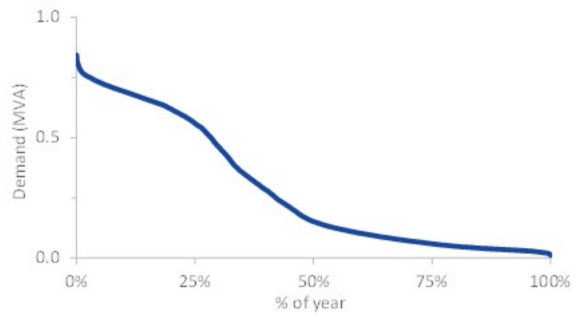
FY24 customer reliability performance

Customer supply group	Number of customers	Average interruption duration	Average number of interruptions	Max interuptions for any customer
Rural C	18			

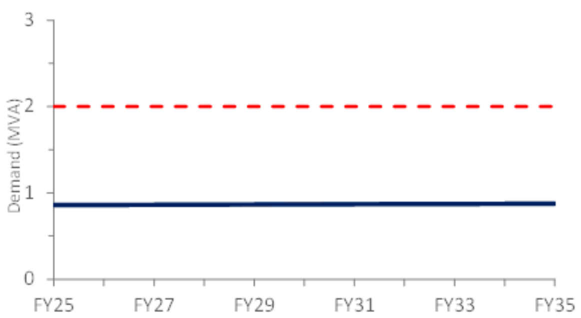
FY24 demand profile



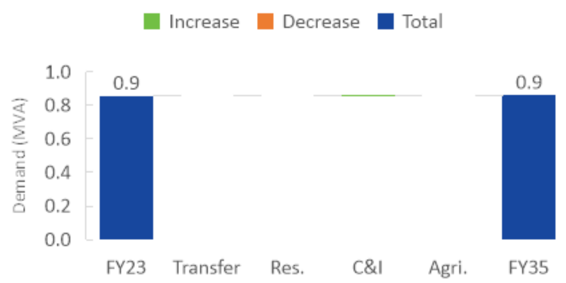
FY24 demand duration curve



10 year demand forecast



New demand breakdown



Customer security of supply summary

Customer supply group	Sub-transmission/Zone substation			Distribution feeder		
	FY26	FY30	FY35	FY26	FY30	FY35
Rural C						

Commentary:

Ruataniwha zone substation has sufficient capacity to meet all demand scenarios and will meet security requirements over the planning period.

Ruataniwha transformer is scheduled for condition based replacement in FY25 and will be sized to cater for planned demand growth closer to the time.

Appendix E – Future network plan - projects

GXP projects

Project 1	North Otago GXP	Cost ($000)	Year	Category
Stage 1 Stage 2 Stage 3	Establish site/consenting/studies Design and build 110 kV switchyard Build 110 kV switchyard	$950 $1,500 $11,541	FY26 FY26 FY27	System growth
Issue	Our demand forecasts indicate that demand at Ōamaru GXP will exceed capacity as early as FY29.			
Solution	This project involves construction of a new North Otago GXP by FY28. Initially this GXP will connect into our 33 kV sub-transmission network and allow us to progressively offload Ōamaru GXP.			
Comments/ alternatives	We engaged an external consultant to peer review our demand scenarios and available options to solve this issue. Options we considered in our business case included: • Reconductoring existing transmission circuits • Grid-scale batteries to reduce demand peaks • Embedded renewable generation • Demand response • Grid bypass options • Building a new GXP Building a new GXP was the best technical and economic solution to provide future capacity and security for our customers. The 220 kV GXP infrastructure will be owned by Transpower, and costs will be funded via a Transpower Works Agreement. We intend to own the 110 kV switchyard, 110/33 kV transformers and downstream 33 kV infrastructure.			

Sub-transmission and substation projects

Project 2	Weston Switching Station security improvements	Cost ($000)	Year	Category
	Design and build	$1,050	FY26	RSEQ
Issue	The Weston 33 kV switch station A and B switchboards are located in the same room with a common bus coupler. There is a high impact low probability risk that a single event could affect both sides of this switchboard. This does not comply with our security standard.			
Solution	The switchboard will be reconfigured to remove the common bus-bar failure risk.			
Comments/ alternatives				

Project 3	New subtrans - North Otago GXP to Awamoko	Cost ($000)	Year	Category
	Construct sub-trans line	$5,968	FY26	System growth
Issue	Under the balanced demand growth scenario, we expect Ōamaru GXP demand will exceed capacity by FY29.			
Solution	We are planning to transfer Te Awamako and Papakaio Zone Substations onto the North Otago GXP once operational in FY28. This circuit is required to enable this transfer and to remedy the security contraint at Te Awamako and Papakaio zone substations. This line will be constructed to 110 kV standard and initially operated at 33 kV. The subtransmission network will be upgraded to 110 kV once the capacity of the 33 kV network is exceeded.			
Comments/ alternatives	Alternatives were considered under Project 1 above.			

Project 4	New subtrans - North Otago GXP to Ngapara	Cost ($000)	Year	Category
Stage 1 Stage 2	Design sub-trans line Construct sub-trans line	$210 $6,060	FY27 FY28	System growth
Issue	Under the balanced demand growth scenario, we expect Ōamaru GXP demand will exceed capacity by FY29.			
Solution	We plan to construct a new sub-transmission line between North Otago GXP and Ngapara Zone Sub to enable Ngapara Zone sub to be supplied from North Otago GXP and to remedy security constraints at Te Awamako and Papakaio Zone Substations. This line will be constructed to 110 kV standard and initially operated at 33 kV. The subtransmission network will be upgraded to 110 kV once the capacity of the 33 kV network is exceeded.			
Comments/ alternatives	Alternatives were considered under Project 1 above.			

Project 5	New subtrans - Ngapara to Oamaru	Cost ($000)	Year	Category
Stage 1 Stage 2	Design sub-trans line Construct sub-trans line	$300 $12,285	FY34 FY35	System growth
Issue	Under the balanced demand growth scenario, (and after transfer of Papakaio and Te Awamoko Zone Substations to the new North Otago GXP) we expect Ōamaru GXP demand will exceed capacity by 2036.			
Solution	In order to transfer Enfield and Five Forks Zone subs onto the new GXP, we need to construct a new subtransmission line between Ngapara Zone Substation and Ōamaru GXP. This line will be constructed to 110 kV standard and initially operated at 33 kV. The subtransmission network will be upgraded to 110 kV once the capacity of the 33 kV network is exceeded.			
Comments/ alternatives	We may be able to defer this project if demand growth is lower than expected.			

