POWERING OUR FUTURE

ASSET MANAGEMENT PLAN 2022 – 2032

Network Waitaki

WWW.NETWORKWAITAKI.CO.NZ

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POWERING OUR FUTURE

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INTRODUCTION

Welcome to our Asset Management Plan (AMP) for the planning period 1st April 2022 to 31st March 2032. 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 summarises the challenges and development ahead for us, including our Capital and Operational 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: summarises the key themes and initiatives that have been 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.

We operate a predominantly overhead rural network supplying the North Otago, Hakataramea, and Ahuriri regions as shown below. We supply the major rural support town of Oamaru as well as several smaller townships.

Figure 1 - Overview of Network Waitaki area of supply

1.1.2 Our Vision

"Powering a vibrant Waitaki"

1.1.3 Our Mission

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

1.1.4 Alignment with key strategic priorities

In 2020 we developed and launched a new 10-year strategic plan that will guide our business to deliver our Vision and Mission. In terms of delivery of this Asset Management Plan our key strategic priorities are:

Excellence and innovation in our core business

This means having leading performance on our electricity network in order to provide safe, reliable, cost effective and environmentally sustainable network services to our customers.

We are committed to being a leader in health and safety by ensuring that our network remains safe at all times and seek to actively manage risks to the public, public property, and our staff. This is a key focus point for asset management decision making, including asset selection, design and construction activities, day to day operation and maintenance of the network, fault and emergency response, and the criteria for removal of assets from operation at or before end of life.

Reliability of supply is of high importance to us and to our customers. Our customer surveys have indicated our customers are generally happy with the reliability they receive for the price that they currently pay. Maintaining and improving this level of reliability in a cost-effective manner through the planning period is a focus in our asset management strategies.

We forecast that there will be a high growth of decarbonisation and irrigation demand over the next ten years along with increasing uptake of emerging technologies such as electric vehicles, solar photovoltaic systems, and battery storage systems nearer the end of this period and increasing rapidly in the decade following. Most of these technologies will be connected to our low voltage networks. Historically, demands on these networks have been predictable and stable over time and our low voltage networks have had very little in the way of monitoring. In order to quantify the impact of these emerging technologies we need to invest in systems that provide us useful data about the performance of our low voltage networks. This will allow us to monitor the quality of supply at the level of our customers and predict and react to developing problems in a timely fashion.

Our network will provide a platform for the decarbonisation of our customers' businesses. Sustainability is an important factor in the ongoing development of Network Waitaki, both from an environmental point of view, and a financial point of view.

Provide the best value for our customers and community

This will be achieved by providing excellent customer service and engagement and will be measured by regular customer engagement and surveying. Our Customer and Community Relations Manager is responsible for developing and managing our customer services and engagement strategy, careers and public safety programmes and internal customer management systems and processes. This will allow us to better understand and meet our customers' needs and priorities.

Offer innovative new solutions to our customers

We will investigate the development of a portfolio of innovative solutions for our customers and community to improve service levels, support decarbonisation, and improve the utilisation of our network. These solutions may include demand response and other non-network opportunities to increase network capacity or defer network investment.

1.1.5 Managing our assets

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

Our asset management practice is to actively seek out best practice both from within our industry, and from other industries where it is appropriate. Examples of this are:

- Trialling technologies such as multi camera aerial platforms and Lidar for asset inspections
- Involvement in industry working groups to do with new technologies
- Hosting onsite industry training courses to improve the capability of our engineers and line mechanics, such as the EEA Safety in Design course.

In FY22 we have undertaken an independent review of our asset management practices business based on the EEA's AMMAT assessment tool. The outcomes from this assessment are being used as the basis for an improvement plan to ensure that our business is focussed on providing excellence in asset management, in order to provide excellent service and value to our customers, owners and other stakeholders.

A key theme of the company's development over the next few years is developing our Asset Management skills and capability to better align with ISO 55000 principles. In the next few years, key focus areas are:

- improving the data that we record about our assets, and modernising how it is captured and handled
- the integration of that data into operational systems to assist us in decision making
- developing a deeper understanding of the criticality of individual assets to better inform our strategies, and improve the experience of our customers

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

Table 1 - Key features of NWL network

Parameter	Value
Number of Poles	21,652
Length of 33 kV lines and cables	222 km
Length of 11 kV lines and cables	1,336 km
Length of LV lines and cables	321 km
Number of zone substations	17
Number of connected customers	13,258
Coincident max demand	62 MW
Annual energy delivered to customers	256 GWh

These assets are discussed in detail in Section 5 Renewals and Maintenance.

We have traditionally managed our asset life via condition-based renewals and replacements, but we are also working towards utilising better analytical and predictive methods for analysing lifecycle of the assets. This includes the introduction of end-to-end processes that capture information digitally in the field and remove paperwork from the process, the integration of electrical modelling software with our GIS system, and the use of integration software to bring disparate data for analysis.

The key theme of managing the lifecycle of our assets is maintaining safe, reliable operation, while providing good value to our customers.

1.1.6 Developing our network

Our Network Development Plan (NDP) is presented in Section 6. Key themes in this year's NDP are:

1.1.6.1 Transmission capacity constraint

There is a capacity constraint on the Transpower 110 kV transmission lines that supply Oamaru GXP and the lower South Canterbury area. This restricts our capacity to connect new demand in the lower Waitaki area, especially as we see increased large scale electrification from process heat decarbonisation.

We have engaged an independent consultant to confirm our assumptions and evaluate our options. Our conclusion is that we will need to build a new GXP by 2027.

In the short-term we have engaged Transpower to investigate a Special Protection Scheme to provide additional N Security capacity at Oamaru GXP until the GXP can be built.

Our plan is detailed further in *Section 6.4.2.6* Network Evolution

To meet our country's climate change objectives, our network will need to be able to connect and optimise an increasing number of renewable energy resources and new technologies such as electric vehicles and batteries. Customers will also change the ways that they use our network and trade their energy. This will require a transformation in the way that we operate our network. Key parts of our Network Evolution Roadmap are presented along with associated action plans.

This is detailed further in *Section 6.4.2.6* Transmission constraint options

1.1.6.2 Decarbonisation demand growth

The Zero Carbon Act was enacted in 2019 and government subsidies have been established to encourage decarbonisation of the public sector and of process heat. The Climate Change Commission has recently released its report to the government which acknowledges that current government policies will not allow us to meet our 2050 targets.

The Climate Change Commission report proposes revised and progressively deeper emissions budgets.

If the government accepts the report, a likely outcome is further incentives for decarbonisation projects (and disincentives for Carbon-based energy usage). This will further accelerate electricity demand in our region.

Two customers have recently made enquiries about converting a significant amount of process heat from coal to electricity. The timing and likelihood of this demand is not yet confirmed but if both customers proceed our demand may exceed the capacity at Oamaru GXP as soon as FY27. We are currently working closely with these customers and

Transpower to refine our forecasts and to select and design a long-term solution to ensure that upgrades are completed in the best possible time once we have some certainty around the new demand.

This is detailed further in *Section 6.3.3* Demand scenario assumptions

1.1.6.3 Irrigation demand growth

The main driver for development in our network has historically been growth in irrigation demand, which has firmly established us as a summer peaking network. We have also seen modest growth in the industrial and domestic sectors.

There is still a reasonably large amount of land in the Papakaio plains area that is still to be converted from border-dyke to spray irrigation which will require an increase in electrical demand. Our modelling shows that this will trigger the requirement for a new Zone Substation in the Awamoko area (and associated subtransmission lines) to be commissioned in FY24.

This is detailed further in *Section 6.3.3.4* Farming demand growth

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 not associated with the lines business. These estimates are considered to be fairly accurate for the first 5 years of the planning period, and less accurate beyond that point. This is primarily due to many of our investment, maintenance and renewal decisions being very dependent on outcomes of inspections in the first 5 years, customer growth, the impact of emerging technologies, and other issues that are currently uncertain, including Transpower constraints in North Otago and South Canterbury, central government initiatives, including decarbonisation, growth due to economic factors and asset relocation work that tends to be driven by third party requests.

Table 2 - Summary of forecast network expenditure

	Forecast expenditure ($000)										
Network capital expenditure	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY32**	**Total**
Consumer Connection	1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366	**13,660**
System Growth	4,331	4,246	4,562	4,252	750	750	750	750	12,950	12,950	**46,291**
Asset Replacement & Renewal	4,665	7,163	5,653	4,319	6,170	4,975	5,474	4,662	4,708	4,662	**52,451**
Asset Relocations	-	-	-	-	-	-	-	-	-	-	**-**
Reliability, Safety & Environment - Quality of Supply	1,125	1,640	2,133	918	1,034	995	492	137	137	137	**8,748**
Reliability, Safety & Environment - Legislative & Regulatory	357	357	366	366	195	195	195	195	195	195	**2,616**
Other reliability, safety, and environment	-	-	-	-	-	-	-	-	-	-	-
Total capital expenditure	**11,844**	**14,772**	**14,080**	**11,221**	**9,515**	**8,281**	**8,277**	**7,110**	**19,356**	**19,310**	**123,766**
Network operational expenditure											
Service Interruptions & Emergencies	460	460	460	460	460	460	460	460	460	460	**4,600**
Vegetation Management	683	683	683	683	683	683	683	683	683	683	**6,830**
Routine & Corrective Maintenance and Inspections	1,448	1,448	1,367	1,295	1,239	1,239	1,239	1,239	1,239	1,239	**12,992**
Asset Replacement & Renewal	677	629	629	524	524	524	524	524	524	524	**5,603**
Total operational expenditure	**3,268**	**3,220**	**3,139**	**2,962**	**2,906**	**2,906**	**2,906**	**2,906**	**2,906**	**2,906**	**30,025**
Total expenditure	**15,112**	**17,992**	**17,219**	**14,183**	**12,421**	**11,187**	**11,183**	**10,016**	**22,262**	**22,216**	**153,791**

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".

This AMP is an integral part of our business planning process alongside other key corporate documents, including our Statement of Corporate Intent, internal strategy plans, annual business plan and budget, Network Development 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, 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 productive efficiency.
- To ensure the sustainable financial future of the company by understanding the resources required to deliver the required capital and operational workstreams and signalling when those resources will be required.
- 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:

- The Commerce Commission
- Our trustees, directors, and management
- Our staff
- Our customers
- Our other stakeholders
- Interested members of the public
- 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 our staff and as a safe utility for the public.
- Meeting our customers' expectations in terms of quality and reliability of supply.
- Identifying and meeting our customers' future energy needs and working closely with them to enable decarbonisation of their energy supply.
- The impact of the constrained Transpower 110 kV supply to Oamaru GXP, and options to manage this constraint.
- Transforming our network technology to allow us to accommodate and enable future new technologies that will be delivered to our customers.
- Resilience to natural events is becoming a more important issue for our communities.
- Continued focus on replacement, inspection, and management of aging assets to reduce risk to network reliability, our employees, and the public.

1.6 DOCUMENT STRUCTURE

Figure 2 below illustrates the structure of this AMP.

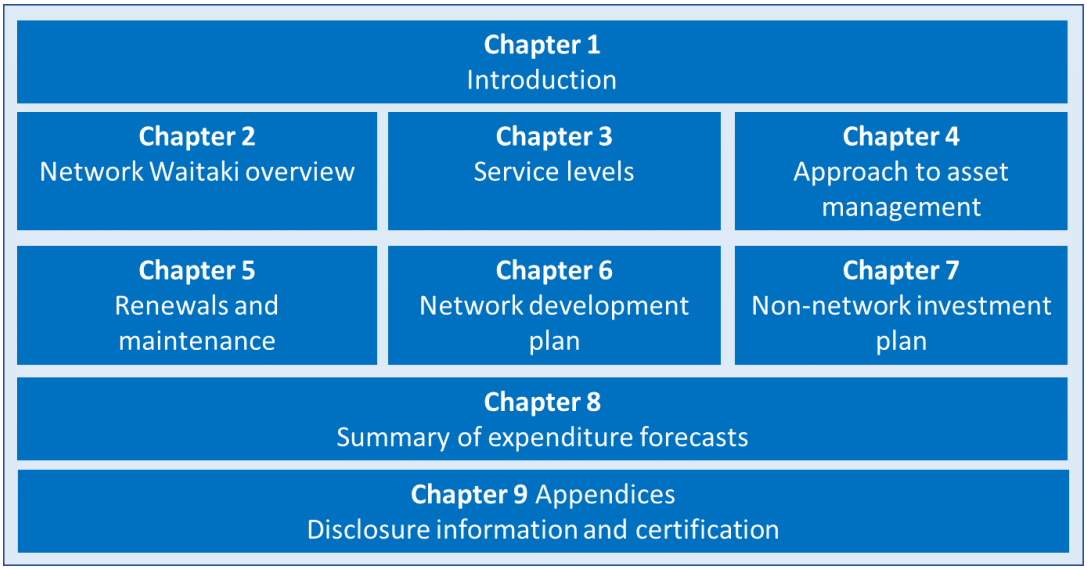


Figure 2 - Structure of Network Waitaki's AMP

1.7 USE OF CONSTANT DOLLAR VALUES

Capital and operational expenditure values are expressed in constant 2021 dollars. We have not included an adjustment for inflation in order to allow for better comparison of expenditure between years.

1.8 APPROVAL DATE

The 2022-2032 AMP was approved by the Network Waitaki (NWL) Board of Directors on 28 March 2022. See Appendix B for a copy of the signed Certificate of Approval.

POWERING OUR FUTURE

02

NETWORK WAITAKI OVERVIEW

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

- **Our company:** outlines our corporate objectives, organisational and governance structures.
- **Operating environment:** an overview on the issues that have an impact on us and our approach to asset management, such as geography, vegetation management, and changes in demand.
- **Stakeholders:** this section describes who our stakeholders are, their interests and expectations, and how these 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; the extent it is overhead and underground; 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, public electric vehicle chargers, and provide private electricity network services to some major customers. We also have a contracting division which incorporates electrical services and vegetation management services, primarily to meet our own needs, but also available to undertake work for other asset owners and contractors.

2.1.1 Ownership structure

NWL is 100% owned by the Waitaki Power Trust (the Trust). The shares of NWL are held on behalf of the NWL consumers (our connected customers) by the Trust, who appoint directors to the Board to carry out the governance functions of the business. The Trust has five trustees. Every three years, three trustees are elected by consumers connected to the network.

In 2021 the Trust carried out a 10 yearly ownership review of the Company. This included an independent review of the ownership options available, with the goal of delivering the best outcome for Network Waitaki's customers. The recommendation of the independent review was that continued Trust ownership is the most suitable model for Network Waitaki.

Subsequent engagement with customers and other stakeholders as part of the ownership review resulted in high levels of support for the Trust ownership model, with over 99% of respondents supportive of the Trust ownership model.

Based on this work the Waitaki Power Trust will retain the total shareholding of Network Waitaki Ltd in Trust on behalf of the 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 to how we operate the company, including our 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 corporate objectives cover four areas:

Health and safety

- To eliminate or minimise the risk of harm to our staff and members of the public as a result of our operations and assets
- To maintain an accredited public safety management system in accordance with NZS7901, with a goal to continually improve our safety outcomes
- To have programmes in place to ensure the health and wellbeing of our people

Our people and culture

- To be the employer of choice in North Otago and amongst our industry
- To attract and retain top talent
- To train and develop our people to meet current and future business needs
- To be an equal opportunity employer promoting inclusiveness and diversity

Our customers and community

- To be the service provider of choice for our customers, providing safe, reliable, cost effective and innovative solutions, with top tier performance in our peer group
- To maintain a positive profile in our community and ensure there is clear value in Trust ownership
- To provide electricity consumers with a safe, efficient, and reliable electricity distribution system
- To be supportive of activities that provide economic growth and wellbeing in our network area

Building a sustainable future

- To operate the business in a commercially sustainable manner and to continually improve the efficiencies of delivery.
- To preserve and grow the value of the business for the long-term benefit of consumers.
- To provide dividends, discounts, and community support activities in accordance with the shareholder's wishes.
- To promote the efficient use of energy as required under the Energy Companies Act 1992 clause 36 (2).
- To operate in a way that minimises the impact on the environment and ensure compliance with the Resource Management Act.
- To comply with all obligations under relevant legislation and regulations.

Together these four areas form the basis for establishing our asset management practices and processes.

2.1.3 Corporate documents

The Company maintains a number of internal and external documents as part of its annual business compliance, disclosure, and planning process. The main documents are the:

- Statement of Corporate Intent (SCI), which is agreed annually between the Board and the Trust, and sets out the objectives, goals, and related performance targets for NWL for the following three years.
- Regulatory disclosure documents, including those associated with information disclosure, financial accounts, and the Commerce Commission's price-quality threshold regime.
- Annual business plan and budget which is approved by the Board for the next financial year.
- Strategic plans to guide the development of the business.
- Monthly board reports, which update the Board on the progress against the annual budget, along with other issues that they need to approve or be made aware of.
- Suite of emergency preparedness documents that detail the plans to maintain and restore supply following emergency events.

2.1.4 Organisation structure

The Trustees appoint the Directors to the Board to govern the company who 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 specific safety, performance, asset management objectives and service targets.

The Board have an involvement in approving projects and budgets needed to support the AMP. The AMP signals the need for future investments so that the Board can assess the long-term issues such as funding requirements. The company ensures that members of the public and other stakeholders have access to the AMP and other disclosure documents on the Company's website[1].

The management team report (amongst other business performance measures) asset management information such as risk management activities, outage statistics, network performance, and work program progress to the Board on a monthly basis. 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.

Most of the annual works program is undertaken by our integrated contracting business unit, which has a staff of approximately 48 people located in Oamaru. Specialist skills are contracted in when required.

[1] https://www.networkwaitaki.co.nz/company/regulatory-disclosures/

2.1.5 Asset management governance

Asset management responsibilities are allocated between the senior staff as follows:

Chief Executive

The Chief Executive is accountable to the Board to ensure that the strategic objectives of the Board and the Trust are delivered.

Chief Financial Officer

The Chief Financial Officer is responsible for the financial activities of the company, including preparation of annual budgets for operating and capital expenditure with input from all areas of the business as well as providing reports that enable financial performance of works programs to be monitored against budgeted costs.

General Manager Network

The Network General Manager is a new role, created in 2021 to provide leadership, coordination, and oversight to all aspects of operating the Network, including asset management, development, and network operations. The role coordinates resources across multiple teams to deliver the outcomes of the AMP and will be a key figure in driving continual improvement of our asset management practices.

Asset Manager

The Asset Manager is responsible for development of the asset management processes and systems, the development of standards and policies, and that projects and programmes of work are initiated to address performance, safety, and reliability risks on the network.

Network Development Manager

The Network Development Manager is responsible for the planning and evolution of our network to ensure we can enable our customers desires. This includes forming a view of our customers' future needs and ensuring that we consider all appropriate options to enable these.

Engineering Manager

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

Health, Safety and Risk Manager

The Health, Safety and Risk manager is responsible for the management of health and safety systems and public safety systems. This includes setting performance initiatives to measure and monitor the effectiveness of critical controls and ensuring risk owners are regularly reviewing and updating their risks.

Regulatory Manager

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

Customer and Community Relations Manager

The Customer and Community Relations Manager is responsible for leading our customer services function and developing and maintaining the interface between the company and the community and other stakeholders.

General Manager Contracting and Operations

The GM Contracting and Operations is responsible for the provision of construction and maintenance staff and equipment in order to complete the annual works plan in those areas of service provided by our in-house contracting team. They are also responsible for seeking out and managing any work outside our network, for other network companies or private customers

2.1.5.1 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 provides the Board with an overview of the risk, options considered, and the economic assessment of the proposed solution.

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

2.1.5.2 Asset management capability and delivery

Our organisational and governance arrangements are structured to ensure that we have the necessary capability to implement this AMP. We ensure that our AMP work program can be achieved by tracking our progress with regular reporting and review of the physical and financial progress of the work program against our plans and budgets. This reporting also includes operational metrics such as SAIDI and SAIFI.

Planning of the delivery of the AMP in any given year balances the requirements of the business to complete particular works program items (e.g., risk, capacity constraints, customer requirements) against our ability to efficiently deliver the works plan. The goal is to develop a works program that is well balanced across the planning period and to avoid major peaks and troughs in work so that our resources can be well matched to the program. The network then benefits from having a stable, experienced, and efficient workforce, without the need to upsize in busy years or downsize in quieter years. Within this plan, this is reflected in the phasing of some renewal and maintenance category budgets towards the later part of 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 and have coordinated the allocation of that work across individual years in order to smooth the delivery work stream around fixed workstreams such as major line builds and new substations.

Delivery of the bulk of the AMP is provided via our internal Engineering and Contracting teams. The skill set of our Contracting team is generally focussed on the core line construction and maintenance roles, including live line work, cable jointing and line construction. Specialist experience such as communications and power technicians are traditionally contracted in as required from external providers that we maintain strong relationships with.

We have recently extended our field capability with the development of vegetation management and electrical services teams within our contracting business. These services were previously contracted out, and so this will reduce our dependency on external providers and is expected to increase the efficiency and quality of the work in these two areas of service delivery.

The sustainable delivery of our AMP requires on ongoing availability of 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 due to attrition as these personnel retire. To address this, we are investing in developing new resources by

bringing on board Contracting trainees, trade apprentices and providing scholarship opportunities for technical education. These developmental initiatives are factored into the overall delivery of the AMP.

Sustainable delivery also requires that we balance the works program to efficiently utilise our available resources, while still meeting the requirements of the plan. In practice this means that we will choose to schedule large projects across the planning period to avoid peaks and troughs in planned work in areas 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 program, when considered strictly on an expenditure basis.

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 at Chief Executive and Board level.

Review of these practices has shown that although this reporting gives us good awareness of the historical performance against the works program budgets, there is room to improve how we forecast ongoing delivery of the works program, which would create opportunities for efficiency in areas such as resource scheduling. Key areas in our strategic plan target improvements in the area of project management practice, financial monitoring and reporting and forward scheduling of the work program.

As a small, tightly knit, flexible company we regularly adjust the work program and coordinate work to take advantage of other activities in a particular area such as a planned outage, to respond to a particular driver such as a weather event or meet a customer's unexpected requirements. Exercising this flexibility while still maintaining delivery of the overall AMP is a key focus of our staff.

2.2 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 conditions.

Extreme weather events can include wind and snowstorms, and floods. We expect to experience 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 in extreme events can affect neighbouring regions as well.

The coastal conditions are comparatively benign with a fairly small zone where equipment corrosion is a concern, although coastal erosion is starting to impact in some areas of the region, with some local road networks being affected. We are monitoring these situations with respect to our assets in the specific affected areas.

The major urban population is centred on Oamaru, a coastal town of approximately 13,900 people located on the east coast of the South Island. The population of the wider Waitaki region is approximately 22,300.

There are several small townships in the region, most which are located on the two state highways that run North to South (SH1) and East to West (SH83) through the region.

The rural economy of the region is based on a mixture of beef and sheep farming, crops, and dairy. Irrigation is used widely throughout the region, via schemes that include border-dyke systems, direct pumping from a local water source, or reticulated systems to the farm gate. Irrigation is a major source of the growth on our network. The Ministry for Business, Innovation, and Employment records that the contribution to the regional economy from the agriculture sector was 15% of GDP in 2017 (most recent published figures).[2]

There is also a significant manufacturing sector in the region, contributing approximately 11.5% to the regional economy in 2017.[3]

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 our operations.

2.2.2 Climate change projections

The Ministry for the Environment have produced climate change projection scenarios for 2040 and 2090[4], compared to a baseline of 1995.

Temperature

Compared to 1995, temperatures are forecast to be 0.6˚C to 0.9˚C warmer by 2040 and 0.6˚C to 2.8˚C warmer by 2090.

By 2090, Otago is projected to have from 4 to 25 extra days per year where maximum temperatures exceed 25˚C, with around 13 to 45 fewer frosts per year.

The rise in ambient temperature will marginally reduce the operating range for thermally rated equipment such as transformers and overhead lines. It is not expected that this will have a significant impact on the capacity of our assets, but this will be taken into consideration when designing long-life assets.

Rainfall

Rainfall will vary locally within the region. The largest changes will be for particular seasons rather than annually. Otago is expected to become wetter, particularly in winter and spring. Seasonal projections show winter rainfall increasing by 4 to 10 per cent in Dunedin and 4 to 27 per cent in Queenstown by 2090.

According to the most recent projections, extreme rainy days are likely to become more frequent in Otago by 2090 under the highest emissions scenario.

This may have an effect on timing and magnitude of irrigation demand but is not expected to have an impact over the planning period.

Snowfall

The Otago region is likely to experience significant decreases in seasonal snow. By the end of the century, the number of snow days experienced annually could decrease by as much as 30-40 days in some parts of the region. The duration of snow cover is also likely to decrease, particularly at lower elevations.

Less winter snowfall and an earlier spring melt may cause marked changes in the annual cycle of river flow in the region. Places that currently receive snow are likely to see increasing rainfall as snowlines rise to higher elevations due to rising temperatures. For rivers where the winter precipitation currently falls mainly as snow and is stored until the

[2] Source: MBIE Regional Economic Activity Web Tool. http://webrear.mbie.govt.nz/summary/new-zealand, Feb 2018
[3] Source: MBIE Regional Economic Activity Web Tool http://webrear.mbie.govt.nz/summary/new-zealand, Feb 2018
[4] Source:2018 '2nd Edition' of Climate Change Projections for NZ https://environment.govt.nz/publications/climate-change-projections-for-new-zealand/

snowmelt season, there is the possibility for larger winter floods. This may have an impact on river flows and the water available for irrigation usage which could impact on the way irrigation is used in our region.

Overhead power lines that are located inland to the west of Kurow are subject to damaging snow falls every few years on average and changing patterns of snow fall may reduce this. We will continue to construct our lines for the present design snow loadings at present but will keep a watching brief on projections.

Wind and storms

The frequency of extremely windy days in Otago by 2090 is likely to increase by between 2 and 5 per cent. Changes in wind direction may lead to an increase in the frequency of westerly winds over the South Island, particularly in winter and spring.

Future changes in the frequency of storms are likely to be small compared to natural inter-annual variability. Some increase in storm intensity, local wind extremes and thunderstorms is likely to occur.

Ultimately, long life assets such as overhead power lines, buildings and transformers will need to be designed for the increase in wind return periods. We will keep a watching brief on changes to wind standards and will work with our peers to integrate changes into overhead line design practices.

Sea level rise

New Zealand tide records show an average rise in relative mean sea level of 1.7 mm per year over the 20th century. Globally, the rate of rise has increased, and further rise is expected in the future. For new assets we will consider potential effects from climate change, such as sea level rise, increased coastal erosion, and inundation when we are selecting the location and construction style of the asset.

2.3 REGULATORY ENVIRONMENT

2.3.1 Pricing

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

One of these funding sources is a moderate increase in line charges. Benchmarking against all other electricity distribution businesses in New Zealand shows that our customers pay some of the lowest line charges in the country and receive some of the best service (see sections 3.3 and 3.4). Our modelling suggests that even with a price increase in FY22 there is further scope for future increases whilst maintaining our pricing relative to our peers and remaining compliant with (shadow) price regulation. We are mindful that we need to balance cost increases to our customers with pricing that provides for sustainable levels of network investment over time.

From an economic regulation perspective, 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 still required, and we are conscious that we must deliver good value to our connected customers in terms of a price of service vs. quality of supply.

Network Waitaki is furthermore subject to regulations set by the Electricity Authority as the electricity market regulator, responsible for the efficient operation of the New Zealand electricity market. One of the focus areas of the Electricity Authority is improvement of 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 a wholesale provider of electricity distribution services, we recognise that there is a mismatch between our pricing structures, which generate much of our revenue through volume-based prices, and our costs, which are essentially fixed.

For this reason, we are adjusting our pricing structures on a staged basis, the ultimate aims of which are to:

- reflect the cost of service more accurately through a better balance of the fixed and volume-based components of electricity distribution prices, thereby assuring the sustainable delivery of a reliable and safe service.
- safeguard revenue reliability through implementation of cost-reflective price structures.

2.3.2 Climate change policy

2.3.2.1 Regulatory response

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) to contribute to achieving the Paris Agreement goal of limiting global warming to well below 2, preferably to 1.5 degrees Celsius, compared to pre-industrial levels.

The government declared a Climate Emergency in December 2020 and has pledged to accelerate the electrification of our transport and industrial sectors in their Clean Energy Policy Statement and implemented a clean car discount for eligible electric vehicles purchased after 1 July 2021.

2.3.2.2 Climate Change Commission final advice to government

He Pou a Rangi – The Climate Change Commission has recently released its final advice to government which acknowledges that current government policies do not put our country on track to meet our 2050 targets.

The Climate Change Commission advice proposes revised and progressively deeper emissions budgets.

The New Zealand Carbon price is currently $65 per tonne up from $35 in November 2020. The Climate Change Commission reported its models suggested carbon would need to lift to $140 by 2030 and $250 by 2050.

If the government accepts the Climate Change Commission report, a likely outcome is increased incentives for decarbonisation projects (and disincentives for Carbon-based energy usage) which will further accelerate electricity demand in our network.

2.3.2.3 Process heat decarbonisation

In January 2020, the government launched the $200m State Sector Decarbonisation Programme which has the following objectives.

- Public sector to be carbon neutral by 2025
- Immediate focus on phasing out largest and most active coal boilers
- Government agencies required to purchase electric vehicles and reduce the size of their car fleet
- Green standard required for public sector buildings

In November 2020, the government launched the $69m Government Investment in Decarbonising Industry (GIDI) contestable fund, administered by EECA, to provide financial assistance to New Zealand's largest energy users to reduce barriers in decarbonising their process heat. A meat processing plant in our area was a successful applicant in the first round of funding and this 0.75 MW project will be commissioned in FY22.

Two customers have recently indicated that it is likely that they will convert a significant amount of process heat from coal to electricity. The timing and likelihood of this demand is not yet confirmed but if both customers proceed our demand may exceed the capacity at Oamaru GXP as soon as FY27.

We are currently working closely with these customers and Transpower to refine our forecasts and to develop a long-term solution that ensures we have capacity to supply this new demand.

2.3.2.4 Other potential government initiatives

The government is proposing the introduction of a Clean Car Standard which will require a carbon dioxide target of 105 g/km for new and used car imports to be phased in from 2021 to 2025.

2.3.2.5 Our view

The Climate Change Commission's final advice, coupled with the government's increasing focus on climate change and subsidies to date, supports our view that government regulation will accelerate the uptake of low Carbon technology which will involve a significant increase in electrical demand in our network. In the past year we have seen two major decarbonisation projects that now indicate that electricity is a likely energy source.

We strongly encourage and support the use of renewable electric energy as an energy source. We are concerned, however, that timeframes accelerated by the government subsidies may not align with the longer timeframes currently required to perform transmission system upgrades.

2.4 STAKEHOLDERS

2.4.1 Stakeholders and their interests

Our stakeholders are the people or 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;	Bi-annual customer surveys – a revamped survey was completed in 2021; face to face meetings with major customers; feedback sought after work or	Maintaining audited Public Safety Management System and other safety initiatives; price/quality trade off; network development plans; investment

Stakeholder	Requirements	Identification of requirements	Requirements incorporated into asset management practices
	emergency and lifeline preparedness.	major outages; public safety performance measures.	planning; asset lifecycle management.
Staff and other workers	Healthy and 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.
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	Trustee meetings; performance measures.	Network development planning; investment planning; asset lifecycle management; organisation and governance structures; integration of risk management into all

Stakeholder	Requirements	Identification of requirements	Requirements incorporated into asset management practices
	community; Effective asset management		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.
Electricity generators and retailers	Safety, reliability, effective communication; statutory and regulatory compliance; fair contractual arrangements; transparent; 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	Meetings to discuss collaboration opportunities	Decisions will be incorporated in future

Stakeholder	Requirements	Identification of requirements	Requirements incorporated into asset management practices
			Network Development Plan

2.5 OUR CUSTOMERS

2.5.1 Major Customers

Our major customer groups are urban residential around Oamaru and other townships, and large rural farming 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 early 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, energy delivered, and number of connected customers served by our network for FY22 and the four years previous is shown in the table below:

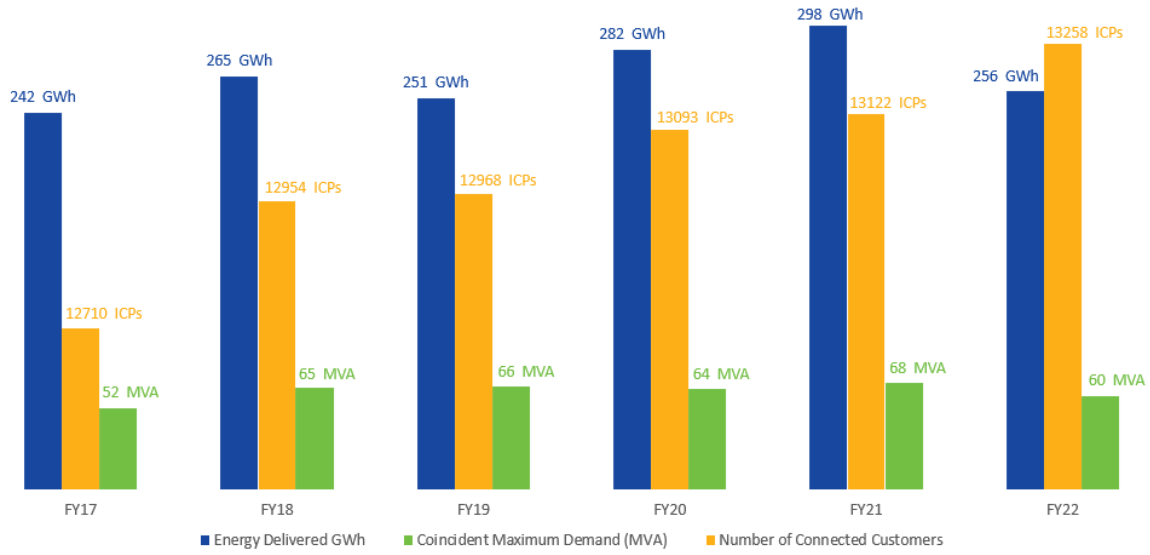


Figure 3 - Network maximum demand, energy delivered and connected customers

These measures are generally trending upwards, however, the energy delivered, and maximum demand may not match the growth in connected customers. This can be seen in FY22 as a result of less irrigation usage after above average summer rainfall.

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 4 below. We supply one major urban area, Oamaru, and several smaller townships.

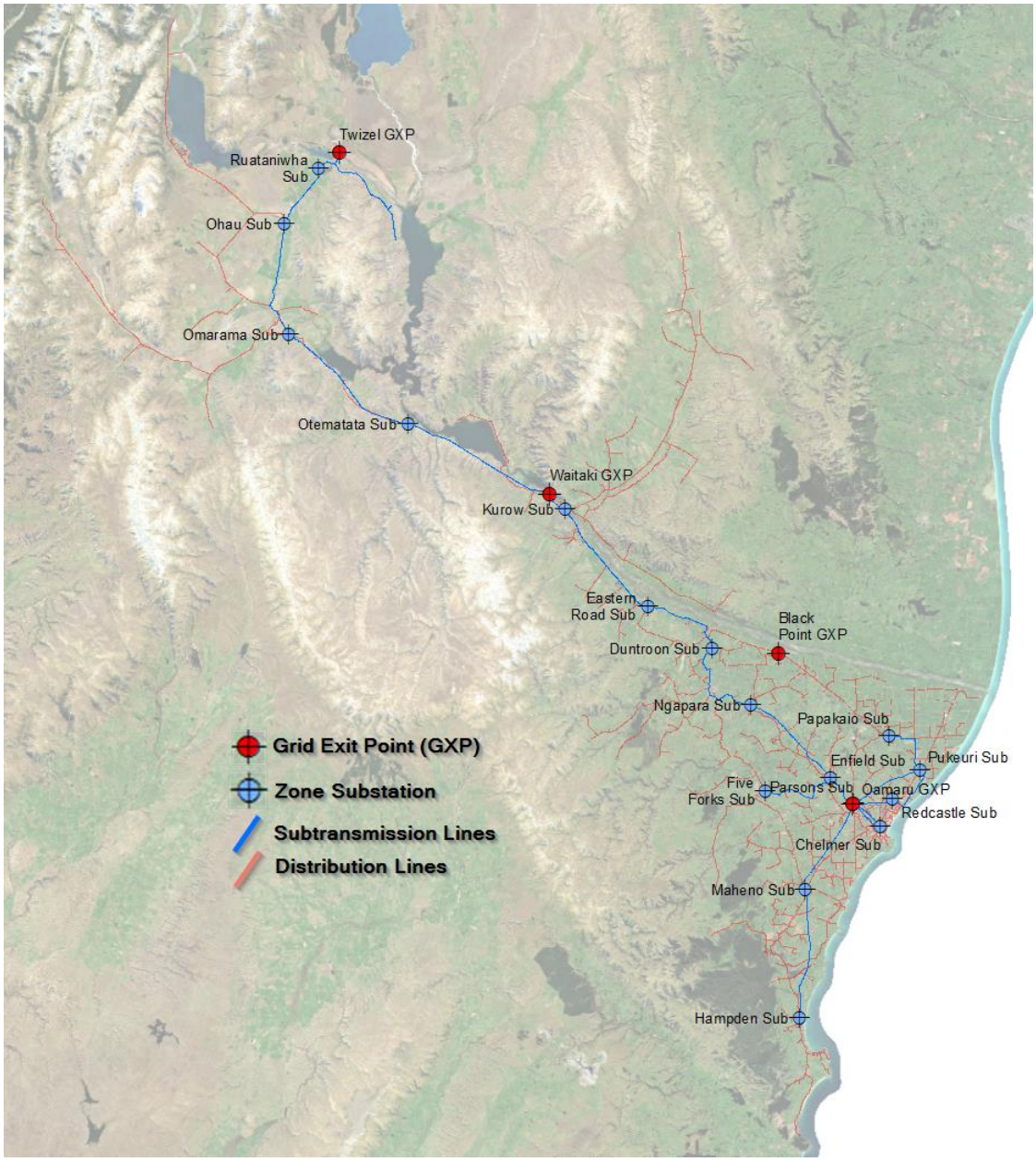


Figure 4 - Map of NWL area of supply and network extent

Bulk supply of electricity is taken from Transpower's network (the national grid) at our four grid exit points (GXPs). This energy is then transported via our subtransmission network at 33,000 volts (33 kV) to our zone substations. Power transformers at the zone substations convert the 33 kV supply to a lower distribution voltage of 11,000 volts (11 kV) which 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 table below:

Table 4 - Characteristics of NWL grid exit points as of 31 March 2022

Grid Exit Point	Voltage	Security	Capacity	Max demand FY22 (Non-Coincident)	Zone Substations supplied
Twizel GXP	220/33 kV	N-1	27 MVA	3.1 MVA	3
Waitaki GXP	11/33 kV	N	24 MVA	11.0 MVA	4
Black Point GXP	110/11 kV	N	25 MVA	15.7 MVA	0
Oamaru GXP	110/33 kV	N-1	45 MVA	36.8 MVA	10

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

Key features of the network are shown in Table 5 below:

Table 5 - Key features of NWL network

Parameter	Value
Number of poles	21,653
Length of 33 kV lines and cables	237 km
Length of 11 kV lines and cables	1,340km
Length of LV lines and cables	321 km
Number of zone substations	17
Number of connected customers	13,258
Coincident max demand	62 MW
Annual energy delivered to customers	256 GWh

These assets are discussed in more detail in Section 5 Renewals and Maintenance.

POWERING OUR FUTURE

03

SERVICE LEVELS

The Service Levels outlined in this AMP reflect our objectives of owning and operating a safe, reliable, and efficient distribution system. This chapter is structured as follows:

Stakeholder engagement: provides an overview of how we interact with our stakeholders, identify their requirements, and how those requirements are incorporated into our asset management processes.

Health and Safety measures and targets: describes our safety objectives, methods, measures, and performance against targets.

Reliability measures and targets: describes our reliability objectives, methods, measures, and performance against targets.

Economic efficiency measures and targets: describes our network performance and efficiency objectives, methods, measures, and performance against targets.

3. Service Levels

3.1 STAKEHOLDER ENGAGEMENT

Growth of our network is dependent on the growth and prosperity of our community, customers, and stakeholders. Our stakeholders operate in an ever-changing world and engaging with them provides insight into the services and service levels that we need to provide in order to help them thrive. We are committed to gaining a better understanding of what is important to our customers and to seeking their perceptions of the organisation, its reputation and service quality.

This engagement primarily occurs with surveys, face to face meetings, attendance at public events such as agricultural field days, industry forums and conferences as well as actively participating in industry consultations relating to statutory and regulatory changes, and Regional and District Plans.

The objectives of this research are:

- To understand the needs of our customers where they interface with the Electricity industry in general, and our network in particular.
- To understand customer's perceptions of our organisation and gauge our reputation in the wider community
- To understand what successful service looks to our customers for the services provided by Network Waitaki
- To identify the key drivers of these perceptions; and
- To identify priority opportunities to enhance customer satisfaction

Where possible we benchmark our performance against other electricity distribution companies, and where appropriate to organisations outside our industry, in order to identify and continually improve in the areas that are most important to our customers.

The key insights from these engagements include:

- Reliability of supply and network maintenance are highly valued by customers.
- The majority of respondents are comfortable with the price/quality trade-off that we offer on our network.
- In the event of unplanned outages, planned or unplanned, communication of accurate restoration time is very important for customers.
- A high percentage of respondents who have experienced unplanned outages indicate that supply is restored within an acceptable timeframe.
- Connected customers who have experienced planned outages indicate that supply is restored within the notice time.
- Although some customers are still not willing to install smart meters, this number is reducing.

This valuable feedback helps us understand our community better and informs our asset management practices, investment plans and service level measures and targets, as well as guiding us to what is relevant for our community regarding energy efficiency, new technologies and environmental initiatives.

Excellence in our customer engagement is a key strategic focus for our business, with a new role of Customer and Community Relations Manager created in 2020 with a directive to elevate customer engagement to provide more insight into how Network Waitaki can contribute to the wellbeing, growth, and development of our community.

3.1.1 Website, social media, and other digital messaging

Network Waitaki has recognised the importance of social media and digital communication in communicating with its customers and the community it serves. We are focused on using various methods of digital communication and are constantly reviewing and improving these in response to customer and community demands.

The use of technology to communicate planned and unplanned outages allows us to target specific customers instantly and to provide more notice for planned outages that they would have received with traditionally mailed notification. This system is also found to be efficient in quickly alerting subscribers to unplanned outages. Whilst customers are free to opt out of the service, due to the success of this communication channel, the opt in numbers remain high.

The Network Waitaki Facebook page allows us to share a wide range of information quickly and efficiently with our customers and community - from the status of our network to community and sponsorship activities. It is also a beneficial way for us to receive and respond to feedback from our community.

3.2 SERVICE LEVEL: HEALTH AND SAFETY

We are committed to ensuring that our network remains safe at all times and seek to actively manage risks to the public, public property, and our staff. To facilitate this, we are focused on continuing to foster a positive health and safety environment for staff and the public. Policies, procedures, and staff competencies are developed, reviewed, and updated in an ongoing process of continuous improvement.

We operate an audited Public Safety Management System (PSMS) where known and likely hazards and risks to the public are documented, along with the controls used to resolve them (eliminate the risk, or minimisation of the risk or likelihood of it occurring). This system is audited annually against the standard NZS7901:2008 *Electricity & Gas Industries Safety Management Systems for Public Safety* by Telarc, an external auditor. The outcomes of the audit process are analysed by our staff to make improvements to the PSMS and how we use it.

3.2.1 Health and safety objectives

Our overall objective is that staff, workers, the public, and their property are safe and free from harm due to the operation of our business. We will not compromise the health or safety of our staff, workers, the public or their property.

In summary, our safety objectives are:

- Safety is integrated in all aspects of our business.
- Staff, workers, and the public are not harmed due to the operation of our business.
- A positive organisational culture is promoted amongst all of our staff and workers.
- Any identified health and safety risks are assessed for risk, prioritised, and mitigated as soon as possible.

3.2.2 Methods

To achieve our objectives, we have undertaken the following initiatives:

- We engage with the public through newspaper and radio safety advertisements to raise public awareness of the hazards associated with working or playing in the proximity of electricity reticulation assets.
- We take part in public events such as agricultural shows to demonstrate electrical safety issues to the public, and to provide opportunities for feedback.
- Provide information and education sessions with emergency services and other businesses to demonstrate electrical safety issues to the public, and to provide opportunities for feedback.
- All known and likely hazards and risks to the public are documented by staff in our Public Safety Management System as they are discovered, along with the controls put in place to mitigate them.
- The instigation of reporting and monitoring of near miss incidents. Staff are encouraged to report near miss incidents with the purpose of identifying cause, mitigating risk, and learning. To facilitate this, we have adopted the Incident Cause Analysis Method (ICAM) as a methodology for incident investigation.
- Training in techniques such as “Safety in Design” is provided for staff in roles that can influence the safety outcomes of the Network.
- Continually improving our data capture and systems to provide accurate and reliable data for informed decision making and information sharing.
- The Board receives and considers health and safety reports at every Board meeting.
- Engagement and participation with our staff and contractors through our health and safety committees (Leadership and Staff) , critical risk program and field engagements to build trusting relationships, to hear their concerns and learn how they do their work.
- Investment in a wellbeing program with Workwell and other experienced external providers.
- Involvement in community safety initiatives such as Safer Waitaki, Business Leaders Forum, Electricity Distribution Industry (EDI) forums, Electricity Engineers Association (EEA) forums.
- Investing in developing and improving the capability of our staff through training and professional development.
- Regularly reviewing our safety policies, procedures, and staff competencies so that they are continuously improved.
- Improvements in the type of personal protective equipment (PPE) used by staff to improve comfort in the field.
- Providing incentives to staff to encourage them to submit ideas that improve the safety of network operations.
- Utilising modern technology to further assist our highly capable staff.
- Maintaining GPS tracking systems with “man-down” functionality in all vehicles and portable radios.
- Coordinating with South Island EDBs to align safety procedures and common competencies where possible.
- Continual monitoring and assessment of the impacts of new global phenomena such as Covid-19.

3.2.3 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 accreditation to NZS7901:2014 for our Public Safety Management System – using Telarc as independent auditors.
- Progress towards accreditation of ISO45001 Health and Safety Management Systems with Telarc
- Independent, third part 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.

Our targets for safety performance are:

- Zero injuries to staff
- Zero injuries to the public
- A downward trend in the number of reported adverse public interactions
- A downward trend in the number of deliberate or accidental unsafe acts by the public
- To work with customers to ensure that no privately owned HV service lines need to be disconnected because of unsafe conditions
- Contracting staff, engineers, managers, and Directors are all required to achieve a number of field-based safety interactions every year.

3.2.4 Performance

Historically measurement of safety performance has focussed on lost time injuries and incidents reported for our workers.

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

Table 6 - Public incidents and accidents

Summary of electrical accidents and incidents involving the public

Activities	FY18	FY19	FY20	FY21	FY22
Rural/Farming activities	16	15	10	4	3
Construction work/trades	7	8	4	4	12
Leisure & sports	0	0	1	0	2
Customer premises issues (Tree cutting/house fires, etc.)	11	4	0	1	3
Vandalism	1	1	0	0	1
Motor vehicles	19	16	19	15	24
Total	**54**	**44**	**34**	**24**	**45**

As can be seen from the figures, the annual number of incidents involving the public has been reasonably consistent over the extended period with a reduction in FY21 largely due to Covid impact. The bulk of the incidents remain to be vehicle accidents with poles and other ground mounted equipment. There has been an increase in construction and trades related incidents, which we believe is related to the increase in construction work volumes in the recent past. We will continue to monitor these areas of public safety to identify any trends where we can intervene with public awareness, training, or targeted improvements to the network.

These are lagging indicators, and while they are of some use, we acknowledge that they are not as effective as leading indicators at improving safety outcomes. We are currently working on a program of developing leading measures, primarily based on numbers of interactions in the following areas:

- An education program aimed at the public, using print and other media to inform them of our assets that they may encounter, and the risks associated with them.
- More targeted safety education aimed at specific higher risk groups such as contracting companies and school students.
- Direct engagement with contractors who are in the high-risk groups from our incident records in order to reach them with specific information regarding their safe operation around our equipment.
- Ongoing site visits and safety audits of contractors who are working near our lines using the close approach or over height load permit systems.
- Sharing of relevant safety alerts with specific industries.
- Increasing the availability of information via trade and DIY outlets.

The key method of improving the performance is educating rural workers, trades workers, contractors, and emergency services staff to be aware of the hazards that our network present in the environment, and to manage the risk accordingly.

Actions currently taken to address this issue include:

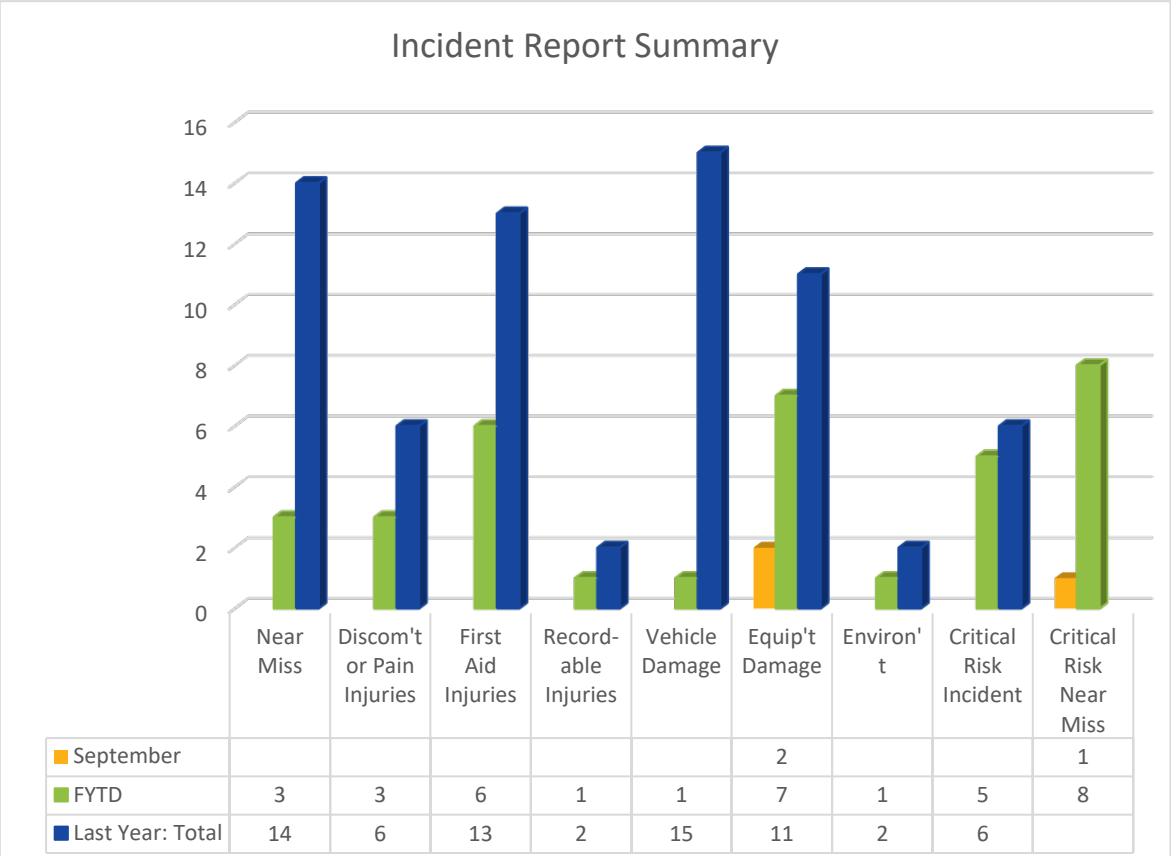
- Using print advertising in local newspapers and radio advertising on local stations to raise public awareness around the hazards of electricity.
- Engaging directly with businesses to discuss the risks and processes of working around electricity network equipment, at public events such as the A & P show, as well as holding targeted education sessions.
- Streamlining permitting processes with the introduction of online applications for high load and close approach consents for contractors such as tree trimmers, agricultural workers, and house movers, to encourage voluntary use of the safety systems available.

