POWERING OUR FUTURE

ASSET MANAGEMENT PLAN 2021–2031

Network Waitaki

WWW.NETWORKWAITAKI.CO.NZ

Contents

POWERING OUR FUTURE

INTRODUCTION

Welcome to our Asset Management Plan (AMP) for the planning period 1st April 2021 to 31st March 2031. 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 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 our network 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 this level of reliability through the planning period is a focus in our asset management strategies.

We forecast that there will be a high uptake of emerging technologies such as electric vehicles, solar photovoltaic systems, and battery storage systems over the next ten years. Most of these technologies will be connected to our low voltage networks. Historically, loads 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 be able to better understand the performance of our low voltage networks. This will allow us to forecast and schedule any investment required to maintain current levels of reliability and regulatory compliance.

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. We have recently employed a Customer and Community Relations Manager who 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:

- Using fault data from the UK via the National Equipment Defect Reporting System (NEDeRS) database to assist in asset decision making.
- Attendance at training from within the industry e.g. Electricity Engineers Association (EEA) courses.
- Attendance at training from subject matter experts outside the industry e.g. asset management practice training from the Institute of Public Works Manage Engineering Australasia (IPWEA).
- Learning from more advanced users of geographical information systems (GIS) such as District Councils about optimising the use of GIS within our business.

We continue to improve our awareness and implementation of Asset Management practices. Assessment of our asset management using the Commerce Commission asset management maturity assessment tool (AMMAT) shows that our asset management practice is reasonably good, but that there is still scope for improvement, with our scores being 2 or 3 out of 4 across all areas of assessment. Our growing awareness of good practice in asset management helps the continuous development of our business.

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, the focusses of this activity will be improving the reliability of our asset data such as condition, and the integration of that data into operational systems, and developing a deeper understanding of the criticality of individual assets.

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

Table 1 - Key features of NWL network

Parameter	Value
Number of Poles	21,699
Length of 33 kV lines and cables	221 km
Length of 11 kV lines and cables	1,328 km
Length of LV lines and cables	322 km
Number of zone substations	17
Number of connected customers	13,070
Coincident max demand	68 MW
Annual energy delivered to customers	298 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. We are improving and strengthening these practices, for instance with the introduction of a new framework for field inspections and specialised training for our line inspectors. With the integration of our asset data systems, we are working towards utilising better predictive methods for analysing lifecycle of the assets. Examples here include rolling out a remote distribution transformer monitoring system and integrating fault and asset data directly from the field into our asset management systems and GIS.

The key theme of managing the lifecycle of our assets is maintaining safe, reliable operation.

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 Irrigation load growth

The main driver for development in our network has historically been growth in irrigation load, 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 6.1.7.4 - Farming load growth

1.1.6.2 Decarbonisation load 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 draft advice to the government which recommends:

- A proposed 2 per cent reduction on 2018 greenhouse gas emissions by 2025; a 17 per cent cut by 2030; and a 36 per cent cut by 2035.
- A call for the Government to develop a national energy strategy, including a goal to lift renewable energy use across the economy to 60 per cent by 2035, from about 40 per cent in 2018.
- Imports of internal combustion light vehicles to stop by 2032.
- Urgently introducing legislation to make ensure no new coal boilers are installed, and for existing coal use in buildings to be eliminated by 2030. Its model assumes the use of coal in food processing will end by 2037.
- New gas connections for homes and businesses would halt by 2025.
- Critical to meeting our targets will be electric vehicles, accelerated renewable energy generation, climate friendly farming practices and more permanent forests, predominantly natives.

This will drive an increased demand for electricity usage in our network.

Two customers have recently made enquiries about converting a significant amount of process heat from coal to electricity. The timing and likelihood of these loads is uncertain but if both customers proceed our demand may exceed the capacity at Oamaru GXP as soon as FY26. We are currently working closely with these customers and Transpower to refine our forecasts and to select and predesign a long-term solution to ensure that upgrades are completed in the best possible time once we have some certainty around the new load.

This is detailed further in Section 6.1.7.3 – Decarbonization of process heat

1.1.6.3 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 load in the lower Waitaki area, especially if we see increased large scale electrification from process heat decarbonisation. We are working with Transpower and our other stakeholders to address this situation and have engaged Transpower to create a concept statement for a Special Protection Scheme to provide additional N Security capacity at Oamaru GXP. We are continuing our investigation into a long-term solution which will also consider options to optimise the impact of the proposed Transmission Pricing Methodology. This may include non-transmission alternatives.

Our plan to manage this constraint is detailed further in Section 6.2.1 – Transmission and GXP

1.1.6.4 Network Transformation

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. Our interim roadmap is presented, and we will refine this as we complete our low voltage monitoring strategy and perform a full gap analysis against the Smart Technologies Working Group (STWG) - Network Transformation Roadmap (NTR) in FY22. We are a member of the STWG and are actively collaborating with other EDBs to ensure that we are aligned in our thinking.

In FY21 we commissioned Digsilent Powerfactory network modelling software and will be integrating this with our GIS system during FY22 with a goal to have the ability to model to distribution substation level by the end of FY22 and to customer level between FY23 and FY25.

We will continue working to gain access to customer smart meter data from metering equipment providers and retailers.

This is detailed further in Section 6.2.2.14 – Network Transformation

1.1.6.5 Emerging technology

We have updated our assumptions around electric vehicle, distributed generation, and battery growth. We will consult this year with our irrigation customers to determine how much irrigation load could be made available to a demand response scheme and quantify the effects that this may have on deferring network or transmission upgrades.

This is detailed further in Section 6.1.7.3 Demand forecast inputs

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 out of our control, including Transpower constraints in North Otago and South Canterbury, or asset relocation work that tends to be driven by third party requests.

Table 2 - Summary of forecast network expenditure

	Forecast Expenditure ($)										
Network Capital Expenditure	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**Total**
Consumer connection	1,301,000	1,301,000	1,301,000	1,301,000	1,301,000	1,301,000	1,301,000	1,301,000	1,301,000	1,301,000	**13,010,000**
System growth	2,652,000	4,364,000	2,950,000	2,165,000	2,120,000	1,154,000	1,298,000	2,693,000	3,200,000	2,100,000	**24,696,000**
Asset replacement and renewal	4,416,000	4,182,000	4,892,000	5,144,000	4,745,000	6,894,000	6,179,000	4,363,000	4,751,000	5,340,000	**50,906,000**
Asset relocations	300,000	-	-	-	-	-	-	-	-	-	**300,000**
Reliability, safety, and environment: Quality of supply	1,174,000	1,128,000	742,000	793,000	1,557,000	396,000	272,000	666,000	131,000	131,000	**6,990,000**
Reliability, safety, and environment: Legislative and regulatory	814,000	240,000	240,000	349,000	342,000	179,000	179,000	179,000	179,000	179,000	**2,880,000**
Other reliability, safety, and environment	-	-	-	-	-	-	-	-	-	-	**0**
Total capital expenditure	**10,657,000**	**11,215,000**	**10,125,000**	**9,752,000**	**10,065,000**	**9,924,000**	**9,229,000**	**9,202,000**	**9,562,000**	**9,051,000**	**98,782,000**
Operational Expenditure											
Service interruptions & emergencies	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	**4,500,000**
Vegetation management	650,000	650,000	618,000	587,000	557,000	529,000	503,000	478,000	454,000	431,000	**5,457,000**
Routine & corrective maintenance & inspection	1,225,000	1,048,000	1,073,000	1,038,000	978,000	1,008,000	1,008,000	1,008,000	1,008,000	1,008,000	**10,402,000**
Asset replacement & renewal	501,000	501,000	435,000	435,000	435,000	435,000	435,000	435,000	435,000	435,000	**4,482,000**
Total operational expenditure	**2,826,000**	**2,649,000**	**2,576,000**	**2,510,000**	**2,420,000**	**2,422,000**	**2,396,000**	**2,371,000**	**2,347,000**	**2,324,000**	**24,841,000**
Total Expenditure	**13,483,000**	**13,864,000**	**12,701,000**	**12,262,000**	**12,485,000**	**12,346,000**	**11,625,000**	**11,573,000**	**11,909,000**	**11,375,000**	**123,623,000**

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.
- To ensure that physical, commercial, and regulatory risks are appropriately managed 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 network.

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.