Project 6	Weston/Redcastle ring protection upgrade	Cost ($000)	Year	Category
Stage 1 Stage 2	Protection upgrade Protection upgrade	$600 $300	FY26 FY27	System growth
Issue	Recent faults have highlighted shortcomings in the ring protection scheme, affecting large numbers of customers.			
Solution	Upgrade the protection scheme on this ring to include line and bus zone differential protection and take advantage of fibre communications to improve protection performance.			
Comments/ alternatives				

Project 7	110/33 kV conversion stations	Cost ($000)	Year	Category
	Secure land for 110/33 kV conversion stations	$500	FY30	System growth
Issue	RDepending on growth, an option is to upgrade part of our subtransmission to 110 kV. This will require land for 110/33 kV conversion stations in the Papakaio and Ngapara areas.			
Solution	Select appropriate locations and secure land and any related easements.			
Comments/ alternatives				

Project 8	Convert Ruataniwha to Zone Substation	Cost ($000)	Year	Category
	Convert Ruataniwha to zone substation	$462	FY29	System growth
Issue	Ruataniwha Zone Substation (ZS) is a 2 MVA transformer supplying a single agricultural customer. Ōhau ZS backup security is currently provided from Ōmārama ZS. We expect in FY29 that load growth may require additional security into Ōhau ZS from Ruataniwha ZS. The existing Ruataniwha transformer phase group means it is unable to connect into our 11 kV network.			
Solution	Relocate a 3 MVA Dyn11 transformer to site. Build a small section of HV line to connect to Ōhau ZS to CB492 Ruataniwha feeder. Install tie switch to connect CB492 and Ruataniwha ZS. Install a recloser on the private Ruataniwha HV network spur.			
Comments/ alternatives				

Project 9	Automated open points into Awamoko Sub	Cost ($000)	Year	Category
	Install automated tie switch	$105	FY26	System growth
Issue	Te Awamako Zone Substation security is provided from neighbouring zone substations. The response time for manual switching operation exceeds our security requirements.			
Solution	Install an automated switch at ABS1289 to enable backup supply from Ngapara zone substation.			
Comments/ alternatives				

Project 10	Ōmārama Zone Sub security/resilience improvement	Cost ($000)	Year	Category
	Install 2 automated switches	$126	FY29	System growth
Issue	For an unplanned outage at Ōmārama Zone Substation, restoration switching is currently performed manually. This does not meet our security standard for township customers.			
Solution	Replace Ōmārama Zone Substation's manual backup switches with automated devices.			
Comments/ alternatives	Work will be aligned with lifecycle power transformer renewal.			

Distribution projects

Project 11	Moeraki security/resilience improvement	Cost ($000)	Year	Category
	Install backup generation	$221	FY26	System growth
Issue	The Moeraki township has experienced low reliability due to exposure to overhead line outages along SH1, lack of a backup supply, and the long travel distance for fault response.			
Solution	Relocate the 0.5 MVA diesel standby generator no longer required at Otematata to Moeraki township and install automatic switch.			
Comments/ alternatives				

Project 12	South Hill HV security/resilience improvement	Cost ($000)	Year	Category
	Install automated switches	$200	FY26	RSEQ
Issue	Following low reliability after needing to operate manual switches to restore power to high numbers of customers, we identified a security gap in this area.			
Solution	To meet our security standard will install two automated switches to allow a remotely operated backup supply from neighbouring feeders.			
Comments/ alternatives				

Project 13	Omarama township security/resilience improvement	Cost ($000)	Year	Category
	Install automated switching	$473	FY27	System growth
Issue	The Ōmārama township does not meet the security standard due to restoration of supply requiring manual switching.			
Solution	A SCADA-enabled ring main unit will be installed within Ōmārama's town centre. Three remote switches will be installed on the township boundaries to enable remote sectionalising and protection from faults on rural overhead circuits.			
Comments/ alternatives				

Project 14	Otematata township security/resilience improvement	Cost ($000)	Year	Category
	HV feeder intertie Install 4 remote switches	$300 $190	FY26 FY27	System growth
Issue	The Otematata township does not meet the security standard due to restoration of supply requiring manual switching.			
Solution	Install a new HV cable to provide backup to Otematata township from neighbouring feeder. Install four automated devices to allow remote reconfiguration of the network and isolate township customers from faults on the rural section of the feeder.			
Comments/ alternatives				

Project 15	Weston security/resilience improvement	Cost ($000)	Year	Category
	Install RMU and automated switches	$431	FY28	System growth
Issue	The Weston township does not meet the security standard due to restoration of supply requiring manual switching.			
Solution	Install an automated ring main unit and two new remotely operated switches.			
Comments/ alternatives				

Project 16	Kurow township security/resilience improvement	Cost ($000)	Year	Category
	Feeder inter-tie	$315	FY28	System growth
Issue	A portion of the Kurow township does not meet our required security standard due to lack of a backup supply and restoration of supply requiring manual switching.			
Solution	Install a new section of HV line to provide backup supply to this section of township. Install two automated switches to allow a remotely operated backup supply from neighbouring zone substation.			
Comments/ alternatives				

Project 17	Ardgowan Road security/resilience improvement	Cost ($000)	Year	Category
	Install remote switch	$74	FY26	RSEQ
Issue	Ardgowan Road customers are exposed to line outages from a significant area of rural overhead line			
Solution	Install a remotely operated switch to improve fault recovery times			
Comments/ alternatives				

Project 18	Horse Gully feeder automation	Cost ($000)	Year	Category
	Install remotely operated switch	$100	FY30	RSEQ
Issue	Parsons Zone Substation only has a single automated tie switch.			
Solution	Install a remotely operated tie switch to improve fault recovery times.			
Comments/ alternatives				

Project 19	Ōhau feeder automated open point	Cost ($000)	Year	Category
	Install automated switch	100	FY30	RSEQ
Issue	The Buscot feeder is exposed to overhead rural circuits and is at risk of excessive outage duration.			
Solution	Replace ABS 1604 with automated switch			
Comments/ alternatives				

Project 20	Waitaki Bridge security/resilience improvements	Cost ($000)	Year	Category
	Install automated switch	100	FY31	RSEQ
Issue	The Waitaki Bridge feeder is exposed to overhead rural circuits and is at risk of excessive outage duration.			
Solution	To meet our security standard will install an automated switch near Seven Mile Rd. to allow a remotely operated partial backup supply from Pukeuri Zone Substation.			
Comments/ alternatives				