Public Safety Telarc. Registered Public Safety NZS 7901

Assuring that our public safety management system conforms to the New Zealand standard NZS 7901:2008/2014 is an annual exercise carried out in conjunction with Telarc. This reaccreditation was continued in 2021 with a satisfactory audit resulting in no “unattained” issues, and the verification of our NZS 7901 compliance. Any items raised as “partially attained” or “opportunities for improvement” are corrected as soon as possible.

The internal audits assist in identifying opportunities to improve our processes and help identify potential issues in a timely manner.

Continuous review of the input/output of information allows better trending 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 which includes performance figures against our goals. Figure 5 below is an example of this reporting. A key feature is the clarity of information on safety performance indicators.



	Near Miss	Discom't or Pain Injuries	First Aid Injuries	Record-able Injuries	Vehicle Damage	Equip't Damage	Environ't	Critical Risk Incident	Critical Risk Near Miss
September						2			1
FYTD	3	3	6	1	1	7	1	5	8
Last Year: Total	14	6	13	2	15	11	2	6	

Figure 5 – Example of an Executive summary of safety performance used in reporting

We have again, had no incidents of unauthorised access to our network equipment or substations in the last year. We believe this shows that our site security and public awareness programs are successful.

High voltage service lines on private property that service one or two customers are usually owned by those customers, rather than Network Waitaki. Network Waitaki acts as the high voltage operator for our customers, managing the operation of the equipment and carrying out safety checks every five years.

We are finding that private line owners often do not understand the risks and obligations of owning high voltage lines on their land. We will be improving our engagement with private line owners to help them better understand the risks and responsibilities of line ownership, with a focus on improving ongoing communication.

The target for work site audits by our engineering staff was met. These audits give an opportunity for the staff that are designing, specifying, and managing work to verify first-hand the level of safe work practices that are applied in the field. This reflects the high level of staff engagement in maintaining a safe work environment.

There has been one lost time incident for the 12 months to March 2022 (the time of writing).

The focus in the coming year is on the continued effectiveness of our health and safety critical risk controls, building competency of staff and management of contractors and suppliers.

3.3 SERVICE LEVEL: RELIABILITY

Reliability of our network is of high importance to us and to our customers. Our customer surveys have revealed that the service attributes most highly valued are "*keeping the power on"* and *"getting the power back on if it goes off*".

3.3.1 Objectives

An important part of our corporate objectives is to *"operate a reliable and efficient distribution network".* Results from our surveys tell us that most of our customers have expressed a preference for similar levels of reliability to what they currently experience. Hence our objective is to retain the same levels of reliability over the term of this AMP as we currently provide and continue to keep outages to as short a time as possible.

3.3.2 Methods

We will meet our reliability objectives by:

- designing and constructing new network to meet modern standards for overhead line construction, considering both the prevailing and any changing environmental conditions
- applying new technology to maintain quality, reliability, and customer service
- regularly inspecting the condition of network assets using modern techniques to ensure that risks to reliability and safety are discovered
- proactively patrolling the network looking for vegetation related issues
- identifying and rectifying vegetation defects in a timely manner
- prioritising and rectifying defects in a timely manner, keeping in mind that minor defects can develop into more serious issues over time
- monitoring condition and age of equipment and proactively replacing assets where it is economical to do so
- where it is not economical to replace aging equipment, deploying automated and remotely controlled devices, such as reclosers, sectionalisers, and tie-switches to limit the number of customers affected by faults and to maintain safety
- optimising the location of isolation devices to minimise the number of customers affected by particular outages
- monitoring and analysing faults data to identify emerging trends
- coordinating work within a geographical area to minimise the impact of planned outages
- examining network performance after major events such as snowstorms to gain insight into Asset Management changes that may improve performance. Even though these events are normalised out of the SAIDI and SAIFI statistics we realise that they do have an impact on customers and aim to improve our resilience against them.

3.3.3 Measures and targets

Two indicators that we use to monitor the reliability of our network are the industry performance measures of System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI).

SAIDI is the accumulated total time that the average customer connected to the network will be without supply in any measurement year as a result of faults and planned outages on our network. The units are in minutes.

SAIFI is the total number of supply interruptions that the average customer connected to the network will experience in a measurement year as a result of faults and planned outages on the network. The units are outages per customer per year. It should be noted that, while an individual customer can only experience a whole number of outages, the target is set as a real number to allow for the effect of averaging.

In our view SAIDI and SAIFI are one effective measure of the extent to which we are able to achieve our objectives of supplying a safe, reliable, and efficient electricity supply to our customers. SAIDI and SAIFI are also used by the Commerce Commission for setting a quality threshold which it uses to determine whether the EDBs that it regulates are performing to an acceptable standard. As an exempt EDB we are not subject to price-quality regulation, however we believe that it makes good sense to subscribe to the same methodology used by non-exempt EDBs. This also allows for functional benchmarking against other EDBs throughout New Zealand.

In line with the approach taken by the Commission, our SAIDI and SAIFI results may be normalised when necessary. Normalisation is designed to exclude the impact of events (such as an extreme weather event or an interruption due to an outage on the Transpower network) that are outside of our reasonable control. We believe that using normalised measures will provide a better indication of the success of our asset management strategies by limiting the extent to which events outside our control impact on our measured performance.

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	***2022-23***	***2023-24***	***2024-25***
Unplanned SAIDI minutes	45	45	45
Planned SAIDI minutes	105	105	105
Total SAIDI minutes	**150**	**150**	**150**
Unplanned SAIFI	0.8	0.8	0.8
Planned SAIFI	0.4	0.4	0.4
Total SAIFI	**1.2**	**1.2**	**1.2**

Our SAIDI results are affected by both the number of customers affected by an outage, and the length of time they are without power. While keeping safety paramount, we are committed to restoring power to our customers as soon as possible should an unplanned outage occur. Our targets for restoration times for different load classes are shown in section 6.3.2.3.

3.3.4 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.

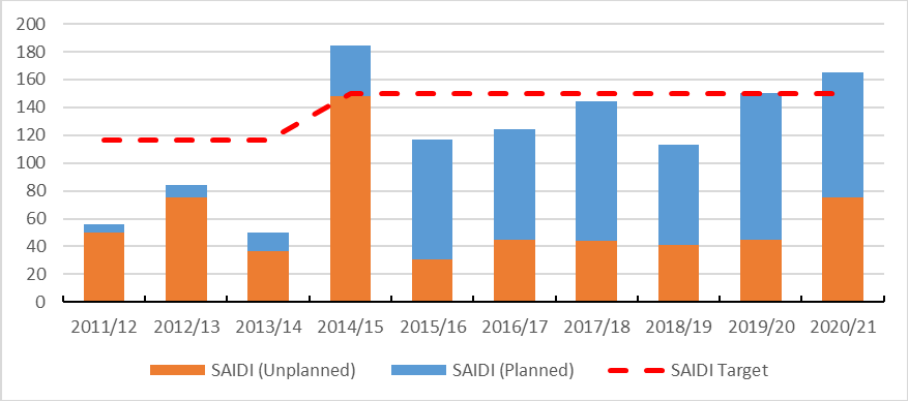


Figure 6 Historical SAIDI performance compared to target

Our SAIDI performance over the last 10 years shows of unplanned outages remain relatively consistent except for external influences. The large increase in 2014/15 year is due to the after-effects of a major storm, where some customers were without power for several days. The performance in 2020/2021 was largely effected due to outages due major fires and subsequent changes to operations of the network.

The impact of our reduction in live line work is partly responsible for the increase in planned SAIDI from 2015/16 onwards. This also reflects the fact that the last few years have involved some significant asset replacement in the area of poles and HV switchgear, necessitating more outages in more densely populated areas of the network.

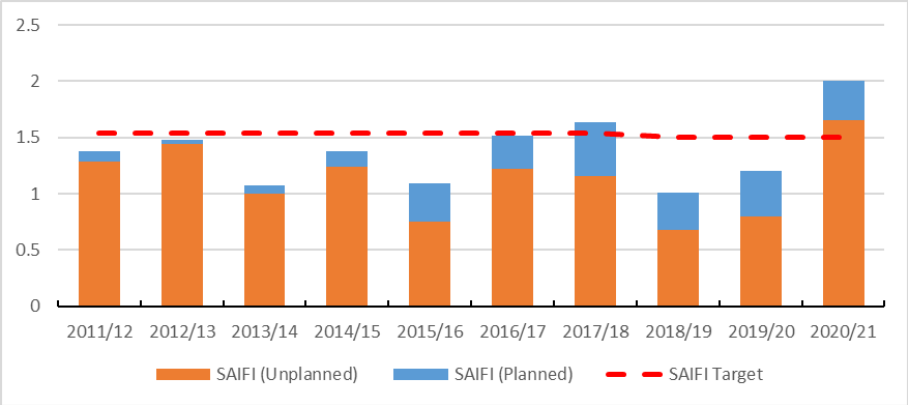


Figure 7 Historical SAIFI performance compared to target

Although there is more variability in SAIFI figures than SAIDI, the trend over the last five years is still reasonably consistent. The last year showed a considerable jump on this, with a handful of larger outages creating a large impact. Incidents were investigated and mitigations put in place where possible to address reduce the occurrence and impact of such outages.

We compare our performance against that of the rest of the industry, to provide a measure of the service level that we provide for our customers against what they might receive in another region. The source for this is performance data published by the Commerce Commission on their website[5], which is taken from the information disclosures provided annually by EDBs to the Commission.

[5] https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-distributor-performance-and-data

One of the common comparative reliability metrics associated is the number of unplanned interruptions (faults) that occur per 100km of circuit length. This provides a normalising factor between networks of different sizes, and the comparison of NWL against all other EDBs based on a three-year average of data is shown in Figure 8 below

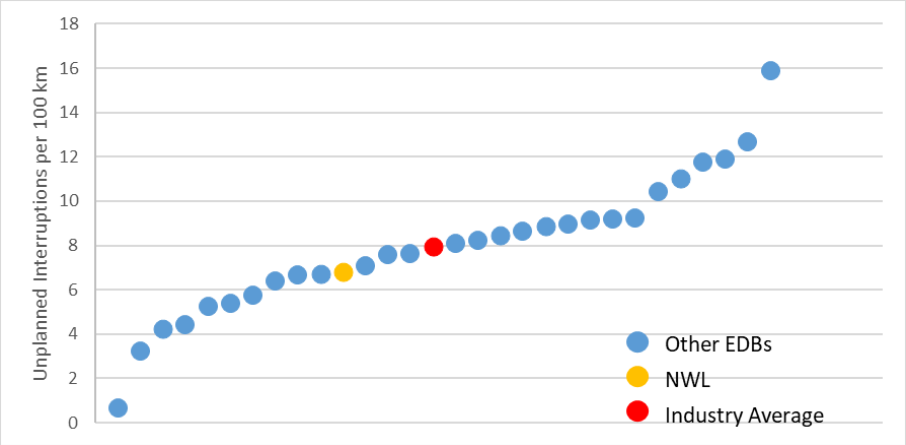


Figure 8 - Comparison of 3-year average of NWL unplanned interruptions per 100km against industry

The 3-year average of unplanned interruptions on our network sits 14% below the average level for all EDB's in New Zealand.

We also compare our outage statistics against our immediate neighbours and other South Island EDB's that have similar operating environments and network characteristics (who we consider our peer EDB's), as listed in Table 8 below. Our targets for our reliability measures are to perform better than the average value for our peer group.

Table 8 - Peer EDBs for the purposes of performance comparison

EDB	Region
Alpine Energy	South Canterbury
Aurora	Dunedin, Central Otago
Buller Electricity	Buller region
EA Networks	Mid Canterbury
Mainpower	North Canterbury
Marlborough Lines	Marlborough
OtagoNet Joint Venture	Otago
Westpower	West Coast

The comparison of our unplanned interruption performance per 100km of circuit length to that of our peer EDBs, averaged over the last three years is shown in Figure 9.

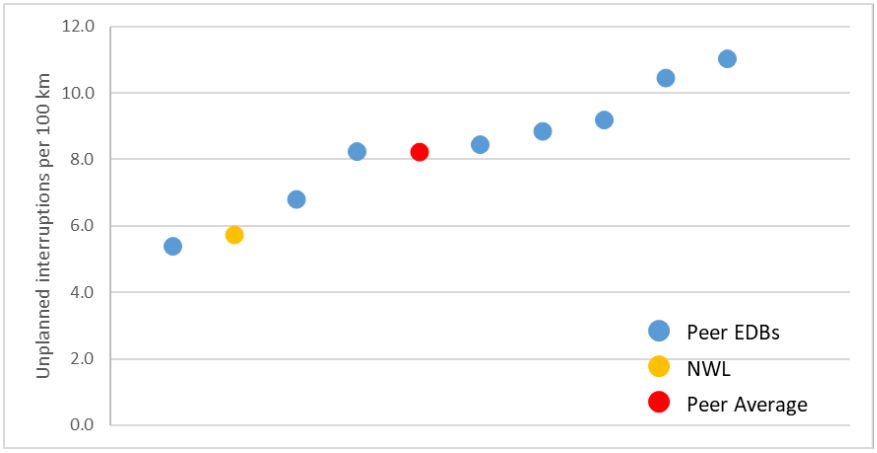


Figure 9 - Comparison of 3-year average NWL unplanned interruptions per 100km of circuit against peer EDBs

This shows that our performance for the incidence of unplanned outages within our peer group is 25% below the average. This meets our target of performing better than the peer group average, and the overall trend is one of improvement in the unplanned interruptions, so we are comfortable that we are moving in the right direction.

When we consider the SAIDI and SAIFI figures for the peer group as shown in the figures below, it is clear that both our 3-year average unplanned and total outage (planned plus unplanned) performance is very favourable compared to our peers. The particularly low SAIDI figure indicates that the combination of network design to restore load quickly, and rapid fault response are providing our connected customers with a good level of service. The consistency of our overall SAIDI and SAIFI over the last 5 years was shown at the start of this section, and we believe that the combination of steady performance combined with our position relative to our peer group demonstrates that we are providing our connected customers with a reliable service. We have met our target of better performance than the peer group average.

In the case of unplanned SAIDI minutes (the outage time that an average customer will experience per annum), we are the best performing of our peers, with our three-year average at approximately 50% of the peer group average.

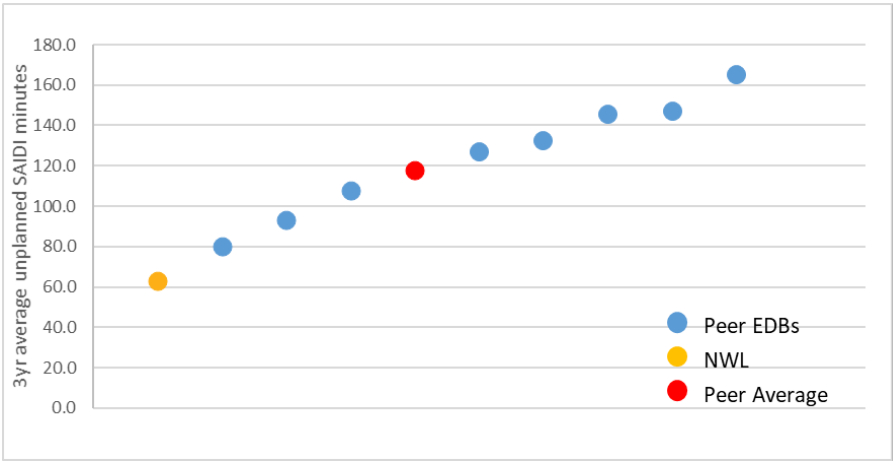


Figure 10 - Comparison of 3-year average unplanned SAIDI against peer EDBs

For total SAIDI we are over 30% lower than our peer group average.

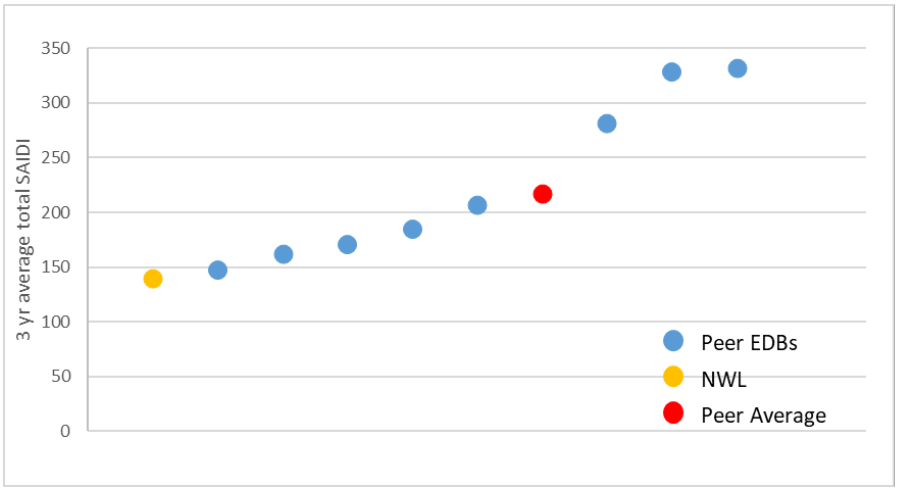


Figure 11 - Comparison of 3-year average total normalised SAIDI against peer EDBs

For unplanned SAIFI (the number of outages an average customer will experience in one year) the 3yr rolling average is also over 30% lower than the average of our peer group. Our customers experience the second lowest unplanned interruptions of our peer group.

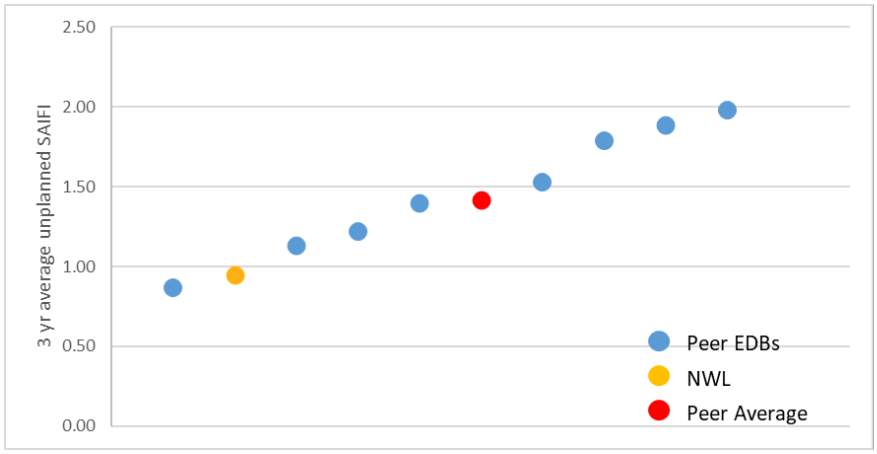


Figure 12 - Comparison of 3-year average unplanned SAIFI against peer EDBs

Total SAIFI includes the effect of planned outages on our customers. Again, our customers experience the second to lowest outage impact in our peer group, with our 3-year rolling SAIFI sitting 25% below the group average.

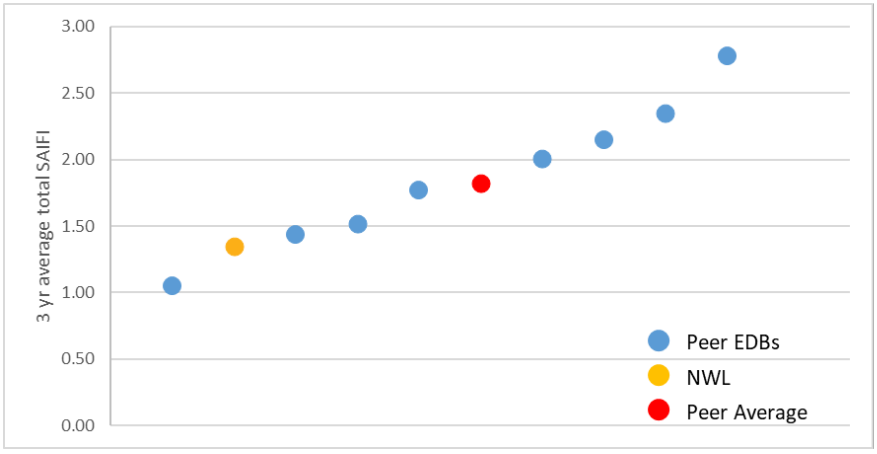


Figure 13 - Comparison of 3-year average total normalised SAIFI against peer EDBs

We have recently added analysis tools to our operations that will allow better insight into outage statistics, and what they can tell us about the long-term performance of our network. We believe that at this stage the data shown in the figures above can give our stakeholders comfort that we are not lagging behind our peers and are performing to a reasonable level.

3.3.5 Analysis of worst performing feeders

The causes of unplanned outages can show areas that require focus in a network. We have 60 distribution feeders and have analysed the number of faults across these feeders for the last three years. This shows that the 10 worst performing feeders are responsible for approximately 45% of all faults. Note that LV faults do not usually impact upon SAIDI and SAIFI statistics, although we do consider them when analysing customer experience.

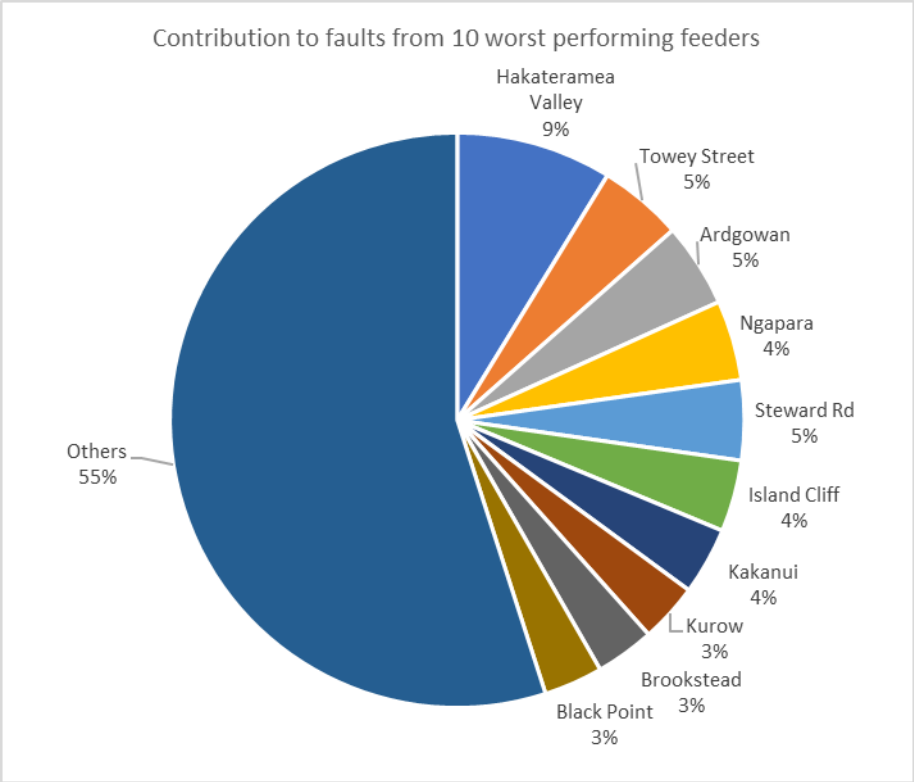


Figure 14 - Worst performing feeders by number of faults

These feeders are all demonstrating higher than average levels of faults in one or more categories. These feeders can be broken into several common groupings, based on geographic location, and common issues.

Common issues causing faults that stand out across these feeders are:

- Defective low voltage switchgear and fuses
- Defective high voltage switchgear and fuses
- Wildlife contacts
- Third party contacts

Our approach is to target particular issues on a feeder where it is clear that this will have a direct impact on the performance. An example of this is a reconductoring program that took place to target the performance of the Steward Rd feeder, which suffered several outages due to conductor condition related faults. As well as replacing the conductor, the feeder was also reconfigured in light of analysis of the impact of the outages, in order to improve the ability to supply customers through interties.

Where there is no specifically targeted work that will improve the feeder performance, we use this data to focus network wide programs to respond to patterns of failures that become apparent and will put more focus into a particular feeder or geographical area. An example of this has been the focus on inspection and maintenance activities for assets and vegetation in the Hakateramea Valley in 2021 following the worsening faults trends.

3.4 SERVICE LEVEL: ECONOMIC EFFICIENCY

As well as delivering supply reliably, there is a need to ensure customers are supplied in an economically efficient and cost-effective manner. We benchmark several measures against other network companies to understand whether our asset investment strategies are delivering efficient outcomes for the benefit of our electricity customers in the region.

3.4.1 Objectives

We have three economic efficiency objectives. These are to:

- minimise energy losses on our network
- optimise the utilisation of our assets
- manage operating costs to minimise the overall supply costs to our customers.

3.4.2 Methods

To ensure that our economic efficiency targets are achieved we:

- 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 an under or overuse becomes apparent
- continually work to improve our works delivery model and processes
- investigate new technology options for improved performance.

3.4.3 Measures and performance

The economic efficiency measures we employ are:

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

3.4.3.1 Total operational expenditure per connection point – measure and targets

This measure provides an understanding as to whether operating expenditures are appropriate given the operating parameters of our company. The target levels are based on comparing our forecast operational expenditure budgets against peer EDBs, including an allowance for inflation. This measure includes all the 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. Adequate levels of operational expenditure per connection point are required to ensure sufficient maintenance is performed to maintain overall system reliability.

3.4.3.2 Total operational expenditure per connection point – performance

Figure 15 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.

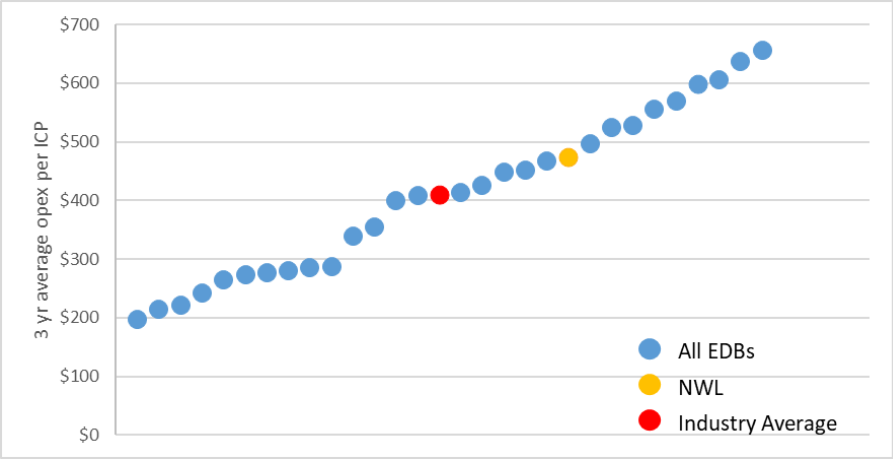


Figure 15 3-year average operational expenditure per connection point performance compared to all EDBs

We believe that it is more appropriate to compare our operating costs to the networks in our peer group. The following graph shows the operational cost comparisons between our peer group of EDBs for the average of the last three years.

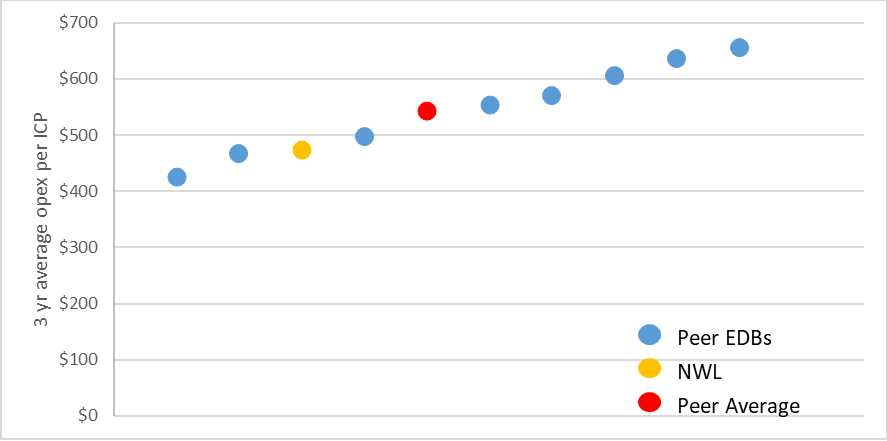


Figure 16 - Comparison of 3-year average total operational expenditure per ICP against peer EDBs

Our 3-year rolling opex/ICP sits 10% below our peer group average. Given our excellent comparative reliability performance (shown in section 3.3) we believe that we are providing a very cost-effective service to our customers, as shown by our OPEX per ICP being below our peer group average, while our SAIDI and SAIFI performance is among the best in our peer group.

3.4.3.3 Network operational expenditure per kilometre of circuit length –measure

This measure provides another 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.

Tracking this measure will link our asset management processes to customer and stakeholder preferences for supply reliability. Adequate levels of operational expenditure per kilometre of circuit length in the network are required to ensure sufficient maintenance is performed to maintain overall system reliability. This compares these costs with our peers and reflects how efficiently we are delivering the levels of reliability that are shown in the sections above.

3.4.3.4 Network operational expenditure per kilometre of circuit length -performance

Referring to **Figure 17** below, our 3-year rolling average for operational costs per kilometre of circuit length is 15% below the average for our peer group of EDBs.

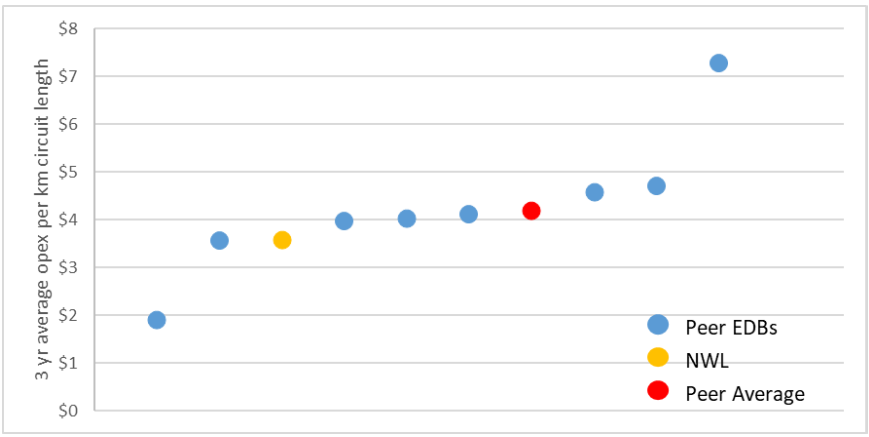


Figure 17 - Comparison of 3-year average network operational expenditure per kilometre of circuit length against peer EDBs

Looking at the combination of operational expenses per length of circuit and per ICP shows that we are successfully managing the operational costs associated with operating an electricity network.

We believe that combined with the peer leading reliability performance shown in section 3.3 this demonstrated that we are delivering above average performance efficiently.

We will work on keeping our operational costs low by:

- ensuring proactive maintenance and repairs are undertaken to ensure fewer faults and asset failures occur.
- evaluating and making 'replace versus repair' decisions before undertaking large corrective maintenance projects.
- tracking and capitalising operational costs for our engineers and support staff where their work is involved with a capital project.
- considering ongoing lifecycle operational costs in the selection of equipment and systems and selecting equipment that balances operational and capital expense.

POWERING OUR FUTURE

04

APPROACH TO ASSET MANAGEMENT

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

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

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

Risk management framework: describes 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 manage keeping our network safe for the public, and how we manage our preparedness for major events.

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

Improvement initiatives/continuous improvement: this section outlines the ways in which we are working to improve our asset management capability.

4. Approach to Asset Management

4.1 ASSET MANAGEMENT PROCESS

The process that we apply to planning our Asset Management is illustrated in Figure 18 below.

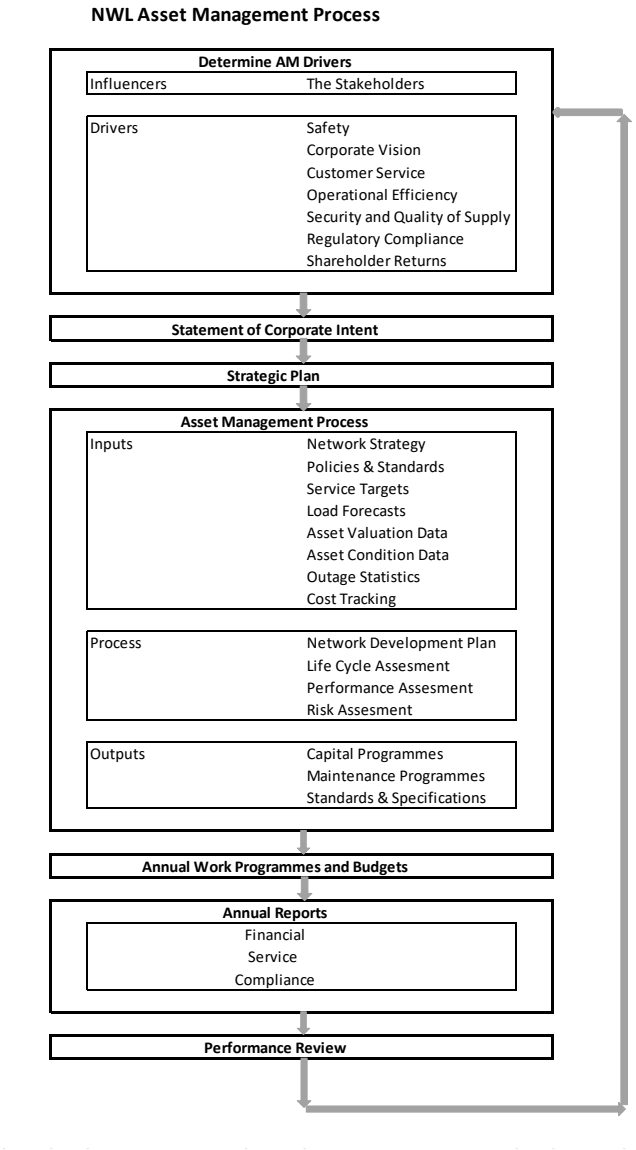


Figure 18 NWL asset management process

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

4.1.1 Company strategic plan

In 2020 we developed and launched a new 10-year strategic plan that will ensure alignment of the entire business to deliver on our mission and vision and the sustainable future of our business. In terms of delivery of this asset management plan the key strategic priorities are:

- Excellence and innovation in our core business – this means having leading performance on our electricity network in order to provide safe, reliable, cost effective and environmentally sustainable network services to our customers.
- Provide the best value for our customers and community – this will be achieved by providing excellent customer service and engagement, to be valued by our customers, region, and our shareholder, and to be recognised as an employer and service provider of choice.
- Offer innovative new solutions to our customers – we will develop a portfolio of innovative solutions for our customers and the Waitaki community to improve service levels and support decarbonisation, and to improve utilisation of our network.

4.1.2 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 provides a focus on delivering a safe, reliable, secure, resilient, and cost-effective supply of electricity that meets the performance expectations of our customers, while complying with all relevant New Zealand laws, regulations, and codes of practice.

4.1.3 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.

4.1.3.1 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 substations, we will purchase sufficient land to enable dual transformer (where appropriate) substations to be built.
- 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.

4.1.3.2 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 aging workforce means that we need to prepare workers to deliver on the strategy during the planning period.
- We will continue to utilise external contractors to maintain our specialist systems such as communications and SCADA networks.
- We will continue to maintain our engineering skill set through the hiring of qualified engineers and supporting the growth of trained engineers by providing scholarships for local students taking engineering qualifications.
- As technology and systems advance, we will actively identify gaps in skillsets necessary to utilise 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 in our business has been a particular issue since the beginning of restrictions related to the Covid 19 pandemic. Skilled immigrants are one of the pools of talent that all EDB's draw upon, and with current difficulties in immigration, combined with an aging workforce, we are having some difficulties filling open positions. This has led to a greater focus on the development of trainees and the identification of components of work where less skilled staff can be used without compromising quality or safety.

4.1.3.3 Materials

We recognise that decisions made around material selection for construction projects can have long term implications on 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 shall consider the total life cycle costs of the offer.
- When bringing new equipment types onto the network we will follow a rigorous procurement process which will examine the risks associated with safety, longevity, maintainability, and operability of the equipment.

The Covid 19 pandemic has had an impact on almost all of our suppliers to some extent or another. International freight disruptions have affected the price and availability of raw and finished materials, leading to some uncertainty on supply arrangements. We expect that some equipment will only be available on longer lead times and will factor this in when purchasing major equipment for projects in the first few years of the works program.

4.1.3.4 Delivery of works program

Where practical our engineering staff commence design for major projects in the financial years prior to the works program that the project is scheduled for. Budgets are developed to provide funds to do this prework where possible. This smooths out the planning and delivery process and allows for consents, long lead time procurement and resourcing scheduling.

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

Progress against the works program is monitored by the management team throughout the year, with careful attention paid to the resourcing and prioritisation of work. The timing of a job may be brought forward or deferred depending on the priority. An example of this is when low priority maintenance such as painting an asset may be moved back in the works program to free up resource to carry out safety related work which may not have been in the original works plan but has arisen through routine inspections.

4.1.3.5 Performance reporting for asset management

We believe that the asset management of our network should be implemented in an open and transparent manner. The key formal reporting mechanisms that we employ are shown in Table 9.

Table 9 - Key asset management reporting mechanisms

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's 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

4.1.4 The Asset Management Plan

This Asset Management Plan (AMP) is intended to provide stakeholders a window into our asset management practices, and to 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 productive efficiency.
- Demonstrate that physical, commercial, and regulatory risks are correctly managed throughout the life of our assets.

4.2 ASSET LIFECYCLE MANAGEMENT

An overview of the typical lifecycle of a network asset is shown in the figure below:

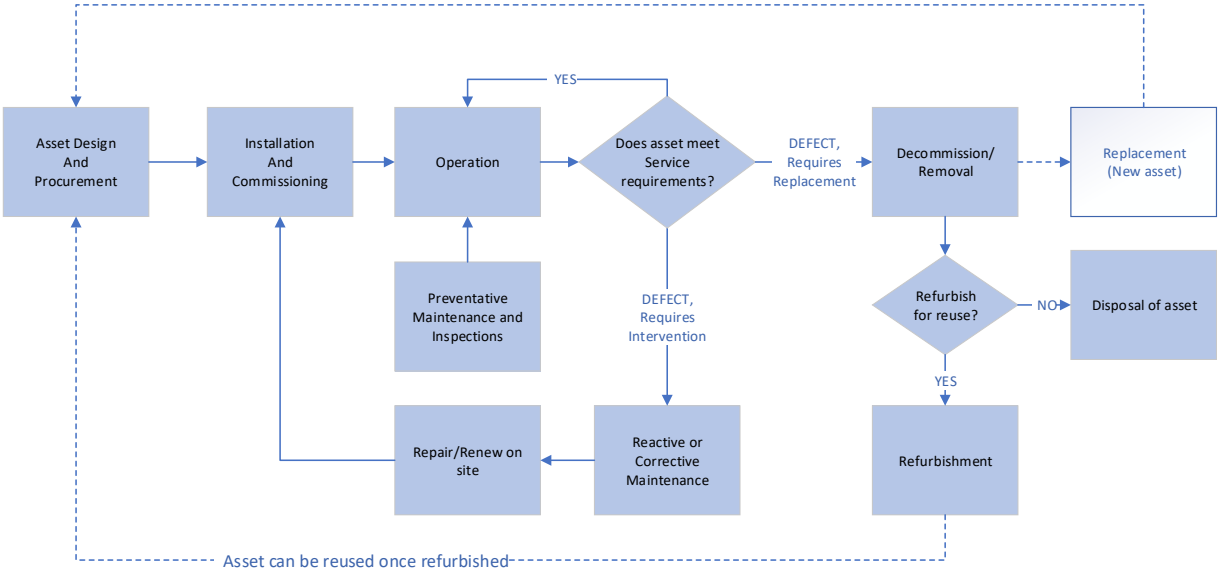


Figure 19 - Typical network asset lifecycle

4.2.1 Design and Procurement

The design and procurement activities 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.

We follow a rigorous change management process to ensure that new equipment can be safely installed, operated, and maintained on the network. This process also identifies any special tools or techniques that a new type of asset may require to be installed and operated, and providing our staff with the training necessary to safely install, operate and maintain the assets

4.2.2 Installation and Commissioning

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

4.2.3 Preventative Maintenance and Inspections

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

Inspections include visual inspections such as a walk around of a substation fence, as well as more in-depth condition monitoring such as the thermal inspection of a roadside distribution transformer, or X-ray and seismic technology for inspections of a wooden power pole. Periodic inspections are usually scheduled at suitable time-based intervals.

An important aspect of our inspection regimes is the safety of our assets for our workers and the public. Safety risk for an asset can be affected by external factors such as public activities in the road or public spaces where our assets are located, or the presence of vegetation near our overhead lines. To mitigate these factors, our inspections consider the public safety component, based on the context of where the asset is, and what activities or external risks are present in the environment.

A specific form of public safety risk management is the control of vegetation risk around our overhead lines. Trees and other vegetation can pose a significant risk to public safety through fires and electric shock hazard, as well as the reliability of our network. We maintain a vegetation management team of specialist Utility Arborists within our Contracting team and engage with the public in multiple ways to inform and educate them of the risks around managing their trees. Our vegetation management team complete scheduled patrols of our overhead network to manage risk to the safe and reliable operation of the network. They work with tree owners to resolve problems within the Electricity (Hazards from Trees) Regulations 2003, and to good practice.

Preventative maintenance is carried out based on the results of condition assessments and at scheduled intervals in order to keep the equipment in good condition. Preventative maintenance includes activities such as greasing and checking the contacts on an air break switch or maintaining the on load tap changer on a power transformer. 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 also trialling real time monitoring on some assets in order to optimise our response to conditions such as overloading, and in some cases to potentially discover defect conditions much earlier than we presently can.

4.2.4 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, including the safety of the public and our workers, and the possible effects on the network. Defects which have a potential risk of causing serious harm to members of the public, employees, or property; or which could have a large impact on the reliability of the network are treated with high priority and must be resolved rapidly.

Information to trigger renewals or maintenance can also come from analysis of fault reports, from observations of 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, through to catastrophic failure.

4.2.5 Repair, renewal, or replacement decisions

When planning remedial work, the risk assessment is reviewed to determine the appropriate intervention strategy. It is important to deal with a defect that has a high safety, environmental or network operational risk attached such as a

damaged ground mount transformer, whereas a less urgent intervention can 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 that type of asset are all considered in making this decision.

Sometimes a renewal program will be triggered based on 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 specific 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.

4.2.6 Standard Life expectancy and asset age 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 we are seeing that the useful (and safe) life of our assets is generally higher than the standard life, and can be highly dependent on location, treatment, and loading. For this reason, wherever possible we avoid using age as a proxy for condition and base asset decisions on observed or tested data.

Some classes of asset have incomplete data for installation dates. Where is evidence supporting a likely installation period (such as neighbouring equipment, or staff knowledge) then we will linearly divide the assets across that period. Otherwise, we will take a conservative approach and place the assets in the earliest likely period for that type of asset. Lack of age data is offset by condition assessment, which serves as a better predictor of remaining asset life than the date of manufacture.

4.2.7 Investment decision framework

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

1. **Accept the constraint**

   The constraint may only exist for a handful of hours per year, or during a very particular set of circumstances, so the decision may be made to accept the risk of the constraint, especially where the cost of remediation is high. This option is not usually implemented for long periods of time and may be used where longer-term solutions cannot meet required time frames 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.

2. **Optimise the network**

   This option could involve altering the configuration of 11 kV feeders to shift load from a heavily loaded to a lightly loaded feeder or it could involve 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 should be included in the cost-benefit analysis.

3. **Control customer demand**

   This option involves NWL acting to reduce customer demand while a constraint is present.

If new load is likely to exceed a constraint limit NWL may choose to impose conditions that allow NWL to control that demand during constraint periods. If the network is upgraded to remove the constraint these conditions may be removed.

Demand that may be controlled includes demand 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 parts of our network or in some cases replace them. In some cases, a remote power system (typically a system combining solar and diesel generation with battery storage) may be more cost effective compared to a traditional power line. The comparative lifecycle costs of non-network solutions are examined where there are new lines, capacity upgrades or replacements being considered. There is more detail on our approach to non-network solutions in *Section 6.2.1 Build and adapt EDB capability programme*.

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.

Customer demand increases are often signalled to us at short notice (in this context, less than 12 months) which may require that options 1 to 3 are used 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.

4.2.8 Expenditure approvals

Following on from this initial prioritisation process, a Project Expenditure Approval is prepared for any budgeted individual project over $50,000; any individual project over $500,000 or major unbudgeted project requires a business case which will approved by the Chief Executive (>$500K) 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.

4.3 RISK MANAGEMENT FRAMEWORK

Our business faces a wide range of risks. Some of those risks relate specifically to our network assets and the physical environment in which they are located, whilst other risks 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 in all our business activities, including policy development, business planning and change management. We adopt a systematic risk management process that is based on *AS/NZS ISO 31000:2009 – Risk management – Principles and guidelines*.

Figure 20 below illustrates the systematic application of risk management according to the standard:

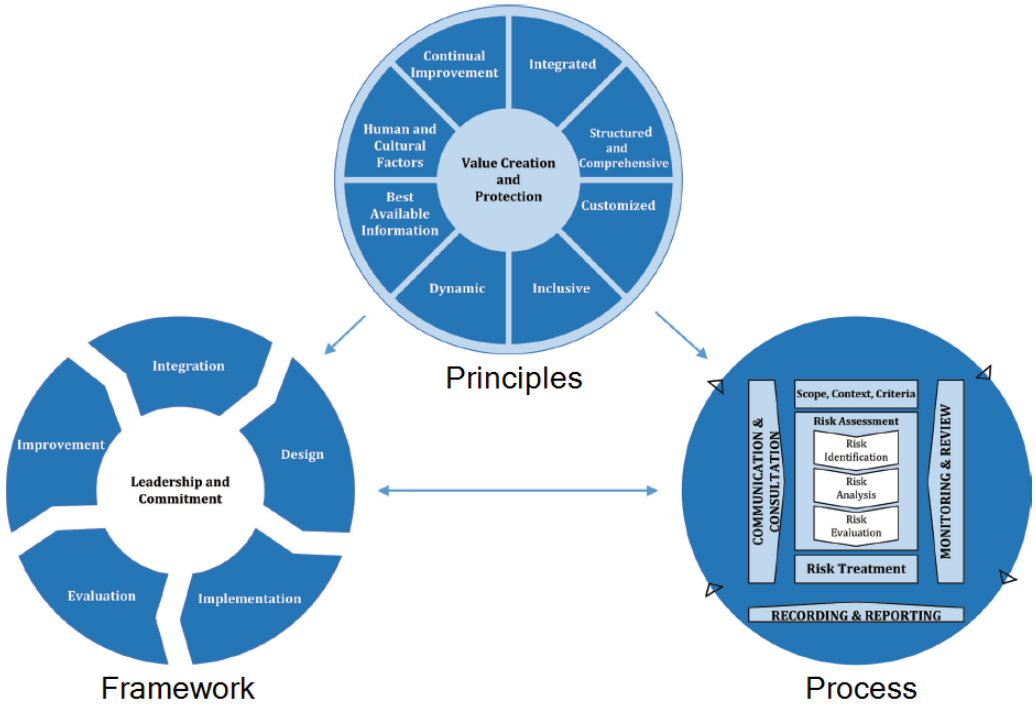


Figure 20 - From ISO31000:2009 relationships between the risk management principles, framework, and process

Our risk management system consists of the following components:

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

4.3.1 Risk Management Policy

Our Risk Management Policy was reviewed in 2021 and is focussed on the development and maintenance of a risk management system to:

- promote continuous improvement
- actively encourage the early and accurate reporting of risks, as health and safety and business continuity is dependent on effective risk management
- set risk management objectives and performance criteria for all work areas and review these annually or more often as required
- develop systems and procedures to eliminate or minimise risk and monitor those controls
- investigate all reported risks to ensure controls are identified and, where appropriate, plans are formulated to take corrective action
- review existing risks and take all reasonably practicable steps to control those risks with controls including elimination or minimisation
- ensure that all workers are made aware of the risks they may be exposed to and are adequately trained to manage those risks to an acceptable level
- encourage consultation, coordination, and participation with workers, including contracted workers and other Person Conducting a Business or Undertaking (PCBU) in all matters relating to risk as far as reasonably practicable.

4.3.2 Risk management framework

Our Risk Management Framework document defines the approach we take to manage risk within our business. It ensures that risk management is integrated into all aspects of our business including governance, strategic planning, operational planning, and reporting.

4.3.3 Risk management process

Our risk management process ensures our risks are identified, understood, and managed consistently across all levels of our business. We assess our known risks in accordance with our likelihood and consequence criteria, to determine which risks need treatment and the priority for treatment.

Our risk management process involves the following steps:

1. **Establishing the context** in which we operate in. This involves understanding our business objectives and values, defining the internal and external environment which we operate in, and setting the scope and risk criteria for the remaining risk management process. We consider many factors including accessibility of our assets by the public, asset age, and location.
2. **Risk identification** is the process of identifying, recognising, and describing our risks and the effect those risks have on the ability to achieve our objectives. Our risks are identified through operational processes including hazard identification recording in our Hazard Register by employees in the field, team and project meetings, our Health and Safety management process which includes recording and tracking workplace safety and training data into our safety management system, and our public safety processes.
3. **Risk analysis.** We use both qualitative and quantitative methods during the risk analysis stage. All our identified risks are analysed in terms of likelihood and consequence.
4. **Risk evaluation.** All our identified risks are evaluated against our likelihood and consequence risk score. This assists us in our decision making to ascertain which risks need treatment and the priority for treatment implementation.

5. **Risk treatment.** We treat a risk depending on the risk score it has been allocated in the analysis and evaluation stage. Risk treatment involves selecting one or more options for modifying risks, and these can include the following:
    - Avoiding the risk by not commencing or continuing the activity
    - Removing the risk source
    - Changing the likelihood
    - Changing the consequences
    - Sharing the risk with another party or parties (e.g., contracts and insurance)
    - Retaining the risk by informed decision
6. **Post treatment risk evaluation.** The risks are reassessed after the application of the treatment to verify that the post treatment level of risk is known and accepted by the company.
7. **Ongoing review of risks.** It is important that once a risk is recorded in the system it is regularly reviewed, as the likelihood and consequence can change. We use the Vault health and safety software package to record and manage risks, including scheduling reviews, and reporting on outstanding risks.

4.3.4 Risk management plans

For complex activities such as major projects or new types of work we employ job safety analysis (JSA) to apply a disciplined risk management approach to planning around the health and safety elements. We are leveraging off this work to develop complete risk management plans for major projects, covering health and safety, financial, environmental, and operating risks for a project. These plans will be developed and approved by the key stakeholders involved in the work in question, such as engineers, managers, and contractors.

4.3.5 Risk registers

Information from the risk management process is recorded, reported, and monitored using our risk registers. There are multiple risk registers in service covering:

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

We are in the process of consolidating the various risks into the online Vault risk management system. This will ensure that all risks can be tracked and managed in one system.

4.3.6 Risk reporting and monitoring

The monitoring of risks is generally carried out at the level of the risk register. The integration of all the registers into Vault has allowed consolidated and consistent management of the different registers. This includes such features as sending emails to staff who have been assigned to manage the risk, and tracking the progress of corrective actions, as well as providing reports summarising the risk items recorded. We have confidence that the monitoring and reporting processes in this area are robust and complete, with monthly reporting on risks in this area going to the board.

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

4.3.7 Health and Safety Critical Risks

We maintain a special awareness and focus on critical risks associated with operating an electricity network. These risks have been identified and assessed in collaboration with other EDB's through our involvement in industry safety groups. We are currently in the process of reviewing the risks that represent the greatest risks to our staff, and how we manage them, using techniques such as Bow-Tie 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 special focus on training and the development of standard work practices, as well as regular monitoring of the risk profile and our performance in these areas. Some of the risk mitigations may involve changes to how we construct or maintain network assets in order to safeguard our staff.

4.4 PUBLIC SAFETY MANAGEMENT SYSTEM (PSMS)

As an electricity network operator, we strive to manage our assets in a way that risk to our people members of the public, and property is reduced to as low as reasonably practical. Our accredited PSMS manages 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. Our 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 an accredited system 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 February 2021, we received confirmation that our PSMS again achieved accreditation to NZS7901:2008 and NZS7901:2014 as appropriate.