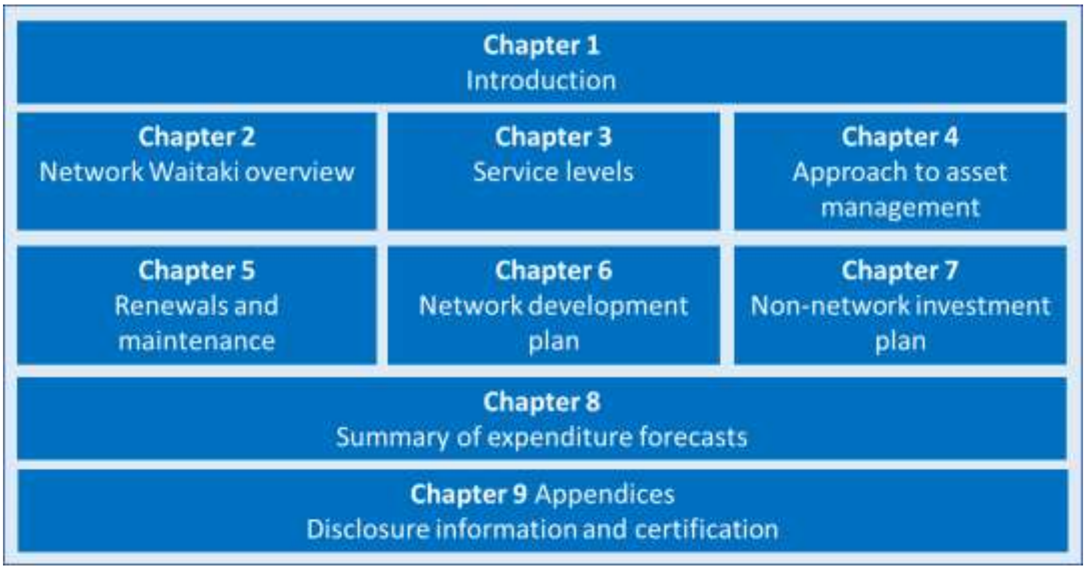

Figure 2 - Structure of Network Waitaki's 2020 AMP

1.7 USE OF CONSTANT DOLLAR VALUES

Capital and operational expenditure values are expressed in constant 2020 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 2021-2031 AMP was approved by the Network Waitaki (NWL) Board of Directors on 29th March 2021. See Appendix B for a copy of the signed Certificate of Approval.

POWERING OUR FUTURE

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 network services to some major customers. We also have a contracting division which incorporates an electrical services and vegetation management business unit providing services primarily to meet our own needs, but also undertaking 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.

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 ensure that no harm comes to our people or members of the public as a result of our operations and assets.
- To maintain safe plant, equipment, and systems of work to keep our people safe by the elimination of risks where reasonably practicable or minimise them with effective management.
- To maintain an accredited public safety management system in accordance with NZS7901.
- 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.
- 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 use company resources in an efficient manner.
- 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.

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 long-term network planning and development, including development of load models and working with key stakeholders such as Transpower and major customers to ensure that our collective future needs are understood and met, and that projects are programmed to address capacity and security constraints.

Engineering Manager

The Engineering Manager has responsibility for the day to day operation of the network and the 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.

Contracting Manager

The Contracting Manager is responsible for the provision of field services in order to complete the annual works plan in those areas of service provided by our in-house contract 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 Field Services teams. The skill set of our Field Services 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 field services 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 field services 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]

[2] Source: MBIE Regional Economic Activity Web Tool. http://webrear.mbie.govt.nz/summary/new-zealand, Feb 2018

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, 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 load 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 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

[3] Source: MBIE Regional Economic Activity Web Tool http://webrear.mbie.govt.nz/summary/new-zealand, Feb 2018

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 taking into account 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 Transmission Pricing Methodology

The Transmission Pricing Methodology (TPM) sets out the mechanism by which Transpower, the operator of the Transmission Grid, recovers its operating costs across New Zealand. The Electricity Authority has been reviewing the TPM for over a decade as it is of the view that its current state does not lead to efficient outcomes and sends the wrong pricing signals to participants. In 2020 the Electricity Authority published TPM guidelines for Transpower to develop a TPM consistent with these guidelines.

Under these guidelines, Network Waitaki could face an increase in annual Transmission charges of $1.6 million (55%) from 2024 onwards with no corresponding increase in service level or capacity from the Transpower network. We opposed the changes to the TPM and have been actively engaged in submissions and dialogue with the Authority to achieve a more favourable outcome for Network Waitaki and our connected customers. We have also supported a request to the Office of the Auditor General (OAG) for a performance audit of the Electricity Authority's Cost Benefit Analysis. We furthermore supported a judicial review against the Electricity Authority's ruling initiated by Trustpower. These actions are still in progress.

As the changes to the TPM are unfavourable to Network Waitaki we will explore available options to optimise our use of the national grid, including investigation of a prudent discount. We will also investigate alternatives to the use of Transpower's transmission network in our area and investment forecasts in this AMP may change in the medium term to reflect this. Being located within the Waitaki Valley with over 800 MW of hydro generation in our network area may allow us to explore bypass options which may be more cost effective to Network Waitaki in the long term. We acknowledge that this could result in a perverse outcome at a national level.

2.3.3 Environmental policy

Government policy regarding climate change and associated decarbonisation is progressing at an unprecedented rate. This will significantly accelerate the move away from Carbon-based energy sources for transport and process heat towards lower Carbon sources such as electricity. This will require timely forecasting and investment in electricity distribution and transmission assets to enable the increased demand. We expect that government regulation and incentives will continue to increase significantly over the planning period in order to meet out climate change targets.

Our Network Development Plan in Chapter 6 further details our thinking around these issues. We are a member of the EDB Sustainability Group, facilitated by Orion and will develop a sustainability roadmap in FY22

2.3.3.1 Zero Carbon Act

The Climate Change Response (Zero Carbon) Amendment Act sets New Zealand's emission reduction targets at Zero net greenhouse gas emissions by 2050 (excluding biogenic methane).

The government has pledged to accelerate the electrification of our transport and industrial sectors in their Clean Energy Policy Statement and declared a Climate Emergency in December 2020.

2.3.3.2 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 through energy efficiency, technology innovation, and fuel switching where they directly reduce the use of fossil fuels and can include support for electricity network infrastructure upgrades where they directly enable an electrification project

Any large process heat conversion to electricity in our supply area will likely require significant investment into our distribution network and upstream transmission network. We are actively working with large coal process heat users in our area to evaluate electricity as an energy source and are working with other South Island EDBs to compile a database of coal boilers in the South Island.

2.3.3.3 Climate Change Commission first draft advice

He Pou a Rangi – the Climate Change Commission released their first draft advice to the Government on 31 January 2021. This will be in consultation until 14th March 2021 and the final version presented to the Government by 31 May 2021 for acceptance or otherwise by 31 December 2021.

Key recommendations that will impact the electricity industry are:

- A proposed 2 per cent reduction on 2018 greenhouse gas emissions by 2025; a 17 per cent cut by 2030; and a 36 per cent cut by 2035.
- A call for the Government to develop a national energy strategy, including a goal to lift renewable energy use across the economy to 60 per cent by 2035, from about 40 per cent in 2018.
- Imports of internal combustion light vehicles to stop by 2032.
- Urgently introducing legislation to make ensure no new coal boilers are installed, and for existing coal use in buildings to be eliminated by 2030. Its model assumes the use of coal in food processing will end by 2037.
- New gas connections for homes and businesses would halt by 2025.
- Critical to meeting our targets will be electric vehicles, accelerated renewable energy generation, climate friendly farming practices and more permanent forests, predominantly natives.

2.3.3.4 Emissions Trading Scheme

The New Zealand Emissions Trading Scheme will replace the fixed price option (currently $35 per tonne) with a price floor and a Cost Containment Reserve (CCR) in 2021, which is designed to stabilise the carbon price at $20-$50 per tonne. The CCR and price floor will increase by 2% per year until 2025. Forecasts beyond 2025 vary significantly but Fonterra is expecting the price of carbon to rise to between $75 and $150 per tonne by 2030. The Productivity Commission believes a carbon price rising to between NZ$75– NZ$150 per tonne is required for New Zealand to transition to a low-emissions economy, while to achieve net-zero emissions the carbon price needs to rise to between NZ$150–NZ$250 per tonne.

2.3.3.5 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.

2.3.3.6 Our view

The Climate Change Commission's draft advice, coupled with the government's recent strong rhetoric regarding 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. The size and timing of any new electrical load is uncertain especially regarding process heat conversion. Carbon prices are also uncertain after 2025 and this may further encourage businesses to apply for subsidies and bring forward their electrification plans.