Project 21	Teaneraki security/resilience improvements	Cost ($000)	Year	Category
	Create feeder tie and install automated switch	270	FY32	RSEQ
Issue	Enfield Zone Substation only has a single automated tie switch.			
Solution	New line on Teaneraki Rd to create tie with Horse Gully feeder. Install a remotely operated tie switch to improve fault recovery times.			
Comments/ alternatives				

Project 22	Hampden township security/resilience improvements	Cost ($000)	Year	Category
	Relocate recloser	$30	FY35	RSEQ
Issue	The Hampden township is exposed to overhead rural circuits and is at risk of excessive outage duration. Due to the lack of an HV intertie and the travel distance for fault response.			
Solution	Relocate recloser R651 to township boundary to reduce township's exposure to rural overhead circuits			
Comments/ alternatives				

Project 23	North Otago Business park security/ resilience improvements	Cost ($000)	Year	Category
	Install remotely operated RMU	$200	FY28	System growth
Issue	The manually operated backup supply into the business park does not meet our security standard switching times			
Solution	Install a remotely operated ring main unit to allow a remotely operated backup supply from neighbouring zone substation.			
Comments/ alternatives				

Project 24	Observatory village security/resilience improvements	Cost ($000)	Year	Category
	Install automated ring main unit	$200	FY28	System growth
Issue	The backup supply for the retirement village is manually operated and switching times exceed our security standard.			
Solution	Install a remotely operated ring main unit to allow a remotely operated backup supply from neighbouring zone substation.			
Comments/ alternatives				

Project 25	Provisional DTx. & LV reinforcement	Cost ($000)	Year	Category
	Provisional DTx. & LV reinforcement projects	$300 $300 $300 $400 $1,500 $1,500 $1,500 $1,500 $1,500 $1,500	FY26 FY27 FY28 FY29 FY30 FY31 FY32 FY33 FY34 FY35	System growth
Issue	Provisional budget for reinforcement projects resulting from customer growth on low voltage networks			
Solution	To be determined.			
Comments/ alternatives				

Project 26	Provisional DTx. & LV reinforcement	Cost ($000)	Year	Category
	Provisional HV reinforcement projects	$200 $200 $200 $200 $200 $200 $200 $200 $200 $200	FY26 FY27 FY28 FY29 FY30 FY31 FY32 FY33 FY34 FY35	System growth
Issue	Provisional budget for HV reinforcement projects resulting from customer growth.			
Solution	To be determined.			
Comments/ alternatives				

Project 27	Provisional network enhancement	Cost ($000)	Year	Category
	Provisional network enhancement projects	$0 $0 $0 $0 $300 $400 $230 $400 $400 $400	FY26 FY27 FY28 FY29 FY30 FY31 FY32 FY33 FY34 FY35	RSEQ
Issue	Provisional budget for HV reinforcement projects resulting from customer growth.			
Solution	To be determined.			
Comments/ alternatives				

Monitoring and communications projects

Project 28	Low voltage monitoring	Cost ($000)	Year	Category
	Low voltage monitoring	$355 $290 $250	FY26 FY27 FY28	RSEQ
Issue	We present our rationale for this project in Section 9.2 – Understanding our low voltage networks			
Solution	Install LV feeder and distribution transformer monitors			
Comments/ alternatives				

Project	Communications projects	Cost ($000)	Year	Category
29	Fibre - Station Peak to Kurow	$360	FY26	RSEQ
30	Fibre - Kurow to Eastern Rd	$440	FY27	
31	Fibre - Eastern Rd to new GXP	$550	FY28	
32	Radio link upgrade	$100	FY26/35	
33	Communications upgrade	$100	FY26/35	
34	Purchase Transpower comms site	$200	FY26	
Issue	Modern high reliability protection and monitoring systems require low latency, secure communications.			
Solution	Subject to our communications roadmap, we will install fibre or upgrade radio links between zone substations to enable modern protection systems.			
Comments/ alternatives				

Consumer connection projects

Project	Communications projects	Cost ($000)	Year	Category
35 36 37 38	New LV Service Connections Install Distribution Transformers - Customers New 11kV Network Extensions Residential Subdivisions	$583 $404 $497 $228	FY26-FY35	Consumer connection
Issue	When a customer requires a new supply, capital expenditure may be required for such items as a new service fuse box, new power line, or new transformer.			
Solution	To be determined per connection.			
Comments/ alternatives	This provisional budget is based on the previous three-year average and may be offset by a customer capital contribution.			

Appendix F – EDB Information Disclosure Requirements Schedules

COMMERCE COMMISSION
NEW ZEALAND

EDB Information Disclosure Requirements
Information Templates

Schedules 11a–13
Excluding 11c

Company Name	Network Waitaki Ltd
Disclosure Date	31 March 2025
AMP Planning Period Start Date (first day)	1 April 2025

Templates for Schedules 11a–13 excluding 11c
Prepared 16 February 2024.

Company Name	Network Waitaki Ltd
AMP Planning Period	1 April 2025 – 31 March 2035

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). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary 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													
9		**11a(i): Expenditure on Assets Forecast**	$000 (in nominal dollars)										
10		Consumer connection	1,630	1,711	1,812	1,914	2,019	2,130	2,247	2,351	2,460	2,573	2,689
11		System growth	3,285	11,239	14,973	9,736	1,638	3,361	3,020	2,926	3,306	3,910	22,922
12		Asset replacement and renewal	9,072	13,001	9,645	7,921	10,415	8,521	11,370	9,248	12,656	10,356	14,003
13		Asset relocations											
14		Reliability, safety and environment:											
15		Quality of supply	1,181	1,323	-	-	-	249	131	371	-	-	47
16		Legislative and regulatory											
17		Other reliability, safety and environment											
18		Total reliability, safety and environment	1,181	1,323	-	-	-	249	131	371	-	-	47
19		Expenditure on network assets	15,168	27,274	26,430	19,571	14,071	14,260	16,769	14,897	18,422	16,840	39,661
20		Expenditure on non-network assets	1,700	2,097	205	148	217	156	229	165	241	174	255
21		Expenditure on assets	16,868	29,370	26,636	19,718	14,288	14,416	16,998	15,061	18,663	17,013	39,916
22													
23	*plus*	Cost of financing											
24	*less*	Value of capital contributions	1,730	1,600	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
25	*plus*	Value of vested assets											
26													
27		Capital expenditure forecast	15,138	27,770	25,636	18,718	13,288	13,416	15,998	14,061	17,663	16,013	38,916
28													
29		Assets commissioned	15,458	23,862	23,430	16,571	23,071	13,260	15,769	13,897	17,422	15,840	38,661
30			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31													
32			$000 (in constant prices)										
33		Consumer connection	1,630	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711	1,711
34		System growth	3,285	11,239	14,143	8,706	1,388	2,700	2,300	2,130	2,300	2,600	14,585
35		Asset replacement and renewal	9,072	13,001	9,110	7,083	8,827	6,846	8,659	6,731	8,804	6,886	8,910
36		Asset relocations	-	-	-	-	-	-	-	-	-	-	-
37		Reliability, safety and environment:											
38		Quality of supply	1,181	1,323	-	-	-	200	100	270	-	-	30
39		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
41		Total reliability, safety and environment	1,181	1,323	-	-	-	200	100	270	-	-	30
42		Expenditure on network assets	15,168	27,274	24,964	17,500	11,926	11,457	12,770	10,843	12,816	11,197	25,236
43		Expenditure on non-network assets	1,700	2,097	200	140	200	140	200	140	200	140	200
44		Expenditure on assets	16,868	29,370	25,164	17,640	12,126	11,597	12,970	10,983	13,016	11,337	25,436
45													
46		**Subcomponents of expenditure on assets (where known)**											
48		Energy efficiency and demand side management, reduction of energy losses											
49		Overhead to underground conversion											
50		Research and development											
52													