4.5 NETWORK RESILIENCE TO HIGH IMPACT LOW PROBABILITY (HILP) EVENTS

4.5.1 Lifeline utility and engineering lifeline groups

The Civil Defence and Emergency Management (CDEM) Act 2002 stipulates the responsibilities and roles of key organisations that provide an essential service within New Zealand. Our core business as an EDB is an essential service and under the CDEM Act we have been classified as a *Lifeline Utility*. As such, we must:

- ensure that we are able to function to the fullest possible extent, even though this may be at a reduced level, during and after an emergency
- have a plan for functioning during and after an emergency
- participate in CDEM strategic planning
- provide technical advice on CDEM when required.

Our staff are actively involved in the Otago Lifeline Utilities Steering Group, which allows us to effectively coordinate with other utilities and Civil Defence management on many factors around this important issue.

We also maintain an active relationship with Civil Defence Emergency Management in the Waitaki region, including having a presence at planning workshops, and coordinating post disaster activities. We coordinate with the local Council, and with our neighbouring EDB's during any events that may escalate into HILP events, such as developing storms.

4.5.2 Improving business resilience

We are subject to the risk of a number of potential high impact, low probability (HILP) events, which could give rise to a major unplanned service outage for an extended period of time. Key examples of HILP events are:

- An earthquake on the South Island's alpine fault
- An earthquake on a major fault line within the Waitaki region
- A tsunami
- A pandemic
- A large snow storm
- Sustained loss of supply from Transpower's transmission system
- A major communications outage

As a lifeline utility provider, we have a responsibility to plan and prepare for HILP events. We currently have a suite of risk management and response documents and policies in place to guide our response to such an event.

We have been working with resilience experts to improve the ability of our business to ride through an abnormal event such as an earthquake or widespread snowstorm, and to operate effectively in the aftermath of such an event.

Our goal is to ensure:

- a safe environment for staff, contractors, and the wider community
- reduction in damage to assets where this is economically viable
- the timely restoration of power supply as far as practicable
- effective communication to the public, Civil Defence Emergency Management, our staff, and other stakeholders
- efficient provision and recovery of information tools for critical business activities.

Our systems were tested during 2020 due to the lockdowns put in place as part of New Zealand's response to the Covid 19 pandemic. The nature of the emergency meant that there was no material damage to deal with, but our processes to work from home stood up successfully, and thanks to exemplary efforts from all staff, the company came through the lockdown periods with no major issues.

Resilience of our key infrastructure is being improved, with the works program item of reinforcing all of our zone substations to importance level 4 (IL4) building rating by 2024. Our office and depot at Chelmer St are being redeveloped over the next three years including a new IL4 office block that will include specific design features to make it more resilient to HILP events and ensure that our operations can continue after any likely events.

4.5.3 Information system security breaches or losses

Our information technology (IT) systems are an important part of our business and operational systems. Our IT department manage the threat from external sources via industry standard approaches, including antivirus software, restricted administrator access, offsite backup systems and firewall technology.

We are involved with the CSSIE (Control Systems Security Information Exchange) group, which is supported by the National Cyber Security Council (NCSC).

Our IT infrastructure has been designed to be robust and includes a standby generator and UPS support for our server room. We utilise remote server hosting in a modern data centre and have disaster recovery facilities in place. We are in the process of migrating many services to cloud based computing platforms that offer better redundancy in the event of a localised disaster, and that will provide access that is less dependent on single points of failure.

4.5.4 Response and reaction to HILP events

Thankfully HILP events are by their nature rare, and our focus has traditionally been to prepare for them rather than having to react to them.

We actively learn from other EDB's and communities that have been impacted by HILP events. This learning occurs through various channels such as:

- Attending industry conferences such as EEA asset management forums.
- direct discussions with staff from other EDB's, for example Canterbury based EDBs that were affected by the Christchurch and Kaikoura earthquakes.
- Involvement in regional peer industry groups such as the Combined Network Operations Group (CNOG),
- involvement in Civil Defence workshops and exercises.
- Utilising experienced consultants to carry out specific reviews of vulnerabilities in our assets and operations and develop remediation plans.

In our network in recent years, we have experienced localised flooding, and the occasional widespread snowstorm. When these HILP events occur, we have coordinated our response to minimise the impact on our customers and to rapidly restore the network where it has been affected. Debriefs and analysis provide the opportunity to review our operational preparation and response, as well as to identify any opportunities to improve asset resilience to particular impacts, where this is cost effective.

Pandemic

The beginning of 2020 saw the emergence and rapid spread of Coronavirus-19 across the globe leading to a global pandemic, which led to New Zealand closing international boarders to non-residents and implementing a four-tiered alert level system of varying restrictions and conditions. Since March 2020 a series of nation-wide and regional lockdowns have been utilised to try and manage the pandemic. These have impacted international, and at times domestic travel.

Improved work practices and efficiencies have successfully enabled our staff to work offsite with disruption to our work force activities generally not due to capability, but to restrictions on the types of work allowed to be performed under a particular lockdown level.

A staff survey was conducted during and after lockdown events, which had high engagement and a positive theme for the short preparation time and the conduct of staff and the overall management team.

4.6 ASSET MANAGEMENT MATURITY

In 2021 we have engaged with an independent assessor to review our Asset Management practices against good practice using the Commerce Commission's asset management maturity assessment tool (AMMAT). This assessment tool is a series of self-assessment questions based around the principles of the ISO55000 suite of standards for Asset Management. The questions cover particular facets of good asset management practice, with scores being applied to each ranging from 0-4 to reflect the maturity level of the organisation. The outcomes are also useful to identify gaps in our asset management systems. We are not currently seeking ISO55000[6] accreditation, but we will be looking to align our systems with the principles of those standards as part of the improvement plan to come out of the review.

4.6.1 Summary of AMMAT assessment

The latest assessment of our asset management practices against the AMMAT is attached in the Appendices. Our scores were all 2 or 3, with the averages in each area shown in Figure 21. As an organisation 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.

[6] ISO 55000 – International Standard for Asset management. Overview, principles, and terminology

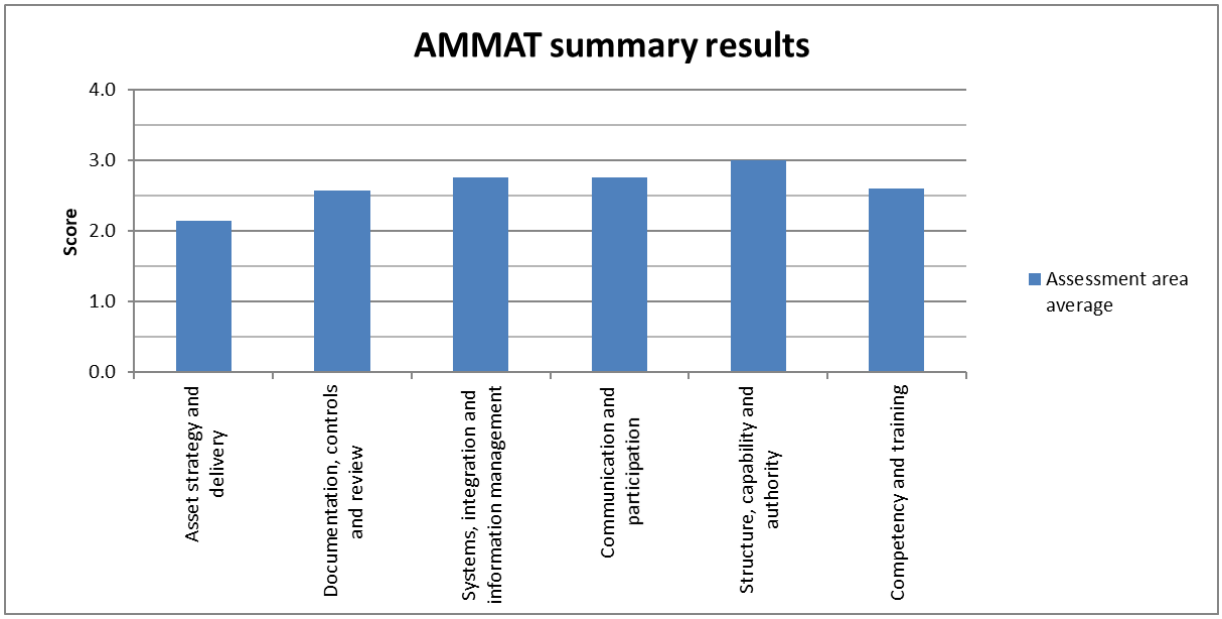


Figure 21 - AMMAT results summary

Generally speaking, our systems and processes are functional and have historically resulted in good network performance. However, they are not particularly efficient and rely heavily on specific knowledge of individual staff. We are still very reliant on paper forms being manually entered and processed. This increases inefficiency of some of our activities, such as asset inspections, documenting project work and dealing with customer requests. Integration and coordination of data across multiple systems can also require considerable human intervention, as can analysis of that data to generate useful information. We are actively involved in improving the efficiency and effectiveness of our systems through the introduction of field-based data capture systems, and the integration of data between software systems such as our GIS and our work management system.

From this original AMMAT assessment point we have been working on improvement in various areas within the 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 ISO55000 good practice within the next five years. One of the overall effects of the new strategic plan will be to improve alignment and integration of asset management strategy with the broader business strategy. In the shorter term there are several specific activities planned to improve our scores in some of the AMMAT assessment categories shown in Figure 21.

A key project for achieving this ISO 55000 alignment and improving our asset management capability is an independent expert review of our capabilities, strategies, systems, and processes in this area. A key outcome of this review is a strategic roadmap to guide the development of our asset management practices and systems, and to identify particular initiatives for focus.

Lifecycle management of all assets will be improved with the development of asset class plans to document good practice activities for all of our assets. This work is expected to take two years to complete for all asset classes, with five high value and high-risk asset groups such as power transformers and switchgear being completed in 2023.

Improvement of our resilience planning has been a focus of efforts over the last 2 years, with a major review and overhaul of our business continuity plans and establishing a seismic resilience review and upgrade program for our substations.

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

A key strategic action in 2022 is the overhaul of our defects management system to a system that provides our field staff with the ability to record and view defects in the field, and that is integrated with our works planning systems. This will also provide meaningful reporting to the business which can be used as a performance measure.

4.6.1.1 Integration of asset management data

We currently operate a number of separate systems to manage our asset data, including some that are paper based, and some that are on old software platforms that are becoming difficult to support. We realise that this is inefficient, and there is ongoing work 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 efficient operation of the business.

Success with this project will result in staff being able to access asset data in the field, and to input information from the field directly into our asset records, rather than being captured on paper for later transcription into our systems. These systems have been trialled in the field in pilot projects, 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 EDB's 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

4.6.1.2 Improvement of Asset data

Many areas of our asset data are complete and accurate, but there are still some where there are deficiencies. This workstream will be ongoing for the next few years and will involve 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 4.6.1.1 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 being used as a marker for replacement decisions. We are reviewing the collection and analysis of condition data for asset classes where there is currently a gap in condition information to establish measures and record data that will allow us to build a future works program that is based more on condition and risk factors and less on strict age bound criteria.

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

4.6.1.3 Develop a better understanding of 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 available will provide a mechanism to assist in planning the most efficient and effective execution of planned work, and assist greatly in improving the 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 on the network, such as the loss of a major subtransmission feeder.

POWERING OUR FUTURE

05

RENEWALS AND MAINTENANCE

This chapter describes how we renew and maintain our network. It covers how we plan this work, our general approach to inspection and monitoring as well as more specific information about our different groups of assets and how they are maintained. This chapter is structured as follows:

Asset quantity summary: provides an overview of our assets.

Asset categories: Outlines assets by function and criticality, which guides how we apply maintenance and renewal regimes.

Zone substations, Subtransmission network, Distribution network and Other system fixed assets: in these sections, we detail the maintenance and renewal approach for each of the different operational levels of our assets. We show the asset population data, population risks, any specific inspection and maintenance practices, or renewal programs, and a summary of forecast renewal and maintenance expenditure.

Renewals and Maintenance Summary: A graphical summary of the forecast expenditure on renewals and maintenance for the planning period.

5. Renewals and maintenance

5.1 ASSET QUANTITY 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 3 and retain the value of the assets for our owners.

Table 10 - Summary of network assets by category

Asset category	Unit	Quantity
Concrete poles / steel structure	No.	9,066
Wood/other poles	No.	12,581
Subtransmission OH up to 66 kV conductor	km	233
Subtransmission UG up to 66 kV (XLPE)	km	4
33 kV Switch (Pole Mounted)	No.	94
33 kV CB (Indoor)	No.	11
33 kV CB (Outdoor)	No.	46
11 kV CB (ground mounted)	No.	84
11 kV CB (pole mounted)	No.	4
Zone Substation Transformers	No.	23
Distribution OH Open Wire Conductor	km	1,258
Distribution UG XLPE or PVC	km	70
Distribution UG PILC	km	11
11 kV CB (pole mounted) - reclosers and sectionalisers	No.	58
11 kV Air Break Switches and Fuses (pole mounted)	No.	4,000
11 kV RMU (individual switches)	No.	189
Pole Mounted Transformer	No.	2,386
Ground Mounted Transformer	No.	549
Voltage regulators	No.	38
LV OH Conductor	km	219
LV UG Cable	km	102
LV Switchgear (Distribution Boxes)	No.	292

5.2 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; and
- 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 with 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. 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 generally to discover any non-compliance or defects and complete work to 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 particular types of assets or in particular areas of the network. Other triggers for renewals or maintenance can also come from patterns of faults reports that 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 the 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 to inspect our assets. 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.

5.3 RENEWALS PLANNING

Planned renewals and replacements are undertaken to ensure network safety and reliability. The difference between renewal and maintenance actions are often around the scale of the work to be carried out on an asset. Common drivers in the renewal programme are age and/or general condition of a group of assets.

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 where 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 rebuild or overhauled) or removed from service and replaced.

5.4 DATA IMPROVEMENT

As mentioned in Section 4.6.1.2 one of the key areas we are working on improving is the asset data that we collect and base decisions on. 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, are 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.

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

5.5 ASSET CATEGORIES

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

- Zone substations
- Subtransmission Network
- Distribution Network
- Other equipment

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

5.6 ZONE SUBSTATIONS

5.6.1 Overview of zone substations

Zone substations house the equipment that connects the bulk electricity supply at subtransmission voltage to our customers for end use. Power transformers convert electricity from 33 kV, which allows efficient transfer of large amounts of energy to 11 kV, which allows 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 Supply	Capacity (MVA)	Security	Date of Construction	Transformer Year of Manufacture	Main Switchgear Year of Manufacture
Ohau	Twizel	3	N	2006	1959	1997
Omarama	Twizel	3	N	1984	1960 & 1963	1985
Ruataniwha	Twizel	2	N	2015	1971	None
Otematata	Waitaki	3	N	1973	1961	2017
Kurow	Waitaki	12.5	N-1	1991	1966 & 1979	2015
Eastern Rd	Waitaki	7	N	2020	2005	2018
Duntroon	Waitaki	7	N	2010	2010	1969
Ngapara	Oamaru	7	N	1970	2005	1972
Papakaio	Oamaru	7	N	2006	2012	2006
Enfield	Oamaru	7	N	2006	2005	2006
Five Forks	Oamaru	7	N	2017	2005	2016
Parsons Road	Oamaru	10	N	1970	1966	2018
Weston switching station	Oamaru	-	N-1	2005	-	2005
Pukeuri	Oamaru	12.5	N-1	1971	1966 & 1966	2017
Chelmer Street	Oamaru	28	N-1	1967	2009	2009
Redcastle	Oamaru	15	N-1	1967	2014	2008
Maheno	Oamaru	5	N	1967	1965	2019
Hampden	Oamaru	7	N	2010	2012	1968
Waitaki GXP	Waitaki	24MVA	N	2013	2013	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,

The life expectancy we apply to our zone substation assets is shown in Table 12 below:

Table 12 - Life expectancy of zone substation assets

Asset Description	Standard life expectancy (years)
Site Development/buildings	70
Power Transformers	60
Indoor switchgear	45
Outdoor switchgear	40
Protection relays	40
DC Supplies/Inverters	20
Batteries	7

5.6.2 Management approach

Our zone substation assets are critical assets as a component failure can have a significant impact on system reliability with a large number of customers affected.

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.

5.6.3 Zone Substation buildings, fences, switchyards, and grounds

5.6.3.1 Age profile and population data

The age 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.

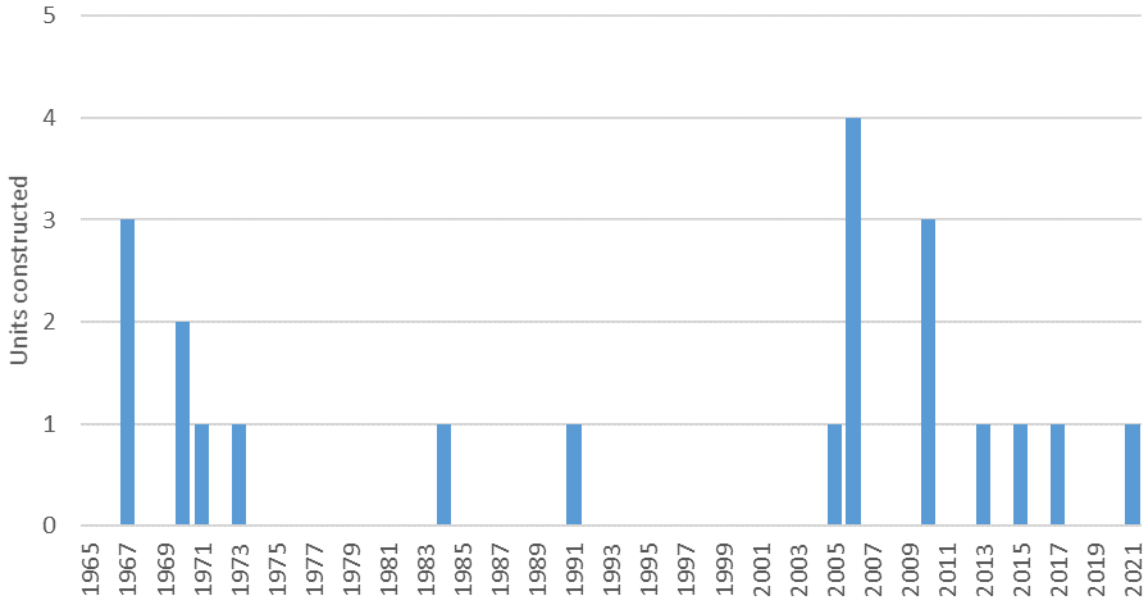


Figure 22 - Age profile for zone substations

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.

5.6.3.2 Inspection and Maintenance Program

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

5.6.3.3 Renewal and Refurbishment Program

In line with our commitments to prepare for HILP events (see section 4.5) 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 plan that remains, which will be completed over the first year of the planning period.

Table 13 - Zone substation remediation required to achieve IL4

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	End of FY22
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	End of FY22
Pukeuri	70%	Low	Required	N/A	no	End of FY22
Five Forks	60%	Medium	Required	Minor	no	End of FY22
Hampden	60%	Medium	Required	Minor	no	End of FY22
Papakaio	60%	Medium	Required	Minor	no	End of FY22
Duntroon	60%	Medium	Required	Minor	no	End of FY22
Enfield	60%	Medium	Required	Minor	yes	End of FY22
Redcastle	55%	Medium	Required	Significant	no	End of FY22
Maheno	100%	Medium	N/A	N/A	no	End of FY22
Parsons	55%	Medium	Required	Minor	no	End of FY22
Ngapara	50%	Medium	N/A	Minor	minor	End of FY22
Weston switch room	40%	Medium	N/A	N/A	no	End of FY22
Chelmer St	35%	Medium	Required	Minor	minor	End of FY24

The work ranges from spot strengthening actions at some substations through to the addition of significant internal steel reinforcing frames in others. A few sites also require some work to be carried out on the surrounding environment (streambanks, slopes) to reduce risks.

We operate Inergen gas flood fire suppression systems at three of our zone substations, Chelmer St, Redcastle and Weston. These systems are due for replacement of major components. Investigations into the suitability of the systems for the substation environment have highlighted that changes in fuel load within the substations may have done away with the need for these systems. Investigations are underway to look at removing the systems.

Other refurbishment and renewal programs include repair, upgrade or replacement of fencing and security systems based on condition assessment, and how effective they are compared to 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 the seismic work.

5.6.3.4 Expenditure Forecast

ZONE SUBSTATIONS - Building, switchyards, grounds	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Capital expenditure forecast ($000)										
Gas flood fire system replacement - Chelmer/Redcastle/Weston	70									
Seismic resilience improvement at zone substations	105	105								
Substation equipment condition based replacements	100	100	100	100	100	100	100	100	100	100
Capital subtotal	**275**	**205**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
Operational expenditure forecast ($000)										
Property maintenance	116	116	116	116	116	116	116	116	116	116
Routine Inspections	26	26	26	26	26	26	26	26	26	26
Substation minor works	20	20	20	20	20	20	20	20	20	20
Operational subtotal	**162**	**162**	**162**	**162**	**162**	**162**	**162**	**162**	**162**	**162**

5.6.4 Zone substation transformers

5.6.4.1 Age profiles and population data

The age profile shown in the following graph is based on the date of manufacture of the transformers.

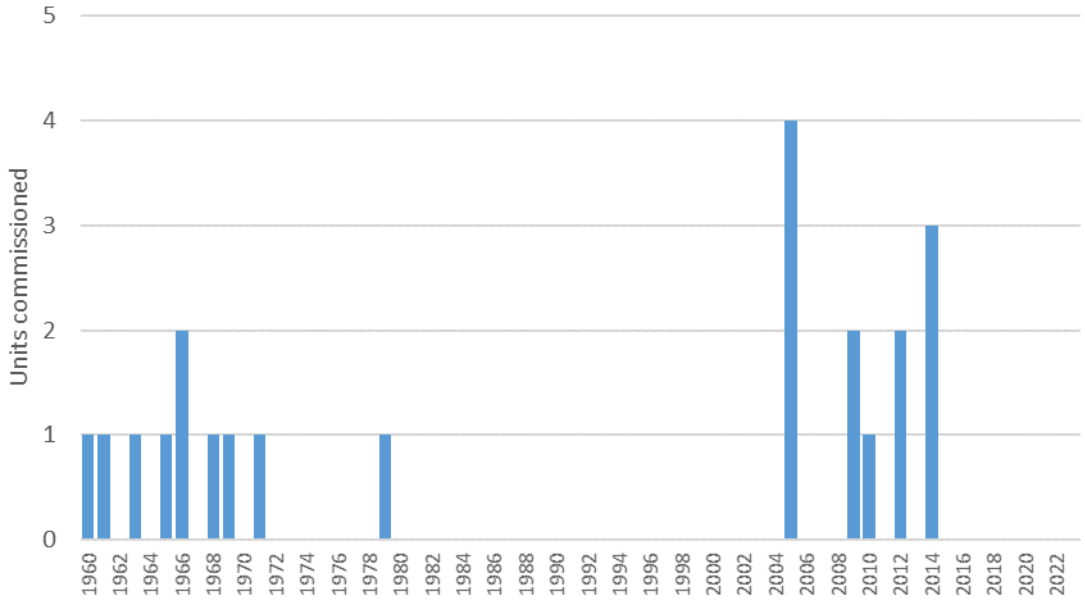


Figure 23 - Zone transformers age profile

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

5.6.4.2 Inspection and Maintenance Program

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.	3 yearly, or 10,000 operations

5.6.4.3 Renewal and Refurbishment Program

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.

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 program 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 do so 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 program, as this work may free up younger existing transformers that can replace older units. At this stage we are budgeting to purchase a spare transformer and replace two transformers of 3 MVA capacity and three of 10/12 MVA capacity within the planning period. The replacements have been planned based on insulating paper condition trends that have been noted in recent transformer assessments.

5.6.4.4 Expenditure Forecast

ZONE SUBSTATIONS - Transformers	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Capital expenditure forecast ($000)										
Replace Power transformers										
Otematata T1	23	554								
Spare Transformer		12	825							
Kurow T1				34	940					
Ohau						23	610			
Capital Subtotal	**23**	**566**	**825**	**34**	**940**	**23**	**610**			
Operational expenditure forecast ($000)										
Power Transformer OLTC maintenance										
3 yearly cycle	53	74	74	74	74	74	74	74	74	74
Zone Tx maintenance										
Allowance for minor maintenance	21	21	21	21	21	21	21	21	21	21
Silica gel replacements	6	6	6	6	6	6	6	6	6	6
Zone Tx DGA	32	32	32	32	32	32	32	32	32	32
Zone Tx Maintenance	37	37	37	37	37	37	37	37	37	37
Zone Tx Oil Processing	11	11	11	11	11	11	11	11	11	11
Operational subtotal	**159**	**180**	**180**	**180**	**180**	**180**	**180**	**180**	**180**	**180**

5.6.5 Zone substation switchgear

Zone substation switchgear allow 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 deenergise sections of the subtransmission and distribution networks for clearance of faults, or to carry out work.

5.6.5.1 Age profiles and population data

The age profile in the following graph is based on the manufactured date of the substation switchgear.

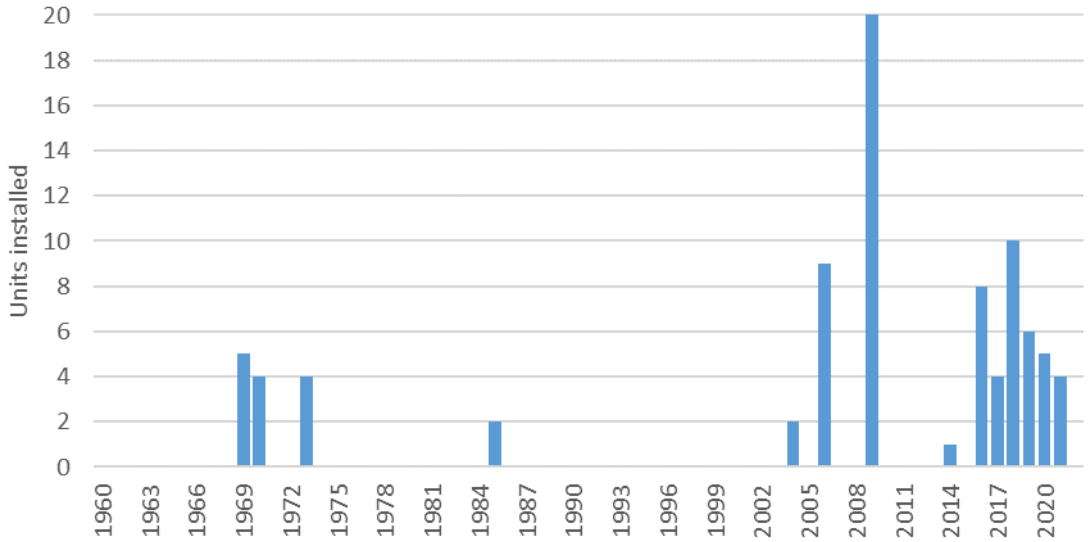


Figure 24 - 11 kV circuit breaker age profile

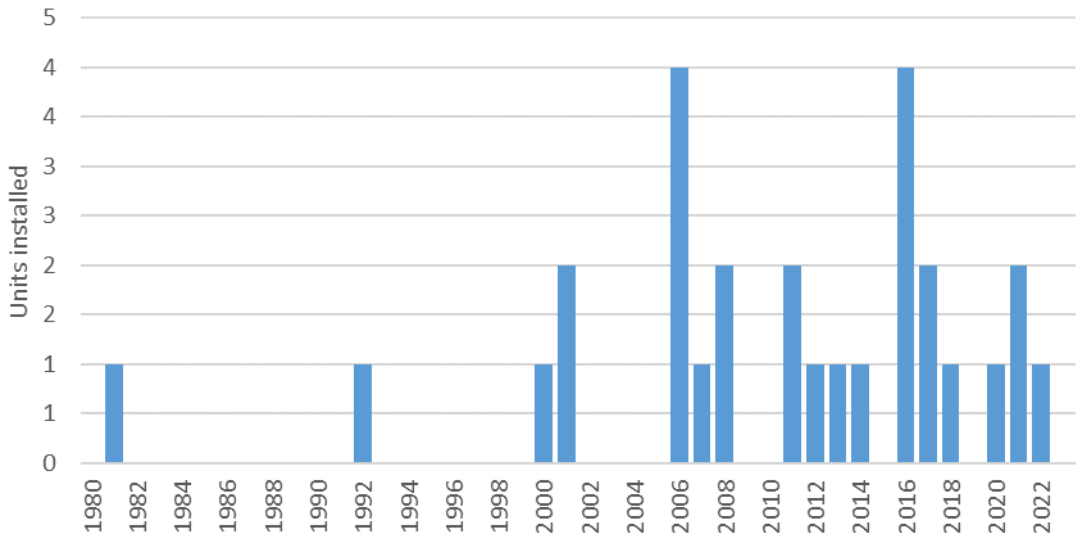


Figure 25 - 33 kV circuit breaker age profile

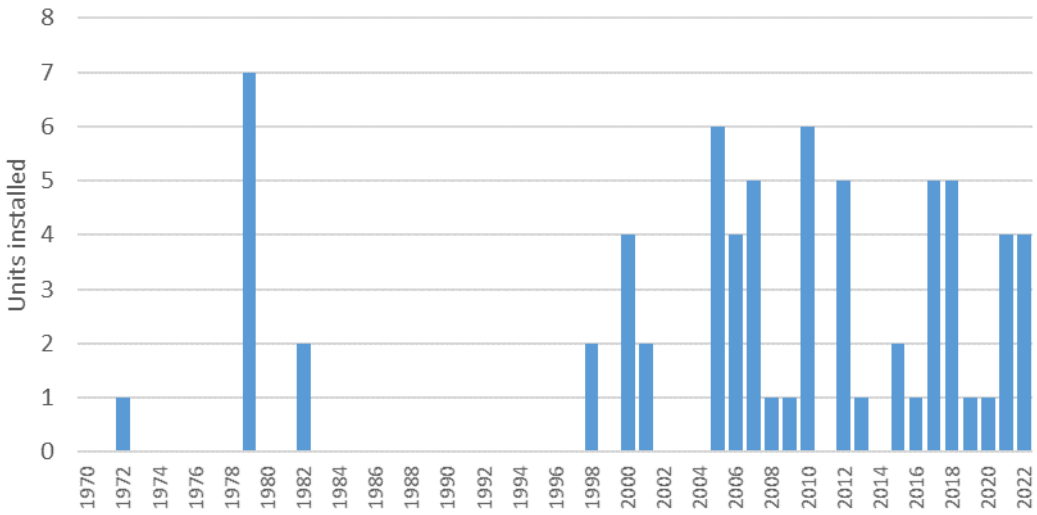


Figure 26 - Zone Substation Isolators

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

5.6.5.2 Inspection and Maintenance Program

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

5.6.5.3 Renewal and Refurbishment Program

A program is underway to replace older (pre-1990) oil filled switchboards with modern, arc fault rated switchboards fitted with vacuum insulated circuit breakers. Four switchboards remain to be replaced, at Ngapara, Hampden, 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 in the process of retrofitting arc flash 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 examples 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.

5.6.5.4 Expenditure Forecast

ZONE SUBSTATIONS - Switchgear	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Capital expenditure forecast ($000)										
Replace 11kV switchboards										
Hampden	410									
Pukeuri Alliance		892								
Duntroon	23	343								
Ngapara		33	436							
Omarama				22	349					
Protection enhancements	64	50	50	50	50	50	50	50	50	50
Ongoing Protection relay replacement	24	24	24	24	24	24	24	24	24	24
33kV ABS replacement	84	84	84	84	84	84	42	42	42	42
Replace 33kV recloser		46				46			46	
Capital subtotal	**603**	**1,470**	**592**	**178**	**505**	**202**	**114**	**114**	**160**	**114**
Operational expenditure forecast ($000)										
Switchgear and protection maintenance										
Five Forks, Kurow, Weston	42									
Otematata, Pukeuri		42								
Parsons, Maheno, Chelmer			42							
Ongoing @ 3 x substations per annum				42	42	42	42	42	42	42
33kV ABS insulator replacement	105	105	105							
Specialty Diagnostics	21	21	21	21	21	21	21	21	21	21
Operational subtotal	**168**	**168**	**168**	**63**	**63**	**63**	**63**	**63**	**63**	**63**

5.6.6 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.

5.6.6.1 Age profile and population data

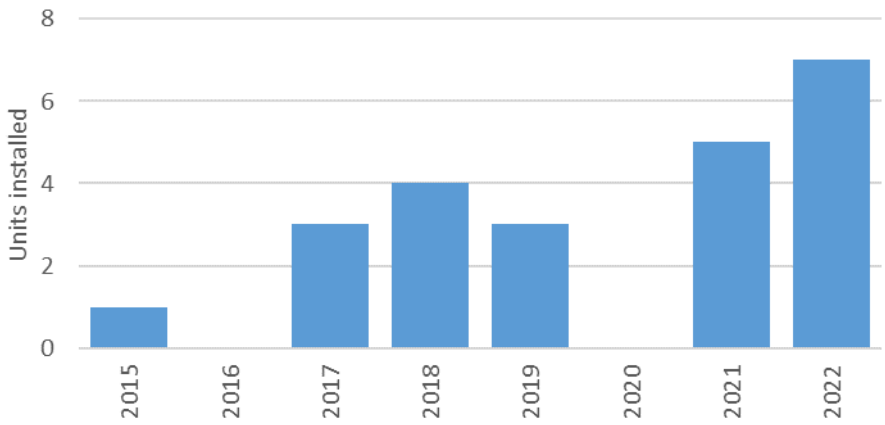


Figure 27 - Age profile data for zone substation batteries

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

5.6.6.2 Inspection and Maintenance Program

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

5.6.6.3 Renewal and Refurbishment Program

Substation batteries are critical to the ongoing operation of the network. We currently plan to replace complete battery banks after no more than 7 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 prior to that time. 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.

5.6.6.4 Expenditure Forecast

ZONE SUBSTATIONS - DC systems	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Capital expenditure forecast ($000)										
Battery bank replacements (5 pa)	11	11	11	11	11	11	11	11	11	11
Capital subtotal	**11**	**11**	**11**	**11**	**11**	**11**	**11**	**11**	**11**	**11**
Operational expenditure forecast ($000)										
Annual battery testing	10	10	10	10	10	10	10	10	10	10
Operational Subtotal	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**

5.6.7 Zone substations 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.

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

5.6.7.1 Age profile and population data

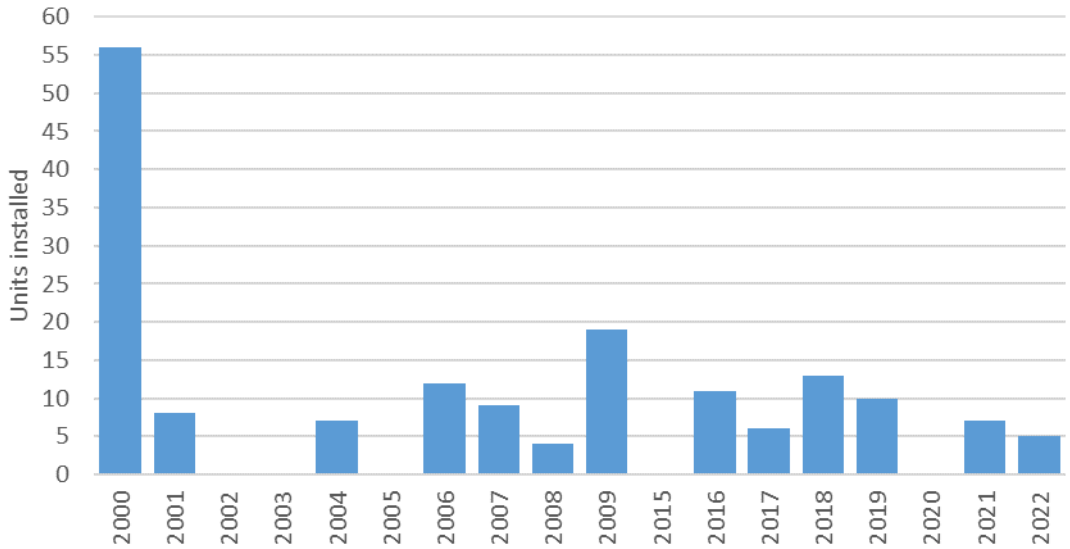


Figure 28 - Age profile data for protection relays

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.

5.6.7.2 Inspection and Maintenance Program

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

5.6.7.3 Renewal and Refurbishment Program

We are working through a program to replace some older feeder 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 subtransmission 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 at this time, and at this time there are no obsolescence issues with the current fleet of relays, but we have allowed an ongoing budget for replacement of protection relays that have surpassed 20 years of operation, as it is likely that we will begin to get some failures in the population from this point.

5.6.7.4 Expenditure Forecast

Expenditure on protection relays is included in the budgets for the associated switchgear, in section 5.6.5.

5.6.8 Zone substation ripple control transmitters

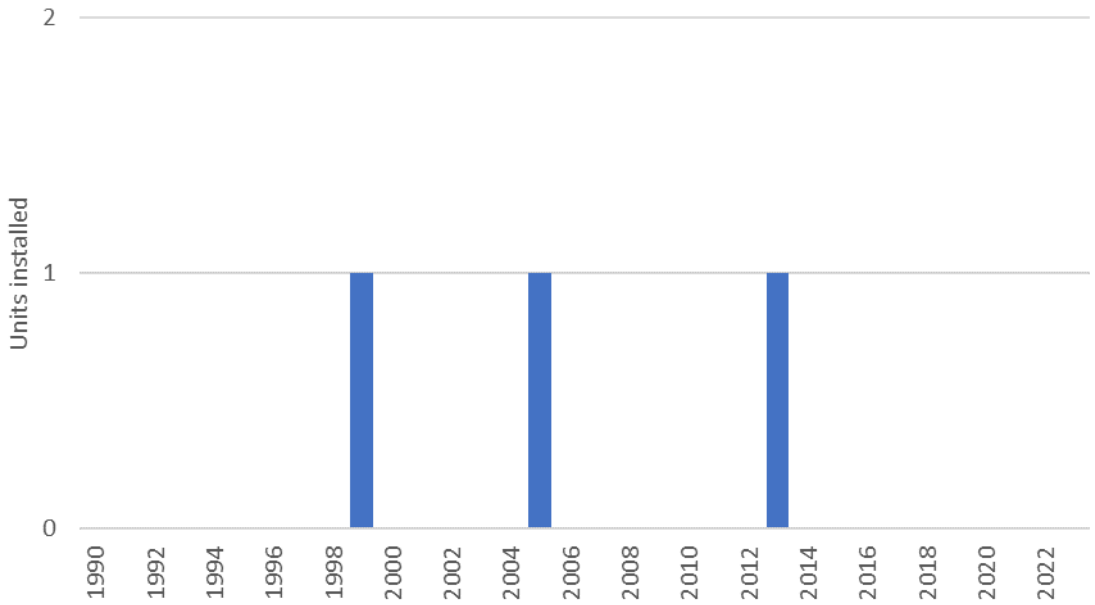
NWL owns and operates Enermet solid state 33 kV Ripple Injection Plants at both the Oamaru and Twizel GXP's. An indoor Enermet solid state 11 kV injection unit is installed at the Kurow Zone Substation and services the demand connected to the Waitaki GXP. We own the ripple control relays installed at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

We utilise Decabit ripple control relays at customer premises to control demand in order to minimise line charge costs and control network demand below certain constraints. Transmitters are located at the following sites:

Zone substation	GXP(s) served
Parsons Rd	Oamaru
Kurow	Waitaki, Twizel
Twizel	Waitaki, Twizel

5.6.8.1 Age profile and population data

Figure 29 - Ripple control transmitters by installation date



Specific risks for ripple control transmitters include:

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

5.6.8.2 Inspection and maintenance program

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

5.6.8.3 Renewal and Refurbishment program

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 program accordingly. We intend to maintain our ripple control capability until after any alternatives are established and proven.

5.6.8.4 Expenditure Forecast

ZONE SUBSTATIONS - Ripple Control Systems	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Capital expenditure forecast ($000)										
	-	-	-	-	-	-	-	-	-	-
Operational expenditure forecast ($000)										
Ripple Control Maintenance	11	11	11	11	11	11	11	11	11	11
Operational Subtotal	**11**	**11**	**11**	**11**	**11**	**11**	**11**	**11**	**11**	**11**

5.6.9 Total Zone Substation expenditure forecast

ZONE SUBSTATIONS	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Capital expenditure forecast ($000)										
Gas flood system replacement - Chelmer/Redcastle/Weston	70									
Seismic resilience improvement at zone substations	105	105								
Substation equipment condition-based replacements	100	100	100	100	100	100	100	100	100	100
Replace Power Transformers	23	554		34	940	23	610			
Spare Transformer		12	825							
Replace 11kV switchboards	433	1,268	436	22	349					
Protection enhancements	64	50	50	50	50	50	50	50	50	50
Ongoing Protection relay replacement	22	22	22	22	22	22	22	22	22	22
33kV ABS replacement for age and condition	84	84	84	84	84	84	42	42	42	42
Replace 33kV recloser		46				46			46	
Battery bank replacements	11	11	11	11	11	11	11	11	11	11
Total capital expenditure	**912**	**2,252**	**1,528**	**323**	**1,556**	**336**	**835**	**225**	**271**	**225**
Operational expenditure forecast ($000)										
Property maintenance	116	116	116	116	116	116	116	116	116	116
Routine Inspections	26	26	26	26	26	26	26	26	26	26
Substation minor works	20	20	20	20	20	20	20	20	20	20
OLTC maintenance	53	74	74	74	74	74	74	74	74	74
Power Transformer maintenance	106	106	106	106	106	106	106	106	106	106
Switchgear and protection maintenance	42	42	42	42	42	42	42	42	42	42
Specialty diagnostics	21	21	21	21	21	21	21	21	21	21
33kV ABS insulator replacements	105	105	105							
Annual battery testing	10	10	10	10	10	10	10	10	10	10
Ripple control plant maintenance	10	10	10	10	10	10	10	10	10	10
Total operational expenditure	**700**	**741**	**741**	**636**	**636**	**636**	**636**	**636**	**636**	**636**

Table 14 - Zone substation and equipment forecast expenditure

5.7 SUBTRANSMISSION NETWORK

5.7.1 Overview of subtransmission network

The subtransmission network connects the supply of electricity from Transpower grid exit points (GXPs) to our zone substations, where it is distributed to customers. Our subtransmission system currently operates at 33 kV, with future plans to operate some sections at a higher subtransmission voltage.

The network is arranged as shown in Figure 30

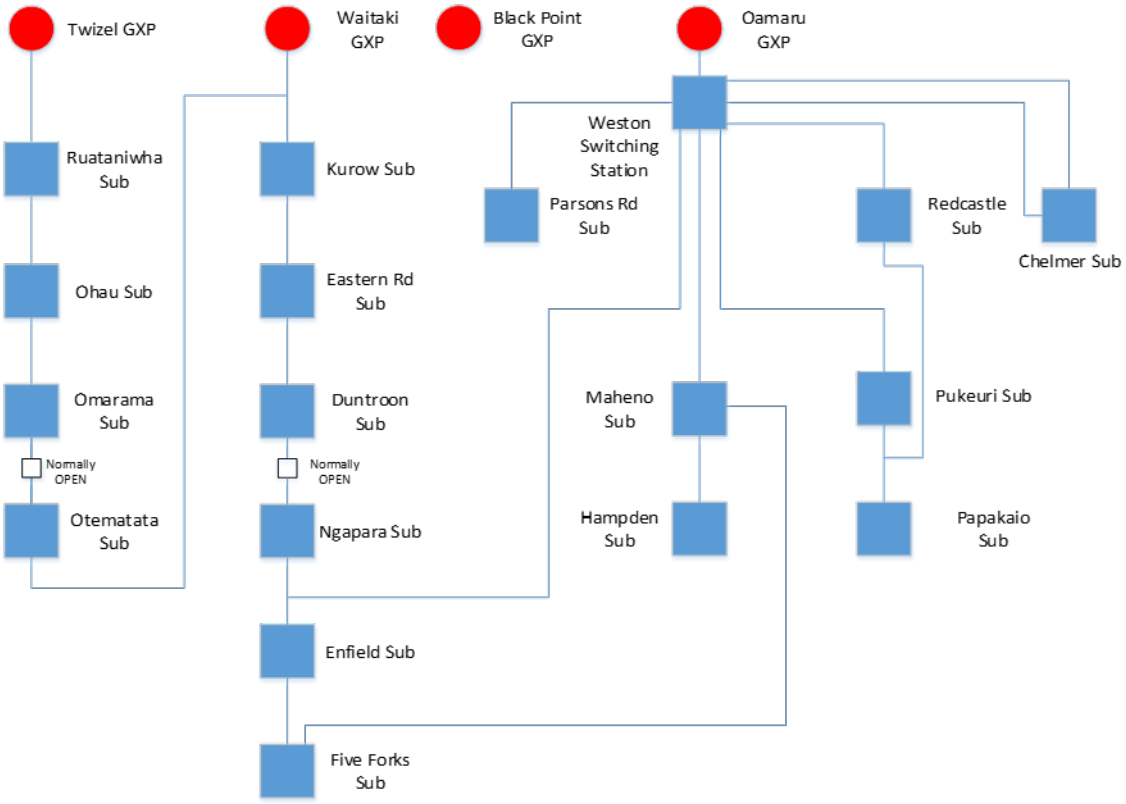


Figure 30- Subtransmission system configuration

The life expectancy we apply to our subtransmission assets is shown in Table 15 below.

Table 15 - Life expectancy of subtransmission assets

Asset Description	Standard life expectancy (years)
Overhead conductor	60
XLPE cables installed <1985	45
XLPE cables installed >1985	55
PILC cables	70
Air Break Switches	35
Concrete Pole	60
Wooden Pole	45
Cross Arm	20

5.7.2 Management approach

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

Our objectives for the maintenance of our subtransmission 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 subtransmission system can affect several zone substations, and hence a large number of customers. The construction of these lines is accordingly to a high standard. Subtransmission supplies to zone substations are generally configured so that they have a backup supply from another subtransmission circuit. This makes them relatively easy to remove from service in order to carry out inspections and repairs.

5.7.3 Subtransmission lines and cables

Our subtransmission overhead circuits are a mixture of ACSR, AAC and AAAC conductors. Line supports are a mixture of wooden poles and concrete poles.

We have a small amount of underground cable on our subtransmission network, all of modern XLPE type.

A summary of the subtransmission lines and cables is shown in Table 16 below.

Table 16 - summary of subtransmission lines and cables

Asset type	Number
Wooden poles	1,985
Concrete poles	354
Overhead conductors	233 km
Cables	4.1 km

5.7.3.1 Age profile and population data

The age profile of these assets is shown in Figure 31, Figure 32 and Figure 33 below.

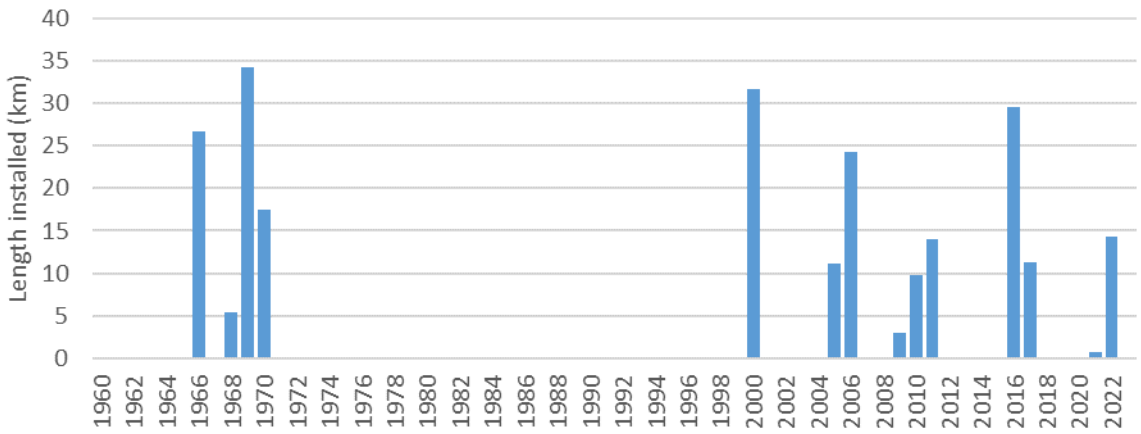


Figure 31 - Age profile of subtransmission overhead conductor

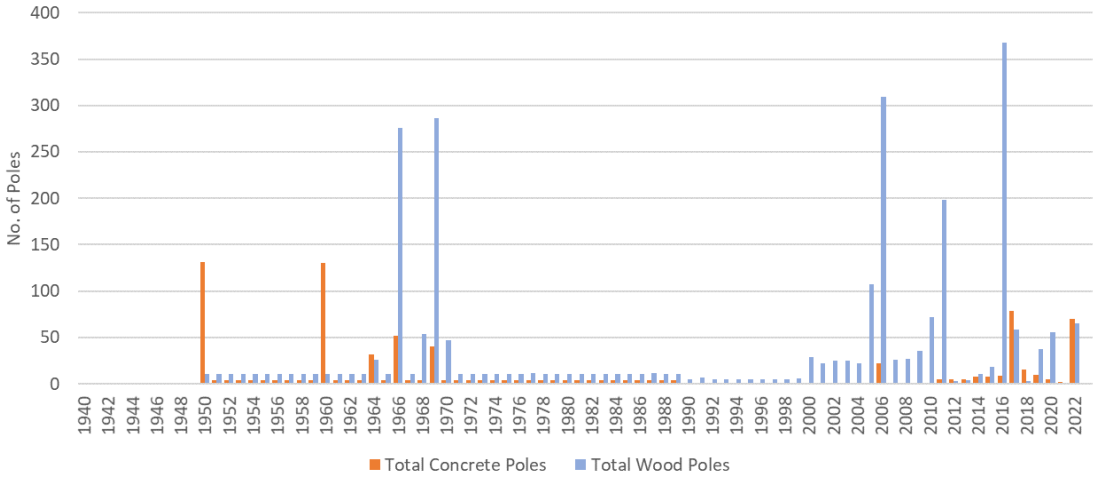


Figure 32 - Age profile for subtransmission poles

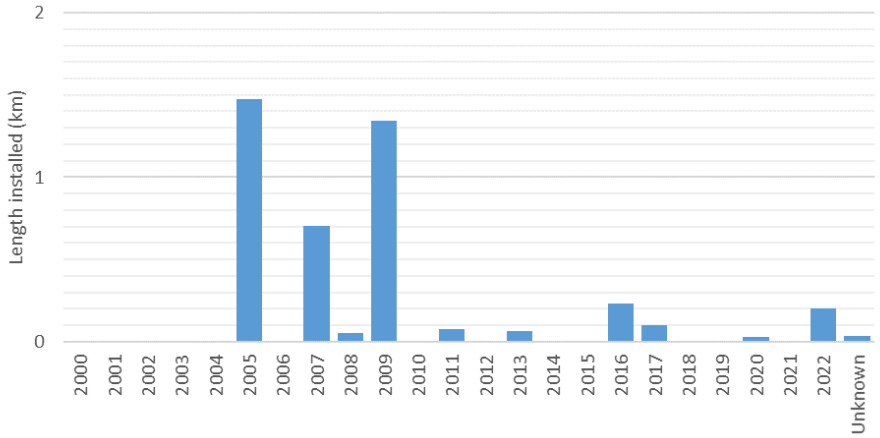


Figure 33 - Age profile of subtransmission underground cables

Major risks to the subtransmission network include:

- vehicle impact – much of the network is built on road reserve
- extreme weather events such as high winds or heavy snow
- external equipment – pivot irrigators moving into, spraying, or being blown into lines
- degradation of structural strength due to age related issues such as corrosion or pole decay.