This will result in significant growth in the use of electricity as an energy source over the planning period. This assumption has been further developed by technology type and presented in our load growth assumptions in Section 6.1.7 which will be revised as new information is released.

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.

We are presently working to identify our preferred solution and perform as much prework as is economically sensible to allow for the best transmission system upgrade timeframes.

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; emergency and lifeline preparedness.	Bi-annual customer surveys – a revamped survey will be run in 2021; face to face interviews with major customers; feedback; public safety performance measures.	Maintaining audited Public Safety Management System and other safety initiatives; price/quality trade off; network development plans; investment planning; asset lifecycle management.

Stakeholder	Requirements	Identification of requirements	Requirements incorporated into asset management practices
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 community; Effective asset management	Trustee meetings; performance measures.	Network development planning; investment planning; asset lifecycle management; organisation and governance structures; integration of risk management into all business processes; quarterly and annual reporting

Stakeholder	Requirements	Identification of requirements	Requirements incorporated into asset management practices
Councils	Alignment with district and regional requirements; statutory compliance.	Meetings; consultations on regional and district plans.	Network development planning for system and load 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 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 load 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 FY21 and the four years previous is shown in the table below:

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

As can be seen in Figure 3, these three measures are generally trending upwards. However, the energy delivered to our customers may not match the year on year growth in maximum demand and connected customers. This is due to the impact of climatic conditions, where a wetter (or drier) than average summer will have a significant effect on irrigation usage and energy delivered. To a lesser extent average winter temperature has a similar effect on the use of space heating.

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.

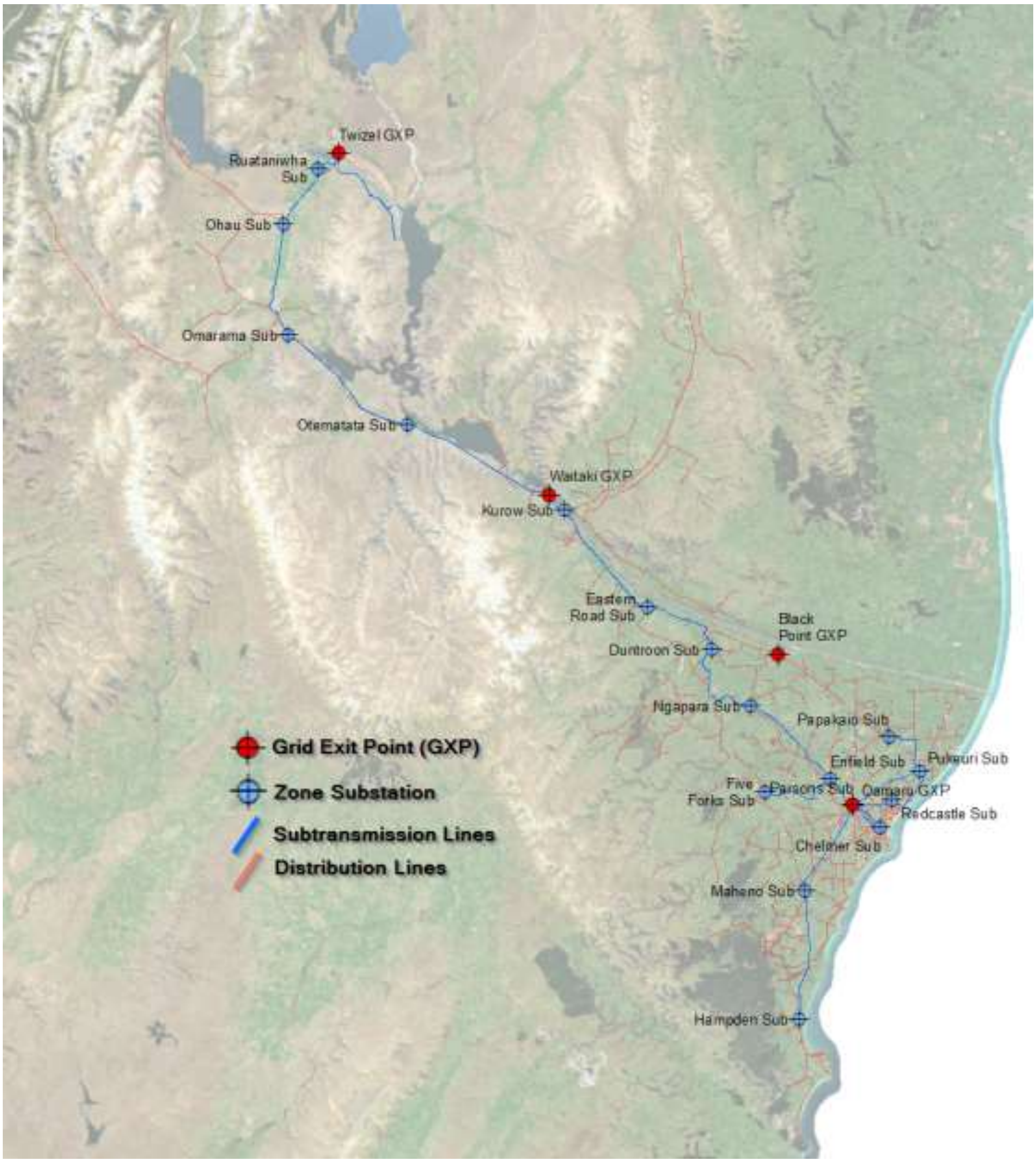

Figure 4 - Map of NWL area of supply and network extent

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 30 November 2020

Supply point	Voltage	Capacity	Max demand FY21 (Non-Coincident)	Zone Substations supplied
Oamaru GXP	110/33 kV	47.5 MVA	40 MVA	10
Black Point GXP	110/11 kV	25 MVA	16 MVA	0
Waitaki GXP	11/33 kV	24 MVA	11.3 MVA	4
Twizel GXP	220/33 kV	20 MVA	3.8 MVA	3

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	21,699
Length of 33 kV lines and cables	221 km
Length of 11 kV lines and cables	1,328km
Length of LV lines and cables	322 km
Number of zone substations	17
Number of connected customers	13,063
Coincident max demand	68 MW
Annual energy delivered to customers	298 GWh

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

POWERING OUR FUTURE

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, 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.
- Analysis of our 2019 survey showed that nearly 30% of customers believe they know enough to make an informed decision on new technologies such as battery storage, electric vehicles, and solar energy.

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.

A customer and community engagement strategy is being developed which will provide an action plan to further improve the effectiveness of our communication with our customers and community, especially in the area of digital communication and social media.

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) methodology for incident investigation.
- 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 and maintains a separate committee to monitor health and safety performance.
- Engagement and participation with our staff and contractors through our health and safety committee, 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, such as fall restraint ladders.
- 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.
- Installing 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
    - lost time injuries, near misses, plant damage or environmental incidents (lagging indicators).

- 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 NZS7901:2008 for our Public Safety Management System – using Telarc as independent auditors.
- Progress towards accreditation of ISO45001 Health and Safety Management Systems with Telarc
- 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	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**
Rural/Farming activities	19	16	15	10	3
Construction work	7	7	8	4	2
Trades	0	0	0	0	0
Leisure & sports	0	0	0	1	0
Customer premises issues (Tree cutting/house fires, etc.)	11	11	4	0	1
Vandalism	1	1	1	0	0
Motor vehicles	19	19	16	19	12
Total	**57**	**54**	**44**	**34**	**18**

As can be seen from the historical figures, the number of incidents involving the public has been trending downwards in almost all areas apart from Motor Vehicles, which have remained fairly constant up until financial year 2021. The bulk of the incidents in recent years have been vehicle accidents or due to unintended contact with our buried cables or overhead lines, typically operators of equipment such as diggers, farm machinery or irrigators.

FY21 has had a significant reduction in incidents, which may be correlated to the Covid 19 pandemic and the restrictions imposed by the various Government Alert Levels reducing overall activity around 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 general 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.

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

Assuring that our public safety management system conforms to the New Zealand standard NZS 7901:2008 is an annual exercise carried out in conjunction with Telarc. This accreditation was continued in 2020 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.

Our PSMS audits are to the latest version of the standard, NZS 7901:2014.

We have also trained staff in the role of internal auditors; these auditors carry out several internal audits annually. The audits assist in identifying opportunities to improve our processes and help identify potential issues in a timely fashion.

With the introduction of the Vault safety management system, recording of our safety performance against targets is simplified. A Health and Safety report is tabled and discussed at each monthly Board meeting and 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.