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
Difference between nominal and constant price forecasts	$000										
Consumer connection	-	-	101	202	308	419	536	640	749	862	978
System growth	-	-	831	1,030	250	661	720	796	1,006	1,310	8,337
Asset replacement and renewal	-	-	535	838	1,588	1,675	2,712	2,517	3,851	3,470	5,093
Asset relocations	-	-	-	-	-	-	-	-	-	-	-
Reliability, safety and environment:											
Quality of supply	-	-	-	-	-	49	31	101	-	-	17
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
Total reliability, safety and environment	-	-	-	-	-	49	31	101	-	-	17
Expenditure on network assets	-	-	1,467	2,071	2,145	2,803	3,999	4,054	5,606	5,642	14,425
Expenditure on non-network assets	-	-	5	8	17	16	29	25	41	34	55
Expenditure on assets	-	-	1,472	2,078	2,162	2,819	4,028	4,078	5,647	5,676	14,480

Commentary on options and considerations made in the assessment of forecast expenditure

EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15

11a(ii): Consumer Connection

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	*Consumer types defined by EDB**	$000 (in constant prices)					
	New LV Service Connections	555	583	583	583	583	583
	Install Distribution Transformers - Customers	385	404	404	404	404	404
	New 11kV Network Extensions	473	497	497	497	497	497
	Residential Subdivisions	217	228	228	228	228	228
	**include additional rows if needed*						
	Consumer connection expenditure	1,630	1,711	1,711	1,711	1,711	1,711
less	Capital contributions funding consumer connection	850	800	600	600	600	600
	Consumer connection less capital contributions	780	911	1,111	1,111	1,111	1,111

11a(iii): System Growth

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	Subtransmission	985	9,018	12,051	6,061		500
	Zone substations	1,840	105			588	
	Distribution and LV lines		721	862	715	200	500
	Distribution and LV cables	300	300	300	931	400	1,500
	Distribution substations and transformers						
	Distribution switchgear						
	Other network assets	160	1,095	930	1,000	200	200
	System growth expenditure	3,285	11,239	14,143	8,706	1,388	2,700
less	Capital contributions funding system growth	880	800	400	400	400	400
	System growth less capital contributions	2,405	10,439	13,743	8,306	988	2,300

11a(iv): Asset Replacement and Renewal

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
		$000 (in constant prices)					
	Subtransmission	2,054	567	572	594	533	533
	Zone substations	1,857	5,467	2,744	749	2,625	602
	Distribution and LV lines	2,554	3,324	3,358	3,404	3,404	3,404
	Distribution and LV cables	166	180	200	171	202	206
	Distribution substations and transformers	344	516	603	732	766	894
	Distribution switchgear	1,560	1,637	1,433	1,433	1,297	1,207
	Other network assets	537	1,310	200	-	-	-
	Asset replacement and renewal expenditure	9,072	13,001	9,110	7,083	8,827	6,846
less	Capital contributions funding asset replacement and renewal						
	Asset replacement and renewal less capital contributions	9,072	13,001	9,110	7,083	8,827	6,846

11a(v): Asset Relocations

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	*Project or programme**	$000 (in constant prices)					
	**include additional rows if needed*						
	All other project or programmes - asset relocations						
	Asset relocations expenditure	-	-	-	-	-	-
less	Capital contributions funding asset relocations						
	Asset relocations less capital contributions	-	-	-	-	-	-

11a(vi): Quality of Supply

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	*Project or programme**	$000 (in constant prices)					
	LV Monitoring	250					
	Fibre Communications	781					
	Radio Link Upgrades	150					
	Weston Switching Station		1,050				
	Other Security/ Resiliance Improvements		273				200
	**include additional rows if needed*						
	All other projects or programmes - quality of supply						
	Quality of supply expenditure	1,181	1,323	-	-	-	200
less	Capital contributions funding quality of supply						
	Quality of supply less capital contributions	1,181	1,323	-	-	-	200

Ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5

11a(vii): Legislative and Regulatory

Ref		Project or programme*	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
144			$000 (in constant prices)					
145								
146								
147								
148								
149								
150		*include additional rows if needed						
151		All other projects or programmes - legislative and regulatory						
152		**Legislative and regulatory expenditure**	-	-	-	-	-	-
153	less	Capital contributions funding legislative and regulatory						
154		**Legislative and regulatory less capital contributions**	-	-	-	-	-	-

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

Ref		Project or programme*	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
158			$000 (in constant prices)					
159								
160								
161								
162								
163								
164		*include additional rows if needed						
165		All other projects or programmes - other reliability, safety and environment						
166		**Other reliability, safety and environment expenditure**	-	-	-	-	-	-
167	less	Capital contributions funding other reliability, safety and environment						
168		**Other reliability, safety and environment less capital contributions**	-	-	-	-	-	-

11a(ix): Non-Network Assets

Ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
173	**Routine expenditure**							
174		*Project or programme**	$000 (in constant prices)					
175		Vehicles			60		60	
176		Information Technology	100	100	100	100	100	100
177		Other Equipment		89	40	40	40	40
178								
179								
180		*include additional rows if needed						
181		All other projects or programmes - routine expenditure						
182		**Routine expenditure**	100	189	200	140	200	140
183	**Atypical expenditure**							
184		*Project or programme**						
185		Depot Redevelopment (Buildings)	1,600	1,908				
186								
187								
188								
189								
190		*include additional rows if needed						
191		All other projects or programmes - atypical expenditure						
192		**Atypical expenditure**	1,600	1,908	-	-	-	-
194	**Expenditure on non-network assets**		1,700	2,097	200	140	200	140

Company Name: **Network Waitaki Ltd**
AMP Planning Period: **1 April 2025 – 31 March 2035**

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.