5.7.3.2 Inspection and Maintenance Program

Activity	Summary	Frequency
Ground patrol	Ground based visual inspection of pole top, cross arms, and pole top hardware. Testing of pole structural condition using Thor hammer and Portascan test sets, digging and probing. 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
Vegetation Patrols	Overhead Subtransmission lines are inspected annually by our specialist vegetation team to maintain safety and reliability	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.	5 yearly
Partial Discharge Monitoring	Subtransmission cable terminations as part of zone substation partial discharge monitoring	Annual
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

5.7.3.3 Renewal and Refurbishment Program

Renewals in the subtransmission network are largely based around repairs and replacements 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 subtransmission circuits that were installed in the 1960s are forecast for such rebuilding during the planning period. In FY23 we are planning to rebuild the Weston to Maheno 33kV circuit due to conductor condition caused by age and vibration. Replacement of conductor on Weston to Chelmer No.1 33 kV is budgeted for FY24, based on the age of the existing conductor, and the criticality of the asset, an in a similar vein the 33 kV conductor between Omarama and Twizel will be

beyond its standard life expectancy during the planning period, and is known to have suffered damage due to heavy weather, including effects of historic heavy snow loads, although is not yet showing end of life characteristics.

During renewals we may also improve the reliability of the subtransmission network by replacing overhead circuits with underground, or by physically separating circuits to increase diversity, when it is economic to do so. Condition based pole replacements that are 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, which will increase the resilience of the substation.

None of the cables on our subtransmission network reach their standard expected life during the planning period, and all are in good condition. We are therefore not planning any renewals of subtransmission cables in the planning period.

5.7.3.4 Expenditure Forecast

SUBTRANSMISSION NETWORK - Lines and cables	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Capital expenditure forecast ($000)										
Subtransmission pole and hardware replacements	300	300	300	300	300	300	300	300	300	300
Subtransmission rebuilds due to age and condition										
Weston to Chelmer St 33kV No.2	57	360								
Weston to Maheno 33kV		900								
Omarama to Twizel 33kV				58	660					
Capital Subtotal	**357**	**1,560**	**300**	**358**	**960**	**300**	**300**	**300**	**300**	**300**
Operational expenditure forecast ($000)										
33kV line maintenance	42	42	42	42	42	42	42	42	42	42
33kV climbing patrols	82	82	82	82	82	82	82	82	82	82
33kV ground patrols	98	98	98	98	98	98	98	98	98	98
Post Construction Retightens	57	47	47	57						
Operational subtotal	**279**	**269**	**269**	**279**	**222**	**222**	**222**	**222**	**222**	**222**
Vegetation management patrols and maintenance	342	342	342	342	342	342	342	342	342	342
Operational Subtotal including vegetation management	**621**	**611**	**611**	**611**	**564**	**564**	**564**	**564**	**564**	**564**

5.7.4 Subtransmission switchgear

We utilise air break, SF6 insulated and vacuum type switchgear in our subtransmission network. Most of this equipment is of recent manufacture, although there are a handful of older items.

5.7.4.1 Age profile and population data

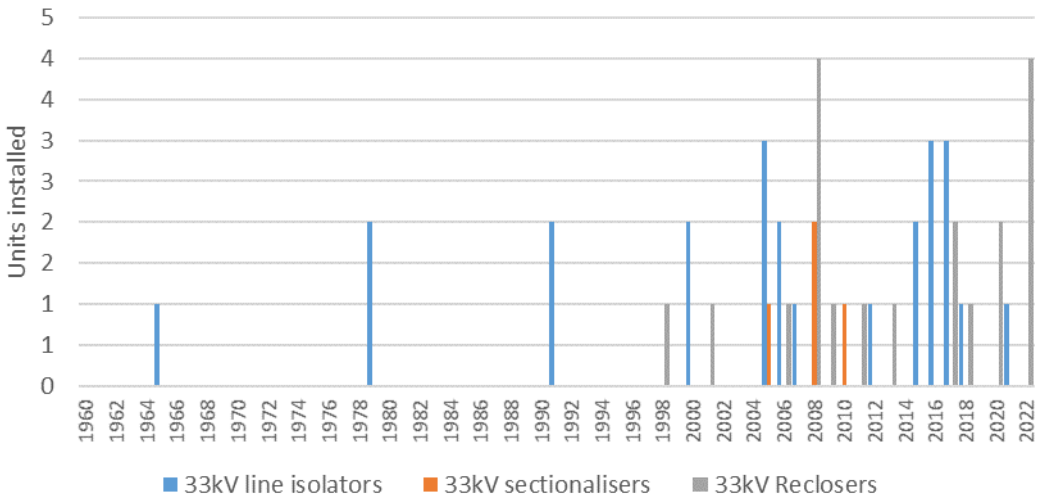


Figure 34 – Age profile of subtransmission switchgear

Risks commonly associated with our subtransmission switchgear include:

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

5.7.4.2 Inspection and Maintenance Program

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

5.7.4.3 Renewal and Refurbishment Program

Switchgear in this category is replaced based on condition assessment or as they become obsolete, and the management of spares becomes problematic. We expect to replace two reclosers in this planning period due to age.

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.

5.7.4.4 Expenditure Forecast

SUBTRANSMISSION NETWORK - Switchgear	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Capital expenditure forecast ($000)										
33kV ABS replacement	21	21	21	21	21	21	21	21	21	21
Capital Subtotal	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**	**21**
Operational expenditure forecast ($000)										
33kV Switchgear maintenance	21	21	21	21	21	21	21	21	21	21
33kV ABS insulator replacement	42	42	42	42	42	42	42	42	42	42
Operational Subtotal	**63**	**63**	**63**	**63**	**63**	**63**	**63**	**63**	**63**	**63**

5.7.5 Total Subtransmission Network Expenditure forecast

Table 17 - Forecast of maintenance and renewal expenditure for subtransmission assets

SUBTRANSMISSION NETWORK	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Capital expenditure forecast ($000)										
Subtransmission pole and hardware replacements	300	300	300	300	300	300	300	300	300	300
Subtransmission rebuilds due to age and condition	57	1,260		58	660					
33kV ABS replacement	21	21	21	21	21	21	21	21	21	21
Total capital expenditure	**378**	**1,581**	**321**	**379**	**981**	**321**	**321**	**321**	**321**	**321**
Operational expenditure forecast ($000)										
33kV line maintenance	42	42	42	42	42	42	42	42	42	42
33kV inspections	180	180	180	180	180	180	180	180	180	180
Post Construction retightens	57	47	47	57						
33kV switchgear maintenance	21	21	21	21	21	21	21	21	21	21
33kV ABS insulator replacements	42	42	42	42	42	42	42	42	42	42
Total operational expenditure	**342**	**332**	**332**	**342**	**285**	**285**	**285**	**285**	**285**	**285**
Subtransmission vegetation management	342	342	342	342	342	342	342	342	342	342
Total operational expenditure (including Vegetation management)	**684**	**674**	**674**	**684**	**627**	**627**	**627**	**627**	**627**	**627**

5.8 DISTRIBUTION NETWORK

5.8.1 Overview of 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 further assist in quicker supply restoration, we have embarked on a program of installing automated open points on 11 kV interconnection between substations.

There are 1,255 km of overhead lines and 81 km of 11 kV cables on our distribution network.

The life expectancy we apply to our distribution assets is shown in Table 18 below:

Table 18 - Life expectancy of distribution assets

Asset description	Standard life expectancy (years)
Overhead conductor	55
XLPE cables installed <1985	45
XLPE cables installed >1985	55
PILC cables	70
Air Break Switches	35
Wooden poles	45
Concrete poles	60
Crossarms	20

5.8.2 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 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 provides the ability to swiftly reconfigure the network to support load in the event of an outage. NWL's loadings are such that security provisions are generally focused on switching to restore supply quickly rather than targeting nil 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 a large number of assets located 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 out ground mounted distribution assets
- maintain the visual condition of our assets in neighbourhood areas

5.8.2.1 Analysis of our worst performing feeders

We examine faults data for patterns that may indicate systemic problems with types of equipment on the network. We can then target asset management practices to deal with the identified issues, and thereby improve network reliability and safety. Part of this analysis is examining the performance of our 10 worst performing distribution feeders, as shown in the following sections. We believe that this analysis can provide insight into asset performance that can be usefully applied to guide asset replacement, or other activities such as vegetation management across the entire network.

5.8.3 Distribution lines and cables

5.8.3.1 Age profiles and population data

The age profile of these assets is shown in the following two charts:

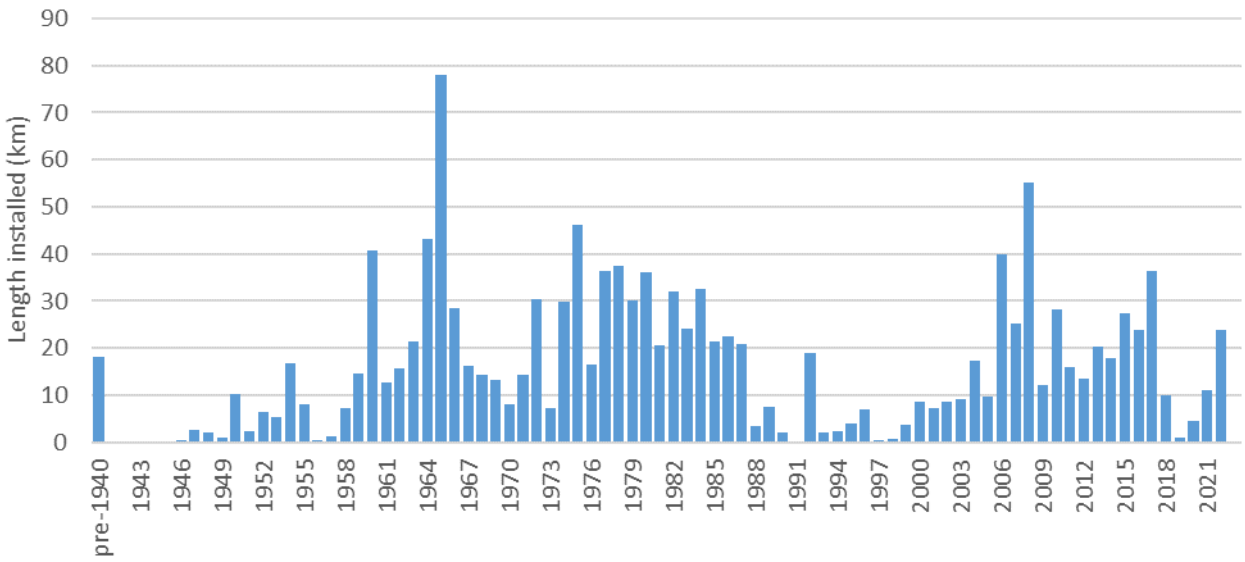


Figure 35 - Age profile of 11 kV overhead lines

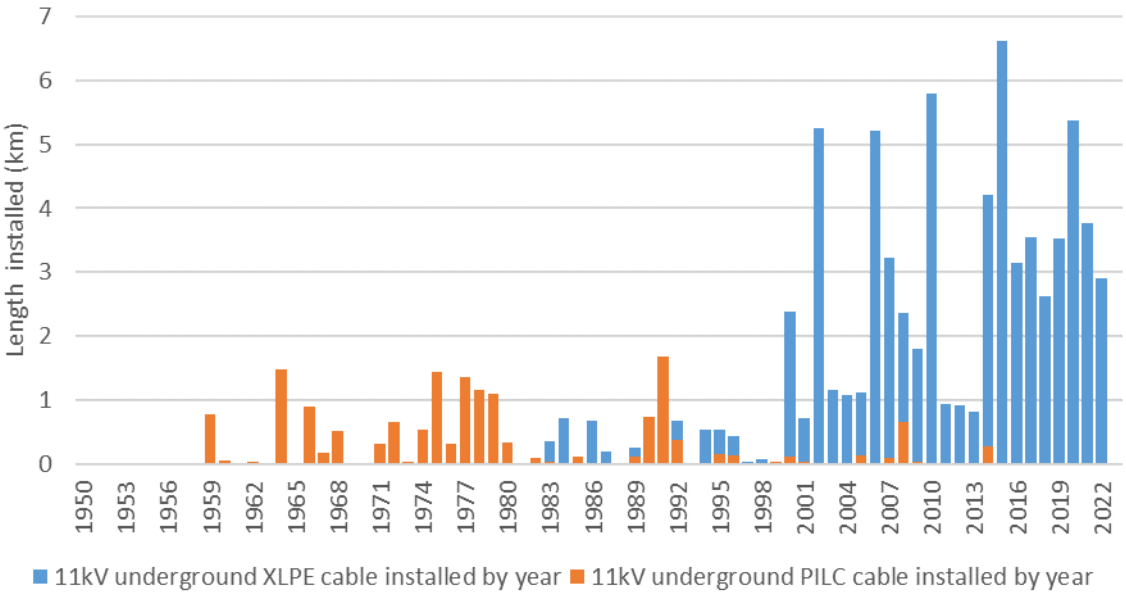


Figure 36 - Age profile of distribution cables

Of the nearly 22,000 poles on our network, approximately 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 5 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.

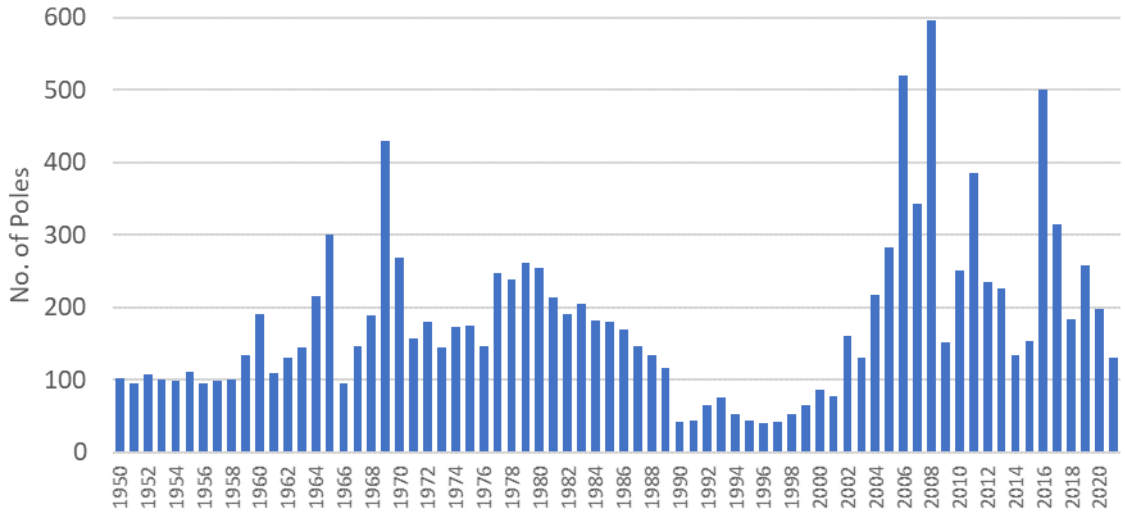


Figure 37- Age profile of wooden poles

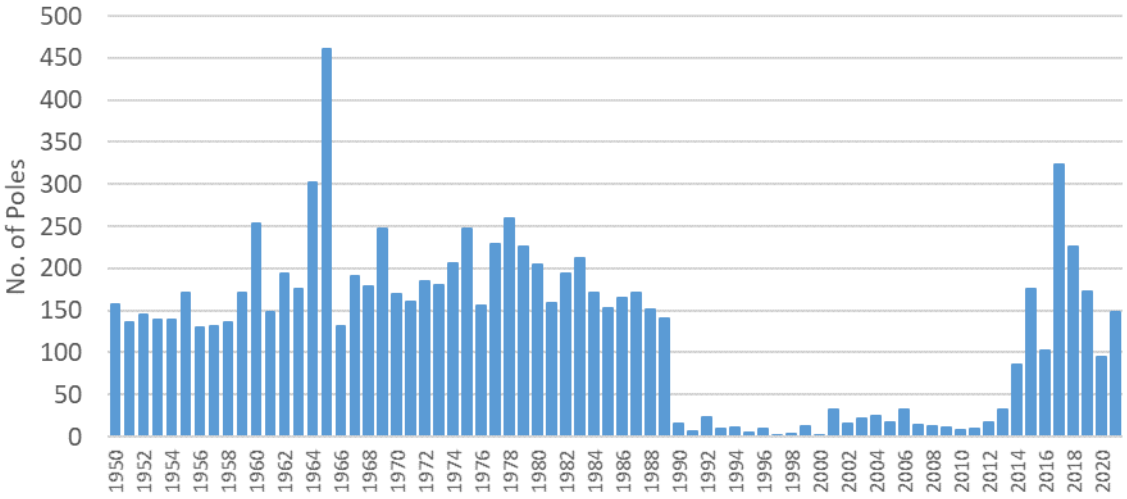


Figure 38 - **Age profile of concrete poles**

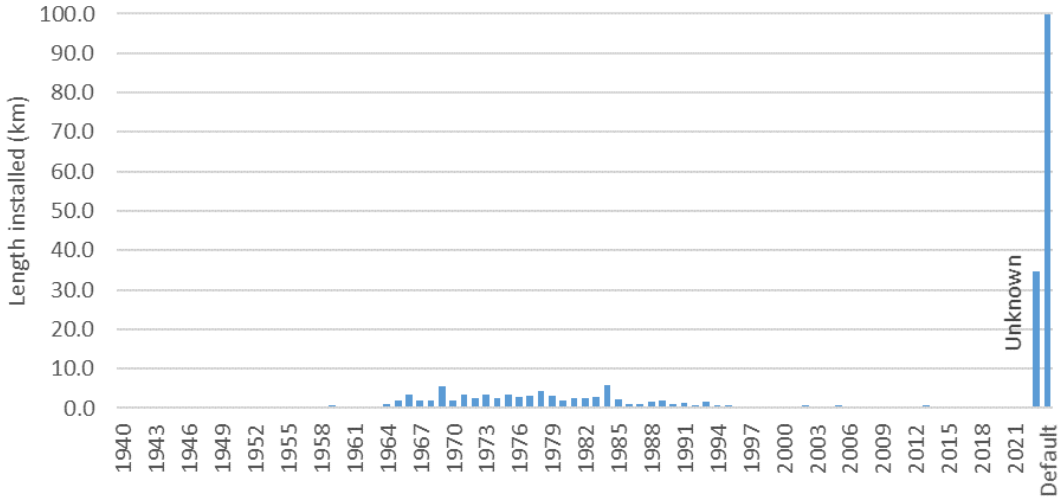


Figure 39 - Age profile of LV overhead network

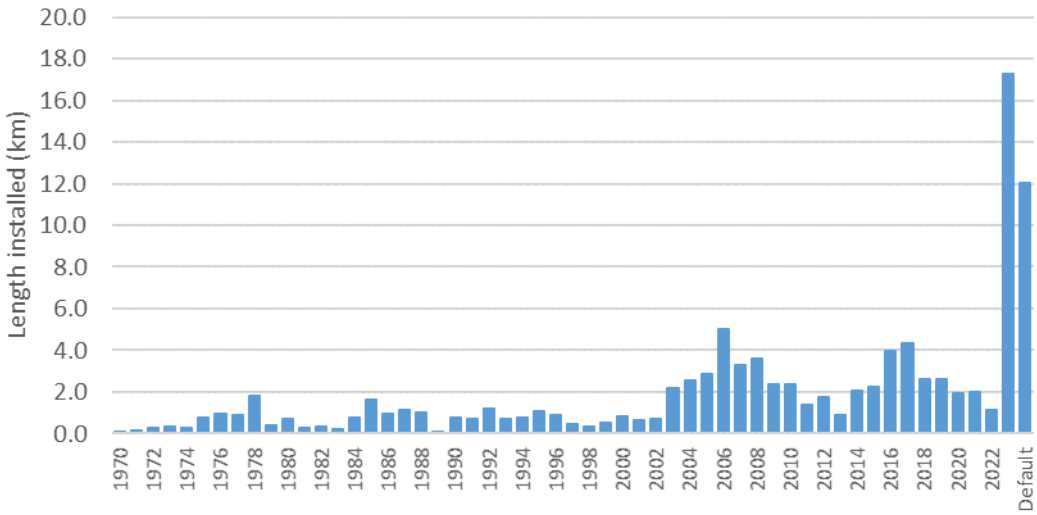


Figure 40 - Age profile of LV cables

We have a number of challenges to do with understanding the age data of our low voltage distribution lines and some of our poles. We are working with archived drawings and construction records to try and improve this information where possible, but the overall approach to date has been to maintain and replace assets based on condition, rather than age.

The distribution network is subject to a number of risks, mainly due to the extensive nature of the network. These risks include:

- Vehicle impact – much of the network is built in road reserve
- Extreme weather events such as high winds or heavy snow
- Third party interference – farm plant such as pivot irrigators moving into, spraying, or being blown into lines
- Third party interference from diggers or other mobile plant
- Degradation of structural strength due to age related issues such as corrosion

5.8.3.2 Inspection and maintenance practices

Activity	Summary	Frequency
Line patrol	Ground based visual inspection of pole top, cross arms, and pole top hardware. Testing of pole structural condition using Thor hammer and Portascan test sets, digging and probing. 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. Privately owned high voltage service lines are inspected to the same standard during the relevant line patrols of NWL Lines.	5 yearly or as required after extreme weather events
Condition and security checks	Visual inspection of lines and cables in high traffic urban areas to identify any public safety risks	Annual
Climbing patrol	Pole top accessed via ladder or EPV in order to tighten fittings, repair loose binders, examine conductor condition etc.	As required based online patrol outcomes
Partial Discharge Testing	Cable terminations as part of distribution switchgear discharge testing	5 yearly
Conductor sample testing	Special targeted testing of conductor to check for issues on older lines	As required
Vegetation patrol	Overhead distribution lines are inspected every 3 years by our specialist vegetation team to maintain safety and reliability	Minimum of 3 yearly, timed to occur between line patrols. More regular patrols for problem areas
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

5.8.3.3 Renewal and Refurbishment Program

Examination of the age profile of our poles shows that by the end of the planning period approximately 6,700 wooden poles and 4,000 concrete poles may be outside the standard life expectancy. Practical experience with these poles in our environment has demonstrated that by operating a condition-based replacement program supported by training and a suitable inspection regime we can safely operate these assets beyond their nominal useful lives.

Our policy is to replace poles when it is clear that they cannot remain in service until the next scheduled inspection. We believe that this is the correct approach to managing the end of life of poles, as it reduces risk by not leaving poles in service if they are in marginal condition. Following this policy, we have found defect rates of around 3% of the aging population per annum, which has been used to set the expected replacement of poles during the planning period at around 200 per year. We will continue to monitor and track the defect rates for different types of poles in order to provide input to the planning process for future replacements.

We have 228 km of copper and galvanised steel overhead distribution conductors that will be older than the standard expected life of 60 years within the planning period. Some sections of these conductors have been in service since the 1930's. Although most of this population does not yet cause reliability issues it is sensible to allow for a reasonable rate of proactive replacement to keep ahead of the potential for increasing faults. In addition, the age and type of a conductor may mean that our contracting team cannot work on it using live line techniques, which increases the reliability impact of any maintenance until the conductor is replaced. Other networks have experienced a rapid onset of end of life failure for these types of conductor and we are proposing to replace these proactively before reliability and safety is impacted. Close visual inspection and metallurgical assessment on samples from this population over the first three years will help to prioritise both the types, geographical areas, and the individual sections of conductor to be replaced.

Key sections of overhead line that are to be assessed and potentially reconductored during the planning period are:

- 20 km of heavy copper conductor on the Weston to Ngapara 11 kV circuit, installed in 1935, along with various copper and galvanised steel types on spur lines from this main feeder.
- 11 km of Mink ACSR conductor on the Pukeuri to Waitaki Bridge circuit that was installed in 1954.
- 3 km of small diameter copper conductor in the Kurow township area, installed in 1948.
- 12 km of single strand No. 8 galvanised steel located on rural feeders through the Ngapara, Danseys Pass and Windsor areas, installed between 1948 and 1968.

5.8.3.4 Expenditure Forecast

DISTRIBUTION NETWORK - Lines and cables	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Capital expenditure forecast ($000)										
Distribution pole and hardware replacements due to condition	1,365	1,365	1,470	1,470	1,470	1,470	1,470	1,470	1,470	1,470
Distribution rebuilds due to line age and condition										
Ngapara No. 8 GS (2900m)	209									
Danseys Pass No. 8 GS (850m)	61									
Kauru Hill Rd No. 8 GS (500m)	36									
Pig Island Rd No. 8 GS (1800m)	130									
Tussocky Rd No. 8 GS (3000m)	215									
Windsor No. 8 GS (2900m)	209									
Kurow Township rebuild 7/16 Cu (3000m)		648								
SH1 Pukeuri North to Waitaki Bridge		58	835							
Weston to Ngapara 11kV Cu replacement (19.8 km)						702	702			
Ongoing rebuild of lines based on conductor type and age	396	400	400	1,500	1,500	1,500	1,500	2,000	2,000	2,000
Remove road crossings on transport corridors to create higher clearances	58	58								
Replace old cable terminations	58	58	58	58	58	58	58	58	58	58
Capital subtotal	**2,737**	**2,587**	**2,763**	**3,028**	**3,028**	**3,530**	**3,530**	**3,528**	**3,528**	**3,528**
Operational expenditure forecast ($000)										
11kV Patrols	315	315	210	210	210	210	210	210	210	210
Distribution line maintenance	310	242	242	242	242	242	242	242	242	242
Conductor sample condition testing	105	105	105							
Operational subtotal	**730**	**662**	**557**	**452**	**452**	**452**	**452**	**452**	**452**	**452**
Vegetation management patrols and maintenance	**342**	**342**	**342**	**342**	**342**	**342**	**342**	**342**	**342**	**342**
Operational Subtotal including vegetation management	**1,072**	**1,004**	**899**	**794**	**794**	**794**	**794**	**794**	**794**	**794**

5.8.4 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 programs that commenced then, and the more recent network reinforcement programs.

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.

Life expectancy for this class of asset is shown in the table below:

Table 19 - Life expectancy for distribution switchgear

Asset description	Standard life expectancy (years)
Air break switch (ABS)	35
Ring Main Unit (RMU)	40
Fused Oil switch	40
Drop out fuse	35
LV Switchgear	45
Service Fuse Box (SFB)	45

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.

5.8.4.1 Age profiles

The age profiles of 11 kV distribution switchgear are shown in the following figures:

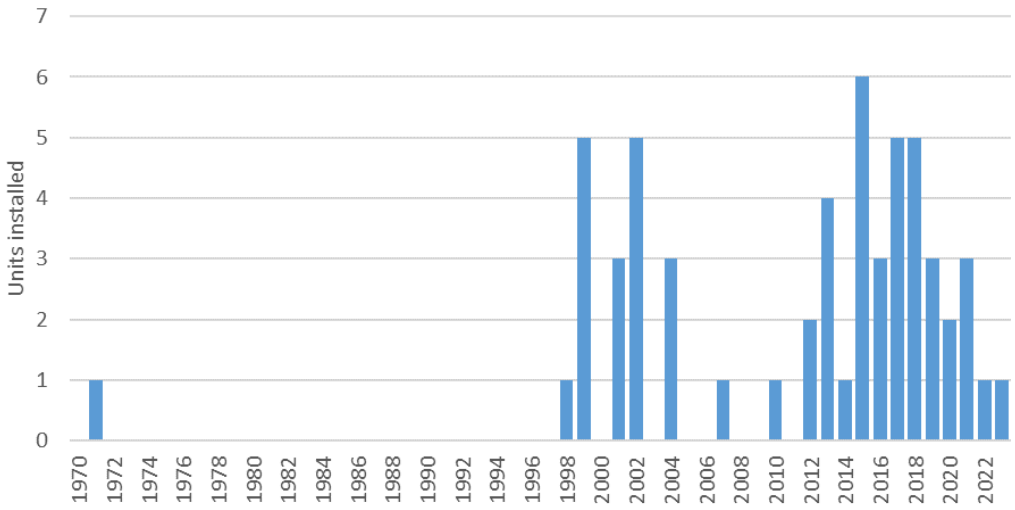


Figure 41 - Age profile of distribution sectionalisers and reclosers

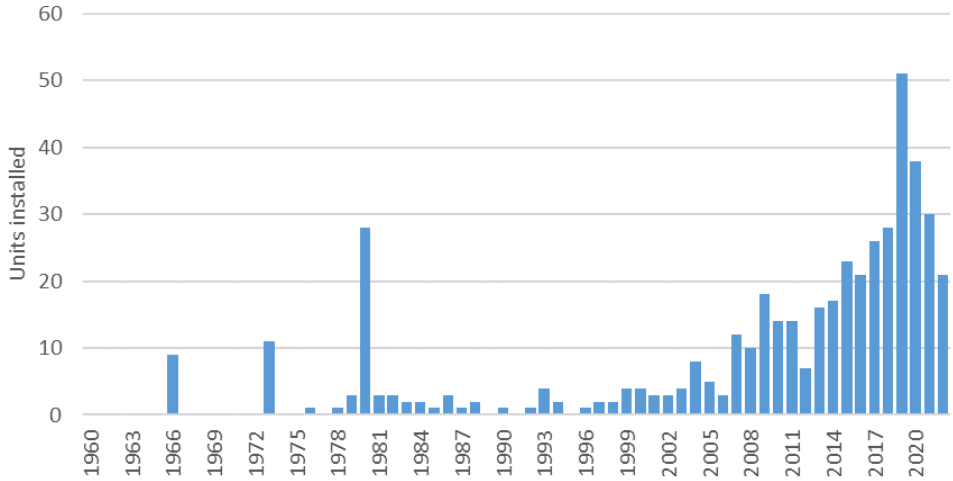


Figure 42 - Age Profile of Pole Mounted ABS

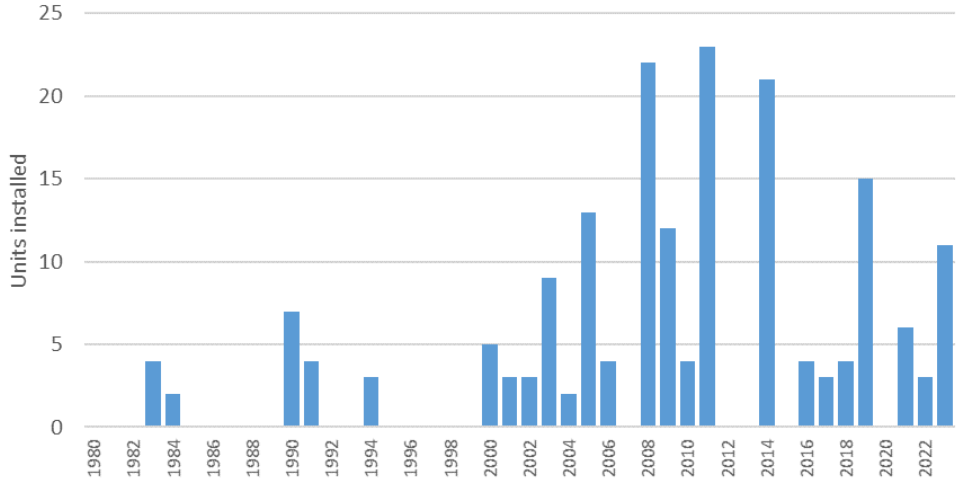


Figure 43 - Age profile of ground mounted distribution switchgear

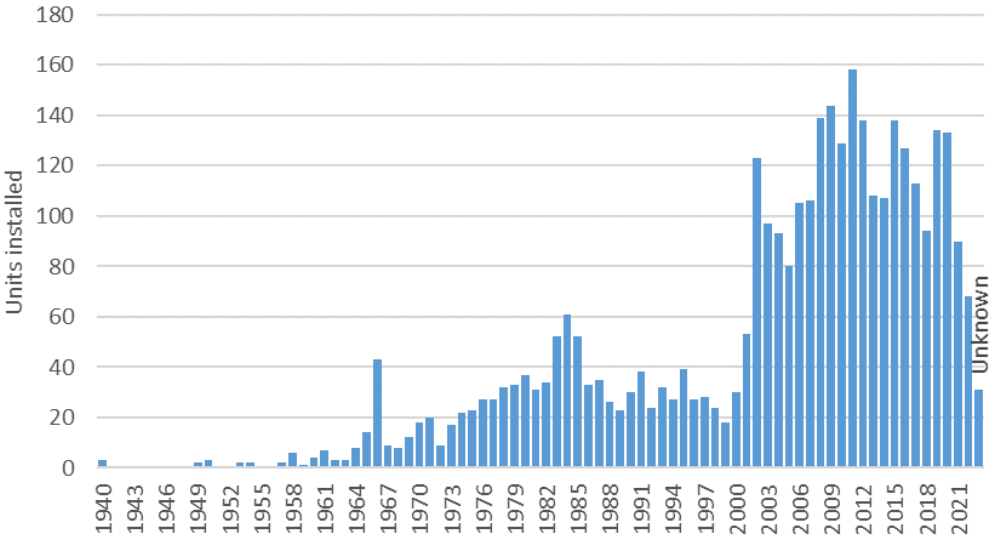


Figure 44 - Age profile of 11 kV fuses

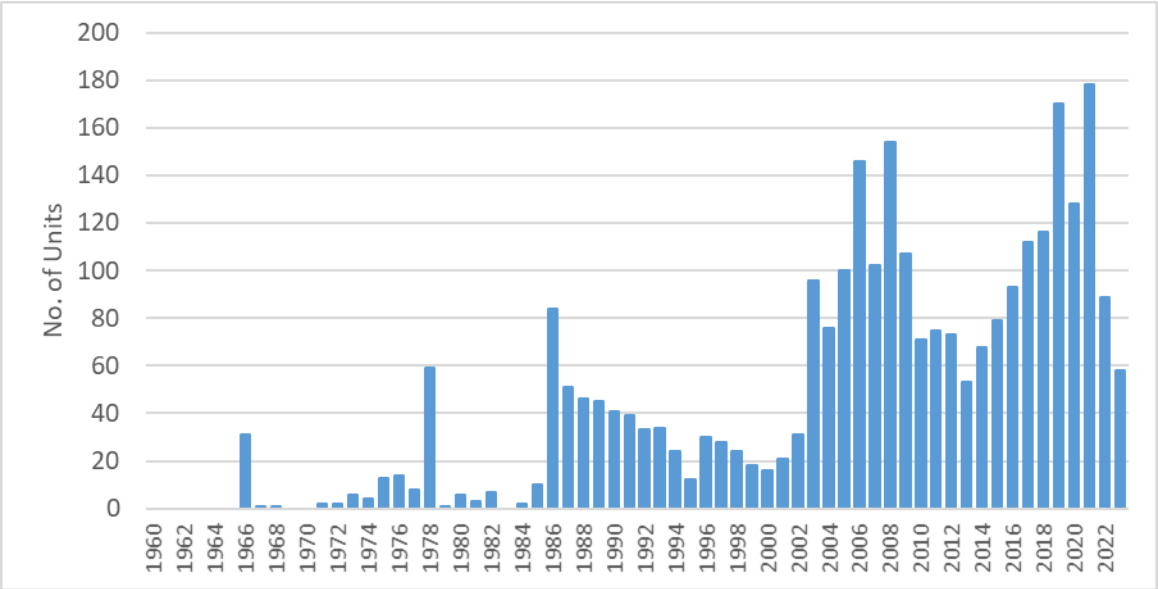


Figure 45 - Age profile of low voltage switch gear

We classify our LV switchgear into two groups:

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

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 is dependent on the 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 with this, an ABS or fuse on a spur line or a low voltage fuse supplying one house has lower overall 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 in close proximity during switching.

Recent operational 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 currently in service 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 these units 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.

5.8.4.2 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	Lubrication, checking operation	5 yearly
Recloser and sectionaliser operational checks	Operational tests and checks. Replace batteries	5 yearly
Insulator checks	Special visual inspection for 11 kV air break switches prone to porcelain insulator failure	6 monthly

5.8.4.3 Renewal and refurbishment program

The renewal and refurbishment program 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 ABS's of the type prone to insulator failures in the early years of the planning period
- Replace other switchgear based on condition assessment from scheduled inspections.
- Replace three oil filled ring main units per year 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.
- A recently installed ring main unit is to be replaced following discovery of a fault within the production batch.

5.8.4.4 Expenditure Forecast

DISTRIBUTION NETWORK - Switchgear	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Capital expenditure forecast ($000)										
Distribution switchgear replacement due to age and condition										
ABS age and condition based replacement	53	53	53	53	53	53	53	53	53	53
EDE ABS Replacement	287	287	287	287	287	287	115			
Recloser/sectionaliser/tie switch replacement	137	137	40	40	40	40	40	40	40	40
Replacement of Cross St RMU	105									
Replace Oil filled RMUs										
Awamoa Park, Ribble St	230									
Two conversions per year ongoing		230	230	230	230	230	230	230	230	230
Install automation equipment	78	78	78	78	78	78	78	78	78	78
Install ABS and spur fusing	36	36	36	36	36	36	36	36	36	36
LV Distribution Box Replacement										
J-type replacements	114	114	286	286	114	114	114	114	114	114
Over Veranda distribution boxes @ 4 per annum	46	46	46	46	46	46	46	46	46	46
Streetlight Control Replacement	23									
Capital Subtotal	**1,109**	**981**	**1,056**	**1,056**	**884**	**884**	**712**	**597**	**597**	**597**
Operational expenditure forecast ($000)										
Ground mount equipment safety and compliance inspections										
Distribution Boxes and RMU – annual inspections	26	26	26	26	26	26	26	26	26	26
SFB Trial & Patrol - 5 yearly	21	21	21	21	21	21	21	21	21	21
Distribution switchgear maintenance										
ABS maintenance	100	100	100	100	100	100	100	100	100	100
Distribution CB's & Protection	21	21	21	21	21	21	21	21	21	21
Switching Station Maintenance	34	34	34	34	34	34	34	34	34	34
Operational Subtotal	**202**	**202**	**202**	**202**	**202**	**202**	**202**	**202**	**202**	**202**

5.8.5 Distribution transformers

The 11 kV distribution network supplies 2,918 distribution transformers, of which approximately 400 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 which are located to accommodate three to four LV feeders. Transformer capacity is normally based on an average After Diversity Maximum Demand (ADMD) of approximately 5.6 kW for a domestic customer.

An LV distribution switchboard is normally housed in or near the transformer cabinet with each feeder being independently fused. The LV switchboard is mounted independently of the transformer cabinet and is fitted with an incomer switch to facilitate 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 transformers which are pole mounted.

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.

The life expectancy that we apply to distribution transformers is shown in Table 20.

Table 20 - Life expectancy for distribution transformers and substations

Asset description	Standard life expectancy (years)
Pole mounted transformer	45
Ground mounted transformer	45
Voltage regulators	25

5.8.5.1 Age profiles and population data

The latest development period is showing a tendency towards larger sized transformers than the earlier period. The age profile of our ground and pole mounted transformers is shown below.

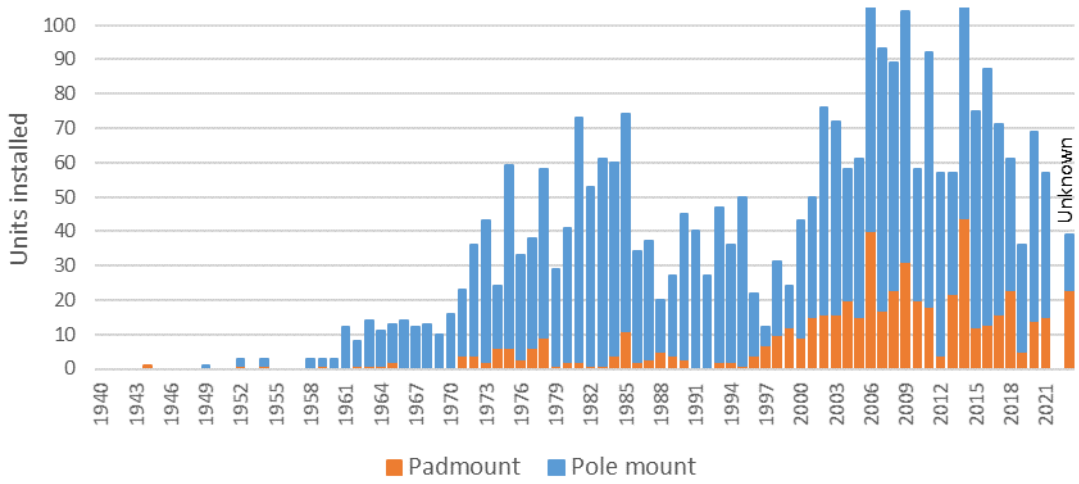


Figure 46 - Age profile of distribution transformers

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 utilised 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 to 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 utilised, 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 the ongoing work to develop a low voltage monitoring system, mentioned in section 6.2.2.1 LV network monitoring and visibility**Error! Reference source not found.**. In addition to the ongoing roll out of the low v oltage 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 in service, with few equipment failures in general.

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

5.8.5.2 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	Annual
MDI reading	Check and record loadings on larger transformers	Annual
Earth testing	Test earth continuity and values	5 yearly

5.8.5.3 Renewal and refurbishment program

The renewal and refurbishment program 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

We are planning to complete a steady number of transformer replacements throughout the planning period, to maintain the average age of the fleet to a reasonable figure. Replacements will often naturally coordinate with other works such as capacity or configuration upgrades.

5.8.5.4 Expenditure Forecast

DISTRIBUTION NETWORK - Transformers	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Capital expenditure forecast ($000)										
Distribution Transformer replacement due to age and condition	230	230	230	230	230	230	230	230	230	230
Upgrade/renew distribution earths	34	34	34	34	34	34	34	34	34	34
Capital Subtotal	**264**	**264**	**264**	**264**	**264**	**264**	**264**	**264**	**264**	**264**
Operational expenditure forecast ($000)										
Dist. Tx. Maintenance	105	105	105	105	105	105	105	105	105	105
Earth Testing - 5 yearly	74	74	74	74	74	74	74	74	74	74
Ground mount equipment safety and compliance inspections	26	26	26	26	26	26	26	26	26	26
Maintain distribution earths	16	16	16	16	16	16	16	16	16	16
Power quality investigations	5	5	5	5	5	5	5	5	5	5
Operational Subtotal	**225**	**225**	**225**	**225**	**225**	**225**	**225**	**225**	**225**	**225**

5.8.6 Total Distribution Network Expenditure Forecast

DISTRIBUTION NETWORK	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Capital expenditure forecast ($000)										
Distribution pole and hardware replacements due to condition	1365	1365	1470	1470	1470	1470	1470	1470	1470	1470
Distribution rebuilds due to line age and condition	1256	1106	1235	1500	1500	2202	2202	2000	2000	2000
Remove road crossings on transport corridors to create higher clearances	58	58								
Replace old cable terminations	58	58	58	58	58	58	58	58	58	58
Distribution switchgear replacement due to age and condition	477	477	380	380	380	380	208	93	93	93
Replace faulty Halo RMU	105									
Replace Oil filled RMUs	230	230	230	230	230	230	230	230	230	230
Install automation equipment	78	78	78	78	78	78	78	78	78	78
Install ABS and spur fusing	36	36	36	36	36	36	36	36	36	36
Distribution Box Replacement	160	160	332	332	160	160	160	160	160	160
Streetlight Control Replacement	23									
Distribution Transformer replacement due to age and condition	230	230	230	230	230	230	230	230	230	230
Upgrade/renew distribution earths	34	34	34	34	34	34	34	34	34	34
Distribution pole and hardware replacements due to condition	1365	1365	1470	1470	1470	1470	1470	1470	1470	1470
Total capital expenditure	**4,110**	**3,832**	**4,083**	**4,348**	**4,176**	**4,878**	**4,706**	**4,389**	**4,389**	**4,389**
Operational expenditure forecast ($000)										
Distribution line maintenance	310	242	242	242	242	242	242	242	242	242
11kV Inspections	315	315	210	210	210	210	210	210	210	210
Conductor sample condition testing	105	105	105							
Ground mount equipment safety and compliance inspections	73	73	73	73	73	73	73	73	73	73
Distribution switchgear maintenance	155	155	155	155	155	155	155	155	155	155
Dist. Tx. Maintenance	25	25	25	25	25	25	25	25	25	25
Earth Testing - 5 yearly	70	70	70	70	70	70	70	70	70	70
Maintain distribution earths	15	15	15	15	15	15	15	15	15	15
Power quality investigations	5	5	5	5	5	5	5	5	5	5
Total operational expenditure	**1,073**	**1,005**	**900**	**795**	**795**	**795**	**795**	**795**	**795**	**795**
Vegetation Patrols and maintenance	342	342	342	342	342	342	342	342	342	342
Total operational expenditure including vegetation management	**1,415**	**1,347**	**1,242**	**1,137**	**1,137**	**1,137**	**1,137**	**1,137**	**1,137**	**1,137**

5.9 OTHER SYSTEM FIXED ASSETS

5.9.1 SCADA

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, the majority of reclosers and sectionalisers are also connected to the SCADA system and can be remotely controlled.

The SCADA system uses UHF radio data communications provided by our licensed radio network. Radio repeaters are sited at Cape Wanbrow, Station Peak and Cloud Hill. They are shared by the VHF radio telephone system NWL uses for operational voice communications between the control room and field operators.

The life expectancy of this equipment is shown in the Table 21 below:

Table 21 - Life expectancy of other fixed network assets

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

5.9.1.1 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.

5.9.1.2 Age profiles and population data

Our SCADA system is approximately 15 years old.

Failure of the SCADA and/or radio communications system would render the control room inoperative, although a reduced level of network operation could continue in the field using other means of communication, and direct operation at substations and field devices.

The major risks to the radio network are the remote locations of our repeater sites – during extended outages due to snow they have failed in the past.

The major risk to our SCADA system is hardware failure, as they operate on specialised PC's. This is to some extent mitigated by having a master and a backup computer. In 2020 a complete offsite control room was commissioned to act as an offsite backup for the main control room.

5.9.1.3 Inspection and maintenance practices

Maintenance of the SCADA and Communications Systems involves an annual radio equipment site check and a support contract with the SCADA system provider.

5.9.1.4 Renewal and refurbishment program

Renewal and refurbishment programs for the planning period include:

- Review and upgrade SCADA and radios. As part of this work, we expect that we will be installing fibre optic communications to several of our zone substations.
- Replace old cascade streetlight control system with ripple control, as necessary.
- Installation of distribution transformer low voltage monitoring systems (see Section 6.2.2.1 - LV network monitoring and visibility for details)
- Ongoing maintenance of access tracks on an as-required basis
- Work with landowners to resolve ongoing access issues to some of our remote radio sites
- Investigate the replacement of our SCADA system with a more modern system that allows up to date outage management and automation operational approaches to be developed.

5.9.2 Total other fixed asset expenditure forecast

Table 22 - Forecast expenditure for other fixed network assets

OTHER	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Capital expenditure forecast ($000)										
LV Monitoring	250	500	500							
SCADA access to Engineering data at substations	50	50								
Demand Response Trial	30									
Radio Link Upgrade (PC Sums, project development in FY23)		160								
Fibre/Comms Projects (Dependent on overall comms plan)	240	651	342	450	589	572	240			
SCADA/OMS replacement				1,255						
Relocation of Cloud Hill repeater (subject to further investigation)		231								
Total capital expenditure	**570**	**1,592**	**842**	**1,705**	**589**	**572**	**240**	**0**	**0**	**0**
Operational expenditure forecast ($000)										
LV Monitoring OPEX	15	24	48	72	72	72	72	72	72	72
Track Maintenance	20	20	20	20	20	20	20	20	20	20
Radio Repeater Maintenance	18	18	18	18	18	18	18	18	18	18
Radio and SCADA support	15	15	15	15	15	15	15	15	15	15
Before U Dig	16	16	16	16	16	16	16	16	16	16
Streetlight Maintenance	10	10	10	10	10	10	10	10	10	10
Total operational expenditure	**94**	**103**	**127**	**151**	**151**	**151**	**151**	**151**	**151**	**151**

5.10 RENEWALS AND MAINTENANCE EXPENDITURE SUMMARY

Forecast expenditure for renewals and maintenance are summarised by asset category in the figure below:

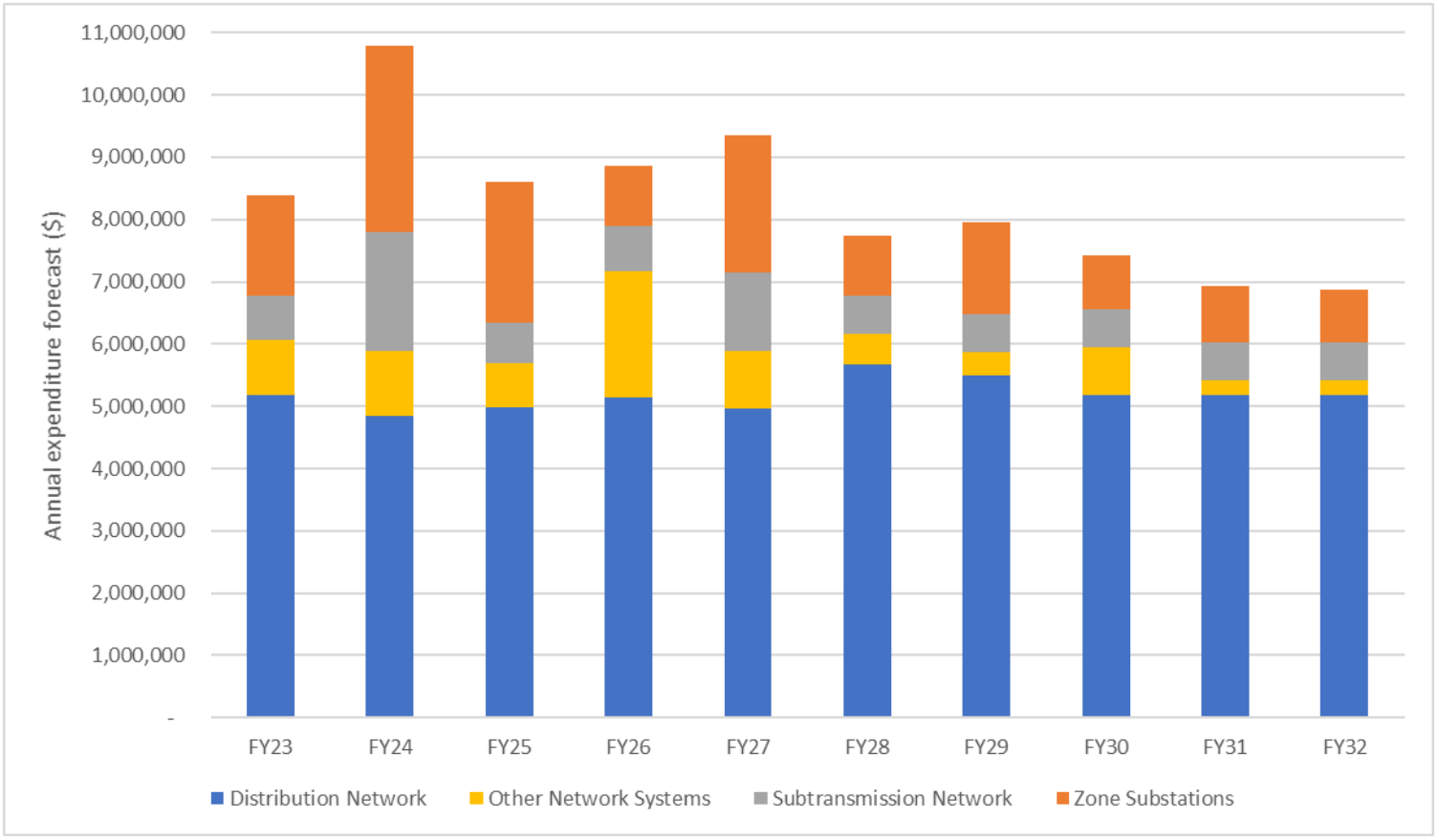


Figure 47 – Renewals and maintenance expenditure forecast by asset category

POWERING OUR FUTURE

06

NETWORK DEVELOPMENT PLAN

This chapter sets out our Network Development Plan and covers:

Planning approach: Explains our focus, development drivers, planning criteria, and demand forecasting methodology.

Network Evolution Roadmap – Our plan to transform our network to achieve the goals of the ENA Network Transformation Roadmap.

Development programs. Capacity and security levels have been analysed for our network over the planning period. Options to solve any capacity or security shortfalls are presented.