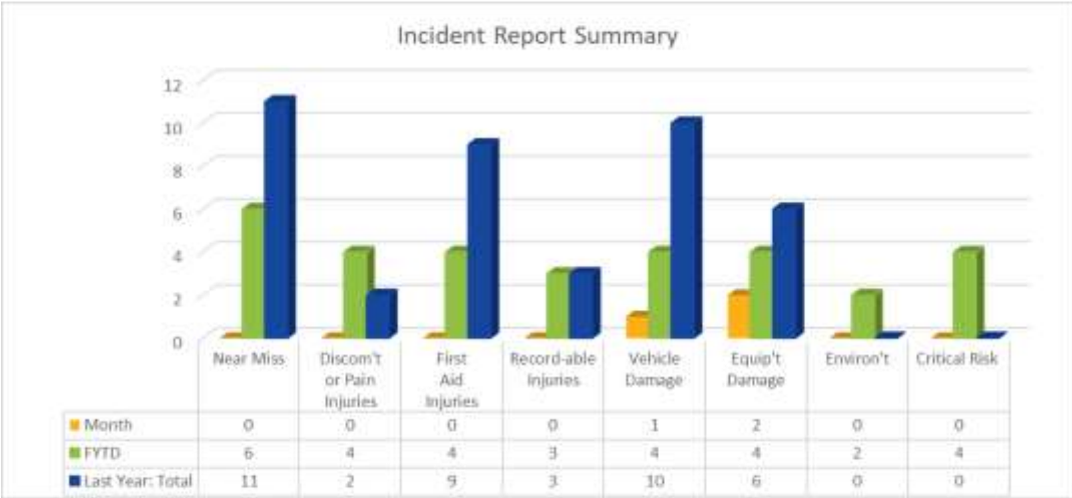

Figure 5 – Example of an Executive summary of safety performance used in reporting

We have again, achieved our target of reducing unauthorised access to our network – there was no 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.

On our network high voltage lines on private property that service one or two customers are usually owned by those customers, rather than Network Waitaki; these are called high voltage service lines. 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. One of our key safety measures is that no high voltage service lines need to be disconnected because of unsafe conditions.

No high voltage service lines were disconnected for safety in the last year, which meets our safety target for this metric. However, we are finding that private line owners often do not understand the risks and obligations of owning high voltage lines on their land. We recognise that this is an area for improvement and are engaging with private line owners to help them understand the risks and responsibilities of ownership, as well as improving communication with private owners regarding the state of their assets.

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 a single lost time incident for the 12 months to February 2021 (the time of writing). We recognise that the use of LTI's as a safety metric is a lagging indicator, and we are actively working on utilising more leading indicators such as maintenance of safety competencies, work site auditing, near miss reporting, and verification of the effectiveness and use of controls for critical risks.

The focus in the coming year is on the implementation and 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, taking into account 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	***2021-22***	***2022-23***	***2023-24***
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 6.1.4.2.

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.

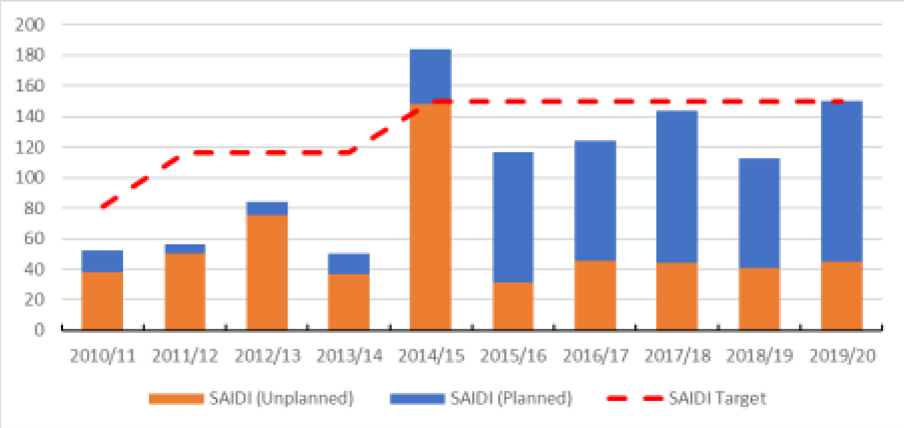

Figure 6 Historical SAIDI performance compared to target

Our SAIDI performance over the last 10 years shows no material change in the impact of unplanned outages. The large increase in 2015/16 year is due to the aftereffects of a major storm, where some customers were without power for several days. The performance for the last five years has been consistent with unplanned outages at around 40 SAIDI minutes.

The impact of our reduction in live line work is partly responsible for the increase in planned SAIDI from 2016/17 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.

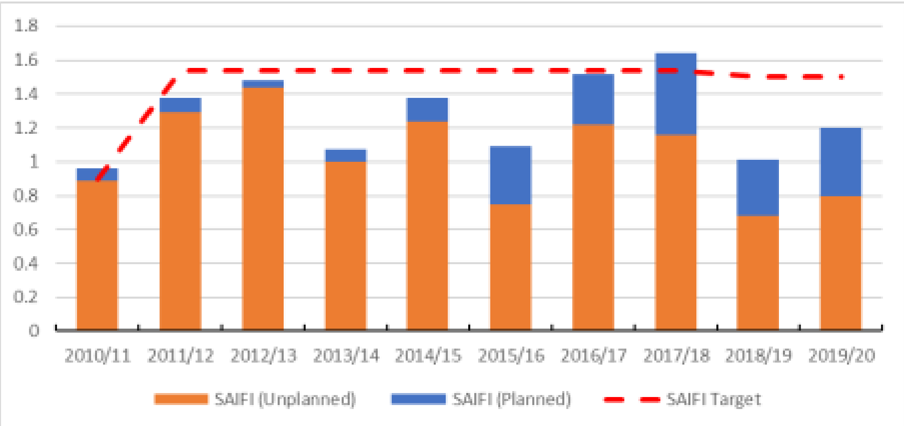

Figure 7 Historical SAIFI performance compared to target

Although there is more variability in SAIFI figures than SAIDI, the trend over the last five years is still reasonably consistent, with an average of around 0.9-1.0 interruptions.

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[4], which is taken from the information disclosures provided annually by EDBs to the Commission.

[4] 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

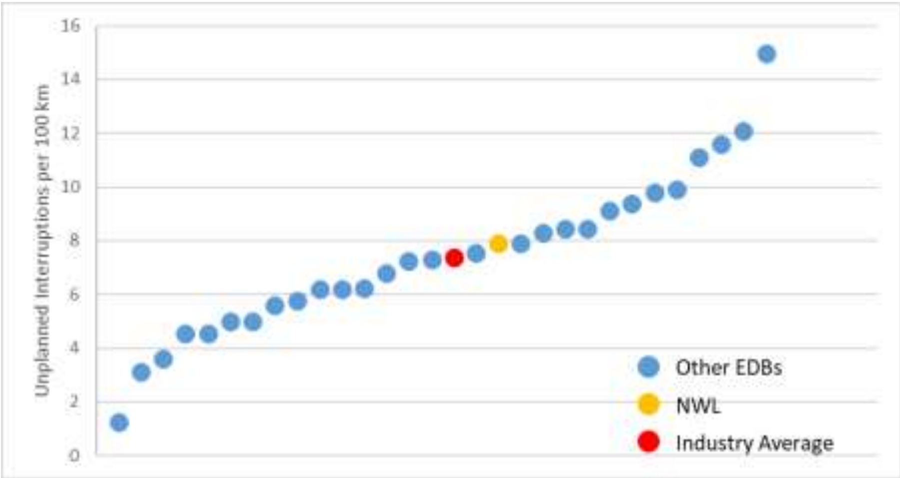

Figure 8 - Comparison of 3 year average of NWL unplanned interruptions per 100km against industry

The number of unplanned interruptions on our network are near 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 with similar operating environments and network characteristics (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.