Operational Expenditure Forecast

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
9			$000 (in nominal dollars)										
10	Service interruptions and emergencies		700	735	760	798	838	879	923	970	1,018	1,069	1,122
11	Vegetation management		769	807	847	890	934	981	1,030	1,081	1,135	1,192	1,252
12	Routine and corrective maintenance and inspection		1,488	1,602	2,097	2,175	2,242	2,398	2,471	2,644	2,725	2,915	3,004
13	Asset replacement and renewal		281	296	280	294	257	269	283	297	312	327	344
14	**Network Opex**		3,238	3,439	3,985	4,157	4,270	4,528	4,707	4,992	5,190	5,504	5,722
15	System operations and network support		4,593	4,674	4,803	4,937	5,073	5,214	5,359	5,507	5,660	5,817	5,979
16	Business support		4,655	4,338	4,456	4,578	4,702	4,830	4,962	5,097	5,236	5,379	5,526
17	Non-network solutions provided by a related party or third party	*Not Required before DY2025*											
18	**Non-network opex**		9,248	9,012	9,259	9,514	9,776	10,045	10,321	10,605	10,897	11,197	11,505
19	**Operational expenditure**		12,486	12,451	13,244	13,671	14,045	14,572	15,028	15,597	16,087	16,700	17,227
20			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
22			$000 (in constant prices)										
23	Service interruptions and emergencies		700	735	723	723	723	723	723	723	723	723	723
24	Vegetation management		769	807	807	807	807	807	807	807	807	807	807
25	Routine and corrective maintenance and inspection		1,488	1,602	1,998	1,973	1,936	1,973	1,936	1,973	1,936	1,973	1,936
26	Asset replacement and renewal		281	296	267	267	222	222	222	222	222	222	222
27	**Network Opex**		3,238	3,439	3,795	3,771	3,688	3,725	3,688	3,725	3,688	3,725	3,688
28	System operations and network support		4,593	4,674	4,674	4,674	4,674	4,674	4,674	4,674	4,674	4,674	4,674
29	Business support		4,655	4,338	4,338	4,338	4,338	4,338	4,338	4,338	4,338	4,338	4,338
30	Non-network solutions provided by a related party or third party	*Not Required before DY2025*											
31	**Non-network opex**		9,248	9,012	9,012	9,012	9,012	9,012	9,012	9,012	9,012	9,012	9,012
32	**Operational expenditure**		12,486	12,451	12,807	12,783	12,700	12,737	12,700	12,737	12,700	12,737	12,700

Subcomponents of operational expenditure (where known)

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
36	Energy efficiency and demand side management, reduction of energy losses											
37	Direct billing*											
38	Research and Development											
39	Insurance	677	703	703	703	703	703	703	703	703	703	703

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

Difference between nominal and real forecasts

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
45			$000										
46	Service interruptions and emergencies		-	-	36	74	114	156	200	246	295	345	399
47	Vegetation management		-	-	40	83	127	174	223	274	329	385	445
48	Routine and corrective maintenance and inspection		-	-	100	202	305	425	535	671	788	942	1,068
49	Asset replacement and renewal		-	-	13	27	35	48	61	75	90	106	122
50	**Network Opex**		-	-	190	386	581	803	1,019	1,267	1,502	1,779	2,034
51	System operations and network support		-	-	129	263	399	540	685	833	986	1,143	1,305
52	Business support		-	-	118	240	364	492	624	759	898	1,041	1,188
53	Non-network solutions provided by a related party or third party	*Not Required before DY2025*	-	-	-	-	-	-	-	-	-	-	-
54	**Non-network opex**		-	-	247	502	764	1,033	1,309	1,593	1,885	2,185	2,493
55	**Operational expenditure**		-	-	437	889	1,345	1,835	2,328	2,860	3,386	3,963	4,526

Commentary on options and considerations made in the assessment of forecast expenditure

EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operational expenditure for the current disclosure year and a 10 year planning period in Schedule 15.

Company Name: **Network Waitaki Ltd**
AMP Planning Period: **1 April 2025 – 31 March 2035**

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

sch ref	Voltage	Asset category	Asset class	Units	Asset condition at start of planning period (percentage of units by grade) H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
10	All	Overhead Line	Concrete poles / steel structure	No.	0.01%	0.72%	5.37%	76.53%	17.37%		3	6.70%
11	All	Overhead Line	Wood poles	No.	0.06%	3.01%	21.12%	51.08%	24.73%		3	9.02%
12	All	Overhead Line	Other pole types	No.							N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km			12.86%	33.09%	54.05%		3	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km							N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km			1.40%	89.77%	8.83%		3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km							N/A	
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km							N/A	
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km							N/A	
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km							N/A	
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km							N/A	
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km							N/A	
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km							N/A	
23	HV	Subtransmission Cable	Subtransmission submarine cable	km							N/A	
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.		5.00%	20.00%	20.00%	55.00%		4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.							N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.				100.00%			4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.		1.82%	23.63%	43.64%	30.91%		4	13.44%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	4.65%	12.79%	30.23%	51.17%	1.16%		3	17.02%
30	HV	Zone substation switchgear	33kV RMU	No.							N/A	
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.							N/A	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.			100.00%				4	
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	7.84%	-	4.91%	50.98%	36.27%		4	7.84%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.		-	75.00%	-	25.00%		4	
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.		15.38%	23.08%	19.23%	42.31%		4	11.54%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km		10.02%	56.84%	19.67%	13.47%		3	7.72%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
42	HV	Distribution Line	SWER conductor	km							N/A	
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km			0.15%	48.00%	51.85%		3	-
44	HV	Distribution Cable	Distribution UG PILC	km	0.08%	17.73%	39.47%	42.72%			3	2.41%
45	HV	Distribution Cable	Distribution Submarine Cable	km							N/A	
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.		13.43%	22.39%	41.79%	22.39%		4	10.45%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.					100.00%		4	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	0.88%	3.99%	16.02%	43.49%	35.62%		3	11.32%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.							N/A	
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.		7.39%	33.00%	35.47%	24.14%		4	14.06%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.12%	7.80%	16.47%	55.05%	20.56%		3	6.23%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.34%	2.21%	11.59%	59.97%	25.89%		4	2.91%
53	HV	Distribution Transformer	Voltage regulators	No.			5.56%	69.44%	25.00%		4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.		30.00%	70.00%				2	-
55	LV	LV Line	LV OH Conductor	km	0.49%	24.32%	70.63%	3.04%	1.52%		2	4.00%
56	LV	LV Cable	LV UG Cable	km	-	-	18.86%	47.19%	33.95%		2	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km		5.00%	50.00%	35.00%	10.00%		2	5.00%
58	LV	Connections	OH/UG consumer service connections	No.		5.46%	19.94%	36.63%	37.97%		2	2.23%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.		5.61%	34.18%	56.63%	3.58%		3	16.84%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot		50.00%	25.00%	15.00%	10.00%		4	50.00%
61	All	Capacitor Banks	Capacitors including controls	No.				100.00%			4	
62	All	Load Control	Centralised plant	Lot			100.00%				4	
63	All	Load Control	Relays	No.		20.00%		80.00%			2	
64	All	Civils	Cable Tunnels	km							N/A	