Summary of expenditure forecasts

6. Network development plan

6.1 INTRODUCTION

Our Network Development Plan is focused on:

- Ensuring our customers receive appropriate security and reliability levels
- Ensuring we make the best decisions to enable the future needs of our customers
- Developing scenarios for our customers' future needs and identifying possible constraints on our network
- Selecting the best solutions to mitigate these constraints

Key themes in this plan are:

- Our roadmap for how we will evolve our network to enable our customers' future needs (Section 6.2, p116)
- How we plan to address our transmission constraint in light of the large, expected decarbonisation demand (Section 0, p147)
- Our view on the effects of future irrigation demand and the impacts of electric vehicles and solar distributed generation (Section 6.3.3.1, p135)

6.2 OUR ROADMAP FOR NETWORK EVOLUTION

To meet our climate change objectives, New Zealand must transition away from carbon-based fuels in our energy supply. Electricity is highly likely to supply a large proportion of this transition as process heat and our transport fleet move away from fossil fuels.

Also, as the proportion of large-scale intermittent solar and wind generation increases on our national grid, we will experience more supply-side variability. This will increase the value for providing demand-side flexibility such as using Distributed Energy Resources (DER) to optimise demand or to supply energy back into the grid. DER can be defined as a controllable energy resource located in the distribution network[7] and includes:

- Solar photovoltaic systems
- Electric vehicle chargers
- Battery storage systems
- Electric hot water cylinders

Over the next decade our customers will increase their take up of DER. This will largely be driven by their views on climate change, government incentives, cost reductions, new value streams from providing control of DER and ownership models which allow access to these technologies with low capital outlay.

We present scenarios for low, expected, and high uptake of DER in Section 6.3.3.1, p139-147.

As our customers take up more of these technologies, they will use our network differently and may change their expectations of how our network should perform. Over the next 24 months, we are developing a customer-centric Network Service Level Standard to replace our traditional Security of Supply Standard.

[7] Transpower-Distributed Energy Resources – exploring the potential – August 2020

To evolve our networks to enable our customers' future desires, Electricity Distribution Businesses need to work together. We are actively collaborating with the industry, both formally and informally, and place great importance on building and maintaining our relations with other EDBs. We are active members of the following industry groups:

- South Island Distribution Group – Developing Distribution System Operator roadmap and collaboration on trials
- South Island Chief Executives – Direction setting to enable collaboration between EDBs
- EEA Emerging Technology Group –Developing technical guidance for DERs
- ENA Smart Technology Working Group – Developing and enabling the Network Transformation Roadmap
- ENA Regulatory Working Group –Working with our regulators to develop sound legislation and fair rules
- ENA Consumer Engagement Working Group – Providing strategic direction and collaboration opportunities

We have based our Network Evolution Plan on the ENA Network Transformation Roadmap which has the goal of providing a 'least regrets' pathway to a framework that underpins:

- sustainable connection of new technology to the distribution network
- trading of energy and capacity between customers and market participants
- distributors being well informed on planning, investment, and operational requirements

The NTR identifies a main programme to establish an Open Network Framework. Four constituent programmes are identified as enablers of the master programme and a further two programmes are concerned with developing an understanding of our customers' and keeping up with technology developments.

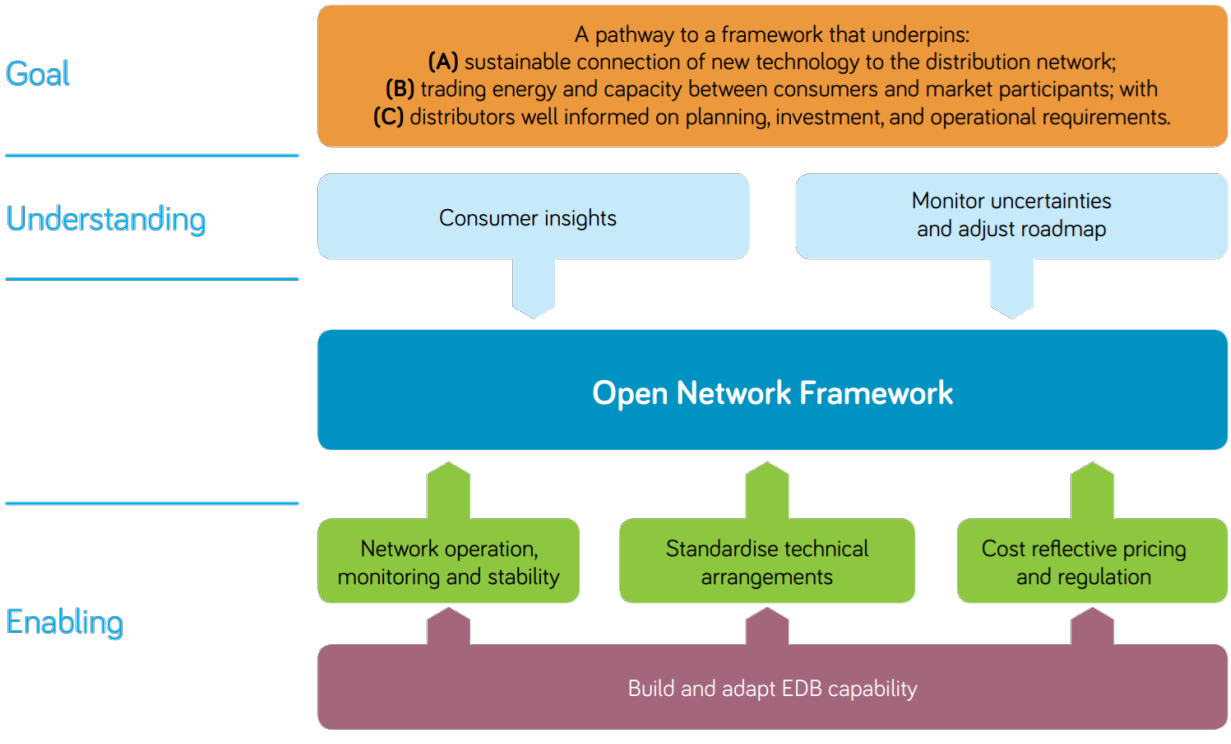


Figure 48 - ENA Network Transformation Roadmap (NTR) programmes

We have analysed our progress toward achieving the Network Transformation Roadmap goals and have developed our Network Evolution Roadmap which details the actions we will take to reach these. These goals and workstreams are aligned with our strategic plan.

Our Network Evolution Roadmap contains full details of our action plans and many of these will be developed collaboratively across the working groups that we are part of.

The following high focus workstreams from the Network Evolution Roadmap are presented in this years' Network Development Plan:

Build and adapt EDB capability programme

- Network understanding
- Contracting for network support
- Off grid power supplies

Network Operation, monitoring, and stability programme

- LV network monitoring and visibility
- Network stability

Customer insights programme

- Access to smart meter data
- Understand Distributed Energy Resource (DER) deployment
- Understand new energy demand

6.2.1 Build and adapt EDB capability programme

6.2.1.1 Network understanding workstream

The goal of this workstream is to understand congestion and hosting capacity on our low and medium voltage networks and to be able to identify opportunities where Distributed Energy Resources (DERs) can mitigate congestion.

Where are we now?

Our ESRI GIS connectivity model is accurate to customer LV level, but we do not have data on which low voltage phase each customer is connected to.

We have integrated our Digsilent Powerfactory network model with our GIS data to zone substation level. Data have been verified and the model is now being used for network planning.

We have built strong relationships with our peer EDBs and key consultants who we will collaborate with as we develop our software and processes.

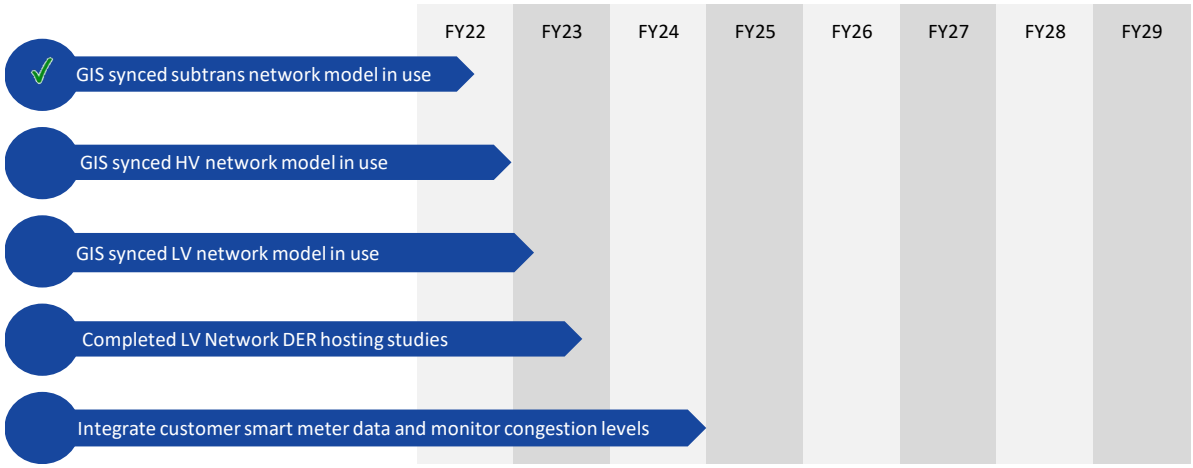
Where do we want to be before FY29?

We will have full synchronisation of our GIS system and our modelling software, understand which phases our LV customers are connected to, and understand the size and quantity of DERs on our network. We will understand hosting capacity and be able to model congestion scenarios and understand where DERs could be utilised to mitigate this.

Next steps

We will conduct preliminary DER hosting capacity studies from our GIS model in Q1 FY23 and are scheduled to have our Powerfactory model in use for low voltage level by the end of FY23**.** We aim to integrate historical customer smart meter data with our Powerfactory model to better understand annual demand diversity and our asset utilisation at a more granular level. Once our LV model is in use, we will develop a roadmap for understanding low voltage customer phase connectivity.

Roadmap



Alignment with our strategic plan

Strategic priority:	Excellence and Innovation in our core business
Initiative:	Effective network development planning

Action:	Implement modern network modelling tools to model down to distribution transformer/LV level

6.2.1.2 Contracting for network support workstream

The goal of this workstream is to ensure we regularly consider the option of contestable procurement of network support as an alternative to traditional network capital expenditure.

Where are we now?

We are members of the ENA Smart Technologies Working Group, the EEA Emerging Technologies Working Group, and the South Island Distribution Group. We have a good relationship with Aurora Energy who have worked through this process for the Upper Clutha Non Network Alternative Project, and we regularly evaluate non-network solutions as an option in our business cases.

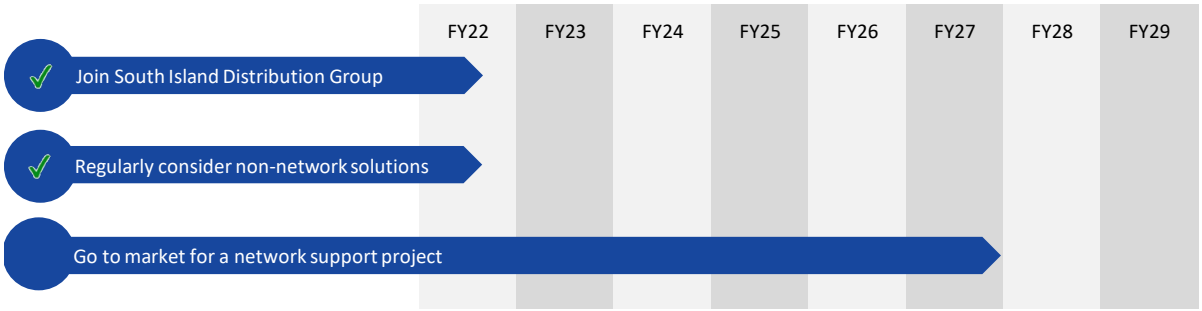
Where do we want to be before FY29?

We will have refined our processes for early identification of projects that may benefit from non-network alternatives and will have asked the market to offer network support services to solve a major network capacity or security issue and procured these services if they are found to be the best option.

Next steps

Our next steps are to refine our processes for early identification of projects that may benefit from non-network solutions and to approach the market for network support solutions to address a constraint near the end of the planning period.

Roadmap



Alignment with our strategic plan

Strategic priority:	Excellence and Innovation in our core business
Initiative:	Solution for our long-term transmission constraint
Action:	Non network alternatives identified and trialed for effectiveness

6.2.1.3 Off grid power supplies workstream

The goal for this workstream is to develop our processes and build relationships which allow us to evaluate off grid power supplies as an option and be ready to select this option where this is more economic than traditional network solutions.

Where are we now?

We have performed technical and economic analysis for an off-grid power supply as an option for a remote network line which was scheduled for condition-based replacement in 2019. In this case it was more economic to install a traditional network solution.

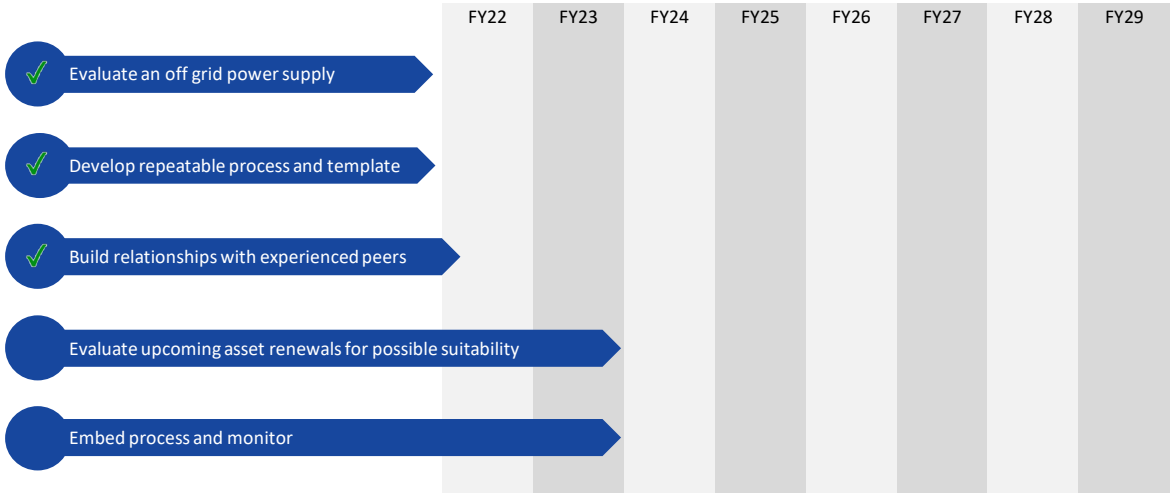
This business case will be used as a template for future analysis, and we have developed contacts with other EDBs who have successfully evaluated and installed off grid power supplies.

We consider off grid power supply solutions when investigating asset renewals or new connections where low numbers of customers are supplied long lengths of line.

Next steps

In FY23, we will examine our asset data to identify locations where condition-based renewals are forecast and where location, line length and customer density indicate that this may be an economic option. This will allow us to evaluate off grid power supplies as an option and programme into our Asset Management Plan.

Roadmap



Alignment with our strategic plan

Strategic priority:	Offer innovative new solutions to our customers
Initiative:	Solution for our long-term transmission constraint
Action:	Non network alternatives identified and trialed for effectiveness

6.2.2 Network operation, monitoring, and stability programme

6.2.2.1 LV network monitoring and visibility

The goal for this workstream is to roll out low voltage monitoring systems (in conjunction with provision of data from smart meters) to assist with network management and to improve the quality and type of monitored data over time. This workstream is an enabler for the Customer Insights Programme and the Open Network Framework programme.

Where are we now?

Our low voltage networks were historically designed for one way power flow from distribution transformer to our customers, based on the assumption that average customer demand will not increase significantly over time. Low voltage upgrades typically resulted from new customer connections or a transformer demand approaching rated capacity.

Transformer demand is currently measured using Maximum Demand Indicators (MDIs) which are read on site annually. These record the maximum current experienced on a transformer during the year but do not provide any information about the time and duration of demand, feeder loads, or any power quality information. These have served us well over the years but provide very little operational benefits and have been known to present false readings if they were not reset after the transformer was used to back up an adjacent transformer.

We currently have ten cloud-connected Distribution Transformer Monitoring (DTM) devices installed across our transformer fleet, which were installed as part of a previous trial.

Where do we want to be before FY29?

With new technology predicted to cause increased customer demand, changing diversity patterns, and two way power flows, we must better understand the performance of our low voltage networks so we can optimise the use of our networks and ensure we operate our assets, in particular our cables, within their ratings. This will allow us to monitor congestion and changes in network usage and program any related investment prudently. We plan to achieve this by installing low voltage monitoring on our distribution transformers and feeders, starting with the transformers with the highest customer density.

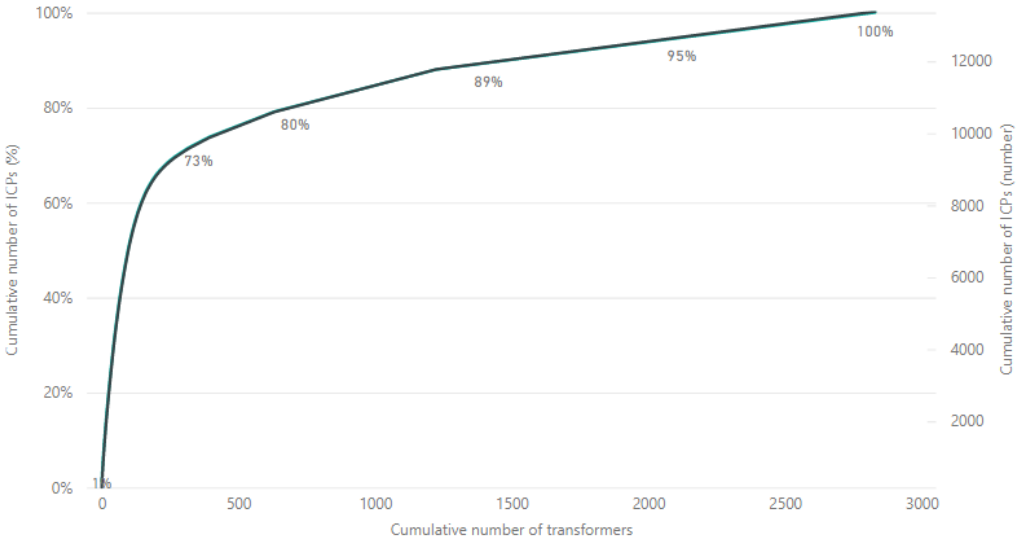


Figure 49 - Connected customers per transformer

The table below shows the number of customers supplied from our distribution transformers and the associated cost:

Number of transformers	Number of customers	Percentage of total number of customers	Capital investment estimate per customer
50	4403	33%	$39
100	6805	51%	$50
200	8813	66%	$77
300	9479	71%	$108
450	10041	75%	$152
1000	11317	85%	$300
2100	12621	95%	$566

We plan to install low voltage monitoring devices at 300 distribution transformers and associated low voltage feeders by the end of FY25, which will cover up to 71% of our connected customers for a total capital investment of $1.5M.

We have selected a preferred supplier which is aligned with one of our peer EDBs. The low voltage monitoring option chosen will be able to be integrated into a future Advanced Distribution Management System.

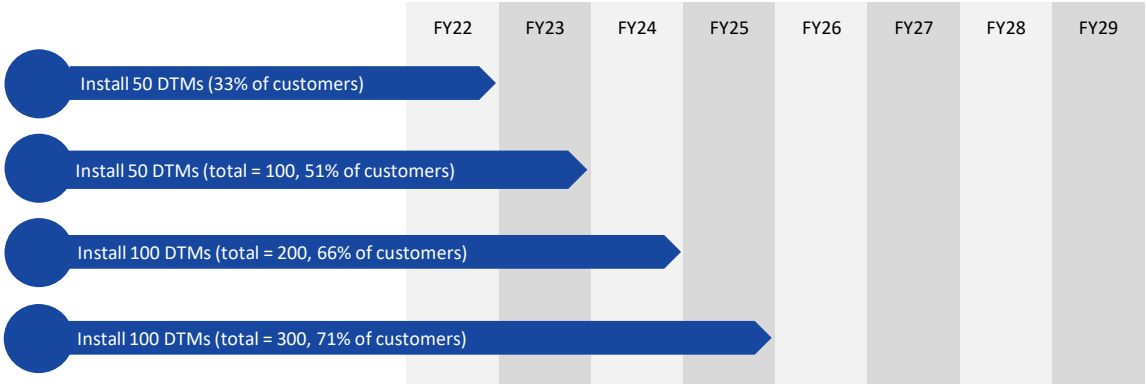
Next steps

In FY22, we purchased low voltage monitoring devices which will be installed at 50 distribution transformers and associated feeders which will cover 33% of our customers. We will install an additional 50 devices in FY23.

Initially data will be hosted by the DTM supplier, and we will access this via a standalone LV dashboard to give indications of power status and quality for planning purposes. In the future, we could host and access the data ourselves, which may result in reduced OPEX requirements.

We will also evaluate operational benefits and develop a plan to integrate these into the business.

Roadmap



Alignment with our strategic plan

Strategic priority:	Excellence and innovation in the core business
Initiative:	Customer Data, Metering and Monitoring
Action:	Develop an LV network management and ICP monitoring solution to improve customer service

6.2.2.2 Network Stability

The goal for this workstream is to investigate the implications of numerous autonomous Distributed Energy Resources (DERs) and methods of controlling these. It is expected that this workstream would be carried out across multiple, if not all, Electricity Distribution Businesses (EDBs) in consultation with other industry and the market.

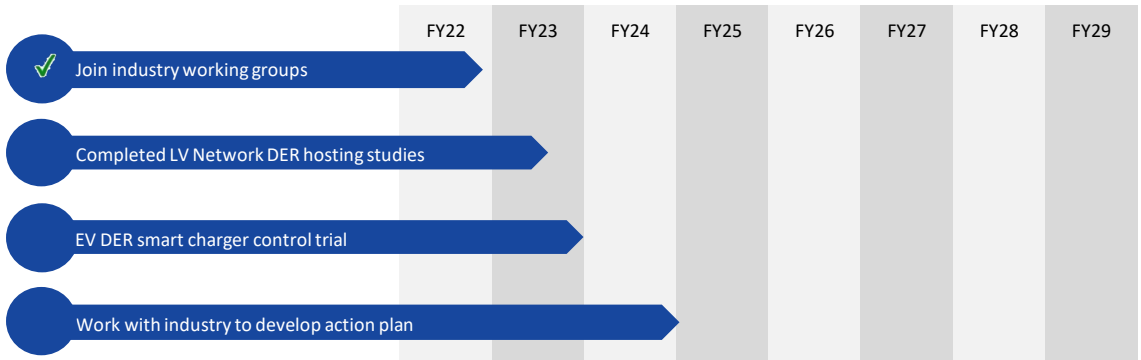
Where are we now?

We have a representative sitting on the ENA Smart Technologies Working Group, which is currently reviewing the Network Transformation Roadmap, the EEA Emerging Technologies Working Group which is looking to develop guidance about DER integration and control, and the South Island Distribution Working group which is investigating the Distribution System Operator function.

Next steps

As part of these groups and with the other New Zealand EDBs, we will develop an action plan to investigate the implications and methods of controlling autonomous DER. We are also performing a hosting study on our low voltage networks in Q4 FY22 and planning an EV control trial with a supplier and the South Island Distribution Group.

Roadmap



Alignment with our strategic plan

Strategic priority:	Offer innovative new solutions to our customers
Initiative:	Develop our future technology strategy
Actions:	Participate in industry working groups
	Develop and maintain a high level of awareness of technology, costs, economics, and market trends
	Collaborate with other EDBs and understand in-progress trials

6.2.3 Customer insights programme

6.2.3.1 Access to smart meter data

The goal for this workstream is to gain access to smart meter data, initially non real-time to aid planning and understanding of our customers' electricity needs and ultimately real-time consumption and power quality data to aid us in our operational decision making.

At a customer level, the value to us is using the data rather than owning monitoring equipment on customers' premises.

Our view is that we will ultimately be able to receive and use data from many different sources in the future. This may be from a combination of smart meters, customer inverters, electric vehicle chargers, streetlight central management systems, utility cabinets and others.

Data from these external sources will augment the data we will receive from our low voltage monitoring devices that we are installing under the LV network monitoring workstream.

Where are we now?

We have recently received smart meter data, from a large retailer in our network, for over half of our domestic customers and a large number of irrigation customers in our supply area under Appendix C of the Default Distributor Agreement. We have developed an information security plan that has been endorsed by the retailer and are starting to use these data to better understand load profiles of our customer groups.

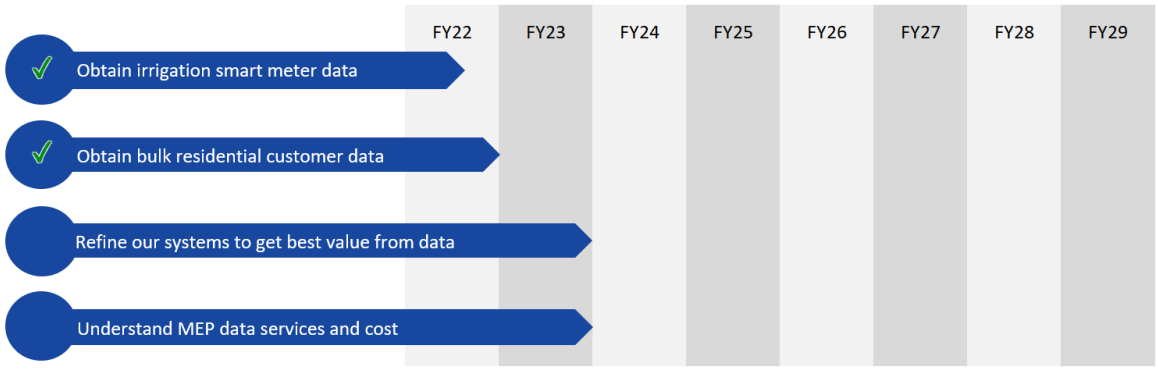
Next steps

We will refine our systems for storing, accessing and using the data we have received already and integrate these into the development part of our business initially.

We will continue to work with our retailers to access our customer's data for network planning purposes and are also talking with MEPs to understand any potential smart meter data services they may offer and the pricing of these services.

Once we understand MEP's smart meter upgrade plans and proposed data services and costs, we will be able to refine our plan.

Roadmap



Alignment with our strategic plan	
Strategic priority:	Offer innovative new solutions to our customers
Initiative:	Develop a suite of energy solutions offerings

Action:	Develop our strategy and plan for access to customer ICP level information

6.2.3.2 Understand DER deployment

The goal for this workstream is to initially understand Distributed Energy Resource (DER) deployment (location, type, and size) and ultimately to be able to model DER scenarios to understand the effects of DER deployment. Note this workstream is closely aligned with the Network Stability workstream.

Where are we now?

We understand the location and size of our controllable hot water demand at an aggregated level. We understand the location, type, and size of distributed generation connection on our network (solar, wind, batteries) but do not currently understand the location or size of individual electric vehicle chargers although we know that we currently have a low penetration of EVs in our district at present.

Next steps

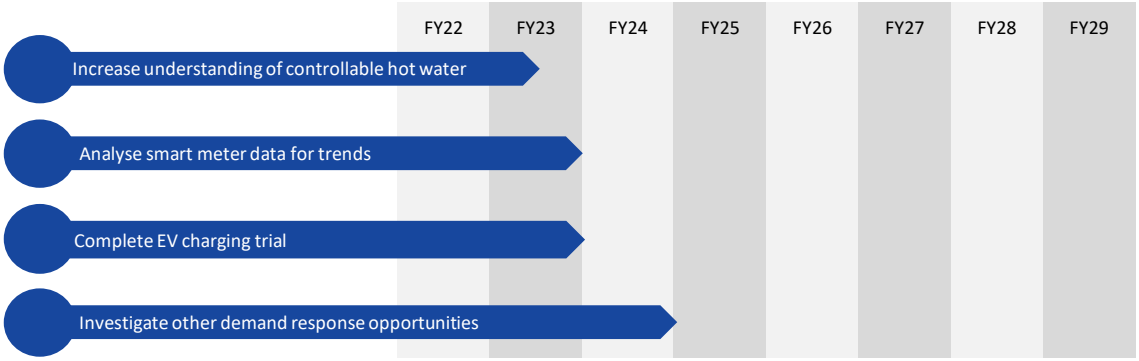
We are performing a study over the next year to increase our understanding of our hot water demand to zone substation level. We will also use smart meter data to further understand the size of individual hot water demand to customer level; to benchmark our existing customer base; and to look for changes in usage patterns from distributed generation, batteries, and electric vehicles.

We will also continue to investigate our customers' appetite for demand response for irrigation demand and for demand with an element of thermal storage such as refrigeration and heating systems.

As we refine our pricing, we will consider ways that we can incentivise electric vehicle owners to advise us of their location and size and to allow us to influence their charging behaviour.

We are also planning an electric vehicle smart charger control trial in conjunction with the South Island Distribution Group.

Roadmap



Alignment with our strategic plan	
Strategic priority:	Offer innovative new solutions to our customers
Initiative:	Develop a suite of new energy solutions offerings
Action:	Demand response programme trial in place

6.2.3.3 Understand new demand

The goal for this workstream is to understand connection requirements for new demand (location, size, and type) so we can model scenarios to understand where congestion issues may occur and to understand how our network is used so we can feed this back into asset management approaches. This workstream is enabled by the LV Network Monitoring and Access to smart meter data workstreams.

Where are we now?

We are actively engaging with our large industrial and irrigation companies so we can understand their plans.

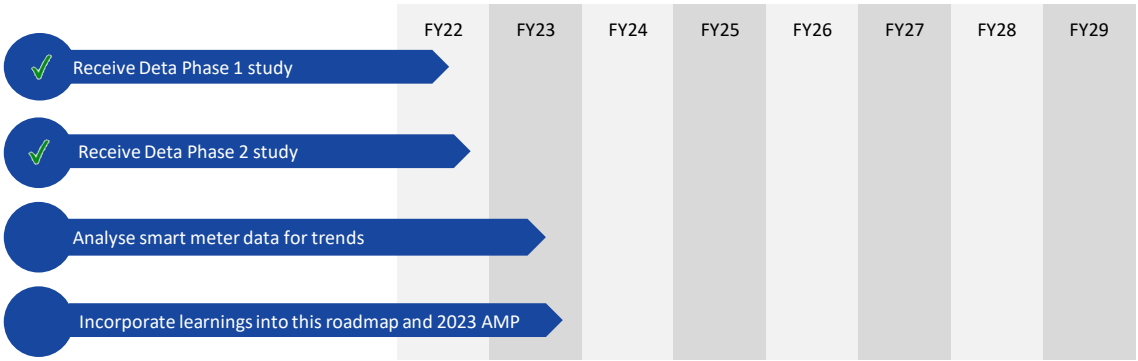
We have worked with a consultant to identify all coal boilers in our supply area over 500 kW and have completed an additional study to further understand the timing and size of this demand. We are working closely with these customers to ensure we can enable their transition to electricity.

Next steps

We have received historical smart meter data for a statistically significant number of our domestic customers. We will analyse these data for trends to refine our understanding of our domestic customer types, diversity, and impact on maximum demand at all levels of our network.

We will conduct a study into irrigation demand to quantity potential irrigation demand remaining at key zone substations in FY23.

Roadmap



Alignment with our strategic plan	
Strategic priority:	Offer innovative new solutions to our customers
Initiative:	Understand our customer preferences and opportunities
Action:	Engage with customers/stakeholders to understand their future energy needs and interests
	Quantify the size and timing of opportunities (solar, storage, decarbonisation projects)
	Develop customer focus groups to test ideas

6.2.4 Network evolution expenditure forecast

Table 23 - Budgetary costs

Workstream	Components	Year (s)	Capital cost (000)
Network Understanding	LV Hosting Studies	FY23	$30
LV Network Monitoring	Phase 1 (50 transformers)	FY22	$250
	Phase 2 (50 transformers)	FY23	$250
	Phase 3 (100 transformers)	FY24	$500
	Phase 4 (100 transformers)	FY25	$500
Network Stability	EV charging trial	FY23	$30
Understand new demand	Irrigation Study per Zone substation	FY23	$20

Notes:

- These costs are also presented in Other system fixed assets in Section 5.9.2

6.3 OUR PLANNING APPROACH

6.3.1 Planning process

- A development driver is triggered. The main drivers are:
  - Safety
  - Regulatory compliance
  - Security of supply
  - Quality of supply
  - Customer reliability
  - Readiness for the future
  - New customer connections[8]
- A business case is prepared detailing options (including non-network options), costs, benefits, risks, and recommendations.
- Once a business case is approved, the project will be designed and scheduled into our works programme.
- After completion, the project is reviewed for effectiveness.

6.3.2 Planning criteria

6.3.2.1 Safety criteria

The safety of our people and the public is paramount to us and is considered at all stages of planning and design in accordance with our Safety in Design Policy.

6.3.2.2 Regulatory criteria

Regulatory criteria are presented in general in Section 2.3 – Regulatory Environment. The following are additional areas that are subject to regulation.

Voltage

The *Electricity (Safety) Regulations 2010* require that we maintain the voltage at the customer point of supply at 230 V +/- 6% (except for momentary fluctuations). This influences the maximum voltage drop we allow for in the design of our network overhead lines and cables.

Voltage performance often drives upgrades in rural areas due to the combination of irrigation demand and long feeders.

Distributed generation

We welcome the connection of distributed generation on our network. If distributed generation is small-scale (less than 10 kW), has an approved inverter with advanced power quality modes and is in an uncongested area, we will fast-track the connection process.

We publish a list of areas that are subject to export congestion or are expected to become congested in the next 12 months, on our website www.networkwaitaki.co.nz.Any areas identified will be analysed to determine whether they trigger a development driver. We have no areas subject to congestion as of 1 April 2022 and do not forecast any areas to become congested in the following 12 months.

[8] For development driven by our customers, we align our investment with our customer's commitment to proceed, to minimise the risk of stranded assets.

Conductor heights

NZECP34:2001 defines the minimum clearances for conductors from the ground or waterways. As the electrical load carried by a conductor increases, the temperature increases, and it will increase in length and sag closer to the ground. This code of practice informs our design standards and line thermal ratings.

6.3.2.3 Security of supply criteria

Security of supply refers to the ability of our network to meet our customers' demand for energy delivery without interruption. Our deterministic security criteria are detailed on the following page.

Where deterministic criteria are triggered, and as appropriate, we conduct probabilistic analysis to allow us to determine the probability of an outage occurring, the time to repair, and to quantify the risk in dollar terms. This allows us to align our investment with the value of the risk.

Security of Supply notes

- Repair time is defined as the time taken to sufficiently repair faulted assets to where they can be livened and will support the required demand. It includes the response time taken to locate and isolate the fault and allows for prioritisation of supply restoration. In a large outage we place priority on restoring supply to the maximum number of customers, ahead of individual security issues.
- Network assets dedicated to a special industrial demand may have a security level determined by customer requirements.
- The security criteria are based on the ability to interrupt irrigation demand for up to 48 hours per event.

Target repair times

- Overhead lines 4 hours
- Underground cables 6 hours
- Distribution equipment 8 hours
- Sub-transmission equipment 12 hours

NWL Security of supply standard - deterministic criteria

Table 24- Security of supply - deterministic criteria

Class	Description	Demand Size (MVA)	First Outage	Second Outage	Bus Fault or Switchgear Failure
Grid Exit Points (GXPs)					
A1	Urban GXPs	Any	No interruption	Restore 50% in switching time and restore rest in repair time	No interruption for 50% and restore rest in 2 hrs
A2	Rural GXPs	>15	Restore 75% in switching time and restore 90% in 8 hrs	Restore 100% in repair time	Restore 100% in repair time
A3	Rural GXPs	<15	Restore 50% in switching time and restore 90% in 12 hrs	Restore 100% in repair time	Restore 100% in repair time
Zone substations and subtransmission feeders					
B1	CBD zone substation	Any	No interruption	Restore 100% in repair time	No interruption for 50% and restore rest in 2 hrs
B2	Urban zone substation	Any	No interruption	Restore 100% in repair time	Restore 100% in repair time
B3	Rural zone substation	>12	No interruption for 50% and restore rest in switching time	Restore 100% in repair time	No interruption for 50% and restore rest in switching time
B4	Rural zone substation	2-12	Restore 100% in switching time	Restore 100% in repair time	Restore 100% in repair time
B5	Rural zone substation	<2	Restore 50% in switching time, restore rest in repair time	Restore 100% in repair time	Restore 100% in repair time
B6	Subtransmission feeder	>15	No interruption	Restore 100% in repair time	Restore 100% in repair time
B7	Subtransmission feeder	<15	Restore 100% in repair time	Restore 100% in repair time	Restore 100% in repair time
Distribution feeders and substations					
C1	Urban 11 kV feeders & CBD LV reticulation	1-4	Restore 100% in switching time	Restore 100% in repair time	Restore 100% in repair time
C2	Urban 11 kV spurs & LV reticulation	<1.5	Restore 50% in switching time and restore rest in repair time	Restore 100% in repair time	Restore 100% in repair time
C3	Rural 11 kV feeders	1-4	Restore 50% in switching time and restore rest in repair time	Restore 100% in repair time	Restore 100% in repair time
C4	Rural 11 kV spurs & LV reticulation	<1.5	Restore 100% in repair time	Restore 100% in repair time	Restore 100% in repair time

NWL Security of supply standard – risk-based approach

A risk-based approach is based on the quantification of risk via the following formula:

Risk ($) = probability of outage x cost of unserved energy

Probability of outage = risk period (year) x equipment failure rate (failures/year)

Cost of unserved energy =repair time (h/failure) x demand at risk (MVA) x VoLL ($/MVAh)

The probability of failure for a particular class of equipment is taken from our own statistics where possible. Where we have insufficient data, industry guidelines such as the EEA Guide for Security of Supply are consulted.

The cost of unserved energy is calculated based on the values of lost load (VoLL) developed in Transpower's 2018 Value of Lost Load Study.

This allows analysis of the financial risk by way of a net present value (NPV) calculation. This will feed into a business case which will also consider other areas of risk, against our risk appetite, according to the following categories from our *Risk Management Framework WR0502*:

- Health and Safety
- Public safety
- Reputation
- Supply reliability
- Customer service
- Delivery of strategic objectives
- Legal or regulatory compliance
- Environmental/Sustainability
- Operational capability

6.3.2.4 Quality of supply criteria

Allowable voltage drop limits on network lines are detailed in our Network Design Standard NS10-10.

Harmonic voltage limits are specified in our *Network Harmonics Standard NS15-05* and NZECP36:1993 *New Zealand Electrical Code of Practice for Harmonic Levels*.

6.3.2.5 Reliability criteria

These criteria are presented in Section 3 – Service Level: Reliability.

6.3.2.6 Environmental and sustainability criteria

Minimising the impact on our environment is very important to us. When we analyse options for a solution, environmental impact and sustainability are factors we consider. The Resource Management Act 1991 and relevant environmental standards are consulted and complied with as appropriate.

6.3.2.7 Equipment rating and selection criteria

Ratings

Where available, equipment ratings are taken directly from nameplate data or manufacturers' published data. Where this is unavailable, ratings are either calculated from first principles or estimated from similar equipment.

Selection

Conductor, cables, and switchgear are generally sized for projected ultimate demand, provided the incremental cost of upsizing is less than the cost to upgrade the equipment in the future.

Depending on the timeframe of projected demand, distribution transformers may be sized for medium-term demand and upgraded as required for ultimate demand. This approach minimises system losses and the risk of over investment if the projected demand does not eventuate.

Standardisation

Where appropriate, network assets are designed using standard sizes and models to minimise spares, maximise interchangeability and reduce stock levels. Standard equipment sizes are specified in our design standards.

Membership of the Southern Buyers' Group gives us the opportunity to standardise equipment and materials between members and allows for increased purchasing power. An initial consideration in any design process is to check whether a standard design exists and whether we can use a standard design that has been developed by others.

6.3.2.8 Energy efficiency criteria

The network is configured to minimise voltage drop and maximise efficiency at times of maximum demand.

At feasibility stage for new builds or for network upgrade projects, the net present value of energy losses is factored into cost benefit calculations. For example, this may result in a larger conductor being selected to minimise lifecycle energy losses.

The costs of network power losses are passed through to our connected customers and Network Waitaki does not directly enjoy the benefits of reduced losses. However, the Energy Companies Act 1992 requires that we have regard to "…ensuring the efficient use of electricity" and we believe that prudent minimisation of losses is in the best interests of our connected customers.

6.3.3 Demand scenario assumptions

Network demand has been steadily increasing over the past two decades and this has been largely driven by irrigation demand growth. Since 2003, our network has consistently experienced peak demand in the irrigation season with peak demand normally occurring between October and February.

Table **25** - Historical maximum GXP demand growth rates (All GXPs except Black Point)

5 year maximum-demand average growth rate	2.0%
10 year maximum-demand average growth rate	2.1%

We use a time-series model to create demand scenarios for the next 20 years.

- Recent recorded maximum demand for each substation is divided into domestic, commercial, and farming categories
- Growth rates for each category are applied
- New demand that has been signalled to us with reasonable certainty is added separately to the relevant category at each substation (growth rates are not applied to this demand)
- Large process heat conversion demand is included under all growth scenarios as this is now highly likely to occur
- Coincident substation demand is aggregated to calculate GXP demand
- All demands and constraints are presented as apparent power (MVA). To allow addition of apparent power figures, a global power factor is calculated from the peak demand day of the year and assumed for all demand. For the FY22 period the power factor recorded at system maximum demand was 0.97 lagging
- FY22 GXP demand data has been sourced from Transpower's half-hour metering data. Substation demand data has been sourced from NWL's SCADA records

6.3.3.1 Domestic demand growth

Our expected domestic demand growth for the next 20 years is shown below for low, expected, and high scenarios. It includes population growth, electric vehicle take-up and distributed generation development. Each of these are detailed in the following sections.

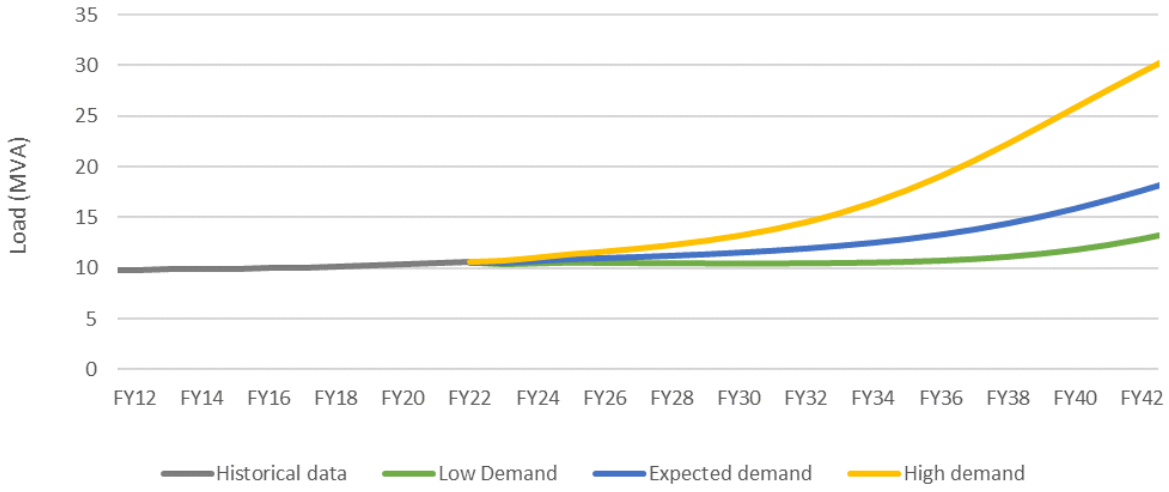


Figure 50 - Domestic load -historical and forecast

Population growth

Historical annual growth rates for new domestic dwelling connections are +0.9% (five-year average) and +0.7% (ten-year average).

Waitaki District Council in its Draft Spatial Plan has predicted the average annual population growth in the Oamaru-Weston-Kakanui area under three scenarios for the period from 2021 to 2051 (updated October 2021).

Table 26 – WDC population growth scenarios

WDC Scenario	Population growth by 2031	Equivalent annual growth (population)	People / house assumption	New houses by 2031	Equivalent annual growth (dwellings)
Low	+ 250	+ 0.16%	1.84	+ 136	+ 0.13%
High	+ 2200	+ 1.31%	1.60	+ 1375	+ 1.24%
High growth + demand shock	+ 4400	+ 2.48%	2.46	+ 1793	+ 1.59%

Our domestic demand growth rates have been aligned with the Waitaki District Council dwelling annual growth scenarios, with our expected growth rate set to match our five-year average of 0.9%.

Numbers in the high growth scenario are higher than our three-year average but are considered prudent, especially with the possibility of increased immigration from New Zealanders returning home and other nationalities seeing New Zealand as a haven from Covid 19. These growth rates are applied consistently to our model over a 20-year period.

Table 27 - Domestic growth scenario rates

Growth scenario	Annual growth
Low growth	+ 0.13%
Expected growth	+ 0.90%
High growth	+ 1.59%

Electric vehicles

According to publicly available statistics, we currently have low levels of electric vehicles (EVs) in our network area (52 EV and 21 Petrol Hybrid EV). The rate of uptake of EVs in New Zealand and the impact that these will have on our electricity networks is subject to a high level of uncertainty over the planning period.

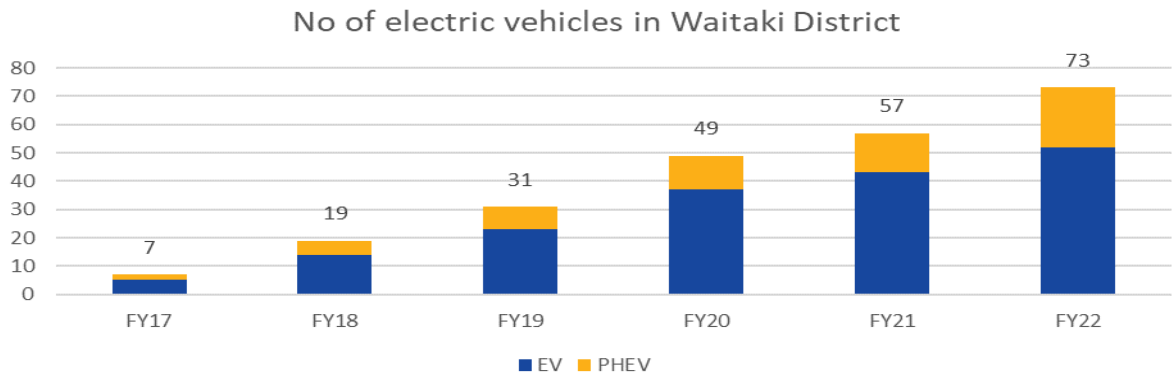


Figure 51 - Electric vehicles in the Waitaki District

Factors that will cause electric vehicle take-up to increase significantly are:

- The Labour Government has pledged to accelerate the electrification of our transport and industrial sectors in its Clean Energy Policy.
- The government Clean Car Standard for new and used car imports will be progressively phased in from 2021 to 2025, requiring a final carbon dioxide target of 105 g/km.
- EVs are expected to reach price parity with internal combustion engine vehicles by midway through this decade.
- The Climate Change Commission draft advice has recommended that the government implement a ban on internal combustion engine vehicles from 2032.
- The Labour Government implemented the Clean Car Discount which gives a rebate on the purchase of eligible new and used electric vehicles first registered in New Zealand between 1 July 2021 and 31 March 2022

We have aligned our EV penetration scenarios with published industry projections which are shown on the graph below (dots). We have developed our low, expected, and high-demand scenarios to fit these projections.

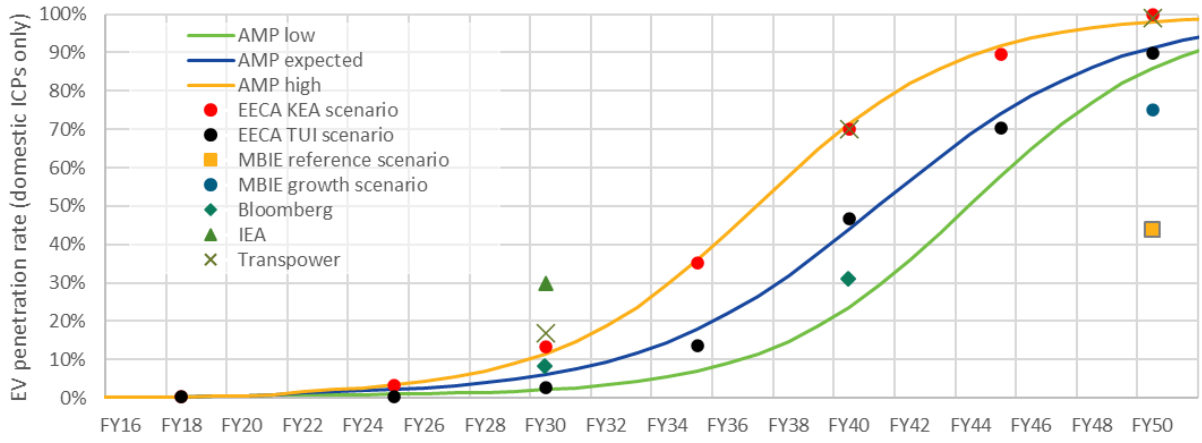


Figure 52 - Electric vehicle penetration scenarios

The existing New Zealand passenger vehicle fleet is comprised of about 5.5 million vehicles, of which 35,000 are EVs. This equates to a penetration of 0.6%.

The Waitaki District (less Palmerston) has a population of 21,505 people. Based on the current New Zealand light vehicle fleet makeup of 833 vehicles per 1,000 people, the vehicle fleet in NWL's supply area is estimated at 18,000 vehicles. We currently have 52 EVs registered in the district, which equates to a penetration of 0.3%. This is half the national penetration, which may be partly due to EV economics currently stacking up better in the larger urban centres with larger commute distances and higher median incomes.

The impact of EVs on the network depends both on the charger power rating and the time of charging. We assume an average charge size of 3 kW for all scenarios to account for a mix of smaller plug-in 1.8 kW chargers (80% of all chargers) and fixed wired 7.4 kW smart chargers (20% of all chargers). We assume that 20% of the EV demand will be present during the peak (at 9am or 4pm) in the low and expected demand scenarios, and 30% in the high-demand scenario. Our assumptions for the three scenarios are summarised below.

Table 28 – Electric vehicle assumptions

Growth scenario	EV charger average size	EV impact on maximum demand	Penetration rate by FY32 (cf graphs)
Low growth	3 kW	20%	3%
Expected growth	3 kW	20%	9%
High growth	3 KW	30%	19%

The impact on the network in terms of contribution to maximum demand is shown below for the whole network.

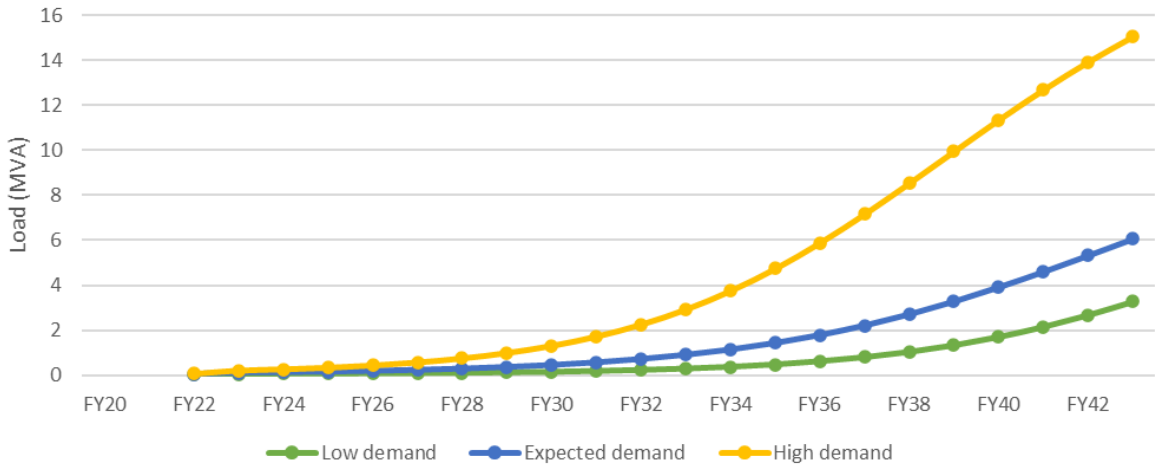


Figure 53 - Total electric vehicle load contribution to maximum demand

Under these scenarios the impact of electric vehicles on our maximum demand over the planning period is low (0.7-2.2 MVA) but the potential impact in the ten years following is subject to a high level of uncertainty. Our plan to reduce this uncertainty and to work with other EDBs to understand electric vehicle charging behaviour is detailed in Section 6.2.3.2-Understand DER deployment, p130.