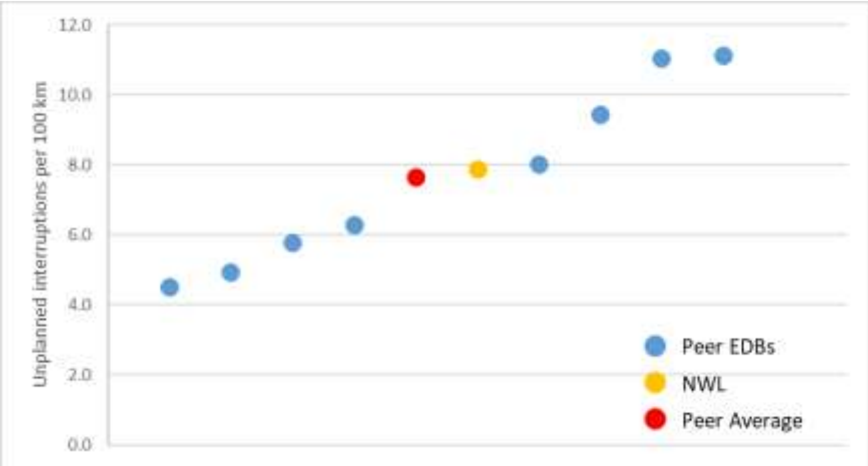

Figure 9 - Comparison of 3 year average NWL unplanned interruptions per 100km of circuit against peer EDBs

This shows that our performance for the incidence of unplanned outages within our peer group is slightly higher than the average. This does not meet our target of performing better than the peer group average, but 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 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, we are the best performing of our peers, with our three year average at approximately 50% of the peer group average.

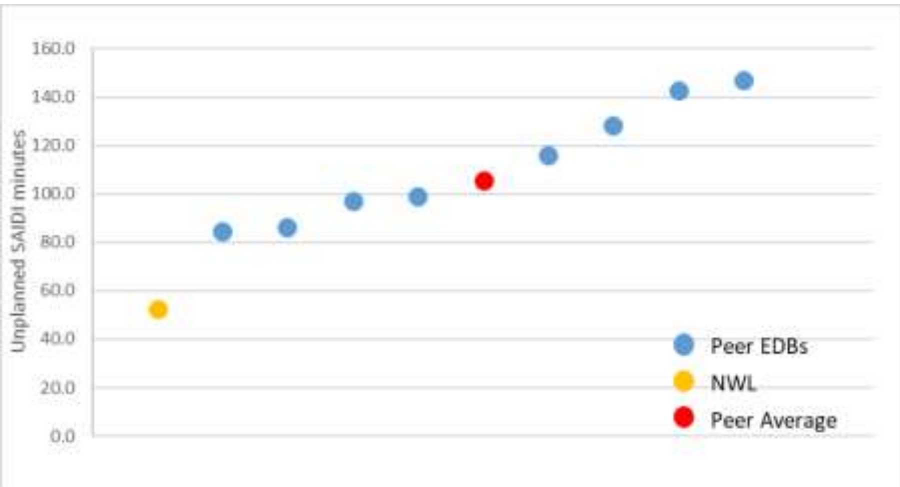

Figure 10 - Comparison of 3 year average unplanned SAIDI against peer EDBs

For the following measures, total SAIDI, unplanned SAIFI and total SAIFI we are at least 20% below the peer group average for each measure.

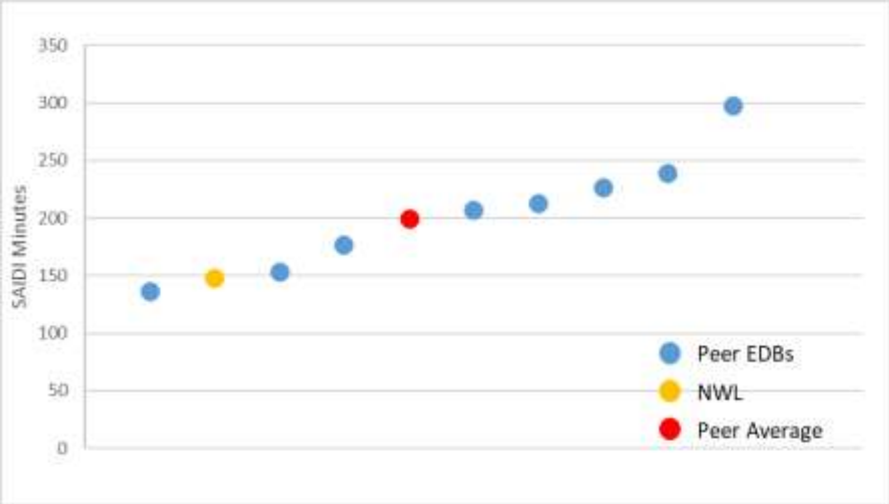

Figure 11 - Comparison of 3 year average total SAIDI against peer EDBs

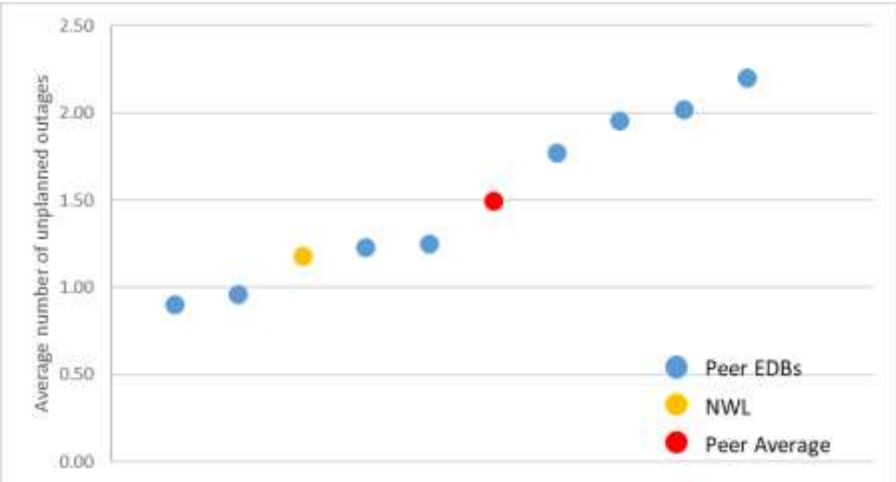

Figure 12 - Comparison of 3 year average unplanned SAIFI against peer EDBs

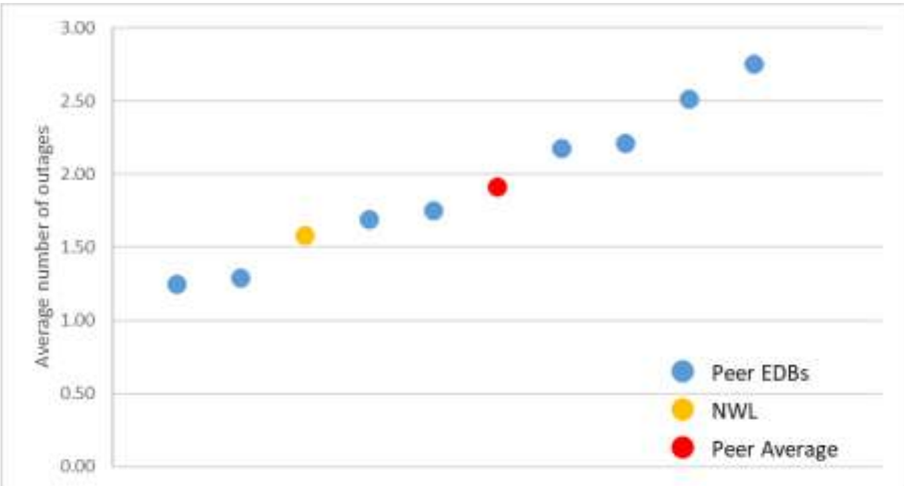

Figure 13 - Comparison of 3 year average total SAIFI against peer EDBs

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 55 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 40% of all faults (30% of HV and 60% of LV) associated with network equipment. Note that LV faults do not usually impact upon SAIDI and SAIFI statistics.