	Company Name	Network Waitaki Ltd
	AMP Planning Period	1 April 2025 - 31 March 2035

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and constraints for each zone substation. 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			*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	*Not Required before DY2025*	
8	*Existing Zone Substations*	Current peak load (MVA)	Current peak load period	Installed operating capacity (MVA)	Current security of supply classification (type)	Current constraint type	Current available capacity (MVA)	Peak load period +5 yrs	Available capacity +5 yrs (MVA)	Security of supply classification +5 yrs (type)	Peak load period +10 yrs	Min. available capacity +10 yrs (MVA)	Max. available capacity +10 yrs (MVA)	Security of supply classification +10 yrs (type)	Forecast constraint type	Year of any forecast constraint	Constraint primary cause	Constraint solution type	Constraint solution progress	Temporary constraint solution remaining lifespan	Explanation
9	Chelmer	13	Winter	28	N-1	No constraint	15	Winter	14	N-1	Winter	8.8	12.1	N-1	No constraint						
10	Duntroon	5	Summer	7	N-1 switched	No constraint	2.4	Summer	2	N-1 switched	Summer	2.3	2.3	N-1 switched	Security	2	Transpower	Network upgrade	Planning stage		Will be alleviated under new GXP project to alleviate Ōamaru GXP constraint
11	Eastern Rd	3	Summer	7	N-1 switched	No constraint	4	Summer	4	N-1 switched	Summer	3.9	4.0	N-1 switched	No constraint						
12	Enfield	3	Summer	7	N-1 switched	No constraint	5	Summer	2	N-1 switched	Summer	2.2	2.3	N-1 switched	No constraint						
13	Five Forks	2	Summer	7	N-1 switched	No constraint	5	Summer	5	N-1 switched	Summer	5.1	5.2	N-1 switched	No constraint						
14	Hampden	1	Summer	7	N-1 switched	No constraint	6	Summer	6	N-1 switched	Summer	5.1	5.4	N-1 switched	No constraint						
15	Kurow	5	Summer	12	N-1 switched	No constraint	7	Summer	7	N-1 switched	Summer	6.2	6.5	N-1 switched	No constraint						
16	Maheno	4	Summer	5	N-1 switched	No constraint	1	Summer	1	N-1 switched	Summer	2.7	3.0	N-1 switched	No constraint						Maheno power transformer scheduled for condition based replacement in FY28 will be upgraded to standard sizing which will provide increased capacity
17	Ngapara	5	Summer	7	N-1 switched	No constraint	2	Summer	2	N-1 switched	Summer	1.9	2.1	N-1 switched	No constraint						
18	Ohau	1	Summer	3	N-1 switched	No constraint	2	Summer	2	N-1 switched	Summer	1.5	1.5	N-1 switched	No constraint						
19	Omarama	2	Summer	6	N-1 switched	Security	4	Summer	3	N-1 switched	Summer	3.4	3.6	N-1 switched	Security	1	Other	Network upgrade	No active planning		Security constraint is related to switching time after a fault. Will be alleviated by adding remote automation to switches at same time as condition replaced replacement of transformer in FY29
20	Otematata	1	Summer	3	N-1 switched	Security	2	Summer	2	N-1 switched	Summer	2.0	2.2	N-1 switched	No constraint	1	Zone substation transformer	Network upgrade	Implementation stage		Condition based replacement of transformer triggered security upgrade which will solve this constraint - will be completed early FY26
21	Papakaio	7	Summer	7	N-1 switched	Security	0	Summer	2	N-1 switched	Summer	2.1	2.2	N-1 switched	No constraint	1	Subtransmission circuit	Network upgrade	Planning stage		Demand shifted to Te Awamako substation will increase capacity at Papakaio - Subtransmission security risk will be alleviated in FY27 when new GXP and associated subtransmission is in service to alleviate Ōamaru GXP constraint
22	Parsons	3	Summer	12	N-1 switched	No constraint	9	Summer	9	N-1 switched	Summer	8.5	8.9	N-1 switched	No constraint						
23	Pukeuri	9	Summer	12	N-1	No constraint	3	Summer	10	N-1	Summer	4.9	10.1	N-1	No constraint						
24	Redcastle	9	Winter	18	N-1	No constraint	9	Winter	6	N-1	Winter	4.5	7.6	N-1	No constraint						
25	Ruataniwha	1	Summer	2	N-1 switched	No constraint	1	Summer	1	N-1 switched	Summer	1.1	1.1	N-1 switched	No constraint						
26	Te Awamako	3	Summer	7	N-1 switched	Security	4	Summer	3	N-1 switched	Summer	3.3	3.3	N-1 switched	Security	1	Subtransmission circuit	Network upgrade	Planning stage		Subtransmission security risk will be alleviated in FY27 when new GXP and associated subtransmission is in service to alleviate Ōamaru GXP constraint
27																					
28																					

29 [1] *Extend table as necessary to disclose all capacity and constraint information by each zone substation*

	Company Name	Network Waitaki Ltd
	AMP Planning Period	1 April 2025 – 31 March 2035