Distributed generation

Distributed generation (DG) in our region is predominantly small-scale photovoltaic panels and this continues to grow. There are 179 DG connections approved on the network, comprising 1.4% of all connections. The average domestic photovoltaic DG installation size is 5 kW.

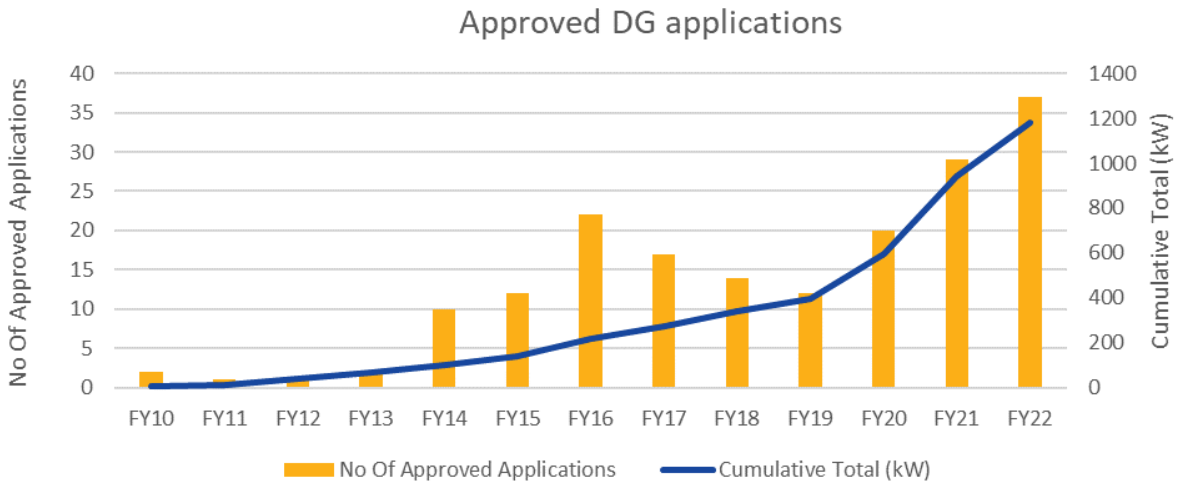


Figure 54 - Distributed generation applications by year

Each of the three scenarios is based on a different penetration rate. The guaranteed contribution of distributed generation to a reduction in network demand has been calculated to be 5% of the total rated power. This is based on statistical analysis of the alignment of worst-case solar performance under full cloud cover with our peak network demand which occurs in the morning and evening.

The main assumptions are summarised in the table below.

Table 293 – Distributed generation assumptions

Growth scenario	DG average size	DG impact on maximum demand	Percentage penetration by FY32 (cf graphs)
Low growth	5 kW	-5%	6%
Expected growth	5 kW	-5%	4%
High growth	5 KW	-5%	2%

Using the assumptions presented in the table, we used the following model to represent residential distributed generation growth in the next 20 years.

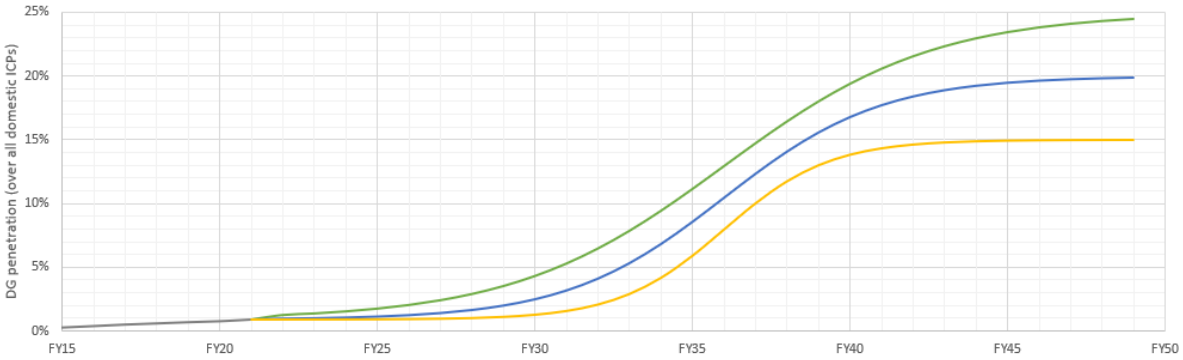


Figure 55 - Distributed generation penetration forecast

We acknowledge that the rate of uptake for distributed generation may increase due to reductions in supply price, increases in electricity supply costs, or changes to regulations. We will continue to refine our models and collaborate with other similar EDBs to share knowledge.

We are also aware of a significant number of large-scale photovoltaic projects underway across New Zealand. Large scale schemes will likely connect to our network at high voltage levels and will be examined on a case-by-case basis as applications are received. We will conduct hosting capacity studies at GXP and Zone Substation level in FY23.

The assumption of 5% of maximum demand reduction leads to a negligible reduction brought about by DG development, as shown below. This is considered a prudent assumption.

Note that the crossing of the low and expected curves is due to the difference in population growth between scenarios.

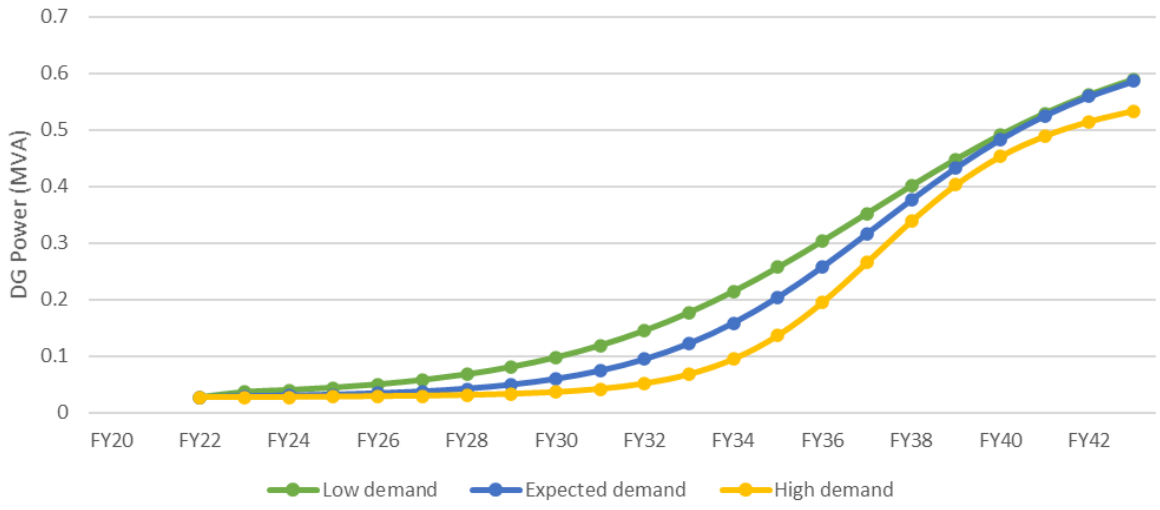


Figure 56 - Distributed generation contribution to demand reduction

Energy efficiency

The transition of customers towards LED lighting, higher efficiency appliances and improved building insulation, will result in a decrease in energy transported on our network. In July 2020, NWL completed a customer energy-efficient LED lighting programme and distributed approximately 35,000 LED light bulbs to our connected customers. This has resulted in significant cost savings to our customers, but these domestic efficiency gains have only had a minimal impact on our maximum demand, which occurs during summer daylight hours.

Efficiency measures that may further reduce our summer maximum demand are:

- Commercial and industrial energy efficient lighting upgrades
- End of life replacement of motors with high efficiency models
- Potential usage of variable rate irrigation

The impact of energy efficiency, as a reduction in demand, has been conservatively modelled as:

Table 30 – Energy efficiency growth scenarios

Growth scenario	Annual growth
Low growth	0.5%
Expected growth	0.4%
High growth	0.3%

Heat pumps

The largest heat pump installer in our region estimates that between 6,000 and 7,000 homes have a single heat pump, and 1,000 have two.

Modern inverter heat pumps are more efficient and have less impact on the network when starting, but this may be offset by anecdotal evidence from the heat pump supplier that customer preferences are changing. In the past, an average customer would set their thermostat at 18°C but many are now setting this as high as 21°C.

Heat pumps in our region are not typically used for cooling and will have a minimal contribution to the summer peak, although there is a risk that if we experience hotter days and/or customer behaviour changes, this may influence our summer peak.

This has not been allowed for in our modelling and we will consider heat pump control as part of our demand response management trials.

Table 31 – Heat pump growth scenarios

Growth scenario	Annual growth
Low growth	-0.1%
Expected growth	0.6%
High growth	0.9%

6.3.3.2 Commercial and Industrial demand growth

Historically, new commercial demand has grown at +1.1% (five-year average) and +0.9% (ten-year average).

Future growth is expected to be due largely to decarbonisation (which is added separately into our model and not included in the base growth rates below).

Growth is expected to continue in line with the ten-year average rate.

Table 32 - Commercial demand growth scenarios

Growth Scenario	Annual Growth
Low growth	0.25%
Expected growth	0.9%
High growth	1.2%

6.3.3.3 Decarbonisation of process heat

As part of a collaboration with the South Island Electricity Distribution Businesses, we jointly engaged a consultant to identify all fossil fuel-based boilers over 500 kW in the South Island. We have now commissioned a second phase of this study to examine this demand in more detail for our area and expand the study to include all school boilers.

We have been working closely with two large industrial customers in our supply area who have recently signalled firm intentions to move away from coal for their process heat needs within the next ten years. Early indications are that the preference is for electricity as the energy source, of which the total demand could be up to 12 MW for these two customers alone. 3.75 MW of this demand may be required in the next 18 months (accelerated by government incentives).

Process heat decarbonisation demand has been added to our model for all scenarios under the Commercial and Industrial group. Demand of this magnitude will trigger significant capital investment for upgrades to our network and the upstream transmission network, which may have timeframes of up to six years. The assets most affected by this proposed decarbonisation demand are Pukeuri Zone Substation, Redcastle Zone Substation and Oamaru GXP.

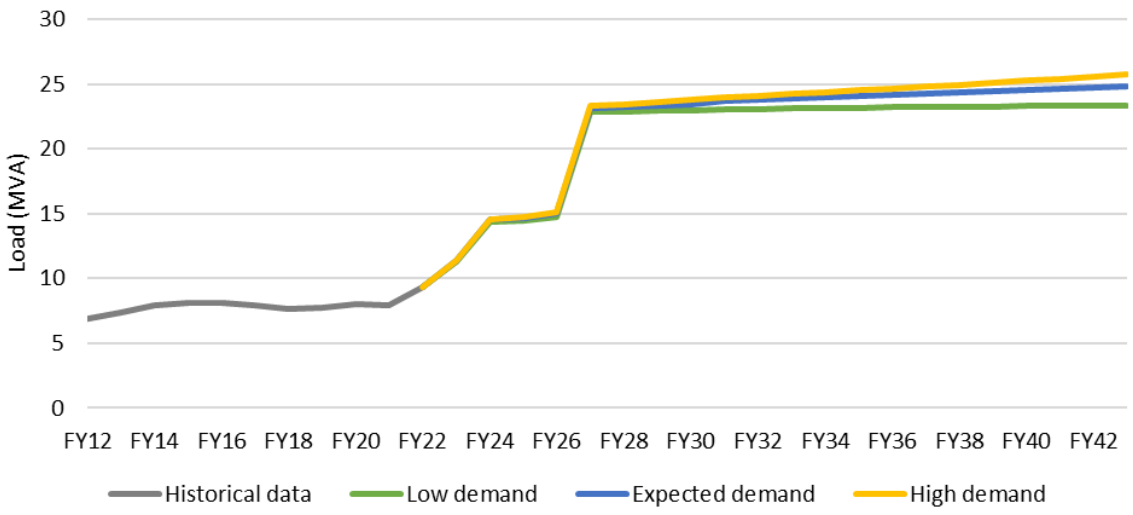


Figure 57 - Historical load growth and future commercial growth scenarios

6.3.3.4 Farming demand growth

Dairy shed growth

Annual new connections for dairy sheds have grown at +0.7% (five-year average) and +1.2% (ten-year average). The last two years have seen no new dairy shed connections.

Conversations with members of the farming community indicate that dairy shed conversions are likely close to saturation in the area supplied by Oamaru GXP. We expect that growth from new dairy sheds will remain low for the foreseeable future.

Irrigation demand growth

Historically, contracted capacity for irrigation pumps has increased +2.3% (five-year average) and +3.6% (ten-year average).

The three-year average has reduced to 2.1% and two-year average to 0.9%, indicating a slow-down in irrigation expansion.

The following irrigation projects are proposed for the Oamaru GXP over the next ten years and have been included as known demand which are added separately, and growth rates do not apply to them.

- An irrigation company advises that approximately 5,000 hectares in the Papakaio plains area are highly likely to be converted from gravity (border dyke) to spray irrigation over the next nine years. At approximately 0.8 kVA per hectare, this equates to 4 MVA of new demand.
- An irrigation company indicates there may be an additional 1 MW of pumping demand to be installed within Waiareka Valley Road, Taipo Road and Dunrobin Road areas.

Regular communication with the farming community allows us to understand upcoming farming demand growth. This allows us to develop more accurate growth scenarios than using an overall growth rate. However, to account for the demand that we are not yet aware of, base growth rates are still applied, as shown in the table below.

Once these proposed projects are completed, we believe that irrigation growth in the region will decrease as most viable land is irrigated. For this reason, we have reduced the base growth rate to 0% in FY42. A linear interpolation is then used to calculate growth rates for all years in between.

Table 33 – Farming demand growth scenarios

Growth scenario	Initial annual Growth	Growth rate in FY42
Low growth	0.1%	0%
Expected growth	0.25%	0%
High growth	0.5%	0%

Total farming demand growth scenarios are shown below (inherent growth rate + individual known demand):

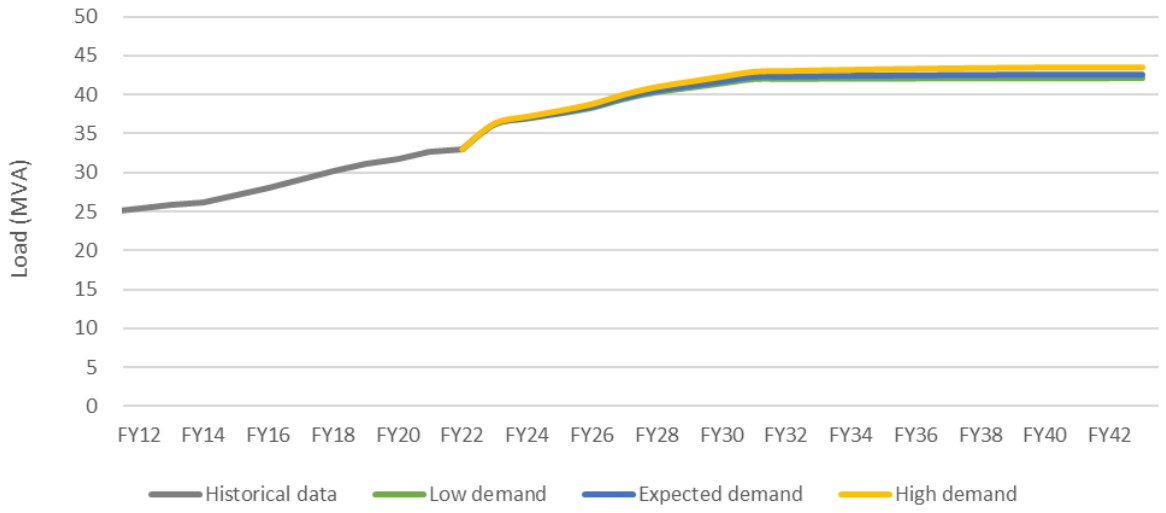


Figure 58 - Historical farming demand growth and future growth scenarios

6.3.3.5 Battery storage

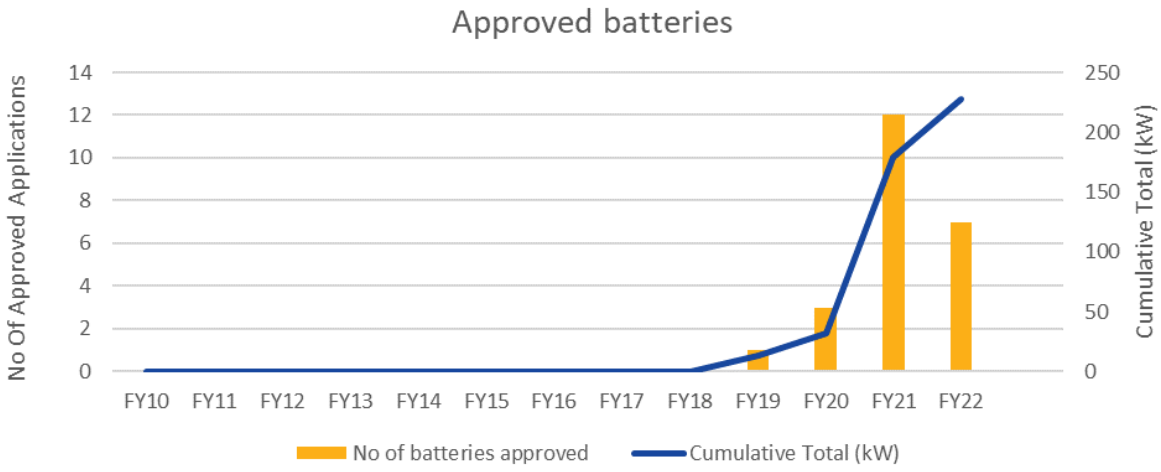


Figure 59 - Batteries approved for connection

We have low numbers (23) of customer-owned battery installations (all associated with solar installations) connected to our network, with a total installed capacity of 228 kWh. As battery costs fall and regulation settings become potentially more favourable, we expect to see a significant increase in the amount of distributed battery capacity connected to our network over the planning period.

The ability to influence when batteries charge and discharge may be useful in minimising congestion and associated upgrades on our network and the upstream transmission network. We have detailed our plans to understand DER deployment in our Network Evolution Roadmap. (Refer to section 6.2.3.2)

6.3.3.6 Demand response management

We currently use demand response management to move a significant amount of hot water heating demand into the period from 11pm to 7am.

During the daytime hours we have approximately 1 MVA of hot water heating demand that we can control off if required.

We do include the impact from control of hot water control in the daytime in our demand growth scenarios. This is used as an operational tool to reduce load during grid or distribution system peaks and emergencies but must be carefully managed as large peaks can be created when these channels are turned back on

We are in the process of conducting a study to update our understanding of the amount of controllable water heater demand on our network.

We can control irrigation pumps during a distribution or grid emergency via our ripple control system on a per feeder basis. This is not available for use in the normal operation of the network.

We have yet to see the effect of customer-led demand-side management (over and above hot water demand management). With the rollout of smart meters and the availability of spot market pricing and flexibility trading in the domestic market, we expect there will eventually be an increase of retailer-led pricing signals to customers to encourage demand management.

Transpower operates a national Demand Response Management (DRM) programme. We have the ability to offer 0.5 MW of generation into this programme.

We are currently refining our demand response strategy and will trial an EV smart charger control project in FY22/23.

6.4 GXP DEVELOPMENT PLAN

6.4.1 Network Waitaki GXP locations

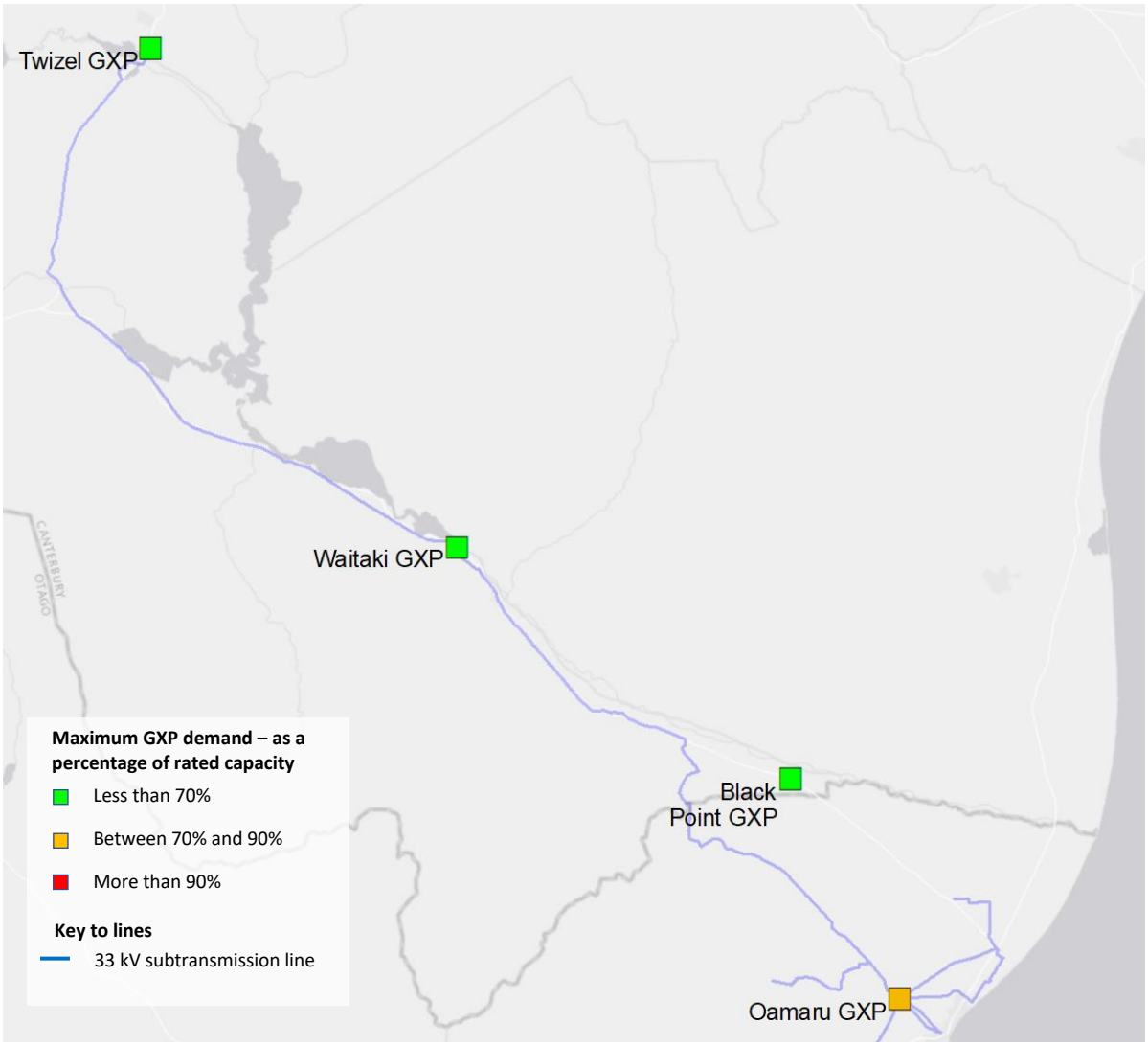


Figure 60 - Network Waitaki GXP locations (FY21 maximum demand as a percentage of rated capacity)

Table 34 - GXP details

Grid Exit Point	Voltage	Security	Capacity	Max demand FY21 (Non-Coincident)	Zone Substations supplied
Twizel GXP	220/33 kV	N-1	27 MVA	4.0 MVA	3
Waitaki GXP	11/33 kV	N	24 MVA	11.8 MVA	4
Black Point GXP	110/11 kV	N	25 MVA	15.7 MVA	0
Oamaru GXP	110/33 kV	N-1	45 MVA	40.7 MVA	10

6.4.2 Oamaru GXP

6.4.2.1 Transmission overview

Transpower's Oamaru Grid Exit Point (GXP) is supplied by two 110 kV transmission circuits from Lake Waitaki, as shown below.

For the 61 km section from Lake Waitaki to Glenavy, the two circuits are installed either side of a single transmission tower line. These circuits are classed by Transpower as *Interconnection Assets non-core grid*. Transpower's Grid Reliability Standard does not require these assets to meet N-1 security level. Transpower have advised us that any security or capacity upgrades to these circuits will not pass their cost-benefit test and must be funded by the connected parties.

The 27 km section from Glenavy to Oamaru GXP is configured with each circuit on a separate pole line. These circuits are classed as *Connection Assets,* as they supply Network Waitaki only. Any upgrades to these circuits are required to be funded by Network Waitaki.

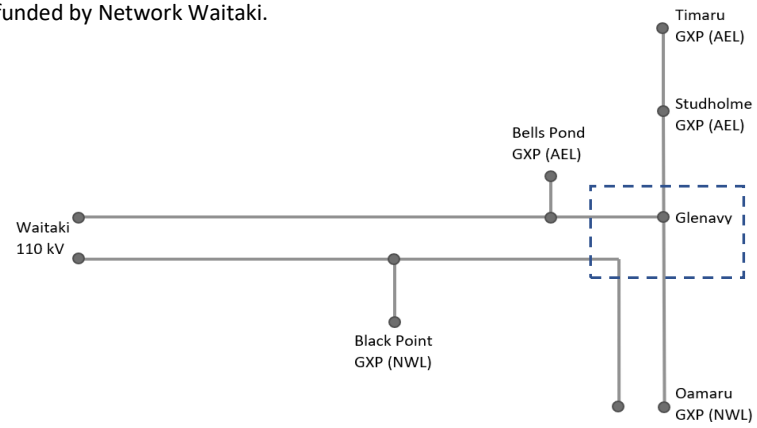
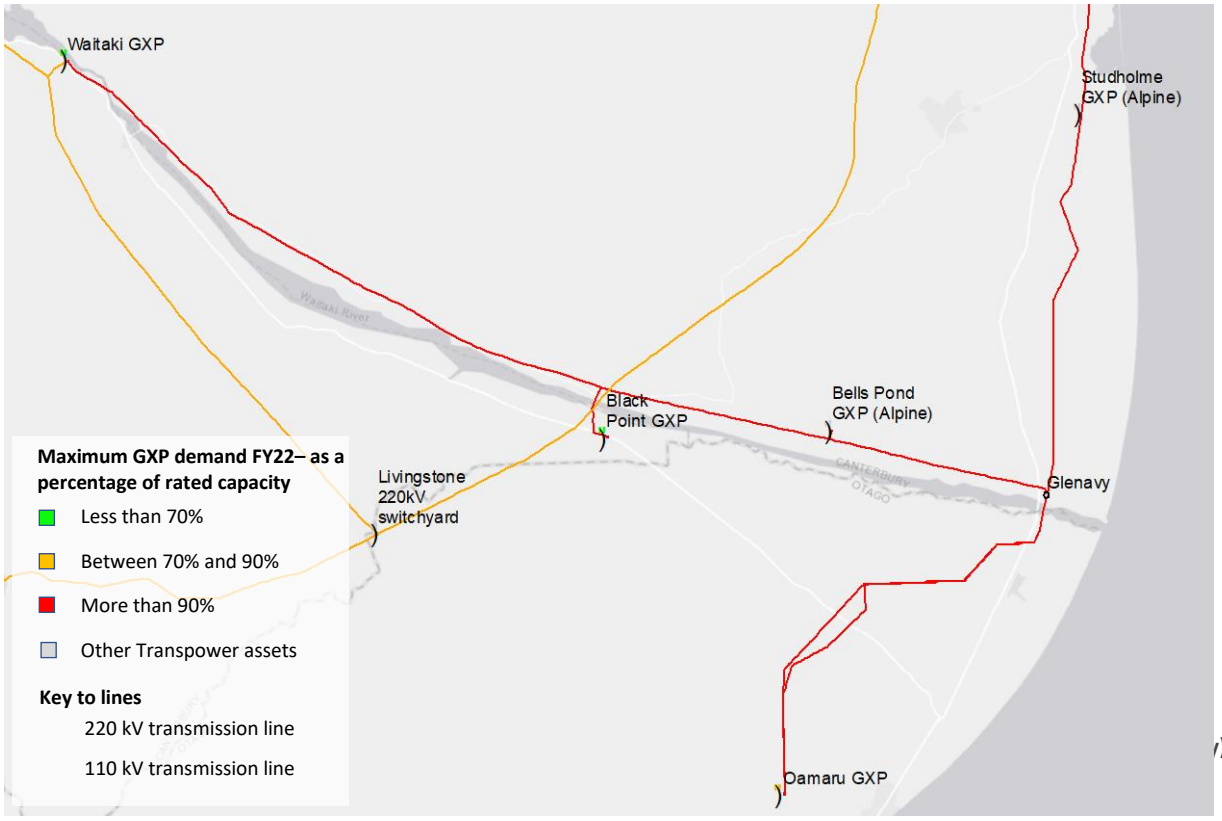


Figure 61 – 110 kV transmission single line diagram



6.4.2.2 Transmission system constraints

Table 35 – Transmission system constraints

Constraint	Type	Constraint limit	Applies pre/post contingency	Description
Waitaki GXP 220/110 kV transformer banks	Transformer thermal rating	100 MVA (N-1)	Both	Thermal limit per transformer bank
110 kV circuit Waitaki - Black Point - Oamaru	Voltage stability	53 MVA	Post	There is a voltage stability constraint if Oamaru demand exceeds 53 MVA with the Studholme -Timaru 110 kV circuit out of service and 56 MVA when the circuit is in service. (Note: this is the limiting constraint on a Special Protection Scheme)
110 kV circuit Lake Waitaki-Bells Pond	Conductor thermal rating	45 MVA	Both	When demand reaches 95% of this constraint, Transpower will firstly call for demand response in the region and if that is insufficient, they will open the tie between Glenavy and Studholme, reducing the security at Studholme GXP to N security from Timaru direction only.
110 kV circuits from Glenavy to Oamaru	Conductor thermal rating	45-51 MVA	Both	Use of Variable Line Rating* (VLR) has allowed for an increase in the thermal rating of this section of the circuits to 45-51 MVA depending on the time of day.
Oamaru GXP 110/33 kV transformers	Transformer thermal rating	60 MVA (N-1)	Both	Thermal limit per transformer
Oamaru GXP voltage	Minimum allowable voltage	96.25 kV	Post	Network Waitaki has a *wider voltage agreement* in place with Transpower that allows the voltage at Oamaru GXP to fall to 87.5% of nominal voltage (96.25 kV) after a contingent event.

** The VLR rating is the maximum allowable rating for a single 110 kV circuit feeding Oamaru GXP if the other circuit is out of service (post-contingency). This constraint is also present when both lines are in service (pre-contingency) as reserve capacity must be left to pick up the demand from the other line should it trip out in a fault.*

6.4.2.3 FY21 maximum demand

The graph below shows the Oamaru GXP demand on the most heavily loaded day in FY21 with the Variable Line Rating (VLR) constraint superimposed, which resulted in 10 MVA of spare capacity.

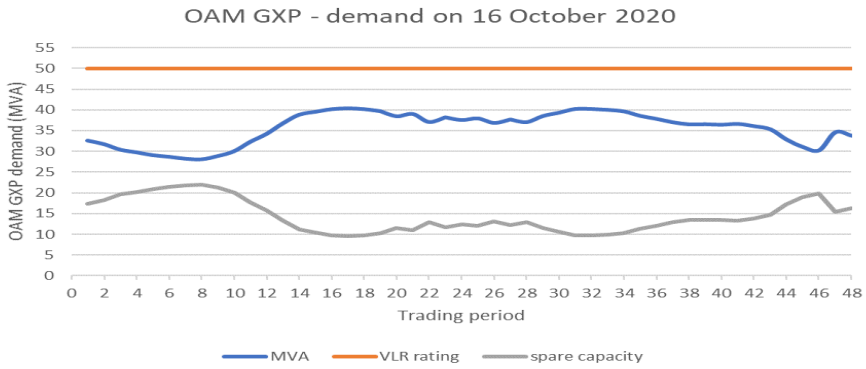


Figure 63 - 16th October 2020 maximum demand curve vs. VLR constraint

Usually, our network peaks occur between December and February when the VLR limit is lower. Applying the January VLR rating curve to the October peak demand results in only 5 MVA of spare capacity between 9:00am and 11:00am.

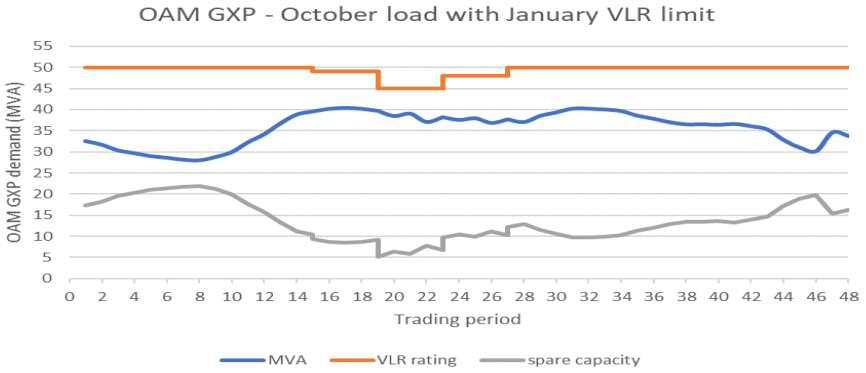


Figure 64 - 16th October 2020 maximum demand curve with January VLR limit

Optimising hot water boost timing between 9:00am and 11:00am is expected to gain up to 1.5 MVA of capacity, resulting in spare capacity at Oamaru GXP of 6.5 MVA.

6.4.2.4 FY21 demand duration

Examining the demand duration curves below it can be seen that:

- The highest 1 MVA of demand was present for 7 hours per year (0.08%)
- The highest 3 MVA of demand was present for 92 hours per year (1%)
- The highest 10 MVA of demand was present for 1715 hours per year (20%)

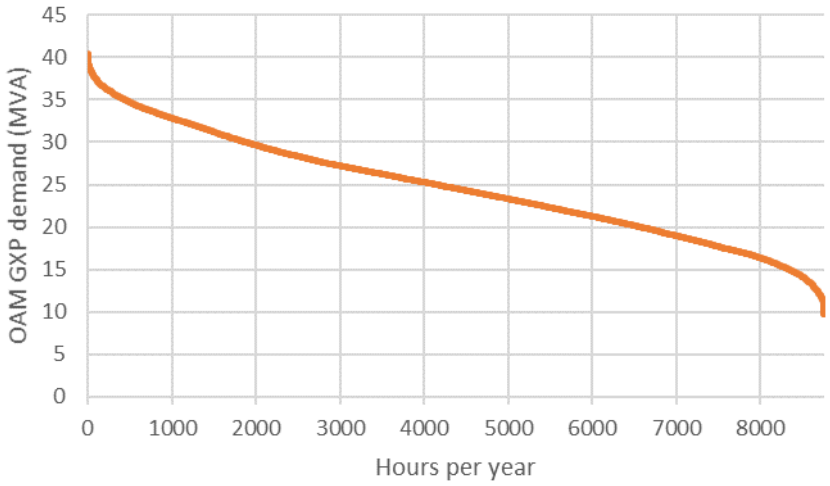


Figure 66 - Oamaru GXP FY21 Full year demand duration curve

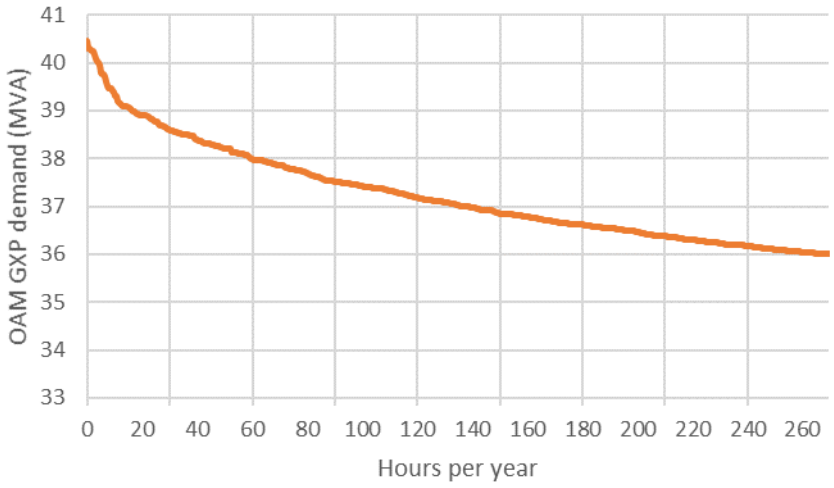


Figure 65 - Oamaru GXP FY21 demand duration curve - Top 4 MVA

6.4.2.5 Demand growth scenarios

Table 36 - Known likely demand

Substation	Demand Type	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Pukeuri	Industrial customer	0.44	0.07		0.30						
Pukeuri	Gravity to spray irrigation	0.20	0.20	0.20	0.20	0.20	0.33	0.33	0.33	0.33	
Papakaio	Gravity to spray irrigation	0.23	0.20	0.20	0.25	0.25	0.25	0.10	0.10	0.10	
Awamoko	Gravity to spray irrigation				0.25	0.25	0.25	0.10	0.10	0.10	
Chelmer	New subdivision	0.10	0.10	0.10							
Chelmer	EV chargers					0.05		0.05		0.10	
Redcastle	Meat processor	0.50									
Five Forks	On farm irrigation	0.15	0.15	0.10							
Maheno	On farm irrigation	0.15	0.15	0.10							
Pukeuri	Decarbonisation	0.75				8.00					
Redcastle	Decarbonisation		3.00								
	Total New Demand (MVA)	**2.5**	**3.9**	**0.7**	**1.0**	**8.8**	**0.8**	**0.6**	**0.5**	**0.6**	**0.0**

Table 37 – Oamaru GXP demand growth scenario (ten years)

Load Growth Scenario	N-1 Security Limit (MVA)	N Security limit (MVA)	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Average Annual Growth Rate 10 yrs
Low demand	46.5	54	41.0	43.7	47.8	48.5	49.6	58.9	59.8	60.4	61.0	61.7	61.7	4.2%
Expected demand	46.5	54	41.0	43.9	48.2	49.1	50.4	59.9	61.0	61.9	62.7	63.6	64.0	4.5%
High demand	46.5	54	41.0	44.1	48.6	49.8	51.3	61.0	62.4	63.6	64.8	66.2	67.0	5.0%
10 year average	46.5	54	41.0	41.9	42.8	43.8	44.7	45.7	46.7	47.7	48.8	49.9	51.0	2.2%

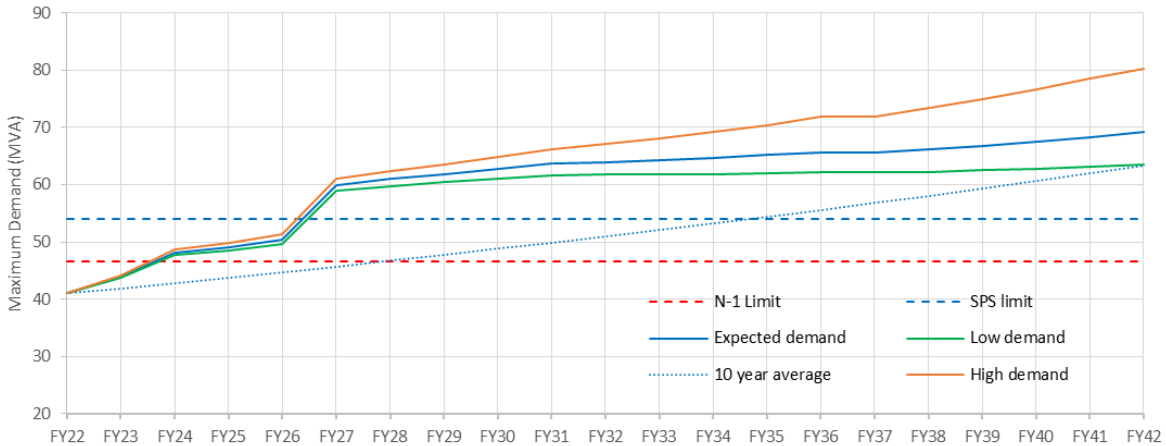


Figure 67 - Oamaru GXP demand growth scenario (20 years)

For all growth scenarios, the N-1 rating of Oamaru GXP will be exceeded in FY24.

With a Special Protection Scheme in service at Oamaru GXP (see next chapter for detail) an additional 8 MVA can be supplied at N Level security. The limit for this scheme will be exceeded in FY27 for all scenarios when the next large block of decarbonisation demand is expected.

6.4.2.6 Transmission constraint options

In FY22, we engaged Power Systems Consulting New Zealand Ltd to produce an independent study into the options available to solve this transmission constraint. This involved reviewing our demand growth scenario methodology and evaluating potential options for viability.

Demand response and grid scale battery options were among the options evaluated. The sheer quantity of the expected decarbonisation demand, combined with our relatively flat summer demand profile, meant that these options were not able to deliver the demand that we require.

To illustrate this, the 2032 demand profile for the expected demand growth scenario shows that demand will be above the SPS limit for 24 hours in a day with no spare capacity during the night to charge a battery system.

The conclusion of the study is that the preferred, and only viable, option is to invest in a new Grid Exit Point. This will be examined in more detail on the next page.

Short-term option – Special Protection Scheme

We are working with Transpower to implement a Special Protection Scheme (SPS) in FY23 which will allow us to supply up to 53 MVA of demand, provided we can immediately reduce demand to below 45 MVA in the event of an outage on one of the 110 kV circuits supplying Oamaru.

The following table shows the amount of demand (expected scenario) and the amount of time that this demand will be subject to N Level security from FY24 to FY26 (which is when a grid-scale solution is proposed to be commissioned).

Year	MVA at N Security	Hrs per year
FY24	3	92

FY25	4	145
FY26	5	342

Long-term option - New Grid Exit Point

We plan to develop a new 220/110/33 kV Grid Exit Point underneath the 220 kV lines in the Black Point area.

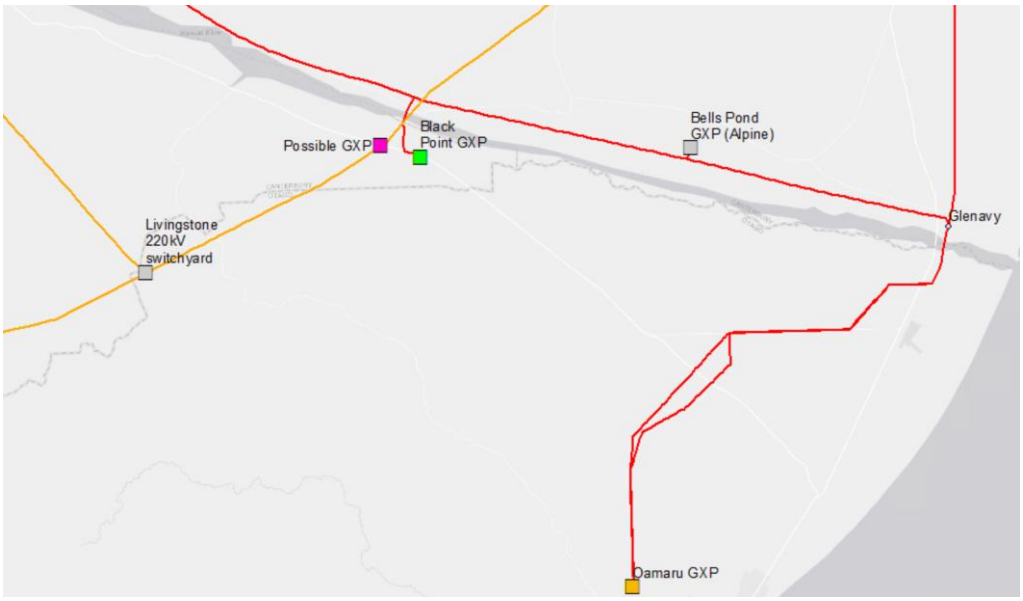


Figure 68 - Proposed new GXP location

The preferred location is underneath the Transpower 220 kV Islington-Roxburgh circuit. This location is optimum for providing electricity to support decarbonisation for the entire Lower Waitaki area.

To cater for Network Waitaki's expected growth, a new GXP will be required by FY27, and this will initially supply into our 33 kV subtransmission system to allow us to progressively offload the Oamaru GXP as we approach the constraint limit.

The new GXP will be designed to accommodate two future 110 kV circuits back to Oamaru GXP. If agreement is reached with Alpine Energy and Transpower to collaborate on a joint solution, this would allow Network Waitaki to disconnect Black Point and Oamaru GXPs from the existing Lower Waitaki 110 kV system and free up capacity into the Alpine Energy supply area. A new GXP in this location may allow Transpower to avoid planned transformer upgrades at Lake Waitaki and optimise their 110 kV network to avoid clearance-related upgrades of the 110 kV circuits from Lake Waitaki to Black Point.

We are keen to collaborate with Transpower and Alpine Energy to ensure that the optimal solution is chosen for all parties and that any first mover disadvantage is managed fairly.

Table 38 – New GXP action plan

Project name	Components	Year (s)	Cost (000)
New GXP	Design stage (note 2)	FY23/FY24	TWA
	Land purchase (note 1)	FY24/FY25	$600
	GXP Build (note 2)	FY25/FY26	TWA
	Integrate GXP into NWL network	FY25/FY26	$1,500
	Build 110 kV circuits to Oamaru GXP (note 3)	FY31/FY32	$24,400

Notes:

1) Network Waitaki will identify and purchase suitable land

2) GXP design and build costs will be funded by way of Transmission Works Agreement (TWA)
3) Provisional on commitment from Alpine Energy and Transpower

6.4.3 Waitaki GXP

6.4.3.1 Waitaki GXP capacity

The Waitaki GXP is rated at *24 MVA N security* and *5.5 MVA N-1 Switched.*

NWL owns the 20/24 MVA 11/33 kV GXP transformer which is supplied from the Meridian Energy Waitaki Power Station 11 kV generator bus.

6.4.3.2 Waitaki GXP demand growth scenario

Table 39 - Waitaki GXP known demands

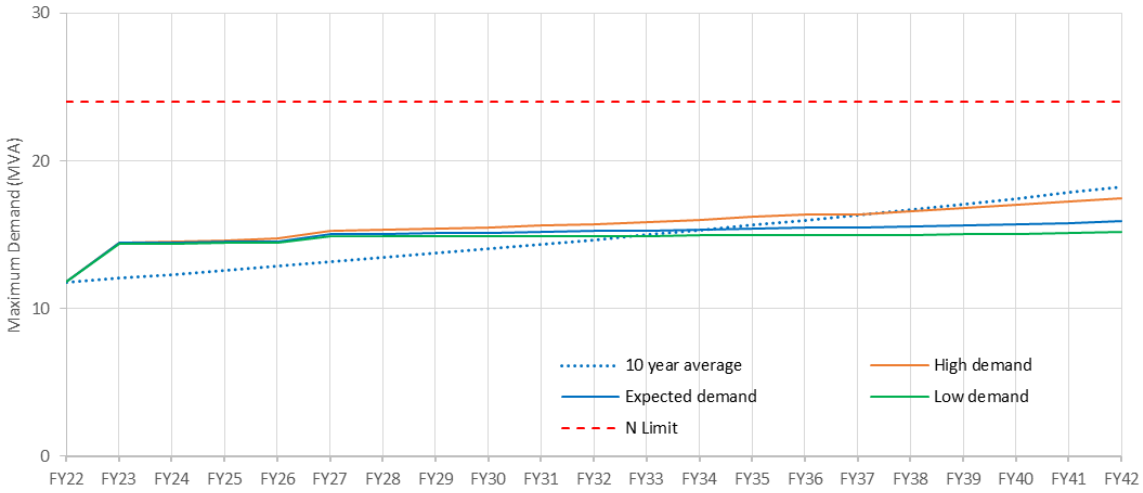
Substation	Demand Type	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Kurow	Irrigation scheme	0.7									
Eastern Rd	Irrigation scheme	1.7				0.4					
	Total New Demand (MVA)	**2.4**	**0.0**	**0.0**	**0.0**	**0.4**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

6.4.3.3 Waitaki GXP constraints

Waitaki GXP has sufficient capacity to meet demand for the next 20 years.

Table 40 - Waitaki GXP load forecast (10 years)

Load Growth Scenario	N-1 Security Limit (MVA)	N Security limit (MVA)	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Average Annual Growth Rate 10 yrs
Low demand	5.5	24	11.8	14.4	14.4	14.4	14.4	14.9	14.9	14.9	14.9	14.9	14.9	2.4%
Expected demand	5.5	24	11.8	14.4	14.5	14.5	14.6	15.0	15.1	15.1	15.1	15.2	15.2	2.6%
High demand	5.5	24	11.8	14.5	14.6	14.6	14.7	15.2	15.3	15.4	15.5	15.6	15.7	2.9%
10 year average	5.5	24	11.8	12.1	12.3	12.6	12.9	13.2	13.4	13.7	14.0	14.4	14.7	2.2%



Our Security of Supply standard requires 50% of demand to be restored in switching time and the remaining 90% within 12 hrs.

Security is currently provided to 11.8 MVA of existing demand from the second Waitaki transformer (5.5 MVA) and from Oamaru GXP via the 33 kV subtransmission network (6.3 MVA). As the demand increases at Oamaru GXP, this security will be eroded.

Table 41 - Waitaki GXP security shortfall

Year	Security available from Oamaru GXP (MVA)	Shortfall (MVA)	Hrs per year
FY24	5	4	145
FY25	4	5	342
FY26	3	6	550

We are investigating the viability of a Static VAR Compensator (SVC) to allow provision of up to 4.5 MVA of security from the Twizel GXP. This will also require the construction of a second 33 kV circuit from Waitaki GXP to Kurow Zone Substation to allow both the Waitaki second transformer and Twizel GXP to supply demand.

In FY26, when a new GXP is commissioned in the Black Point area, the security constraint into Waitaki GXP will be alleviated.

6.4.3.4 Waitaki GXP security upgrade

This project is provisional on technical investigations and options analysis.

Table 42 - Project budgetary cost

Project Name	Components	Year (s)	Cost (000)
Waitaki GXP upgrade	Second 33 kV line from Waitaki GXP to Kurow	FY23	$714
	Install Static VAR Compensator	FY24	$300

6.4.4 Twizel GXP

6.4.4.1 Twizel GXP capacity

The Twizel GXP supplies NWL and Alpine Energy networks. The GXP has dual transformers and is operated with a split 33 kV bus with one side feeding each network, providing *27 MVA, N-1 Switched* security level to NWL and Alpine. Transpower is converting the 33 kV switchboard from an outdoor to an indoor type and will run the new switchboard in a closed bus configuration which will increase the security level to *27 MVA, N-1.*

6.4.4.2 Twizel GXP demand growth scenario

Table 43 - Twizel GXP demand forecast (ten years)

Load Growth Scenario	N-1 Security Limit (MVA)		FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	Average Annual Growth Rate
Low demand	27		2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	0.0%
Expected demand	27		2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	0.4%
High demand	27		2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.2	0.9%
5 year average	27		2.0	2.0	2.1	2.1	2.1	2.2	2.2	2.2	2.3	2.3	2.3	1.5%
10 year average	27		2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.5	2.2%

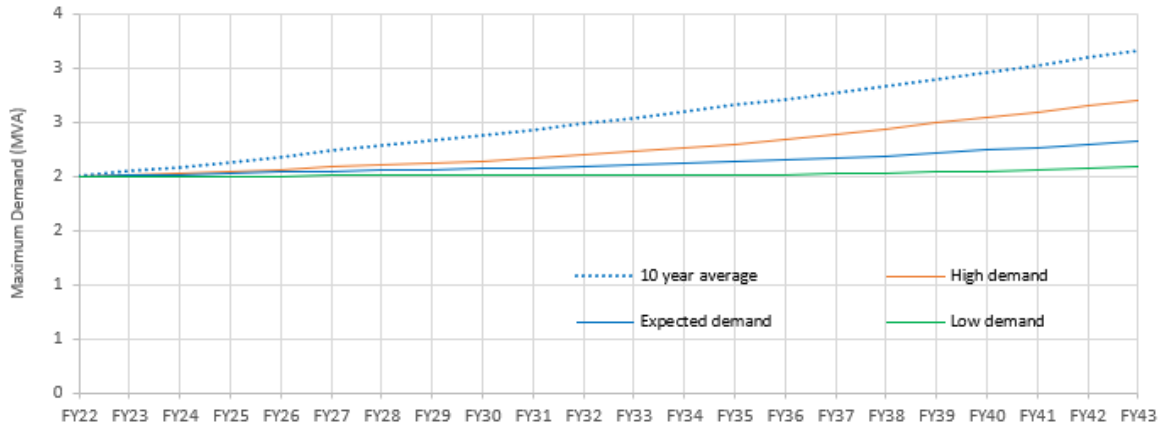


Figure 70 - Twizel GXP demand forecast (20 years)

6.4.4.3 Twizel GXP constraints

The Twizel GXP has sufficient capacity to meet demand within the planning period.