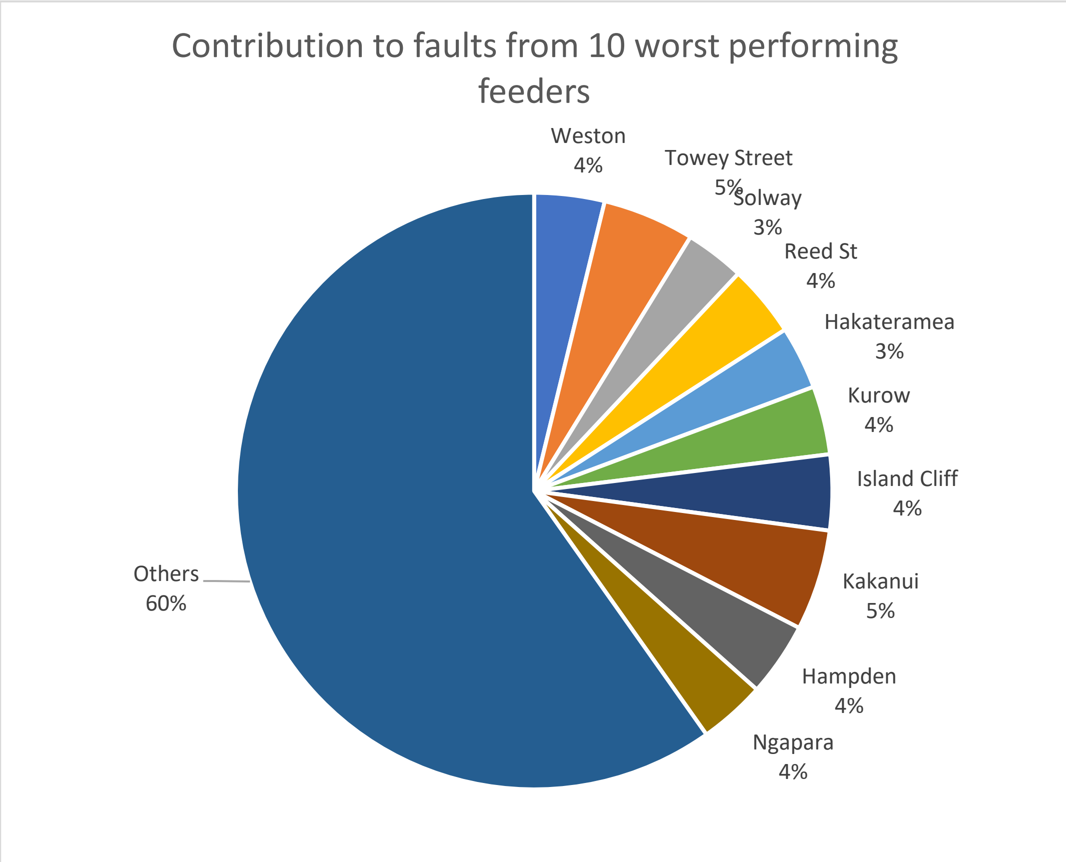

Figure 14 - Worst performing feeders by number of faults

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

It should be noted that we will not be specifically targeting work on these feeders but will be using this data as a way to focus network wide programs to respond to patterns of failures that become apparent. This will benefit these feeders as well as the rest of the network. In the distribution network area of section 5 (Renewals and Maintenance) we detail how we intend our planned renewal spends are likely to improve the performance of these feeders.

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 over use 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.

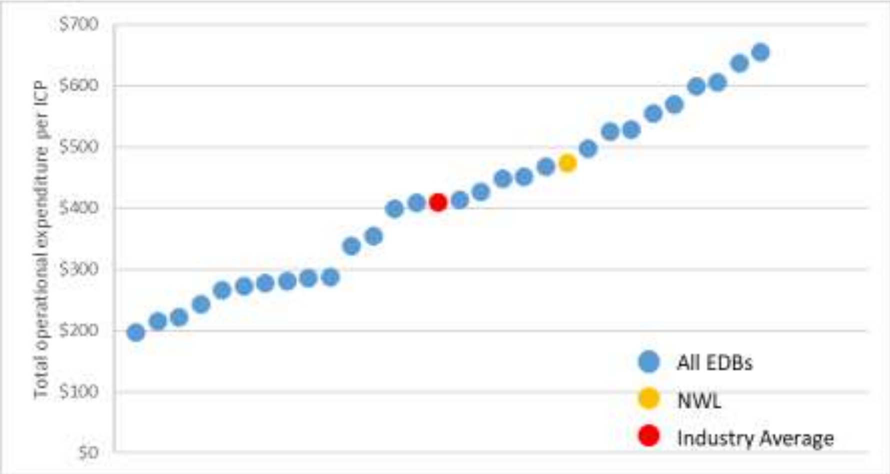

Figure 15 3 year average total operational expenditure per connection point performance compared to all EDBs

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.

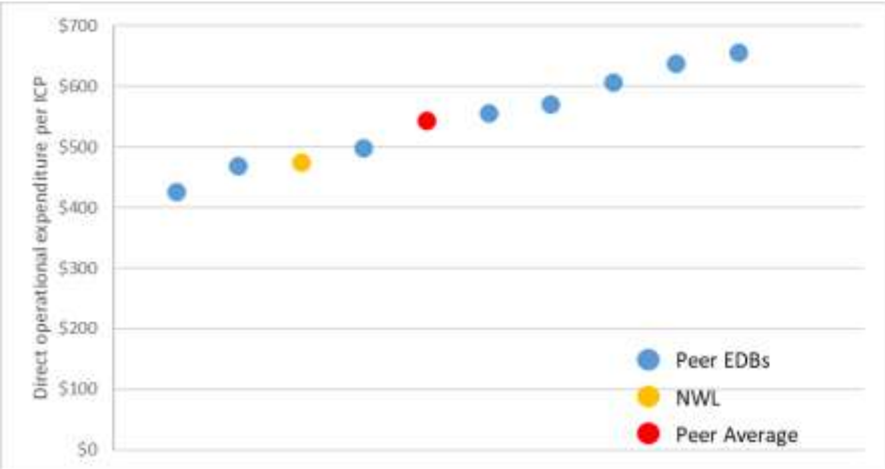

Figure 16 - Comparison of 3 year average total operational expenditure per ICP against peer EDBs

We believe that we have had the balance between operational costs and network reliability correct, 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 direct network operating expenditures (preventative maintenance, corrective maintenance, reactive maintenance and vegetation management) 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 direct network 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 the costs per length of network related operational activities in comparison with our peers and reflects how efficiently we are delivering these activities.

3.4.3.4 Network operational expenditure per kilometre of circuit length -performance

Referring to **Figure 17** below, our operational costs per kilometre of circuit length is 25% below the average for our peer group of EDBs.

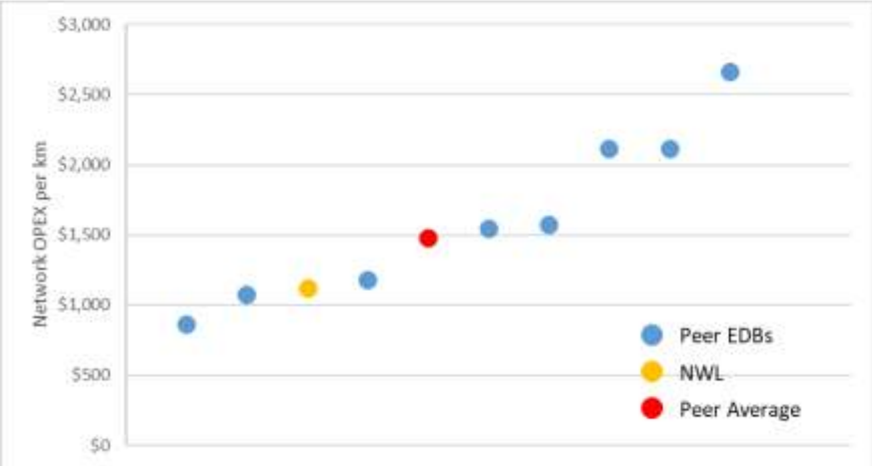

Figure 17 - Comparison of 3 year average network operational expenditure per kilometre of circuit length against peer EDBs

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 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.

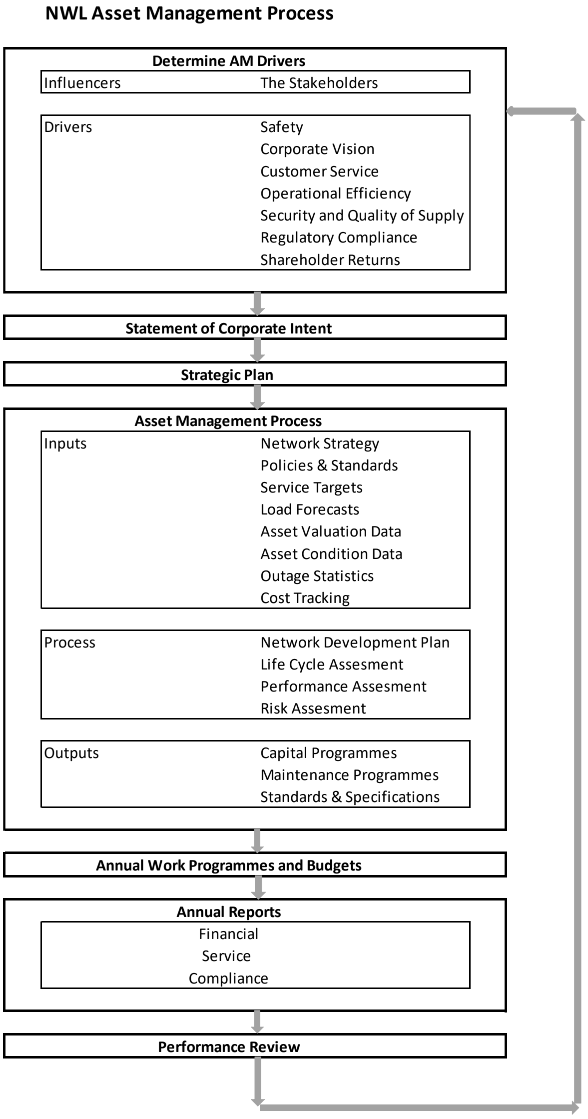

Figure 18 NWL asset management process

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.