SCHEDULE 12c: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

7 **12c(i): Consumer Connections**

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
8	*Number of ICPs connected during year by consumer type*			Number of connections			
9		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
10							
11	*Consumer types defined by EDB**						
12	Small:Residential and commercial to 15 kVA	90	90	90	90	90	90
13	Medium: residential and commercial 16 kVA to 50 kVA	9	9	9	9	9	9
14	Large: commercial and industrial 51kVA and above	13	13	13	13	13	13
15	Independent Contract Customers (IND)	-	-	-	-	-	-
16							
17	Connections total	112	112	112	112	112	112
18	**include additional rows if needed*						
19							
20							
21							
22	**Distributed generation**	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
23	Number of connections made in year	45	50	58	70	86	110
24	Capacity of distributed generation installed in year (MVA)	343	384	443	531	657	836
25	**12c(ii): System Demand**						
26		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
27	**Maximum coincident system demand (MW)**						
28	GXP demand	70	72	75	77	77	78
29	*plus* Distributed generation output at HV and above						
30	Maximum coincident system demand	70	72	75	77	77	78
31	*less* Net transfers to (from) other EDBs at HV and above						
32	Demand on system for supply to consumers' connection points	70	72	75	77	77	78
33	**Electricity volumes carried (GWh)**						
34	Electricity supplied from GXPs	283	287	293	299	305	311
35	*less* Electricity exports to GXPs						
36	*plus* Electricity supplied from distributed generation	1.8	2.4	3.0	3.7	4.2	4.5
37	*less* Net electricity supplied to (from) other EDBs						
38	Electricity entering system for supply to ICPs	285	289	296	303	309	316
39	*less* Total energy delivered to ICPs	271	275	281	288	294	299
40	Losses	14	14	15	15	16	17
41							
42	Load factor	46%	46%	45%	45%	46%	46%
43	Loss ratio	5.0%	5.0%	5.1%	5.0%	5.1%	5.2%

Company Name	Network Waitaki Ltd
AMP Planning Period	1 April 2025 – 31 March 2035
Network / Sub-network Name	All

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*
8		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9							
10	SAIDI						
11	Class B (planned interruptions on the network)	105.0	105.0	105.0	105.0	105.0	105.0
12	Class C (unplanned interruptions on the network)	55.0	55.0	55.0	55.0	55.0	55.0
13	SAIFI						
14	Class B (planned interruptions on the network)	0.50	0.50	0.50	0.50	0.50	0.50
15	Class C (unplanned interruptions on the network)	1.30	1.30	1.30	1.30	1.30	1.30

Company Name	Network Waitaki Ltd
AMP Planning Period	1 April 2025 – 31 March 2035
Asset Management Standard Applied	ISO 55001

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?	4	The Board of Directors has approved an updated Asset Management Policy compliant with ISO 55001 requirements. A summary of the policy is included in the Asset Management Plan (AMP) and is accessible to staff and stakeholders. The policy has been explicitly communicated through an all-hands meeting and is promoted as a guiding framework for asset management decision-making.		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	There are linkages within the Asset Management Plan (AMP) between Network Waitaki's strategic priorities, service levels, and the strategies described in the AMP.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (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	Maintenance and renewal investments are supported by Fleet Management Plans covering the most critical asset classes.		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	The work program is documented and includes a comprehensive work plan containing detailed information on projects, their budgets, and the assets they will impact. This work plan serves as the baseline for the approved project list, later summarized in the Asset Management Plan (AMP). There is a clear demonstration of alignment between the work plan and the organization's strategy and objectives.		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

Company Name	Network Waitaki Ltd
AMP Planning Period	1 April 2025 - 31 March 2035
Asset Management Standard Applied	ISO 55001

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.

Company Name	Network Waitaki Ltd
AMP Planning Period	1 April 2025 - 31 March 2035
Asset Management Standard Applied	ISO 55001

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 Engineering Manager and contracting team regularly conduct coordination meetings to communicate the plan's requirements and negotiate timing and variations with stakeholders, such as the Network Lifecycle Manager, who is also invited to attend these meetings.		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	The MS Project system is used to assign and schedule pre-construction tasks, while the contracting team is responsible for the execution of construction.		The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	2	Using the work plan, a work program is developed in Microsoft Project, where each project is represented by a simplified work breakdown structure highlighting essential phases such as long lead time procurement, design, and construction.		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	Network Waitaki has a comprehensive and up-to-date Crisis Management Plan (CMP) that provides a framework for responding to various events of different types and scales. CIMS training has been provided for key staff, but the full integration of CIMS into Network Waitaki's processes has not been adopted. This approach reflects the organization's size and the routine nature of storm and network damage responses within its operations. Notably, the CMP was recently tested in a simulated cyberattack scenario, demonstrating its utility and relevance for crisis situations.		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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AMP Planning Period	1 April 2025 - 31 March 2035
Asset Management Standard Applied	ISO 55001

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.