6.4.5 Black Point GXP

6.4.5.1 Black Point GXP capacity

This GXP is dedicated to the North Otago Irrigation Company (NOIC) irrigation scheme, which was commissioned in 2006. The GXP is rated as *25 MVA, N security*.

6.4.5.2 Black Point GXP constraints

NOIC recently completed an expansion to raise their maximum demand from 10.7 MVA to approximately 16 MVA.

Constraints on the Transpower 110 kV supply required the installation of a special protection (demand control) scheme between Waitaki GXP, Oamaru GXP, Black Point GXP, Bells Pond and Studholme to allow NOIC to increase their demand beyond 10.7 MVA. In the event of a contingent event (fault on the Waitaki-Bells Pond-Oamaru 110 kV line) during a constraint period, the special protection scheme may operate to reduce the NOIC pumping demand below the constraint.

6.4.5.3 Black Point GXP demand growth scenario

NOIC advise that they are in the process of selling the remaining shares on the scheme, which will increase demand for water supply from the scheme, and as a result we expect that maximum demand at Black Point GXP will reach the maximum expected 20 MVA by FY24.

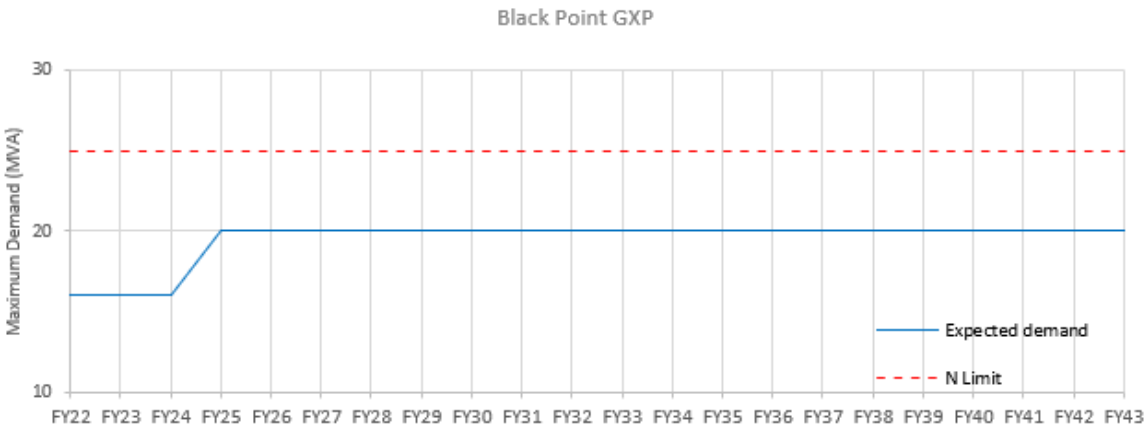


Figure 71 - Black Point GXP demand growth scenario

6.5 SUBTRANSMISSION AND SUBSTATION DEVELOPMENT PLAN

6.5.1 Oamaru GXP zone substation overview

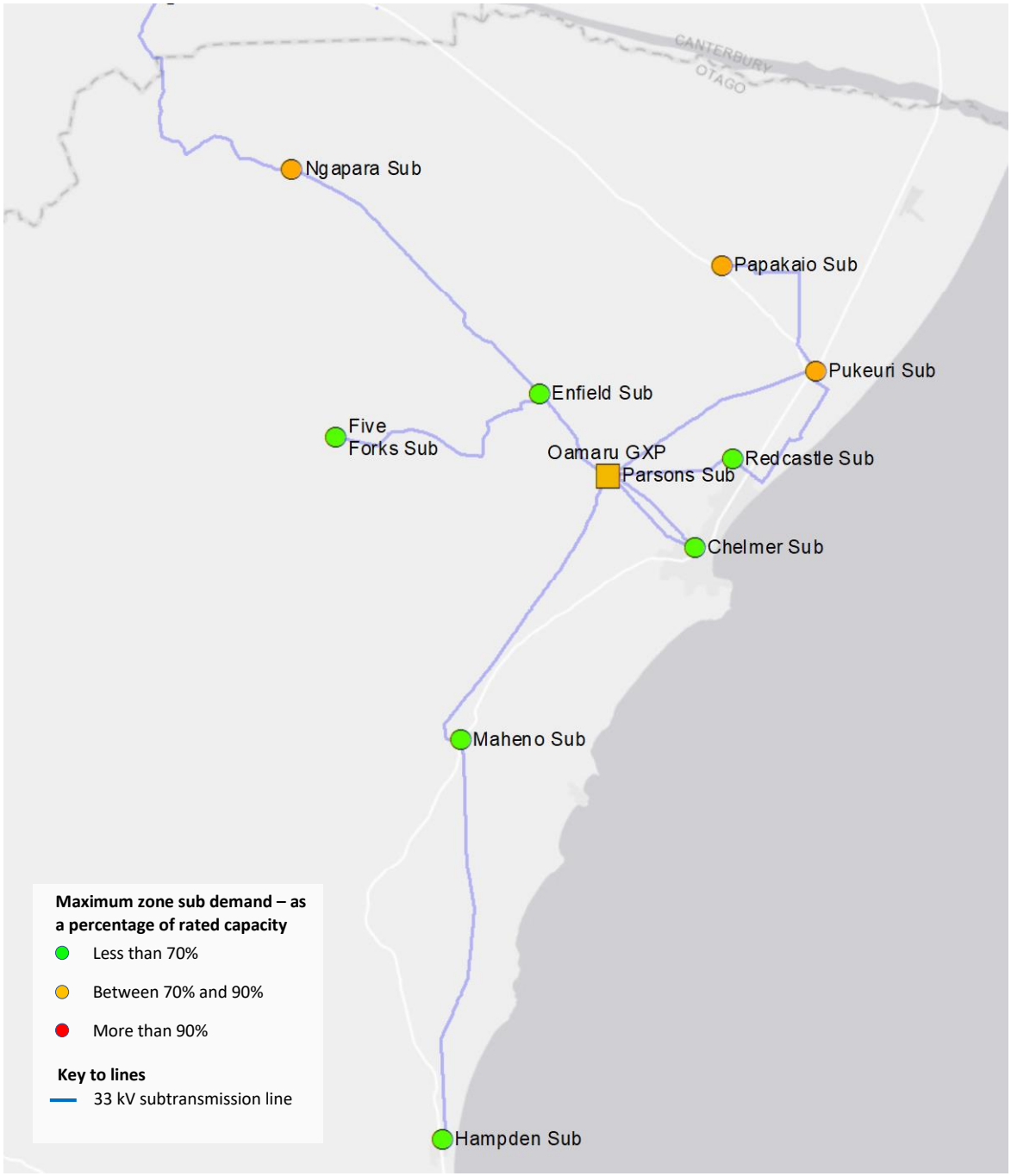


Figure 72 - Waitaki GXP zone substations (FY21 maximum demand as a percentage of rated capacity)

6.5.1.1 Ngapara Zone Substation

Table 44 – Security ratings

Required security of supply level	**B4 rural zone substation**
Substation rating	**7 MVA N security**
GXP	N-1 security
Subtransmission	N-1 switched security[1]
33 kV incomer circuit breaker	N security
33/11 kV transformer	N security
11 kV incomer circuit breaker	N security
11 kV bus	N security
Inter-tied zone substations (11 kV)	Duntroon, Enfield, Papakaio

[1] At times of peak demand, supply at 33 kV can only be provided from Oamaru GXP.

Table 45 - Demand details

Distribution substations supplied	227
Customer connections supplied	383
Farming	117
Commercial	41
Domestic	225

Existing maximum demand varies from 1 MVA in winter to 5.5 MVA in summer, which is predominantly due to irrigation demand. No capacity related upgrades are proposed at Ngapara in the planning period.

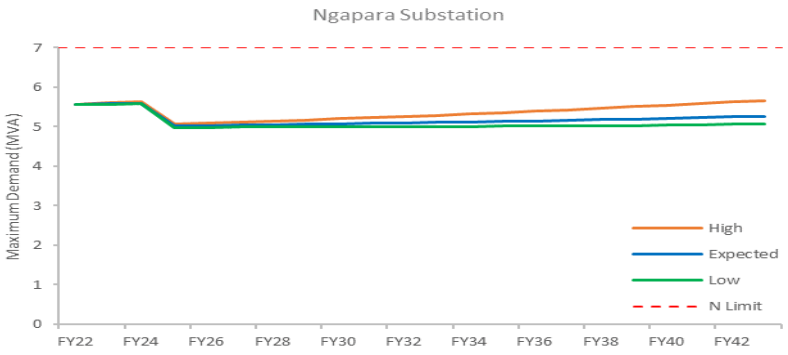


Figure 73 - Ngapara Zone Substation - load forecast

Security Analysis

During summer peak demand, B4 security may not be able to be achieved for outages of N security components due to demand exceeding the 11 kV inter-tie capacity from neighbouring zone substations.

In the event of an outage on an N security component at Ngapara Zone Substation, all individual ICPs will be resupplied from inter-ties from neighbouring zone substations within switching time. Irrigation demand will be staged back on until the capacity of the inter-tie feeders is reached. Dependent on the time of year, up to 2.5 MVA of irrigation demand may be subject to rostering until the fault is repaired. In the event of a transformer failure, this could be up to five days while the transformer is replaced with a spare unit.

This constraint will remain until the Awamoko Zone Substation is commissioned in FY24.

6.5.1.2 Papakaio Zone Substation

Table 46 - Security rating

Required security of supply level	**B4 rural zone substation**
Substation rating	**7 MVA N security**
GXP	N-1 security
Subtransmission	N security
33 kV incomer circuit breaker	N security
33/11 kV transformer	N security
11 kV incomer circuit breaker	N security
11 kV bus	N security
Inter-tied zone substations (11 kV)	Pukeuri, Duntroon, Ngapara

Table 47 - Substation demand details

Distribution substations supplied	261
Customer connections supplied	398
Farming	161
Commercial	29
Domestic	208

Existing maximum demand varies from 2 MVA in winter to 6.1 MVA in summer, which is predominantly due to irrigation demand. If nothing were done to address this constraint, maximum demand is expected to exceed the zone substation rating in FY26 for the expected demand growth scenario. (Note: the graph below includes the effect of transferring demand onto a new Awamoko Zone Substation in FY24)

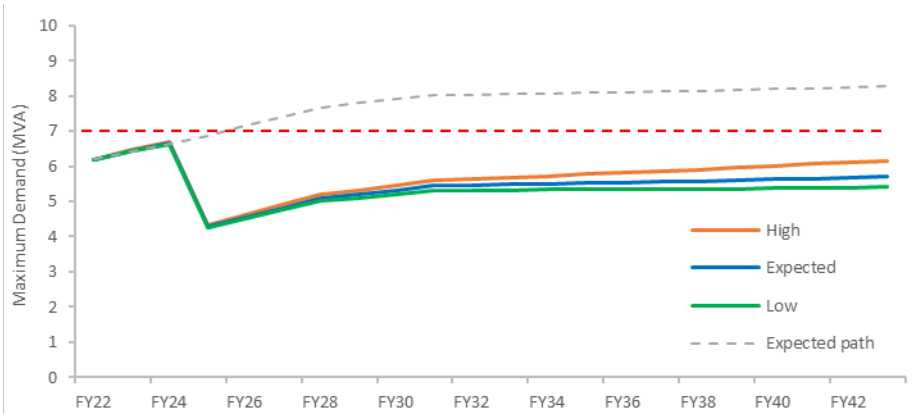


Figure 74 - Papakaio Zone Substation demand forecast

Security analysis

During summer peak demand, B4 security may not be able to be achieved for outages of N security components, due to demand exceeding the 11 kV inter-tie capacity from neighbouring zone substations.

In the event of an outage on an N security component at Papakaio Zone Substation, all individual ICPs will be resupplied from inter-ties from neighbouring zone substations within switching time. Irrigation demand will be staged back on until the capacity of the inter-tie feeders is reached. Dependent on the time of year, up to 2.3 MVA of irrigation demand may be subject to rostering until the fault is repaired. In the event of a transformer failure, this could be up to five days while the transformer is replaced with a spare unit. This constraint will remain until a new zone substation is commissioned in the Awamoko area.

Development plan

A new Awamoko Zone Substation is proposed to be commissioned in FY24 to reduce demand and to alleviate security constraints on Papakaio Zone Substation. Initially the subtransmission supply shall be from Papakaio and ultimately continued to Duntroon to form a subtransmission loop, which will increase security to Awamoko and Papakaio Zone Substations.

6.5.1.3 Awamoko Zone Substation (proposed)

A new zone substation is proposed in the Awamoko area to remedy security and capacity constraints on Papakaio Zone Substation and provide improved security to Duntroon and Ngapara Zone Substations. 12.5 km of new subtransmission line is proposed to be installed from Papakaio to Awamoko, followed by 16 km of new subtransmission line from Duntroon to Awamoko.

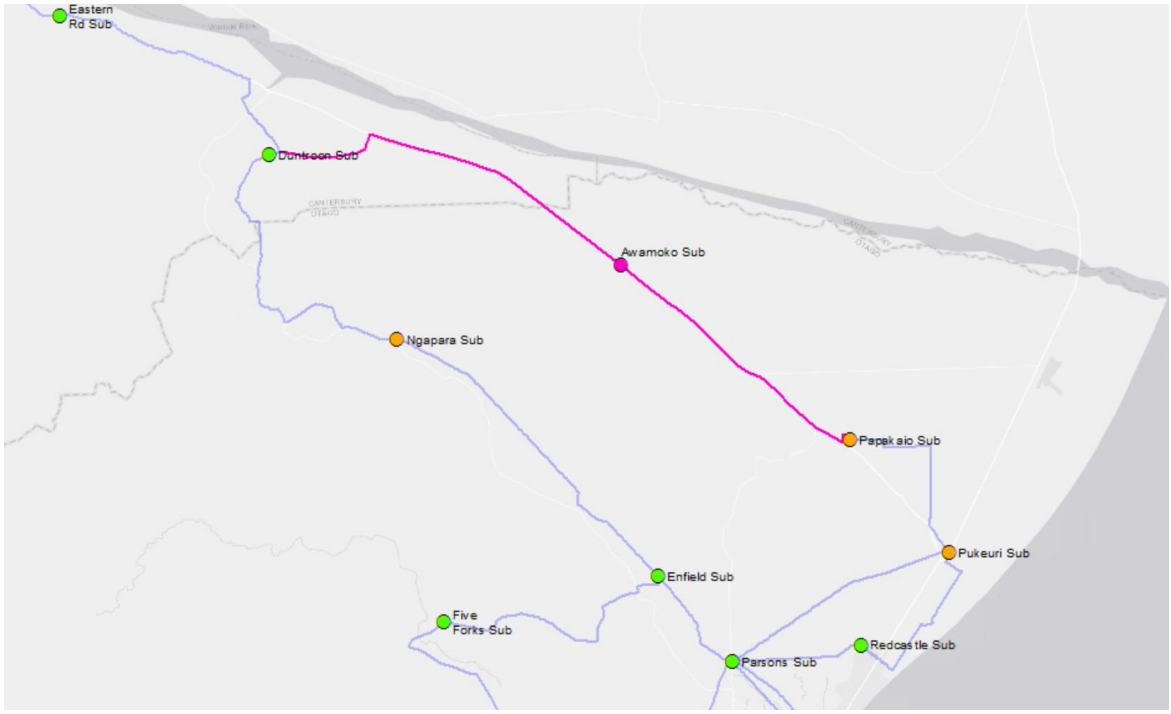


Figure 75 - Proposed Awamoko Zone Substation location

Table 48- Security rating

Required security of supply level	**B4 rural zone substation**
Substation rating	**7 MVA N security**
GXP	N-1 security
Subtransmission	N-1 switched security
33 kV incomer circuit breaker	N security
33/11 kV transformer	N security
11 kV incomer circuit breaker	N security
11 kV bus	N security
Inter-tied zone substations (11 kV)	Papakaio, Duntroon, Ngapara

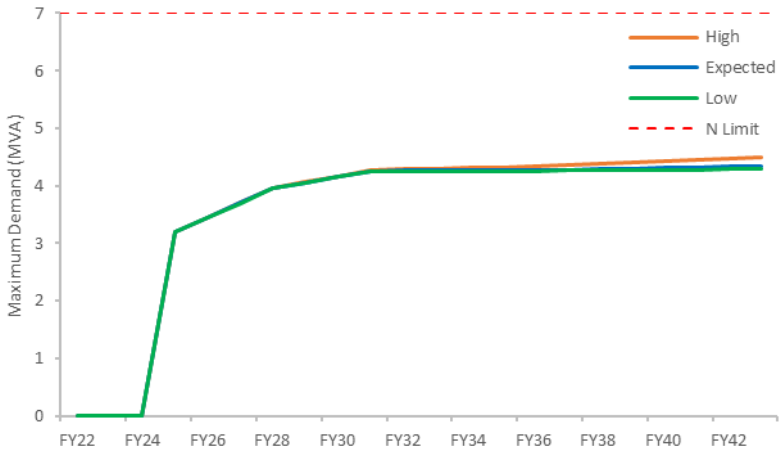


Figure 76 - Proposed Awamoko demand forecast

Table 49 - Cost estimate Awamoko Zone Substation

Project Name	Components	Year (s)	Budget cost (000)
Awamoko Zone Substation	Detailed design, Geotech study, procure land Major equipment procurement New Zone substation	FY23 FY23 FY24	$210 $522 $1,575
Papakaio/Awamoko subtransmission	Design and procure easements New subtransmission line Stage 1 New subtransmission line Stage 2 Retighten line (OPEX)	FY23 FY23 FY24 FY25	$50 $1,365 $1,365 $45
Duntroon/Awamoko subtransmission	Design and procure easements New subtransmission line Stage 1 New subtransmission line Stage 2 Retighten line (OPEX)	FY24 FY25 FY26 FY27	$50 $1,700 $1,700 $54

6.5.1.4 Pukeuri Zone Substation

Table 50- Security rating

Required security of supply level	**B2 urban zone substation**
Substation rating	**12 MVA N-1 security**
GXP	N-1 security
Subtransmission	N-1 security
33 kV incomer circuit breaker	N-1 security
33/11 kV transformer	N-1 security
11 kV incomer circuit breaker	N-1 security
11 kV bus	N-1 security
Inter-tied zone substations (11 kV)	Papakaio, Redcastle

Table 51- Substation demand details

Distribution substations supplied	205
Customer connections supplied	463
Farming	107
Commercial	55
Domestic	301

Existing maximum demand varies from 5.5 MVA in winter to 8.7 MVA in summer, with the difference being predominantly due to irrigation demand. Pukeuri Zone Substation is predicted to exceed the N-1 security limit in FY27 for all scenarios, due to conversion of a large amount of process heat from coal to electricity for a large customer.

The two Pukeuri power transformers are required to be upgraded before FY27 to cater for this demand increase. Subtransmission upgrades may also be required and this will be modelled and quantified in FY23.

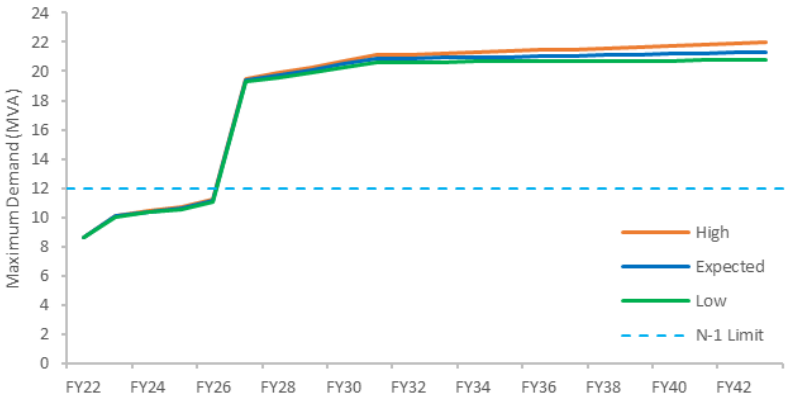


Figure 77 - Pukeuri Zone Substation demand forecast

Table 52 - Cost estimate Pukeuri Zone Substation transformer upgrade

Project Name	**Components**	**Year (s)**	**Budget cost (000)**
Pukeuri Zone Substation transformer upgrade	Detailed design Replace transformer 1 Replace transformer 2	FY24 FY25 FY26	$46 $1,061 $1,051

6.5.1.5 Enfield Zone Substation

Table 53- Security rating

Required security of supply level	**B4 rural zone substation**
Substation rating	**7 MVA N security**
GXP	N-1 security
Subtransmission	N-1 switched security[1]
33 kV incomer circuit breaker	N security
33/11 kV transformer	N security
11 kV incomer circuit breaker	N security
11 kV bus	N security
Inter-tied zone substations (11 kV)	Ngapara, Parsons, Five Forks

[1]At times of peak demand, supply at 33 kV can only be provided from Oamaru GXP.

Table 54- Substation demand details

Distribution substations supplied	178
Customer connections supplied	323
Farming	93
Commercial	24
Domestic	206

Existing maximum demand varies from 0.5 MVA in winter to 2.3 MVA in summer, with the difference being predominantly due to irrigation demand. No capacity related upgrades are proposed during the planning period.

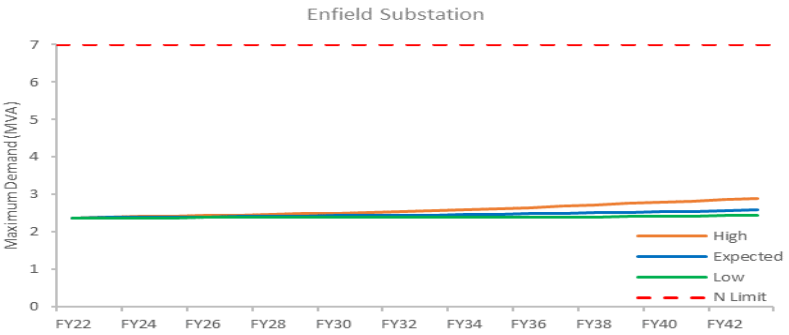


Figure 78 – Enfield Zone Substation demand forecast

6.5.1.6 Parsons Zone Substation

Table 55- Security rating

Required security of supply level	**B4 rural zone substation**
Substation rating	**12 MVA N security**
GXP	N-1 security
Subtransmission	N-1 switched security
33 kV incomer circuit breaker	N security
33/11 kV transformer	N security
11 kV incomer circuit breaker	N security
11 kV bus	N security
Inter-tied zone substations (11 kV)	Enfield, Papakaio, Redcastle, Chelmer, Maheno

Table 56- Substation demand details

Distribution substations supplied	312
Customer connections supplied	1,055
Farming	67
Commercial	101
Domestic	887

Existing maximum demand varies from 2.7 MVA in winter to 3.9 MVA in summer, with the difference being predominantly due to irrigation demand. No capacity upgrades are proposed during the planning period.

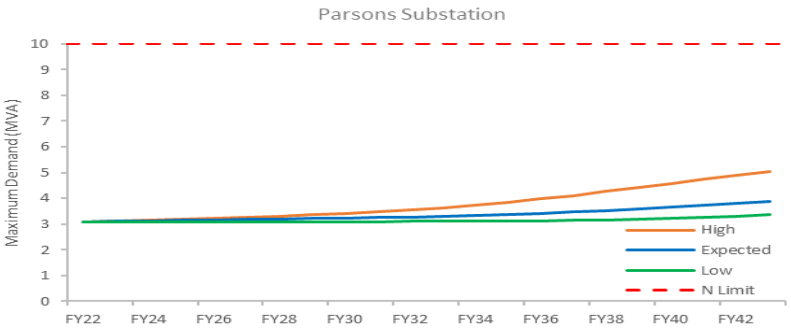


Figure 79 – Parsons Zone Substation demand forecast

6.5.1.7 Five Forks Zone Substation

Table 57- Security rating

Required security of supply level	**B4 rural zone substation**
Substation rating	**7 MVA N security**
GXP	N-1 security
Subtransmission	N security
33 kV incomer circuit breaker	N security
33/11 kV transformer	N security
11 kV incomer circuit breaker	N security
11 kV bus	N security
Inter-tied zone substations (11 kV)	Ngapara, Enfield, Maheno

Table 58- Substation demand details

Distribution substations supplied	110
Customer connections supplied	176
Farming	62
Commercial	15
Domestic	99

Existing maximum demand varies from 0.4 MVA in winter to 2 MVA in summer, with the difference being predominantly due to irrigation demand. No capacity upgrades are proposed during the planning period.

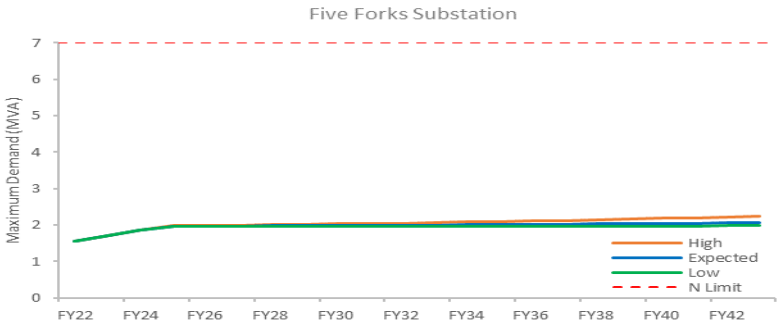


Figure 80- Five Forks Zone Substation demand forecast

6.5.1.8 Chelmer Zone Substation

Table 59- Security rating

Required security of supply level	**B2 urban zone substation**
Substation rating	**28 MVA N-1 security**
GXP	N-1 security
Subtransmission	N-1 security
33 kV incomer circuit breaker	N-1 security
33/11 kV transformer	N-1 security
11 kV incomer circuit breaker	N-1 security
11 kV bus	N-1 security
Inter-tied zone substations (11 kV)	Redcastle, Parsons, Maheno

Table 60 – Substation demand details

Distribution substations supplied	135
Customer connections supplied	4,102
Farming	14
Commercial	650
Domestic	3,438

Chelmer Zone substation is a winter-peaking substation. Existing maximum demand varies from 13.8 MVA in winter to 9.2 MVA in summer. Note that the growth changes after FY32 due to the increasing EV penetration rate.

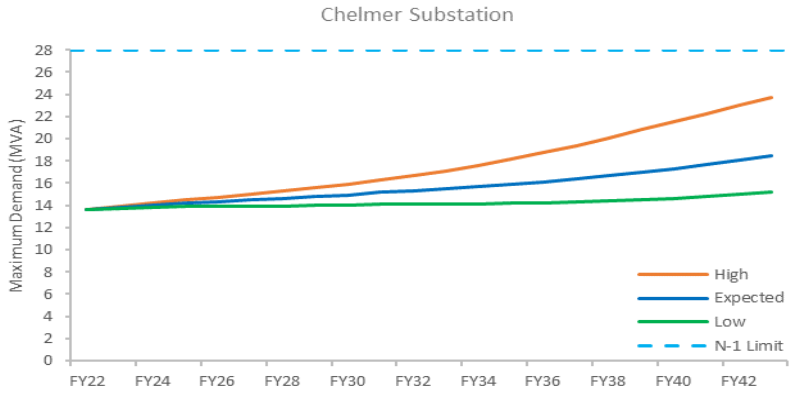


Figure 81 - Chelmer Zone Substation demand forecast

6.5.1.9 Redcastle Zone Substation

Table 61- Security rating

Required security of supply level	**B2 urban zone substation**
Substation rating	**15 MVA N-1 security**
GXP	N-1 security
Subtransmission	N-1 security
33 kV incomer circuit breaker	N-1 security
33/11 kV transformer	N-1 security
11 kV incomer circuit breaker	N-1 security
11 kV bus	N-1 security
Inter-tied zone substations (11 kV)	Pukeuri, Parsons, Chelmer

Table 62- Substation demand details

Distribution substations supplied	92
Customer connections supplied	2,324
Farming	9
Commercial	169
Domestic	2,146

Redcastle Zone substation is a winter-peaking substation supplying urban Oamaru. Existing maximum demand varies from 9.3 MVA in winter to 7 MVA in summer. All scenarios include an allowance for conversion of a large amount of process heat from coal to electricity. No capacity related upgrades are planned during the next ten years. In the high growth scenario, transformer upgrades could be required in 16 years and this will be evaluated closer to the time. Note that the growth changes after FY32 are as a result of increasing electric vehicle penetration rate.

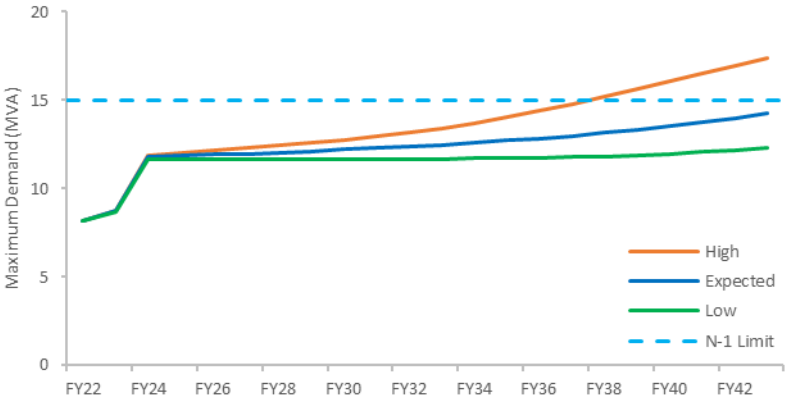


Figure 82 - Redcastle Zone Substation demand forecast

6.5.1.10 Maheno Zone Substation

Table 63- Security rating

Required security of supply level	**B4 rural zone substation**
Substation rating	**5 MVA N security**
GXP	N-1 security
Subtransmission	N security
33 kV incomer circuit breaker	N security
33/11 kV transformer	N security
11 kV incomer circuit breaker	N security
11 kV bus	N security
Inter-tied zone substations (11 kV)	Five Forks, Parsons, Chelmer, Enfield, Hampden

Table 64- Substation demand details

Distribution substations supplied	350
Customer connections supplied	1,021
Farming	150
Commercial	109
Domestic	762

Existing maximum demand varies from 1.7 MVA in winter to 3.5 MVA in summer, with the difference being predominantly due to irrigation demand. No capacity upgrades are proposed during the planning period. Note that the growth changes after FY32 due to the increasing electric vehicle penetration rate.

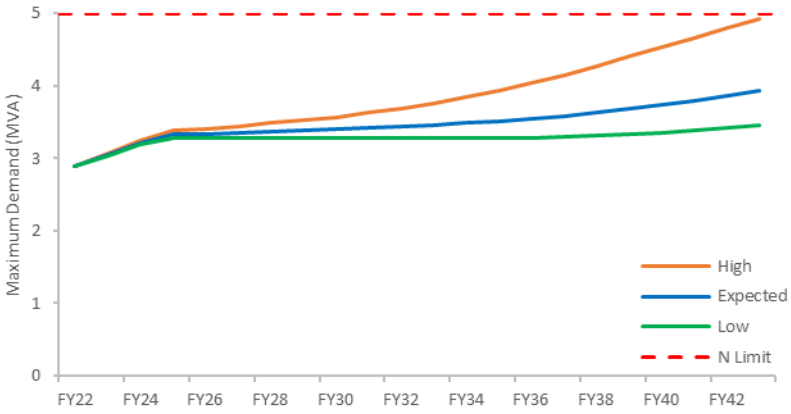


Figure 83 – Maheno Zone Substation demand forecast

6.5.1.11 Hampden Zone Substation

Table 65- Security rating

Required security of supply level	**B4 rural zone substation**
Substation rating	**7 MVA N security**
GXP	N-1 security
Subtransmission	N security
33 kV incomer circuit breaker	N security
33/11 kV transformer	N security
11 kV incomer circuit breaker	N security
11 kV bus	N security
Inter-tied zone substations (11 kV)	Maheno

Table 66- Substation demand details

Distribution substations supplied	233
Customer connections supplied	810
Farming	68
Commercial	80
Domestic	662

Existing maximum demand is flat at 1.4 MVA throughout the year.

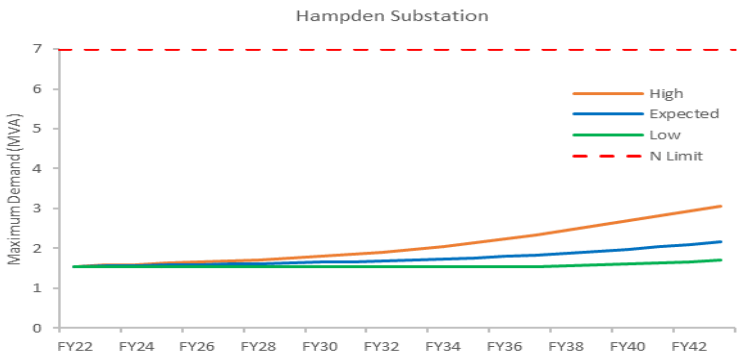


Figure 84 – Hampden Zone Substation demand forecast

6.5.2 Waitaki GXP zone substation overview

Figure 85 - Waitaki GXP zone substations (FY21 maximum demand as a percentage of rated capacity)

6.5.2.1 Otematata Zone Substation

Table 67- Security rating

Required security of supply level	**B5 rural zone substation**
Substation rating	**3 MVA N security**
GXP	N-1 switched security
Subtransmission	N-1 switched security
33 kV incomer circuit breaker	N security
33/11 kV transformer	N security
11 kV incomer circuit breaker	N security
11 kV bus	N security
Inter-tied zone substations (11 kV)	None

Table 68- Substation demand details

Distribution substations supplied	35
Customer connections supplied	523
Farming	10
Commercial	44
Domestic	469

Demand is less than 0.5 MVA for most of the year, peaking at 1.1 MVA over the Christmas holiday period as the town swells with holiday makers.

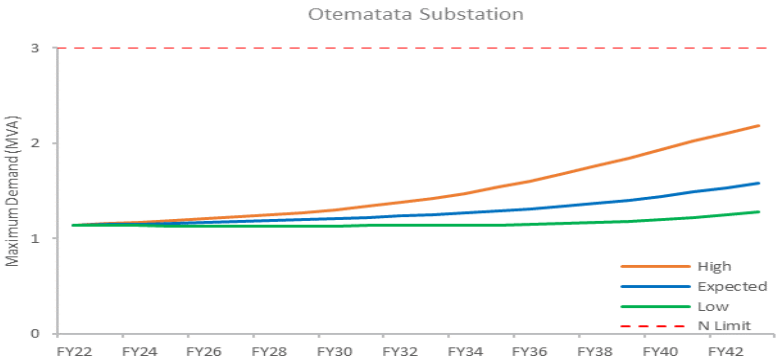


Figure 86 - Otematata substation demand forecast

Security is currently provided by a 0.5 MW backup diesel generator. In FY21 there were 272 hrs where demand exceeded the generator rating. Our security levels are not met during peak demand periods.

In the short-term we will manage this by relocating an additional 0.5 MW diesel generator to site over the 2021/22 Christmas holidays. A project is scheduled for FY23 to install an additional synchronised 500 kW backup diesel genset.

Project Name	**Components**	**Year (s)**	**Budget cost (000)**
Otematata security	Install new 500 kVA diesel backup generator	FY23	$350

6.5.2.2 Kurow Zone Substation

Table 69- Security rating

Required security of supply level	**B4 rural zone substation**
Substation rating	**12 MVA N-1 security**
GXP	N-1 switched security (up to 5 MVA)
Subtransmission	N-1 switched security[1]
33 kV incomer circuit breaker	N-1 security
33/11 kV transformer	N-1 security
11 kV incomer circuit breaker	N-1 security
11 kV bus	N-1 security
Inter-tied zone substations (11 kV)	Eastern Rd

[1]At times of peak demand, supply at 33 kV can only be provided from Waitaki GXP.

Table 70- Substation demand details

Distribution substations supplied	324
Customer connections supplied	767
Farming	155
Commercial	117
Domestic	495

Existing maximum demand varies from 1 MVA in winter to 5.1 MVA in summer, which is predominantly due to irrigation demand.

No security or capacity related upgrades are proposed at Kurow in the planning period.

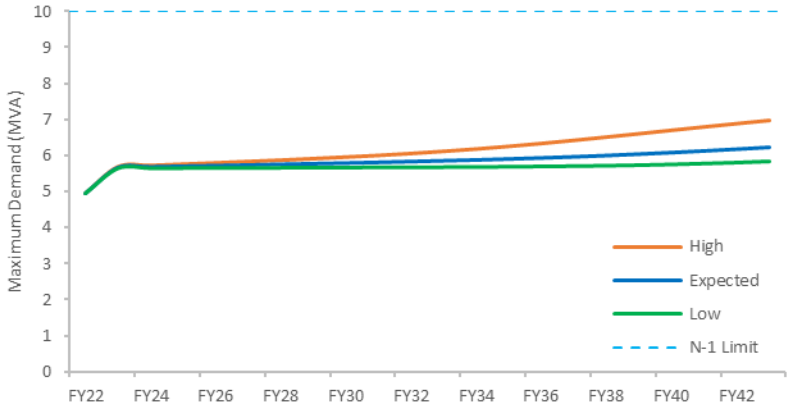


Figure 87 - Kurow substation demand forecast

6.5.2.3 Eastern Rd Zone Substation

Table 71- Security rating

Required security of supply level	**B4 rural zone substation**
Substation rating	**7 MVA N security**
GXP	N-1 security[1]
Subtransmission	N-1 switched security
33 kV incomer circuit breaker	N security
33/11 kV transformer	N security
11 kV incomer circuit breaker	N security
11 kV bus	N security
Inter-tied zone substations (11 kV)	Kurow, Duntroon

[1]At times of peak demand, supply at 33 kV can only be provided from Waitaki GXP

Table 72 - Substation demand details

Distribution substations supplied	95
Customer connections supplied	153
Farming	58
Commercial	10
Domestic	85

Existing maximum demand varies from 0.7 MVA in winter to 2.6 MVA in summer, which is due to effects of irrigation demand.

No security or capacity related upgrades are proposed in the planning period.

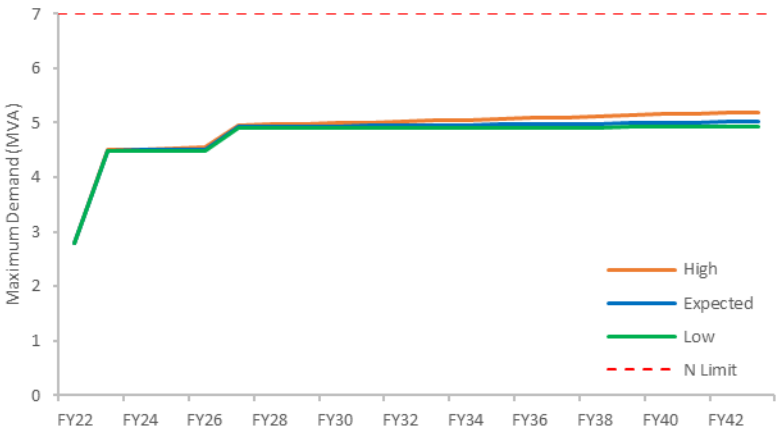


Figure 88 - Eastern Rd substation demand forecast

6.5.2.4 Duntroon Zone Substation

Table 73- Security rating

Required security of supply level	**B4 rural zone substation**
Substation rating	**7 MVA N security**
GXP	N-1 security
Subtransmission	N-1 switched security[1]
33 kV incomer circuit breaker	N security
33/11 kV transformer	N security
11 kV incomer circuit breaker	N security
11 kV bus	N security
Inter-tied zone substations (11 kV)	Eastern Rd, Ngapara

[1]At times of peak demand, supply at 33 kV can only be provided from Waitaki GXP.

Table 74- Substation demand details

Distribution substations supplied	104
Customer connections supplied	204
Farming	63
Commercial	25
Domestic	116

Existing maximum demand varies from 0.8 MVA in winter to 3.7 MVA in summer, which is predominantly due to irrigation demand. No security or capacity related upgrades are proposed in the planning period.

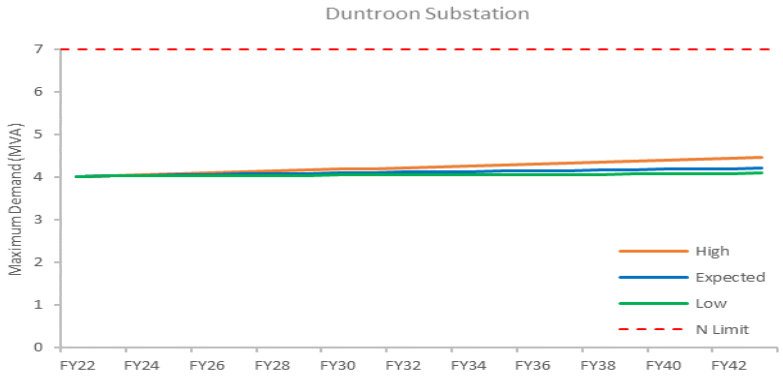


Figure 89 - Duntroon substation demand forecast

6.5.3 Twizel GXP zone substation overview

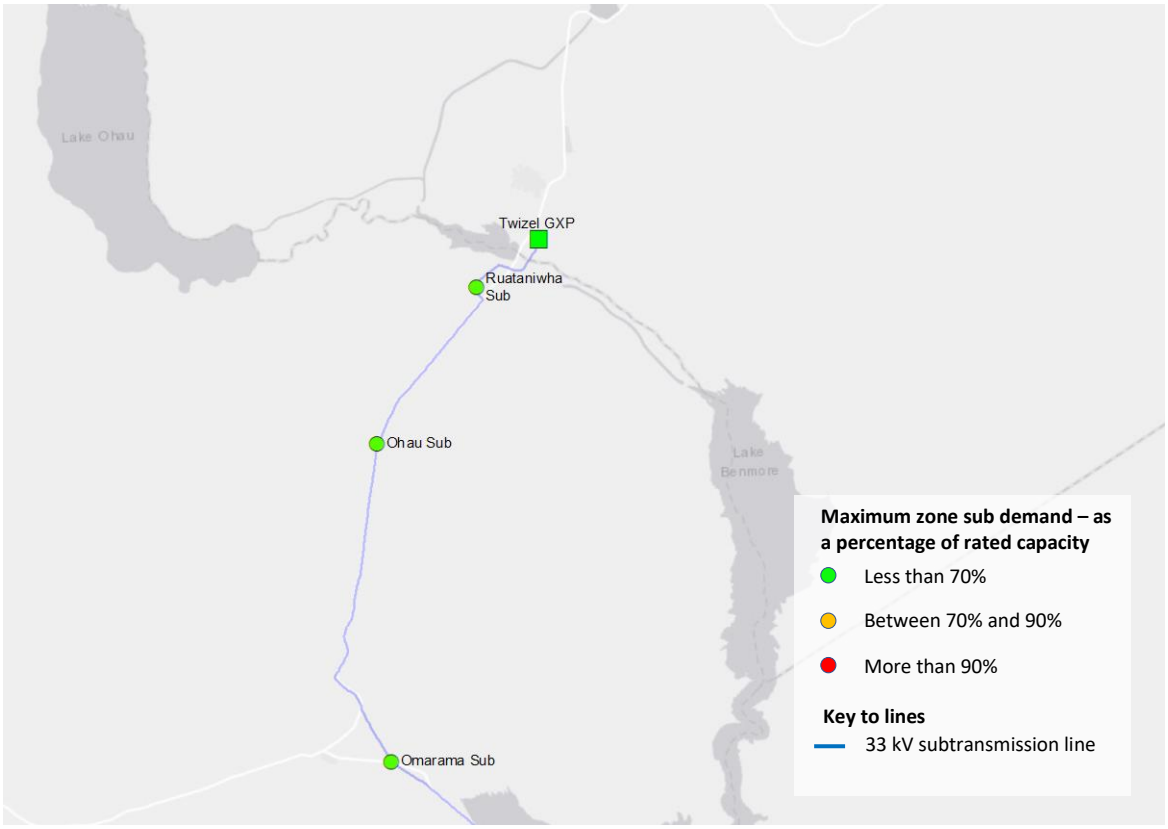


Figure 90 - Twizel GXP zone substations (FY21 maximum demand as a percentage of rated capacity)

6.5.3.1 Ruataniwha Substation

Table 75- Security rating

Required security of supply level	**Customer substation**
Substation rating	**2 MVA N security**
GXP	N-1 switched security
Subtransmission	N-1 switched security
33 kV incomer circuit breaker	N security
33/11 kV transformer	N security
11 kV incomer circuit breaker	N security
11 kV bus	N security
Inter-tied zone substations (11 kV)	None

Ruataniwha 33/11 kV substation is a single customer substation. NWL has an 11 kV circuit terminating close to this customer substation, which will allow NWL to resupply via our 11 kV network within 8 hours.

Table 76- Substation demand details

Distribution substations supplied	12
Customer connections supplied	18
Farming	10
Commercial	2
Domestic	6

Existing maximum demand varies from 0.1 MVA in winter to 0.8 MVA in summer, which is predominantly due to irrigation demand. No security or capacity related upgrades are proposed in the planning period.

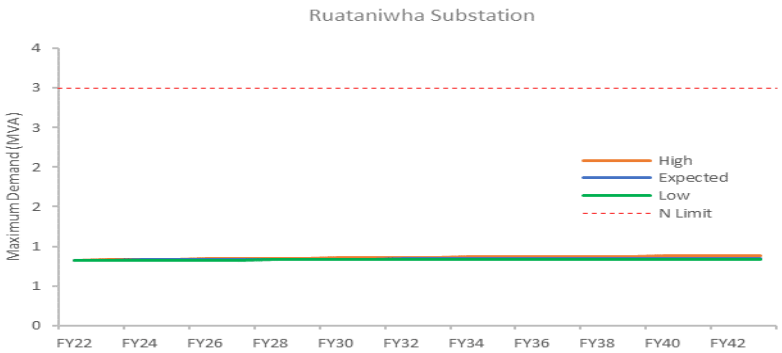


Figure 91 – Ruataniwha Substation demand forecast

6.5.3.2 Ohau Zone Substation

Table 77- Security rating

Required security of supply level	**B5 rural zone substation**
Substation rating	**3 MVA N security**
GXP	N-1 switched security
Subtransmission	N-1 switched security
33 kV incomer circuit breaker	N security
33/11 kV transformer	N security
11 kV incomer circuit breaker	N security
11 kV bus	N security
Inter-tied zone substations (11 kV)	Omarama

Table 78- Substation demand details

Distribution substations supplied	59
Customer connections supplied	157
Farming	29
Commercial	23
Domestic	105

Ohau supplies the Ohau lodge and Ohau Snowfields. Winter maximum demand is 1.1 MVA when snowmaking is occurring at the Ohau Snowfield, and summer maximum demand is 1.4 MVA which is primarily irrigation driven. No security or capacity related upgrades are proposed in the planning period.

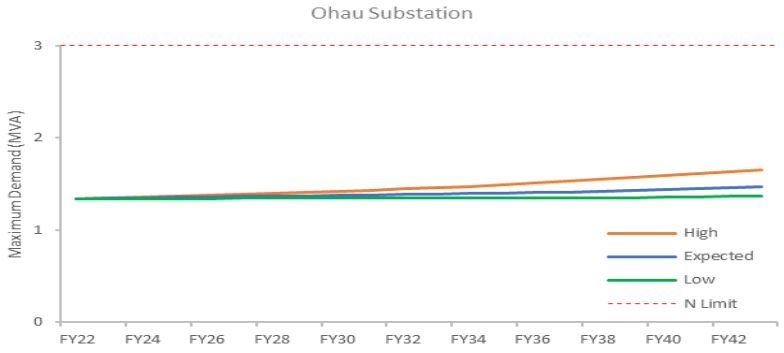


Figure 92 - Ohau Substation demand forecast

6.5.3.3 Omarama Zone Substation

Table 79- Security details

Required security of supply level	**B5 rural zone substation**
Substation rating	**3 MVA N security**
GXP	N-1 switched security
Subtransmission	N-1 switched security
33 kV incomer circuit breaker	N security
33/11 kV transformer	N-1 switched security
11 kV incomer circuit breaker	N security
11 kV bus	N security
Inter-tied zone substations (11 kV)	Omarama

Table 80- Substation demand details

Distribution substations supplied	113
Customer connections supplied	465
Farming	46
Commercial	71
Domestic	348

Existing maximum demand varies from 0.9 MVA in winter to 1.5 MVA in summer, which is due to effects of irrigation demand.

No security or capacity related upgrades are proposed at Omarama in the planning period.

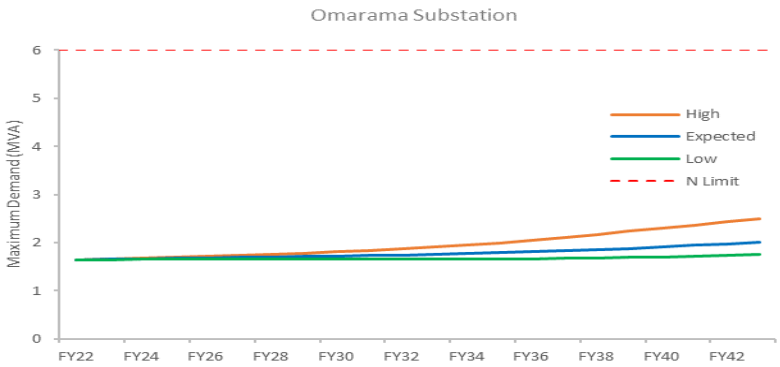


Figure 93 – Omarama Substation demand forecast

6.6 HV AND LV DISTRIBUTION DEVELOPMENT PLAN

6.6.1 Capacity

A large industrial customer connected to Redcastle Road Zone Substation has advised that they are highly likely to connect an additional 3 MVA of demand in FY23. This will require a new section of HV feeder cable to be installed to allow the customer to be supplied from a dedicated feeder.

This project budget is provisional based on the customer's commitment to proceed.

Project name	Components	Year (s)	Budget cost (000)
Woolen Mills feeder upgrade	Install new underground section of feeder cable	FY23	$400

6.6.2 Security

Detailed analysis of 11 kV inter-tie capacity and security for zone substations will be completed during the FY22 period once our new modelling system is commissioned. The outcome of this work may be the strengthening and upgrading of various 11 kV feeders across the network to adequately support demand transfer between substations. Business cases will be completed for any proposed upgrades.

During the FY23 year it is expected that growth related security and capacity issues may arise on the 11 kV and LV networks. The following budget has been provisionally allocated to remedy any issues arising, subject to an approved business case.

Project Name	Components	Year (s)	Budget cost (000)
Provisional budget	HV/LV capacity/security upgrades (across all GXP supply areas)	FY23	$350

6.7 NETWORK DEVELOPMENT PROGRAM

Table 81 - Summary of system growth projects

System Growth	FY23 ($000)	FY24 ($000)	FY25 ($000)	FY26 ($000)	FY27 ($000)	FY28 ($000)	FY29 ($000)	FY30 ($000)	FY31 ($000)	FY32 ($000)	Grand total
GXP											
Special protection scheme - NWL protection changes	120										**120**
WTK GXP security enhancements		300									**300**
New GXP land purchase		300	300								**600**
Integrate GXP into network			750	750							**1,500**
Build new 110kV circuits into Oamaru									12,200	12,200	**24,400**
Subtransmission											
Subtransmission line - Waitaki GXP to Kurow	714										**714**
Subtransmission line - Papakaio to Awamoko	1,415	1,365									**2,780**
Subtransmission line - Duntroon to Awamoko		50	1,701	1,701							**3,452**
Zone Substations											
Otematata security upgrade	350										
New Awamoko substation	732	1,575									**2,307**
Replace Pukeuri transformer #1		33	1,051								**1,084**
Replace Pukeuri transformer #2		23	10	1,051							**1,084**
Distribution											
Woollen Mills Feeder upgrade	400										**400**
Network enhancement opportunities	250	250	250	250	250	250	250	250	250	250	**2,500**
Reactive HV and LV reinforcement	350	350	500	500	500	500	500	500	500	500	**4,700**
Grand Total	**4,331**	**4,246**	**4,562**	**4,252**	**750**	**750**	**750**	**750**	**12,950**	**12,950**	**46,290**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NON-NETWORK INVESTMENT PLAN

This section details our non-network investment program.