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.

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	Chief Executive's statement in company annual report includes narrative of year's highlights. 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:

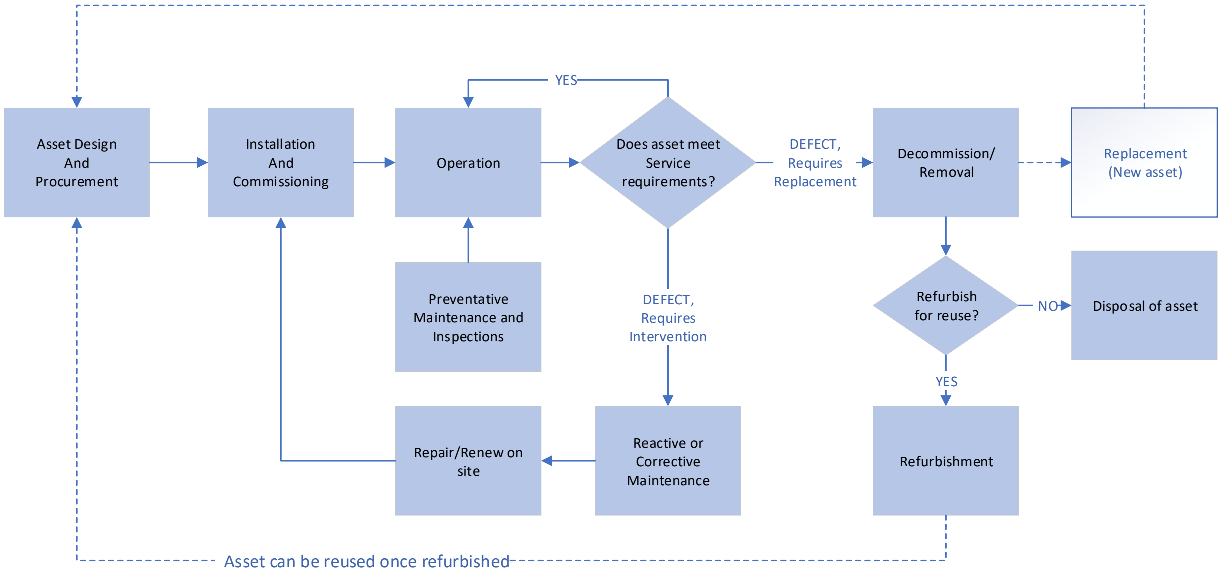

Figure 19 - Typical network asset lifecycle

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.

Preventative maintenance is carried out based on the results of inspections as well as at defined 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 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 load**

   This option involves NWL acting to reduce customer load 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 load during constraint periods. If the network is upgraded to remove the constraint these conditions may be removed.

   Loads that may be controlled include load traditionally available for interruption such as water heaters and load that is specified as controllable in our Security of Supply Standard (e.g. Irrigation load).

4. **Non-traditional solutions**

   This option may be used to augment parts of our network or in some cases replace them. A remote power system could be used to replace a traditional power line if the lifecycle costs of this are less than the costs of building or maintaining the line or solar and/or batteries could be installed to avoid upgrade of existing assets by reducing peak loading. There is scope in this option for innovative solutions to be developed.

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 load 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 be presented to the board for approval.

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:

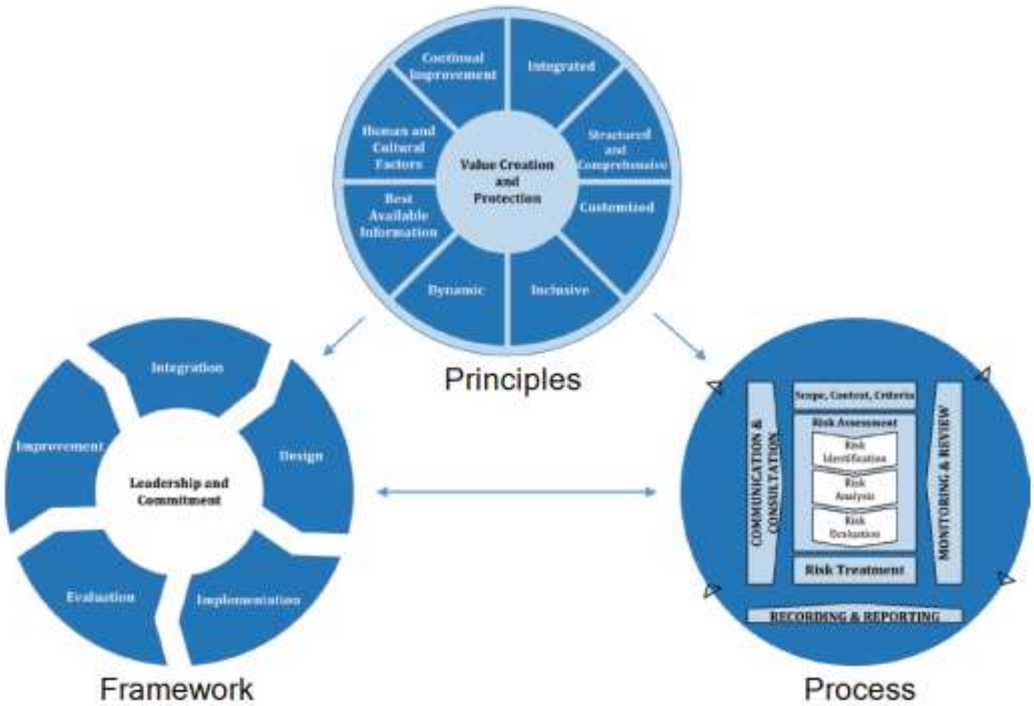

Figure 20 - From ISO31000:2009 relationships between the risk management principles, framework, and process

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 rewritten in the past year and 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 Network 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. 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 2020, we received confirmation that our PSMS again achieved accreditation to NZS7901:2008. Future audits will be against the latest version of the standard, NZS 7901:2014.

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 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.

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.

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 offsite server hosting in a modern data centre and have disaster recovery facilities in place.

All data is backed up to an offsite facility daily to provide protection in case of local site damage.

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 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. March 2020 a nation-wide 'lockdown' of Alert Level 4 was enforced until May 2020 where Alert Levels changed, easing restrictions and conditions to minimise the impact of the pandemic.

The speed at which the virus spread, caught the world by surprise and Network Waitaki was no different. A review of business continuity processes was underway prior to this pandemic, to deal with potential natural and other disasters that may affect operations and electricity supply to customers, which influenced a review of priorities leading to Alert Level 4.

The learnings taken away and implemented were:

- Improved work practices and efficiencies to enable offsite working by all staff through the deployment of information technology systems, in particular mobile devices and video conferencing software
- Improvements in information and digital technology access and systems and a move towards more paperless activities
- Establishment of a field services structure, which allowed us to comply with social distancing restrictions, but to be able to work effectively and safely to maintain the operation and safety of the network
- Collaboration and information sharing across other businesses within the electricity sector
- The importance of being connected to staff and work mates and the ongoing the support systems during stressful times
- The importance of maintaining a robust supply chain
- The requirement to rigorously plan, prepare and test emergency and disaster responses and implement those learnings.

A staff survey was conducted during and after Alert Level 4, which had high engagement and a positive theme for the short preparation time and the conduct of staff and the overall management team.

Forest Fire

In early October 2020, during a period of extremely high winds, a wildfire started in the Lake Ohau area which burnt through over 5,000 hectares of conservation and farm land, and devastated the village of Lake Ohau in the northwest of our network. Our field service crews responded to isolate the network for safety and to allow fire fighting, and then and then worked in with other responders to safely inspect, repair and return the network to operation, and to support the ongoing recovery of the village as homeowners moved back in. During the same period of extreme weather, a private tree (out of notice zone) fell across lines in the Livingstone area which then resulted in a widespread forest fire burning through over 800 hectares. These two events, while still under investigation, highlight the changes to the climate we are experiencing, and the risk caused by extreme weather events and dry ground conditions – particularly the elevated fire risk arising from hot dry periods.