Company Name	Network Waitaki Ltd
AMP Planning Period	1 April 2025 - 31 March 2035
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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	The Asset Management team has undergone a restructuring to better align with NWL's strategy, enhancing roles, accountabilities, and key result areas. Further refinements are programmed to facilitate the ongoing needs of the company.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3	This is evident through the creation of several new roles such as Network Lifecycle Manager, Asset Engineer (x2), Network Information Manager, Technical Specialist, and Network Strategic Manager (currently vacant), as seen in the new organizational chart. These structural changes and the increase in staff indicate that the company has recognized past resource gaps and is now executing a plan to address those gaps. Changes to the asset fleet strategies have allowed alignment of forecast network requirements to be aligned with other 10 year business modelling being utilised to drive business strategies.		Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	The importance of meeting asset management requirements appears to be well communicated by top management. Currently, managers appear to have sufficient authority to achieve their objectives, and there is evidence of alignment between available resources and asset management goals.		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	A formal service partnership agreement has been established between the Network and Contracting Divisions, defining the responsibilities for carrying out the majority of the work program. This agreement outlines required service levels, financial arrangements, and processes. Processes for engaging external contractors are largely based on past performance, pricing, and local availability. While this approach could be formalized, it appears to be effective, given the relatively small volume of services procured using this method. For specialist services, Network Waitaki takes an outcome-based approach, specifying end results and relying on the contractors' expertise to define work methods		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2	Position descriptions for all roles have been developed with performance indicators generally clearly linked to asset management objectives.		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	Competence requirements stated in job profiles, however, do not generally specify role-related competencies, relying instead on broad descriptions of experience, sometimes expressed in the number of years of experience. A documented framework for asset management competencies, while under development, is not currently in place.		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	3	A one-on-one staff/manager review form is available to add structure to manager/staff interactions. There is evidence that staff are engaged in training and continual professional development associated with their roles. An example of this is asset management-specific training being undertaken by members of the Network Lifecycle team.		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	The AMP represents a significant stakeholder communication tool providing detailed information to any interested stakeholder. The annual survey serves as a tool for assessing customer preferences and perceptions of service, with the gathered insights incorporated as inputs into the AMP. The AMP also includes a formal stakeholder engagement plan that identifies stakeholders, outlines their requirements, and details how these are considered and integrated into asset management practices.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	2	Network Waitaki has documented an overall approach to asset management in the AMP (Chapter 4) describing the broad elements of an asset management system and referring to other Network Waitaki policies and standards where these are available. While indicating awareness of the need for an overarching system, the Chapter reads more as a statement of intent rather than a clear description of a system of interrelated policy, processes, standards, and control mechanisms. It is acknowledged that for an organization the size and scale of Network Waitaki it may not be cost efficient to implement a comprehensive asset management system. Rather Network Waitaki should identify the elements of an asset management system that provide the greatest benefit in assuring delivery of the corporate objectives and managing risks.		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	An asset information review conducted by external consultants provides analysis and recommendations for the information systems required by NWL. The review outlines a program for system implementations and replacements, including discussions on business capabilities and supporting data requirements, and includes a proposed timeline for these activities.		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?	2	Scheduled inspections and pre-work site preparation provide confirmation that asset data is accurate. Field software is being adopted to maximise efficiency and reduce errors from the field. Personell in the office are responsible for recording information from teh field, with some already being electronically reported. Data audits are regularly carried out, and discrepancies corrected.		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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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	The asset management information systems is sized to foreseeable needs and aligned with good industry practice. Work continues with users to identify their ongoing needs, as developments continue. Systems are review and updated as required to meet asset management goals.		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	A risk framework is in place and has been authorized and implemented. Risks are being identified using a range of tools chosen to meet the task and required level of assessment. An audited public safety management system is in place. A process mapping tool Promap is used for documenting and managing critical processes and formally managing corrective actions arising from these processes.		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	3	Bowties are used for formally analyzing critical risks, a system 'Vault' is used for recording incidents near misses and associated corrective actions. A training framework is under development which will have linkages to risk assessments and where appropriate the outcome of incident investigations.		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 formal legal compliance management system (ComplyWith) has been implemented and is being actively used. This system includes a registry of requirements and declarations of compliance. Risk registers are in place that can be used to record risks associated with compliance.		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	**Network Waitaki Ltd**
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Asset Management Standard Applied	**ISO 55001**

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?	2	The portfolio management function has been implemented. The Engineering Manager is currently responsible for managing the work plan. Both the work plan and the project programmes estimate resourcing requirements and identify long lead time items and the lead times for designs or plant purchases.		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	Network Waitaki (NWL) has implemented a functional approach for specifying inspection and maintenance requirements for its asset fleets. This approach is supported by maintenance standard documents that outline broad inspection and maintenance requirements, as well as field data collection apps that enable electronic data collection and collation of inspection results. The collected data is assessed by the lifecycle team to determine appropriate corrective and maintenance actions. The systems leverage existing GIS, spreadsheets, and other tools within NWL's business productivity ecosystem		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	Systems are in place for measuring the performance of Network Waitaki's assets as required by Commerce Commission information disclosures. These include network performance metrics SAIDI, SAIFI and asset condition measures using health indicators. Asset performance records include cause codes suitable for analysis. Asset condition is assessed by a combination of age, asset inspection information and expert judgement. Some advanced assessment methods such as partial discharge testing are used. Standards or handbooks exist providing guidance regarding the grading of defects. There is however limited evidence of use of asset condition data for developing forward looking renewal forecasts and plans with the current approach somewhat reactive based on the results of condition inspections. For example, the current AMP provides asset age profiles without reference to asset condition.		Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	3	At present a formal incident management process for asset related failures is not in place. This is manageable given the relatively small size of Network Waitaki coupled with the relatively low frequency of incidents which is also related to the organizations size. Investigation skills exist within the organization with some staff members trained in the ICAMS methodology. Incidents with safety consequences are formally investigated and their outcomes recorded and managed using the Vault risk register system. The new process management system Promap includes the ability for process users to highlight process non-conformities and have these formally recorded and actioned. External experts are engaged to investigate major failures or technical failures outside of the skill set of engineering staff.		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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Asset Management Standard Applied	ISO 55001

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3	Network Waitaki conducts annual self-assessments using the Commerce Commission's AMMAT framework. The company's public safety management system is also formally audited and certified by an external audit party. The process mapping system Promap includes periodic review and of compliance with processes. There are also periodic audits of field work to ensure safety compliance and work quality. While audit processes are in place, there could be some scope for increased scrutiny of asset management processes and systems and formalization of an internal audit plan.		This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	Network Waitaki has several systems that record actions arising from investigations or non-conformances. These include the system Vault which is associated with risks and safety incidents an an improvement register implemented using the Microsoft planner application. The Promap process mapping system also has an internal mechanism for creating improvement opportunities for implementation. Management meeting minutes are another place where corrective and preventive actions may be recorded. While these mechanisms are in place, they are somewhat distributed and not formalized as would be the case in an ISO9001 type system.		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	A plan for improving asset management has been created based on the recommendations of previous AMMAT audits. The plan includes a list of initiatives, priorities, target completion dates, and the responsible manager. Evidence shows that the actions are being progressively addressed and proactively managed through results accomplished		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	Network Waitaki actively seeks and acquires new knowledge regarding asset management related technology and practices through engagement and participation in industry bodies and working groups such as the EEA and ENA and their associated working groups. The organization's commitment to continual improvement is further demonstrated by the employment of a Continuous Improvement Manager, who plays a key role in driving these initiatives forward and embedding a culture of ongoing development within the business.		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.
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 G – Board Certification of AMP

Certification for Year-Beginning Disclosures

Pursuant to Schedule 17

Clause 2.9.1 of section 2.9

Electricity Distribution Information Disclosure Determination 2012

We, Michael de Buyzer and Jonathan Kay, being directors of Network Waitaki Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) the following attached information of Network Waitaki Ltd prepared for the purposes of clauses, 2.6.1, 2.6.2, 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.

a) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Network Waitaki Ltd.'s corporate vision and strategy and are documented in retained records.

Michael J. de Buyzer
Chairman of the Board of Directors

Date: 31 March 2025

Jonathan Kay
Director

Date: 31 March 2025