7. Non-network investment plan

7.1 FIVE YEAR FORECAST

Component	FY23 ($000)	FY24 ($000)	FY25 ($000)	FY26 ($000)	FY27 ($000)
Buildings	4,552	2,051			
Vehicles		120	110	120	
Plant	73				
Information Technology	391	250	207	218	310
Total	**5,016**	**2,421**	**317**	**338**	**310**

7.2 COMMENTARY

The buildings component of our non-network expenditure forecast includes the redevelopment of the Chelmer Street site (our administration and operations site) between FY22 and FY24. 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. Also included is development at our Airedale Road site which is used for operational purposes as well as storage of poles and large plant and materials.

The vehicles and plant components include end of life replacement of network vehicles and plant.

Information Technology includes routine replacement of server hardware, computers, and mobile devices, as well as investment in systems to replace aging software, and to enhance the business operations.

POWERING OUR FUTURE

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EXPENDITURE FORECAST SUMMARY

8. Summary of expenditure forecasts

The summary of our forecast expenditure for the planning period are presented on the following pages.

These forecasts are reasonably accurate 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 very dependent the outcomes of inspections in the first five years, customer growth, and other issues that are currently out of our control, such as the development of the Transpower transmission network.

Table 82 - Summary of expenditure forecasts

Forecast expenditure ($000)											
Network capital expenditure	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY32**	**Total**
Consumer Connection	1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366	**13,660**
System Growth	4,331	4,246	4,562	4,252	750	750	750	750	12,950	12,950	**46,291**
Asset Replacement & Renewal	4,665	7,163	5,653	4,319	6,170	4,975	5,474	4,662	4,708	4,662	**52,451**
Asset Relocations	-	-	-	-	-	-	-	-	-	-	**-**
Reliability, Safety & Environment - Quality of Supply	1,125	1,640	2,133	918	1,034	995	492	137	137	137	**8,748**
Reliability, Safety & Environment - Legislative & Regulatory	357	357	366	366	195	195	195	195	195	195	**2,616**
Other reliability, safety, and environment	-	-	-	-	-	-	-	-	-	-	-
Total capital expenditure	**11,844**	**14,772**	**14,080**	**11,221**	**9,515**	**8,281**	**8,277**	**7,110**	**19,356**	**19,310**	**123,766**
Network operational expenditure											
Service Interruptions & Emergencies	460	460	460	460	460	460	460	460	460	460	**4,600**
Vegetation Management	683	683	683	683	683	683	683	683	683	683	**6,830**
Routine & Corrective Maintenance and Inspections	1,448	1,448	1,367	1,295	1,239	1,239	1,239	1,239	1,239	1,239	**12,992**
Asset Replacement & Renewal	677	629	629	524	524	524	524	524	524	524	**5,603**
Total operational expenditure	**3,268**	**3,220**	**3,139**	**2,962**	**2,906**	**2,906**	**2,906**	**2,906**	**2,906**	**2,906**	**30,025**
Total expenditure	**15,112**	**17,992**	**17,219**	**14,183**	**12,421**	**11,187**	**11,183**	**10,016**	**22,262**	**22,216**	**153,791**

Figure 94 - Annual capital expenditure forecast by category

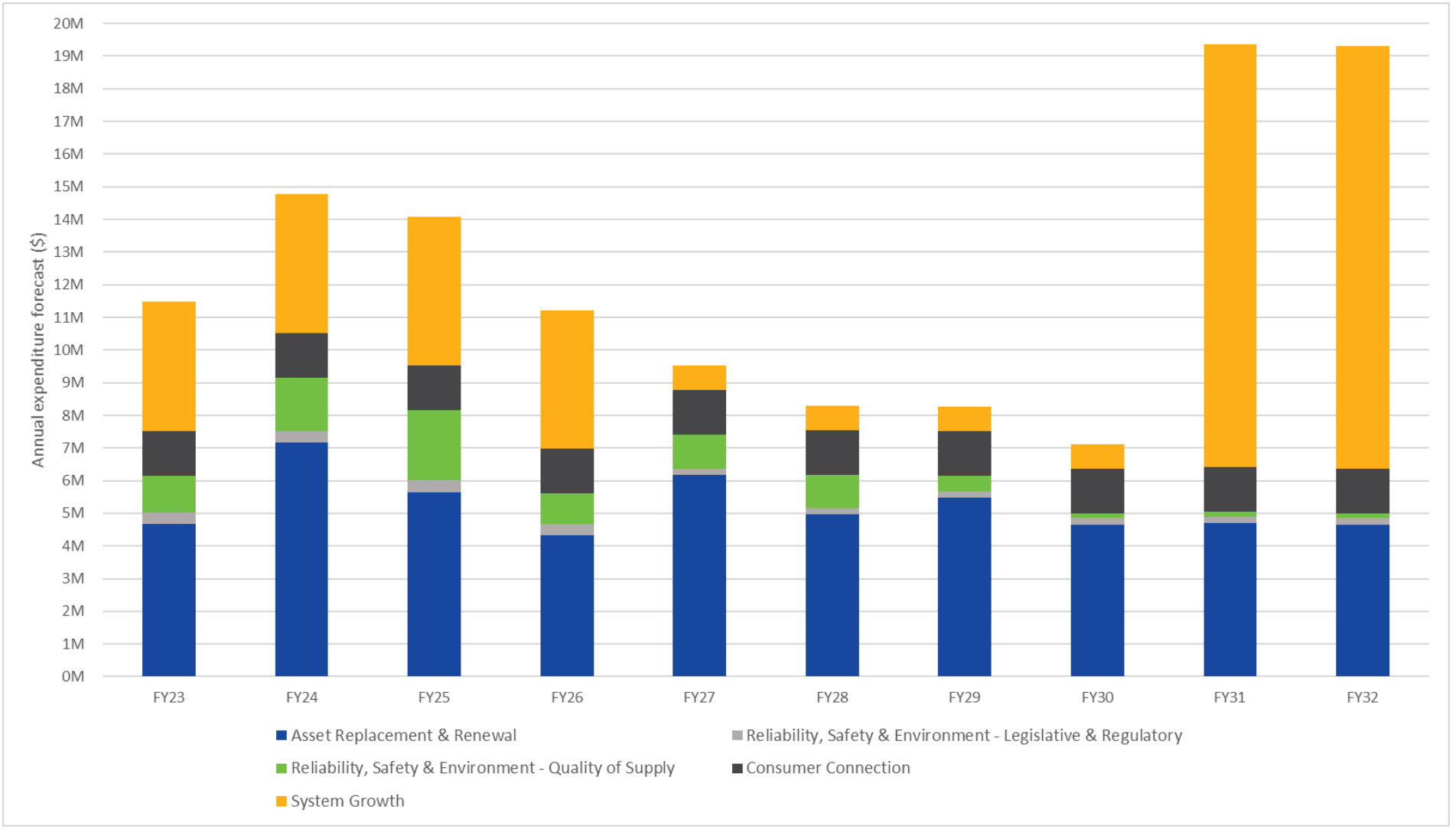


Figure 95 – Annual operational expenditure forecast by category

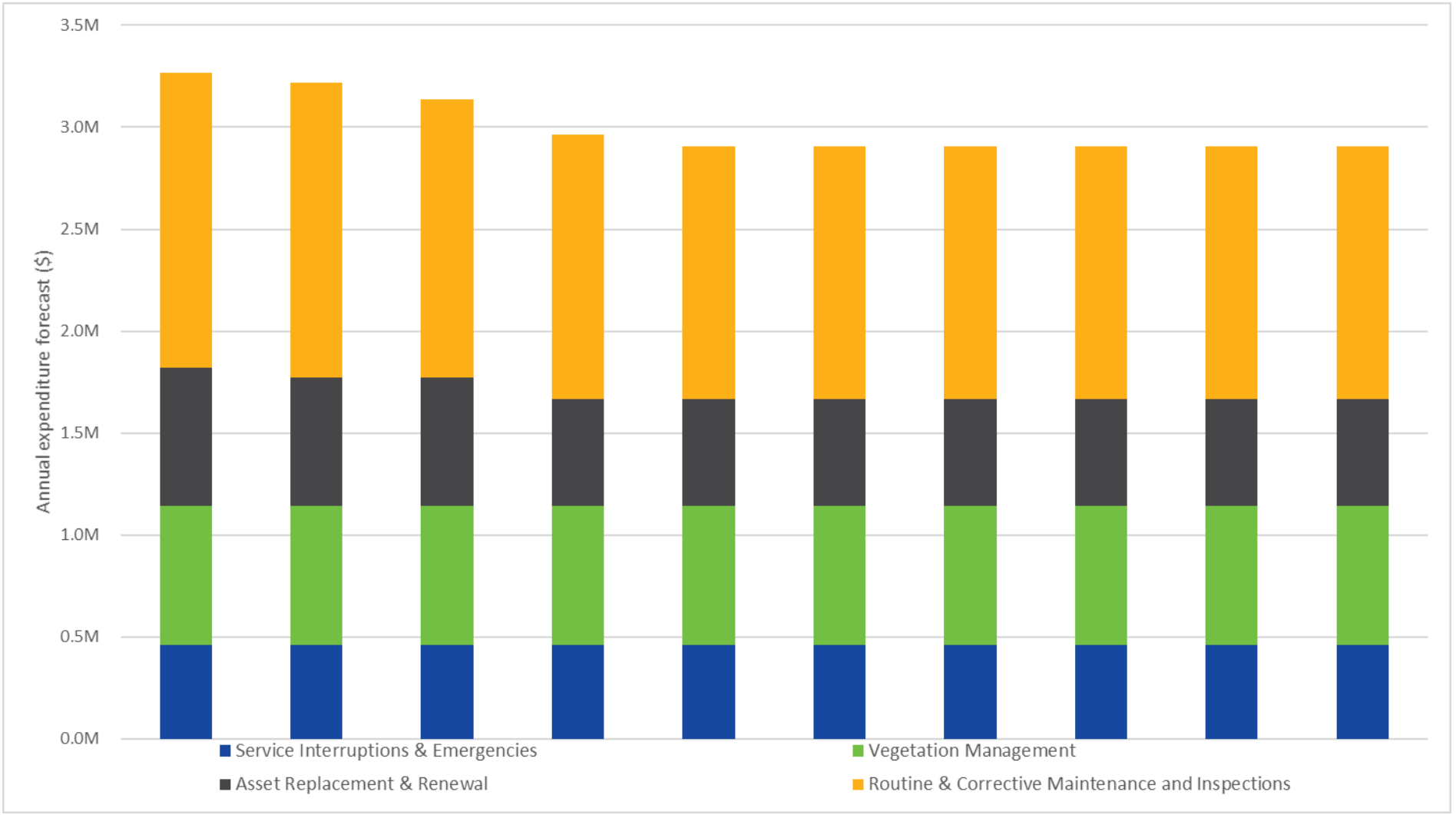
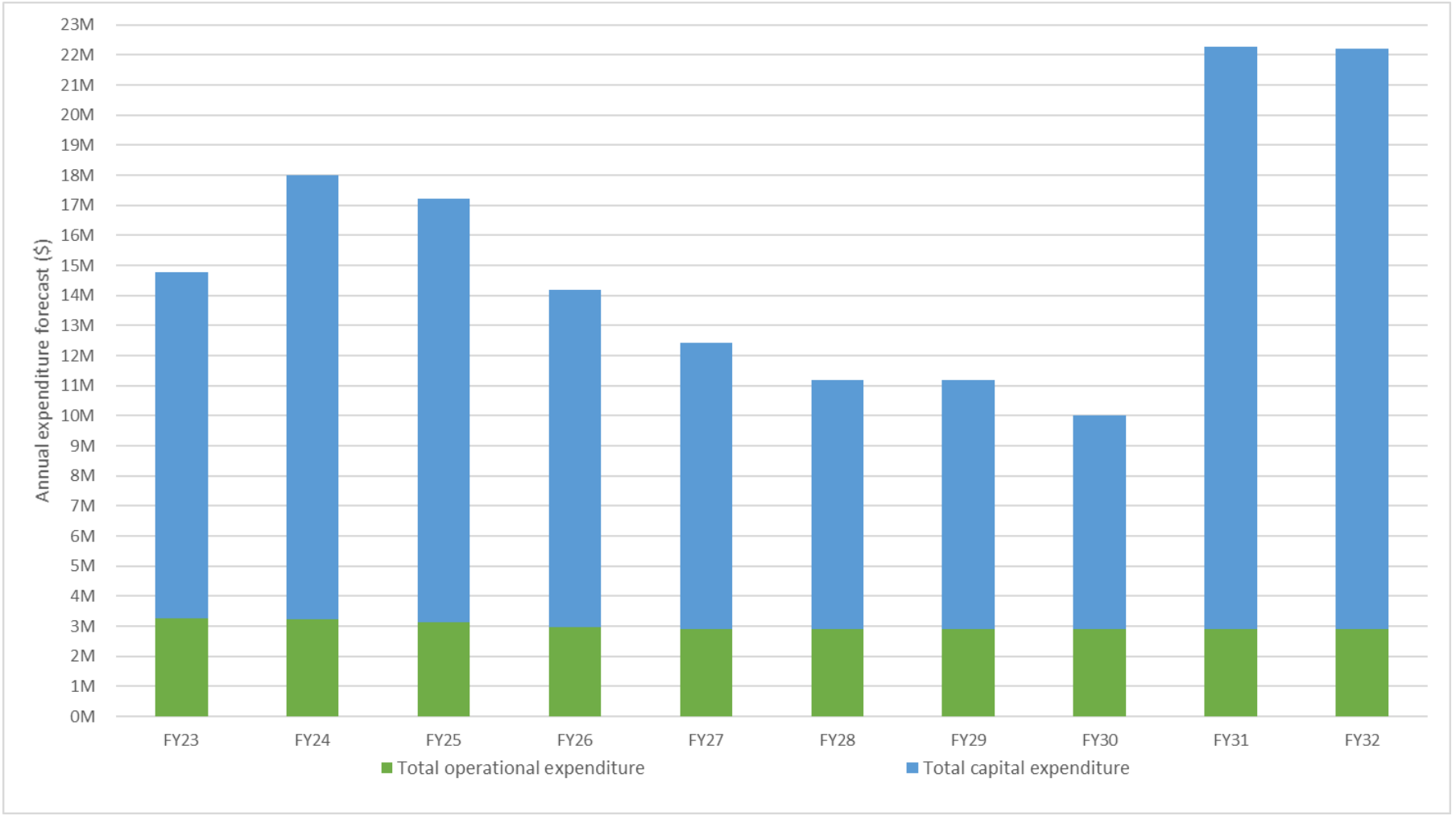


Figure 96- Summary of total network expenditure forecast across planning period




POWERING OUR FUTURE

APPENDIX

9.1 APPENDIX A – COMPLIANCE SCHEDULE TO INFORMATION DISCLOSURE REQUIREMENTS 2015

Information Disclosure Requirements 2015 clause	AMP Section
3 The AMP must include the following -	
3.1 A summary that provides a brief overview of the contents and highlights information that the EDB considers significant	Executive Summary
3.2 Details of the background and objectives of the EDB's asset management and planning processes	Section 4 Section 6.1-6.3
3.3 A purpose statement which-	
3.3.1 makes clear the purpose and status of the AMP in the EDB's asset management practices. The purpose statement must also include a statement of the objectives of the asset management and planning processes	4.1.4
3.3.2 states the corporate mission or vision as it relates to asset management	4.1.1
3.3.3 identifies the documented plans produced as outputs of the annual business planning process adopted by the EDB	2.1.3 Section 4 Section 6.1-6.3
3.3.4 states how the different documented plans relate to one another, with particular reference to any plans specifically dealing with asset management	4.1
3.3.5 includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes, and plans	2.1 4.1
3.4 Details of the AMP planning period, which must cover at least a projected period of 10 years commencing with the disclosure year following the date on which the AMP is disclosed	1
3.5 The date that it was approved by the directors	1.8
3.6 A description of stakeholder interests (owners, consumers etc.) which identifies important stakeholders and indicates-	
3.6.1 how the interests of stakeholders are identified	2.4
3.6.2 what these interests are	2.4
3.6.3 how these interests are accommodated in asset management practices; and	2.4
3.6.4 how conflicting interests are managed	2.4
3.7 A description of the accountabilities and responsibilities for asset management on at least 3 levels, including-	
3.7.1 governance—a description of the extent of director approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to directors	2.1.5
3.7.2 executive—an indication of how the in-house asset management and planning organisation is structured and	2.1.5

Information Disclosure Requirements 2015 clause	AMP Section
3.7.3 field operations—an overview of how field operations are managed, including a description of the extent to which field work is undertaken in-house and the areas where outsourced contractors are used	2.1.5
3.8 All significant assumptions	Assumptions are detailed in each section that they apply
3.8.1 quantified where possible	
3.8.2 clearly identified in a manner that makes their significance understandable to interested persons, including	
3.8.3 a description of changes proposed where the information is not based on the EDB's existing business	
3.8.4 the sources of uncertainty and the potential effect of the uncertainty on the prospective information; and	
3.8.5 the price inflator assumptions used to prepare the financial information disclosed in nominal New Zealand dollars in the Report on Forecast Capital Expenditure set out in Schedule 11a and the Report on Forecast Operational Expenditure set out in Schedule 11b.	Information Disclosures in appendices
3.9 A description of the factors that may lead to a material difference between the prospective information disclosed and the corresponding actual information recorded in future disclosures	Information Disclosures in appendices
3.10 An overview of asset management strategy and delivery	4.1
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
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, 5.2
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	2.1.5
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	-

Information Disclosure Requirements 2015 clause	AMP Section
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-	
4.1.1 the region(s) covered	1.1.1, 2.6
4.1.2 identification of large consumers that have a significant impact on network operations or asset management priorities	2.5.1
4.1.3 description of the load characteristics for different parts of the network	Throughout section 6
4.1.4 peak demand and total energy delivered in the previous year, broken down by sub-network, if any.	2.5.2
4.2 a description of the network configuration, including-	
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;	2.6
4.2.2 a description of the subtransmission system fed from the bulk electricity supply points, including the capacity of zone substations and the voltage(s) of the subtransmission network(s). The AMP must identify the supply security provided at individual zone substations, by describing the extent to which each has n-x subtransmission security or by providing alternative security class ratings;	5.6.1
4.2.3 a description of the distribution system, including the extent to which it is underground;	5.8.1
4.2.4 a brief description of the network's distribution substation arrangements;	5.8.1
4.2.5 a description of the low voltage network including the extent to which it is underground; and	5.8.1
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
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

Information Disclosure Requirements 2015 clause	AMP Section
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.	3.2, 3.3, 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;	6.3
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;	Throughout section 6
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;	4.1.3, throughout section 6
11.4 The use of standardised designs may lead to improved cost efficiencies. This section should discuss-	

Information Disclosure Requirements 2015 clause	AMP Section
11.4.1 the categories of assets and designs that are standardised; 11.4.2 the approach used to identify standard designs.	4.1.3, throughout sections 5, 6 4.1.3, throughout sections 5, 6
11.5 A description of strategies or processes (if any) used by the EDB that promote the energy efficient operation of the network.	6.3.2.8, 6.3.3
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.	6.3
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;	6.4 6.4 6.4
11.8.3 identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period; and	Section 6
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.	6.3.3.1
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;	 Section 6 Section 6
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-	

Information Disclosure Requirements 2015 clause	AMP Section
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;	Section 6
11.10.2 a summary description of the programmes and projects planned for the following four years (where known); and	Throughout AMP
11.10.3 an overview of the material projects being considered for the remainder of the AMP planning period.	Throughout AMP
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.	6.3.2
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	6.2.1.2
11.12.2 the potential for non-network solutions to address network problems or constraints.	Throughout section 6
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;	5.2
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

Information Disclosure Requirements 2015 clause	AMP Section
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
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.	4.6.1
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, 4.1.3.2
16.2 The organisation structure and the processes for authorisation and business capabilities will support the implementation of the AMP plans.	2.1.5

9.2 APPENDIX B - EDB INFORMATION DISCLOSURE REQUIREMENTS SCHEDULES

COMMERCE COMMISSION NEW ZEALAND

EDB Information Disclosure Requirements

Information Templates

for

Schedules 11a–13

Company Name	Network Waitaki Ltd
Disclosure Date	31 March 2022
AMP Planning Period Start Date (first day)	1 April 2022

Templates for Schedules 11a–13 (Asset Management Plan)
Template Version 4.1. Prepared 21 December 2017

Company Name	**Network Waitaki Ltd**
AMP Planning Period	**1 April 2022 – 31 March 2032**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref												
7		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	1,833	1,366	1,393	1,421	1,450	1,479	1,508	1,538	1,569	1,601	1,633
11	System growth	1,645	3,981	4,331	4,746	4,512	812	828	845	862	15,173	15,476
12	Asset replacement and renewal	3,111	4,665	7,306	5,881	4,583	6,679	5,493	6,165	5,356	5,516	5,572
13	Asset relocations	303	-	-	-	-	-	-	-	-	-	-
14	Reliability, safety and environment:											
15	Quality of supply	784	1,125	1,673	2,220	975	1,119	1,099	554	158	161	164
16	Legislative and regulatory	376	357	364	381	389	211	215	219	224	228	233
17	Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
18	**Total reliability, safety and environment**	1,160	1,482	2,037	2,601	1,363	1,330	1,314	773	381	389	397
19	**Expenditure on network assets**	8,052	11,494	15,067	14,649	11,908	10,299	9,143	9,320	8,168	22,679	23,078
20	Expenditure on non-network assets	1,058	5,016	2,469	330	359	336	331	338	345	351	359
21	**Expenditure on assets**	9,110	16,510	17,537	14,979	12,267	10,635	9,474	9,658	8,512	23,030	23,436
22												
23	*plus* Cost of financing											
24	*less* Value of capital contributions	1,033	851	611	623	636	648	661	675	688	702	716
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-			
26												
27	**Capital expenditure forecast**	8,077	15,658	16,926	14,355	11,631	9,987	8,813	8,984	7,824	22,329	22,720
28												
29	Assets commissioned	8,179	9,009	23,275	11,905	14,381	9,987	8,813	8,984	7,824	10,129	34,920
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	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**
32		**$000 (in constant prices)**										
33	Consumer connection	1,833	1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366	1,366
34	System growth	1,645	3,981	4,246	4,562	4,252	750	750	750	750	12,950	12,950
35	Asset replacement and renewal	3,111	4,665	7,163	5,653	4,319	6,170	4,975	5,474	4,662	4,708	4,662
36	Asset relocations	303	-	-	-	-	-	-	-	-	-	-
37	Reliability, safety and environment:											
38	Quality of supply	784	1,125	1,640	2,133	918	1,034	995	492	137	137	137
39	Legislative and regulatory	376	357	357	366	366	195	195	195	195	195	195
40	Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
41	**Total reliability, safety and environment**	1,160	1,482	1,997	2,500	1,285	1,229	1,190	686	332	332	332
42	**Expenditure on network assets**	8,052	11,494	14,772	14,080	11,221	9,515	8,281	8,276	7,110	19,356	19,310
43	Expenditure on non-network assets	1,058	5,016	2,421	317	338	310	300	300	300	300	300
44	**Expenditure on assets**	9,110	16,510	17,193	14,397	11,559	9,825	8,581	8,576	7,410	19,656	19,610
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses											
48	Overhead to underground conversion	303										
49	Research and development											

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
for year ended		31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32
Difference between nominal and constant price forecasts		$000										
Consumer connection		-	-	27	55	84	113	142	172	203	235	267
System growth		-	-	85	184	260	62	78	95	112	2,223	2,526
Asset replacement and renewal		-	-	143	228	264	509	518	691	693	808	910
Asset relocations		-	-	-	-	-	-	-	-	-	-	-
Reliability, safety and environment:												
Quality of supply		-	-	33	86	56	85	104	62	20	24	27
Legislative and regulatory		-	-	7	15	22	16	20	25	29	33	38
Other reliability, safety and environment		-	-	-	-	-	-	-	-	-	-	-
Total reliability, safety and environment		-	-	40	101	79	101	124	87	49	57	65
Expenditure on network assets		-	-	295	569	687	784	862	1,044	1,057	3,323	3,767
Expenditure on non-network assets		-	-	48	13	21	26	31	38	45	51	59
Expenditure on assets		-	-	344	582	708	810	893	1,082	1,102	3,374	3,826

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
11a(ii): Consumer Connection						
*Consumer types defined by EDB**	$000 (in constant prices)					
Install Distribution Transformers - Customer	316	455	455	455	455	455
New 11kV Network Extensions	302	342	342	342	342	342
New LV Service Connections	868	228	228	228	228	228
Residential Subdivisions	347	342	342	342	342	342
*include additional rows if needed						
Consumer connection expenditure	1,833	1,366	1,366	1,366	1,366	1,366
less Capital contributions funding consumer connection	1,617	1,011	1,011	1,011	1,011	1,011
Consumer connection less capital contributions	216	355	355	355	355	355
11a(iii): System Growth						
Subtransmission	1,564	2,249	2,015	2,751	2,451	-
Zone substations		732	1,631	1,061	1,051	-
Distribution and LV lines	81	1,000	600	750	750	750
Distribution and LV cables						
Distribution substations and transformers						
Distribution switchgear						
Other network assets						
System growth expenditure	1,645	3,981	4,246	4,562	4,252	750
less Capital contributions funding system growth						
System growth less capital contributions	1,645	3,981	4,246	4,562	4,252	750

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended		31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27

11a(iv): Asset Replacement and Renewal

	$000 (in constant prices)					
Subtransmission	354	378	1,581	321	378	981
Zone substations	82	832	2,176	764	363	1,612
Distribution and LV lines	2,097	2,622	2,470	2,705	2,970	2,970
Distribution and LV cables	89	57	57	57	57	57
Distribution substations and transformers	264	229	229	229	229	229
Distribution switchgear	225	524	419	322	322	322
Other network assets		23	230	1,255	-	-
Asset replacement and renewal expenditure	3,111	4,665	7,163	5,653	4,319	6,170
less Capital contributions funding asset replacement and renewal						
Asset replacement and renewal less capital contributions	3,111	4,665	7,163	5,653	4,319	6,170

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended		31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27

11a(v): Asset Relocations

*Project or programme**	$000 (in constant prices)					
Asset relocation - North end Oamaru	303					
include additional rows if needed						
All other project or programmes - asset relocations						
Asset relocations expenditure	303	-	-	-	-	-
less Capital contributions funding asset relocations						
Asset relocations less capital contributions	303	-	-	-	-	-

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended		31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27

11a(vi): Quality of Supply

*Project or programme**	$000 (in constant prices)					
Arc flash protection upgrades	75	21	43	43	45	21
Protection relay replacements	-	22	22	22	22	22
Purchase spare power transformer 10/15 MVA	-	-	23	825	-	-
Fibre optic communications to substations	167	240	651	342	450	589
Install automation equipment	55	79	79	79	79	79
Install ABS and spur fusing	52	36	36	36	36	36
Replace ABS units with reliability issues	199	286	286	286	286	286
Low voltage monitoring system	208	250	500	500	-	-
Demand Response Trial	-	30	-	-	-	-
Line differential protection	28					
Radio Link upgrade	-	160	-	-	-	-
include additional rows if needed						
All other projects or programmes - quality of supply						
Quality of supply expenditure	784	1,125	1,640	2,133	918	1,034
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	784	1,125	1,640	2,133	918	1,034

11a(vii): Legislative and Regulatory

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
*Project or programme**	$000 (in constant prices)					
Distribution Box replacements	152	160	160	332	332	160
Improve high load transport corridors	20	57	57	-	-	-
Upgrade distributon earths		34	34	34	34	34
Seismic resilience improvement at zone substations	204	105	105	-	-	-
*include additional rows if needed						
All other projects or programmes - legislative and regulatory						
Legislative and regulatory expenditure	376	357	357	366	366	195
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions	376	357	357	366	366	195

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

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
*Project or programme**	$000 (in constant prices)					
*include additional rows if needed						
All other projects or programmes - other reliability, safety and environment						
Other reliability, safety and environment expenditure	-	-	-	-	-	-
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	-	-	-	-	-	-

11a(ix): Non-Network Assets

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27
Routine expenditure						
*Project or programme**	$000 (in constant prices)					
Vehicles	300		120	110	120	
Plant		73				
Information Technology	758	391	250	207	218	310
*include additional rows if needed						
All other projects or programmes - routine expenditure						
Routine expenditure	1,058	464	370	317	338	310
Atypical expenditure						
*Project or programme**						
Depot upgrade and new building		4,552	2,051			
*include additional rows if needed						
All other projects or programmes - atypical expenditure						
Atypical expenditure	-	4,552	2,051	-	-	-
Expenditure on non-network assets	1,058	5,016	2,421	317	338	310

Company Name	**Network Waitaki Ltd**
AMP Planning Period	**1 April 2022 – 31 March 2032**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref												
7		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	587	460	469	479	488	498	508	518	528	539	550
11	Vegetation management	672	683	696	710	724	739	754	769	784	800	816
12	Routine and corrective maintenance and inspection	995	1,448	1,477	1,422	1,375	1,341	1,367	1,395	1,423	1,451	1,480
13	Asset replacement and renewal	507	677	642	654	556	567	579	590	602	614	626
14	**Network Opex**	2,761	3,268	3,284	3,265	3,143	3,145	3,207	3,272	3,337	3,404	3,472
15	System operations and network support	2,402	3,912	3,682	3,839	3,800	3,981	4,142	4,309	4,483	4,665	4,853
16	Business support	3,524	3,916	3,907	4,090	4,209	4,442	4,621	4,808	5,002	5,205	5,415
17	**Non-network opex**	5,926	7,828	7,589	7,929	8,009	8,423	8,763	9,117	9,486	9,869	10,268
18	**Operational expenditure**	8,687	11,096	10,872	11,194	11,152	11,568	11,971	12,389	12,823	13,273	13,740

19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	587	460	460	460	460	460	460	460	460	460	460
23	Vegetation management	672	683	683	683	683	683	683	683	683	683	683
24	Routine and corrective maintenance and inspection	995	1,448	1,448	1,367	1,295	1,239	1,239	1,239	1,239	1,239	1,239
25	Asset replacement and renewal	507	677	629	629	524	524	524	524	524	524	524
26	**Network Opex**	2,761	3,268	3,219	3,138	2,962	2,905	2,905	2,905	2,905	2,905	2,905
27	System operations and network support	2,402	3,912	3,610	3,690	3,581	3,678	3,751	3,827	3,903	3,981	4,061
28	Business support	3,524	3,916	3,830	3,931	3,966	4,104	4,186	4,270	4,355	4,442	4,531
29	**Non-network opex**	5,926	7,828	7,440	7,621	7,547	7,782	7,937	8,096	8,258	8,423	8,592
30	**Operational expenditure**	8,687	11,096	10,659	10,759	10,509	10,687	10,842	11,001	11,163	11,328	11,497
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance	365	561	572	584	595	607	619	632	644	657	670

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

38

39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	9	19	28	38	48	58	68	79	90
43	Vegetation management	-	-	14	28	42	56	71	86	101	117	133
44	Routine and corrective maintenance and inspection	-	-	29	55	79	102	129	156	184	213	242
45	Asset replacement and renewal	-	-	13	25	32	43	55	66	78	90	102
46	**Network Opex**	-	-	64	127	181	239	302	367	432	499	567
47	System operations and network support	-	-	72	149	219	303	390	483	580	683	792
48	Business support	-	-	77	159	243	338	436	539	648	763	884
49	**Non-network opex**	-	-	149	308	462	641	826	1,021	1,228	1,446	1,676
50	**Operational expenditure**	-	-	213	435	643	881	1,128	1,388	1,660	1,945	2,243

Company Name	**Network Waitaki Ltd**
AMP Planning Period	**1 April 2022 – 31 March 2032**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref						Asset condition at start of planning period (percentage of units by grade)							
8	Voltage	Asset category	Asset class	Units	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.	0.50%	5.00%	94.50%				2	5.00%
11	All	Overhead Line	Wood poles	No.	1.00%	8.00%	91.00%				2	10.00%
12	All	Overhead Line	Other pole types	No.							N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km		20.00%	55.00%	25.00%			3	6.00%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km							N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km		10.00%	90.00%				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		30.00%	70.00%				3	
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.		6.00%	88.00%	6.00%			3	
25	HV	Zone substation Buildings	Zone substations 110kV+	No.							N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.				100.00%			3	
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.		5.00%	45.00%	50.00%			3	2.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.		10.00%	90.00%				3	10.00%
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%				3	
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.		10.00%	85.00%	5.00%			3	20.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.		10.00%	90.00%				3	

					Asset condition at start of planning period (percentage of units by grade)							
	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	5.00%	5.00%	40.00%	27.00%	23.00%		3	10.00%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	5.00%	10.00%	80.00%	3.00%	2.00%		3	5.00%
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		10.00%	87.00%	3.00%			3	
44	HV	Distribution Cable	Distribution UG PILC	km	3.00%	20.00%	77.00%				3	3.00%
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.		5.00%	80.00%	10.00%	5.00%		3	2.00%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.							N/A	
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	10.00%	10.00%	65.00%	10.00%	5.00%		3	15.00%
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.		5.00%	80.00%	10.00%	5.00%		3	5.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	2.00%	3.00%	90.00%	3.00%	2.00%		3	5.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	1.00%	1.00%	91.50%	6.50%			3	2.00%
53	HV	Distribution Transformer	Voltage regulators	No.			40.00%	50.00%	10.00%		3	
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.		30.00%	70.00%				2	
55	LV	LV Line	LV OH Conductor	km		4.00%	96.00%				2	4.00%
56	LV	LV Cable	LV UG Cable	km			100.00%				3	
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km		5.00%	95.00%				3	5.00%
58	LV	Connections	OH/UG consumer service connections	No.		2.00%	98.00%				3	2.00%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.		3.00%	77.00%	10.00%	10.00%		3	3.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot			100.00%				3	100.00%
61	All	Capacitor Banks	Capacitors including controls	No.				100.00%			3	
62	All	Load Control	Centralised plant	Lot			100.00%				3	
63	All	Load Control	Relays	No.		20.00%		80.00%			3	
64	All	Civils	Cable Tunnels	km							N/A	

Company Name	**Network Waitaki Ltd**
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SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP.
Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

12b(i): System Growth - Zone Substations

Existing Zone Substations	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
Ruataniwha	1	2	N	1	40%	2	46%	No constraint within +5 years	
Ohau	1	3	N	2	47%	3	50%	No constraint within +5 years	
Omarama	2	6	N	5	25%	6	27%	No constraint within +5 years	
Otematata	1	3	N	2	27%	3	20%	No constraint within +5 years	
Kurow	5	10	N-1	5	51%	10	62%	No constraint within +5 years	
Eastern Road	3	7	N	4	37%	7	71%	No constraint within +5 years	
Duntroon	4	7	N	3	53%	7	57%	No constraint within +5 years	
Ngapara	6	7	N	2	79%	7	76%	No constraint within +5 years	
Awamoko	-	-	-	-	-	7	54%	No constraint within +5 years	
Papakaio	6	7	N	1	83%	7	67%	No constraint within +5 years	
Enfield	2	7	N	5	31%	7	34%	No constraint within +5 years	
Parsons Road	4	10	N	6	39%	10	41%	No constraint within +5 years	
Pukeuri	9	12	N-1	3	78%	12	96%	No constraint within +5 years	
Chelmer Street	14	28	N-1	14	49%	28	52%	No constraint within +5 years	
Redcastle	9	15	N-1	6	62%	15	69%	No constraint within +5 years	
Five Forks	2	7	N	5	29%	7	37%	No constraint within +5 years	
Maheno	4	5	N	2	70%	5	82%	No constraint within +5 years	
Hampden	1	7	N	6	20%	7	24%	No constraint within +5 years	
					-				
					-				

[1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Company Name	**Network Waitaki Ltd**
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SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

12c(i): Consumer Connections

Number of ICPs connected in year by consumer type

		Number of connections					
		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
	*Consumer types defined by EDB**						
	Small: residential and commercial to 15kVA	11,147	11,180	11,280	11,382	11,484	11,588
	Medium: residential and commercial 16kVA to 50kVA	1,441	1,466	1,479	1,493	1,506	1,520
	Large: commercial and industrial 51kVA and above	584	589	595	600	605	611
	Independent Contract Consumers ("IND")	86	86	87	88	89	90
	Connections total	13,258	13,322	13,442	13,563	13,685	13,808

**include additional rows if needed*

Distributed generation

	Number of connections	180	185	193	204	221	243
	Capacity of distributed generation installed in year (MVA)	1	1	1	1	1	1

12c(ii) System Demand

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	Maximum coincident system demand (MW) for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
	GXP demand	60	76	81	86	87	97
plus	Distributed generation output at HV and above						
	Maximum coincident system demand	60	76	81	86	87	97
less	Net transfers to (from) other EDBs at HV and above						
	Demand on system for supply to consumers' connection points	60	76	81	86	87	97
	Electricity volumes carried (GWh)						
	Electricity supplied from GXPs	272	328	342	358	362	392
less	Electricity exports to GXPs						
plus	Electricity supplied from distributed generation						
less	Net electricity supplied to (from) other EDBs						
	Electricity entering system for supply to ICPs	272	328	342	358	362	392
less	Total energy delivered to ICPs	256	308	322	336	340	369
	Losses	16	20	21	21	22	24
	Load factor	52%	49%	48%	48%	48%	46%
	Loss ratio	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%

Company Name	**Network Waitaki Ltd**
AMP Planning Period	**1 April 2022 – 31 March 2032**
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
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)	45.0	45.0	45.0	45.0	45.0	45.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.40	0.40	0.40	0.40	0.40	0.40
15	Class C (unplanned interruptions on the network)	0.80	0.80	0.80	0.80	0.80	0.80

Company Name	**Network Waitaki Ltd**
AMP Planning Period	**1 April 2022 – 31 March 2032**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

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

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2	We have an Asset Management policy approved by the Board and CEO. It is reviewed by senior management and shared with all staff. This policy drives the direction of development of the AMP, among other activities, aligning with the company strategy. Communication of the policy, and how it affects staff in their day to day work, is not as effective as it needs to be to warrant a score of 3.		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?	2	Most Asset Management drivers are closely linked to stakeholder direction, such as the consumer surveys, and in some cases (such as the AMP) are subject to signoff from our board of directors. There is regular reporting on our asset management performance to stakeholders such as the board and the Consumer Trust. Staff engage directly with major customers with respect to their particular needs for asset management. There is feedback through to modify the drivers where necessary. The inter-relationship between corporate strategies and network asset management is understood and recognised. Changes to non-network parts of the business (e.g. delivery of IT services) are reviewed in the light of the effect on delivery of good asset management, with risk reviews carried out. However, we cannot yet say that "all linkages are in place" to say that there are no missed opportunities to align internal strategies and policies with the asset management strategic focus, therefore cannot score 3 in this section.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (e.g., as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same 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?	2	We have a comprehensive range of planning, maintenance and inspection standards that reflect asset lives and characteristics. Recent work has shown that these are focussed on high risk and high value assets, and that there are gaps in coverage for "less important/less critical" assets. Updating our standards to keep up with good practice sometimes takes a back seat to actually getting best practice into the field. An active workstream is to develop asset class plans to identify any gaps with respect to good practice, and to provide simple to use references for our staff.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	2	The entry of new types of assets initiates the generation of policies and training/operating /maintenance documentation, based on industry practice and our specific circumstances. These plans reflect the expected lives, unique characteristics and recommended maintenance intervals for assets. However, there is still scope for the update and retroactive generation of this documentation for existing asset types. We are currently developing a system of formal fleet management plans to support the training and operational activities associated with the lifecycle of network equipment.		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

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AMP Planning Period	**1 April 2022 – 31 March 2032**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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

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AMP Planning Period	**1 April 2022 – 31 March 2032**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3	The AMP is available to the public, the wider staff, and the Consumer Trust on our website, or by calling into our offices. Many staff, including senior management and the CEO, as well as key contractor personnel are involved in the preparation and review of the AMP. Our Board approves our budgets and reviews and signs off on the AMP. Larger customers are directly consulted on the implications of our planning on their operations.		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 AMP is available to the public, the wider staff, and the Consumer Trust on our website, or by calling into our offices. Many staff and key contractor personnel are involved in the preparation and review of the AMP. Our Board approves our budgets and actively reviews and signs off on the AMP.		The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	3	The asset management plan is developed with a focus on the ability to deliver the plan, and an awareness of the resources available. We try to balance our works plan to avoid major peaks and troughs that cause ebbs and flows in work for our contracting team. This allows our contracting team to invest in the correct levels of training, personnel and plant to efficiently deliver the program. We monitor our workforce to identify gaps in training and competencies. We have been employing new trainees to build up staff levels to account for staff who are nearing retirement age. Resources are limited in the Asset Management and Network Planning areas of the business.		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	We have a comprehensive suite of Business Continuity Plans that cover asset failure, natural disasters and interruption to key processes. Our plans include working with external agencies such as the Police, Fire Service, and Civil Defence. These plans have been developed as part of a wider risk management framework based on ISO 31000 that considers a range of mitigation measures. This has resulted identifying risk reduction items within the business (such as provision for remote working, and developing new backup control room facilities), as well as developing a work program to make key network assets more resilient against natural disasters. Our operational yard and offices in Chelmer Street have been assessed as not providing an adequate level of resilience and are we are in the planning process for a new fit for purpose facility. Components of our business continuity plans have successfully exercised in reality with the Covid 19 lockdowns and response over the last two years.		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 2022 – 31 March 2032**
Asset Management Standard Applied	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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

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AMP Planning Period	**1 April 2022 – 31 March 2032**
Asset Management Standard Applied	

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	Our management structure and company organisation are designed to remove silos and encourage cross talk between the different groups involved in the management of the network, from Engineering to Finance to Field services. The small size of the business and the culture of working together means that all members of the management team have involvement in asset management. Accountability for outcomes ranges from formal KPI's at an annual level, formal monthly management meetings after each Board meeting, to daily discussions of progress. The Board operates a dedicated Risk and Audit committee responsible for monitoring ongoing risk in the business and the network. This structure makes risk very transparent, and provides at all levels with visibility of, and responsibility for delivery of asset strategies.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	2	The AMP and budgets are considered with respect to all resource levels required for delivery of the plan, including internal contracting resource, external contractors, engineering and support staff. If resources are not available for a particular reason we will decide between contracting in extra resources, or rescheduling the work to fit around our existing workforce. We are actively recruiting trainees to safeguard succession as senior staff retire. Long term planning is still a challenge at times, and we are developing methods for improving this.		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 leadership team and Board convey a consistent message of our goal to operate a safe and reliable network at all times. Monthly all-of-staff staff meetings are held where Network performance, workstreams and safety are all discussed, led by the CEO and other senior staff. All senior staff and the Board take part in regular field visits to work sites to maintain a connection with field staff. A major part of this effort is to communicate directly to field staff about the importance of the asset management goals of the company. All staff at all levels in the company are operating towards the common goal, and individual staff have an understanding of how what they do affects the achievement of that goal.		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?	2	A Contractor Approval Procedure is used to vet external contractors against our safety and skill requirements prior to them working on our assets. All external contractors are provided with all necessary network Standards, Procedures etc, and their work is subject to inspections and completion audits. There is still opportunity to improve this area through the use of standardised contracts etc. to guarantee that all external interactions provide the highest levels of performance. Performance of outsourced activities is monitored to ensure that our goals are achieved efficiently and safely. If they are not, then we will find alternative ways of delivering the activity. An example of this was the outsourcing of our System Control function which was being provided by an external party. Examination of the performance of the activity showed that there were unexpected performance issues. We worked with the service provider to improve the service, but when performance still did not meet our required levels the activity was brought back in house. Next steps are to bring that level of rigour to lower level activities, which are sometimes lacking oversight.		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)?	3	We are a small company and we have sought out staff with Asset management experience, and then provided further training. We are active in training staff, and engaging with other EDBs, and membership and involvement in industry bodies such as EEA, CIGRE and IPWEA to find about best practice in the area of asset management. Gaps in the skillset to deliver on our strategic plans are identified and training tailored to fit. Where we cannot build specialist capability we will form long term relationships with contractors who can operate closely with the business.		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	NWL competence framework is detailed in document NC2004. This covers the field staff very well, and is being developed further to cover the development of other staff in the business. Induction, personal development/training and position descriptions are kept for all staff, and are reviewed for alignment with the requirements of the roles. All managers develop training plans for their staff that are aligned with the strategic goals of their business units. Where appropriate, our team is aligning this competency framework with other South Island EDB's to ensure that interoperability is enhanced.		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	Managers and senior personnel identify the skills that are needed to deliver our asset management outcomes and carry out gap analysis for the missing skills in their teams. The Managers develop specific training plans for their workers, and there is an overall role based training plan aimed at ensuring all workers have the relevant competencies to carry out their work effectively and safely. Internal auditors compare the training records of staff against our requirements to keep on top of maintaining adequate numbers of staff with certain competencies, and keeping up with training requirements. However, the outputs of the question above means that there is still room for improvement in this area to close gaps in the skillset of our staff. Refresher training is regularly completed and reviews occur at regular intervals, and as a result of incidents or other indicators of knowledge gaps. Asset management delivery plans are based around providing adequate training time and budget for all staff who require it.		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	We have put a lot of focus into providing work packs of a high standard to field services that are suitable for the safe and efficient delivery of our asset management tasks. We have an open door policy, whereby contracting staff are encouraged to discuss assigned tasks with engineering staff. This encourages the free flow of information from the field to the planners. However, there is evidence that there are still perceived to be barriers in effective communication between all levels of the business, and are working towards identifying ways to improve communication. Field staff are widely equipped with tablets and laptops to provide access to work and asset data in the field. We are actively developing applications for these devices to improve the information flow to and from the field.		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	NWL has a comprehensive range of policies, standards and procedures that address all Asset Management activities. NWL also has a Safety management System in place, which requires a high level of document control. These documents are regularly revised and amended. We have digital tools that allow the processes to be updated, accessed and easily followed and provides links between procedures where required. Our understanding of best practice in asset management has revealed gaps which we were previously unaware of, and documentation is being developed to fill these, such as Asset Class Plans.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (i.e., the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (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?	2	We have an excellent GIS system with accurate data that assists with many operational aspects of our asset management. We have developed methods to accurately capture field data direct to our GIS and asset management system, with some processes being fully based in these apps. Key personnel in the field have access to digital tools via data enabled devices. We are in the process of developing links between our asset data systems, and improving the overall handling of data within the organisation.		Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.
63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	3	Our on-going inspections and pre-work site assessment provide confirmation that asset data is accurate. Field software is being adopted to maximise efficiency and reduce errors from the field. Personnel in the office are responsible for recording information from the field, with some already being electronically reported (our vegetation management process is completely cloud based). 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	We have sized our asset management information systems to our foreseeable needs, based on industry good practice and by buying reputable products. We are still working with users to identify their ongoing needs, as developments continue. We are updating systems to ensure that we can meet our asset management goals, with a company wide view of support systems currently underway.		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	Our risk management process is clearly documented in the AMP, and is based on the principles of ISO 31000. Operational risks are regularly reviewed. Compliance to regulatory requirements is reported to the Board each quarter. High focus risks are given special attention. Our PSMS, which includes asset risks, is audited to NZS7901 - we have consistently passed these audits. We are updating the PSMS to move from compliance to NZS 7901:2008 to NZS 7901:2014, with an eventual goal to gain alignment with ISO 45000 for Health and Safety. We are developing critical risk profiles, including bowtie analyses.		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	Risk management is embedded in our day to day work , ranging from safety in design risk assessments and job safety analysis between stakeholders on a project to the "tail gates" and activities on site for a fault response. Feedback from these exercises can be directed either informally (via a conversation with an engineer) or formally (via meeting minutes, specific defects, or discussion at a management meeting).		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	We reference ENA & EEA newsletters, and notifications from the Commerce Commission and Electricity Authority. Each manager is formally made aware of their compliance obligations at monthly management meetings, and through the Complywith compliance software system that we have implemented in the last year. We have a culture of discussing potential non-compliances with the relevant authorities.		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	We have a comprehensive range of Policies, Standards and Procedures that address the entire asset life cycle from planning, design, construction, commissioning, operation, maintenance, renewal and removal. These policies are strictly controlled by a document management system, and are regularly reviewed. We are developing asset fleet plans which will incorporate the standards, practices, data requirements and other relevant information into a single plan for each asset class.		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?	2	Inspection and Maintenance Policies and Standards, programmes etc, are used to manage the implementation of asset management decisions. Compared to best practice we can improve the formal feedback loops that will verify that successful outcomes are consistently occurring. Change is managed via a change management system. We carry out regular audits of field work and monitor outcomes. We work closely with other affected parties (such as Councils) to ensure that our asset management work meets their compliance standards		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	We have clearly specified AM objectives, primarily Reliability and Safety, but also including other measures such as Works Programme progress and financial performance. These measures are continually assessed against targets by respective managers, with action taken to correct variances. These measures are informally reported to the CEO regularly, and formally to the Board each month. We are developing improvements in how the capture and use of this data adds value to the asset management process. Development of field applications for completing inspections will allow field capture of condition data, and its efficient integration into our asset records.		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	We have a range of tools available to investigate incidents where the potential for harm or major damage was high. Root cause investigations are completed where necessary to ensure that lessons can be captured from all incidents. Lessons learned during the closeout of incidents are adequately processed through into all of our asset management systems and policies. At the time of incident investigations the appropriate Personnel are given responsibility to enact the required change, and progress is monitored regularly and reported back through the business, including to Board level.		Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3	We have a document management system in place that specifies regular review and amendment of specific Policies, Standards, Procedures etc. The audit requirements for the Safety Management System overlapped some of the AM procedures. We subscribe to the PowerCo standards system, which provides extra expertise in certain technical areas. Opportunities for improvement raised during PSMS audits are given high priority. A review and gap analysis of our asset management systems and processes is currently underway.		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?	2	Defects are logged and tracked, with engineering staff responsible for rectifying them. GIS based systems help with field collection of defects, making the reporting of issues simpler and more accurate. Serious incidents are investigated thoroughly using root cause analysis techniques, and actions from the investigations aim at removing any systemic problems. We are in the process of improving our data collection and management to do with defects to make the system more efficient.		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	We apply continuous improvement across all areas of the business. Our safety requirements and asset practices are regularly updated to meet or surpass good industry practice. Maintenance and Inspection standards are written to ensure that the risk of in-service asset failure is minimised. We subscribe to the NEDERs equipment failure database, and incorporate information on failures into our practices. We track costs against various categories of work which allows the monitoring of performance against planning.		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	We actively monitor external sources of advice or comment such as the EEA and engage with other EDB's and suppliers and manufacturers on latest practice and equipment. We are actively using data from the NEDERs asset failure database to inform our asset management practice. Design staff are involved in industry forums in their area of expertise. We encourage staff to talk with colleagues in other companies and industries, and invite vendors to demonstrate and discuss new techniques and technologies. We actively trial new technologies to verify the utility for our operation. We engage with forums and businesses that are outside our traditional peers in the electrical industry, such as working with District Councils on our GIS project.		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.

Schedule 14a Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018.)

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause2.6.6.

2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.7. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

3. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts
Network Waitaki Limited referred to predictions for CPI as extracted from the Reserve Bank of New Zealand Monetary Policy Statement, February 2022. For CY+1 forecast a CPI of 3% was applied. From CY+2 to CY+10 a CPI forecast of 2% per annum was applied.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts
Network Waitaki Limited referred to predictions for CPI as extracted from the Reserve Bank of New Zealand Monetary Policy Statement, February 2022. For CY+1 forecast a CPI of 3% was applied. From CY+2 to CY+10 a CPI forecast of 2% per annum was applied.

9.3 APPENDIX C - 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, Christopher J. Dennison and Michael C. Underhill, 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.

Christopher J. Dennison
Chairman of the Board of Directors

Date: 28 March 2022

Michael C. Underhill
Director

Date: 28 March 2022