As a precautionary measure in response to this unprecedented event at Ohau, we have adjusted the routine inspection schedule for our assets in the Mackenzie basin from five yearly to annually and have reviewed our control room practices around auto reclose during periods of strong wind. These changes highlight the need for us to constantly evaluate changes to our operating environment and update business processes and practices to suit.

4.6 ASSET MANAGEMENT MATURITY

We have applied the Commerce Commission's Asset Management Maturity Assessment Tool (AMMAT) to review the maturity of our asset management practices. 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[5] accreditation, but we will be looking to align our systems with the principles of those standards within the next two years.

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.

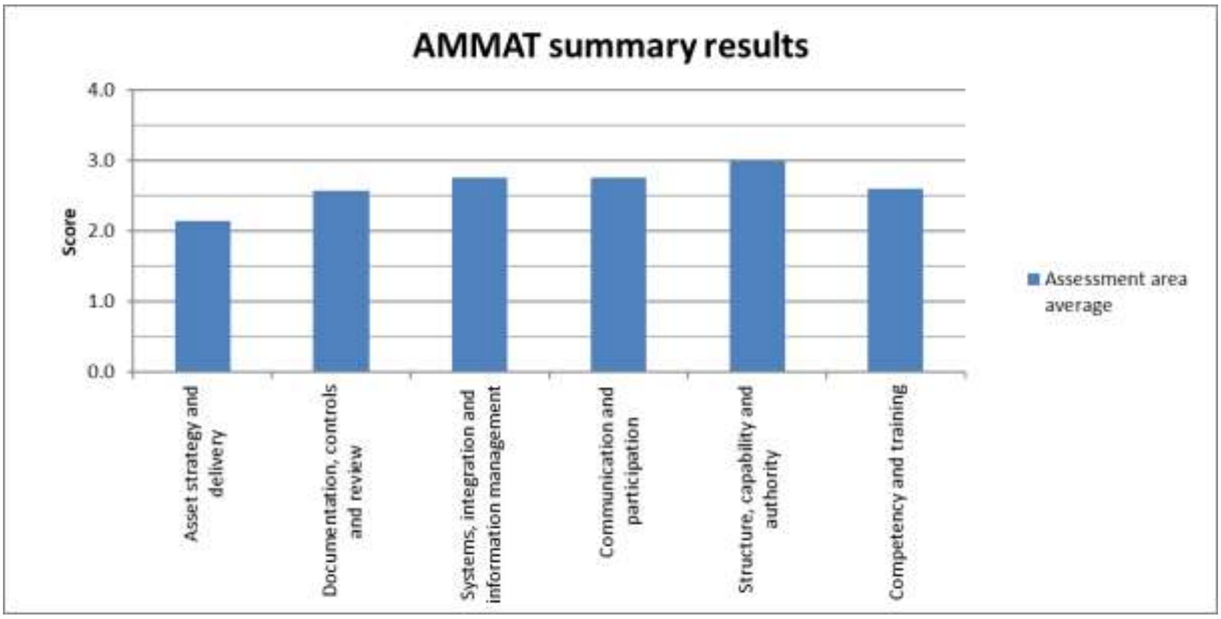

Figure 21 - AMMAT results summary

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

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

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 is an expected outcome of the refresh of our long-term strategic plan. 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.

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 2021.

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. A focus for 2021 is developing detailed operational contingency plans for all critical loads on the network. These activities will close the gap in the area of maturity to do with Contingency planning.

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 2021 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.

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.

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.


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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.	9,018
Wood/other poles	No.	12,681
Subtransmission OH up to 66 kV conductor	km	217
Subtransmission UG up to 66 kV (XLPE)	km	4.1
110 kV CB (Outdoor)	No.	1
33 kV Switch (Pole Mounted)	No.	101
33 kV CB (Indoor)	No.	11
33 kV CB (Outdoor)	No.	44
11 kV CB (ground mounted)	No.	80
11 kV CB (pole mounted)	No.	4
Zone Substation Transformers	No.	23
Distribution OH Open Wire Conductor	km	1,252
Distribution UG XLPE or PVC	km	67
Distribution UG PILC	km	9
11 kV CB (pole mounted) - reclosers and sectionalisers	No.	57
11 kV Air Break Switches and Fuses (pole mounted)	No.	3,935
11 kV RMU (individual switches)	No.	180
Pole Mounted Transformer	No.	2,377
Ground Mounted Transformer	No.	541
Voltage regulators	No.	38
LV OH Conductor	km	221
LV UG Cable	km	101
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.

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 load 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 load profiles. We are working to identify and close these gaps based on the value to good asset management practice.

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 load. 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

Zone Substation	GXP Supply	Capacity (MVA)	Security	Date of Construction	Transformer Year of Manufacture	Main Switchgear Year of Manufacture
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

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.

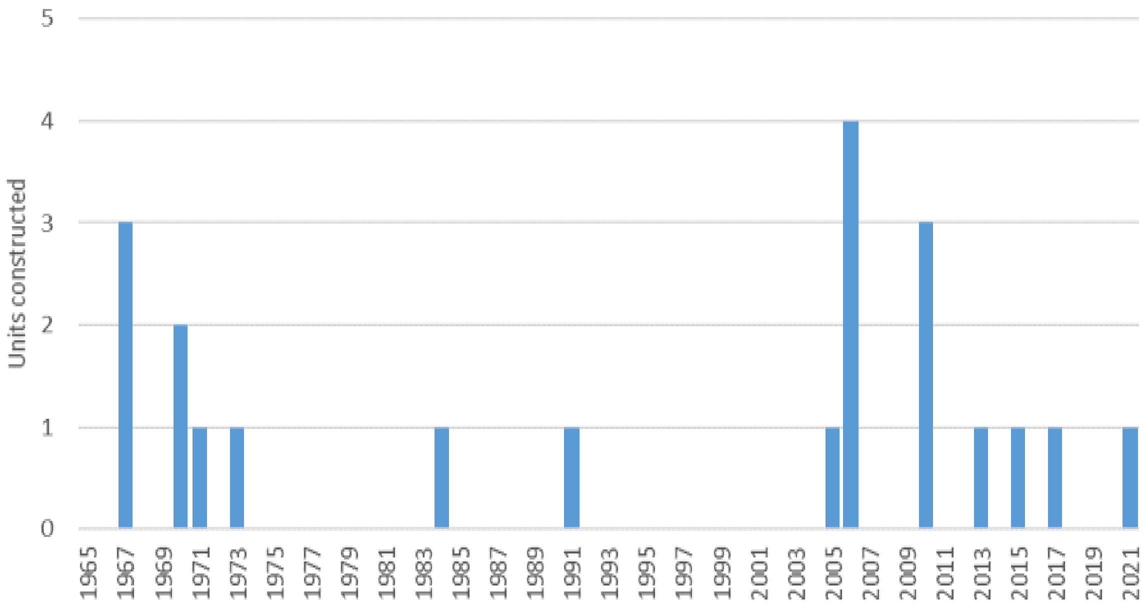


Figure 22 - Age profile for zone substations

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
Black Point	100%	Low	N/A	Minor	no	End of FY22
Waitaki GXP	100%	Low	N/A	Minor	no	End of FY22
Kurow	100%	Low	N/A	Minor	yes	End of FY22
Twizel	100%	Low	N/A	N/A	no	End of FY22
Ruataniwha	100%	Low	N/A	N/A	no	End of FY22
Ohau	100%	Low	N/A	N/A	yes	End of FY22
Omarama	100%	Low	N/A	N/A	no	End of FY22
Otematata	100%	Low	N/A	Significant	no	End of FY22
Pukeuri	70%	Low	Required	Minor	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	55%	Medium	N/A	N/A	no	End of FY22
Parsons	55%	Medium	Required	Minor	no	End of FY22
Ngapara	50%	Medium	N/A	Minor	yes	End of FY22
Weston switch room	40%	Medium	N/A	N/A	no	End of FY22
Chelmer St	35%	Medium	Required	Minor	yes	End of FY23

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. Other aspects of the building envelopes will be refurbished at the same time as this seismic work.

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 ongoing lifecycle costs have shown that the most cost effective action is to replace the Inergen with a lower maintenance system that will be more effective within the substation buildings. This work is scheduled for the first year of the planning period.

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	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital expenditure forecast ($000)										
Gas flood fire system replacement - Chelmer/Redcastle/Weston	185									
Seismic resilience improvement at zone substations	570									
Substation equipment condition based replacements	87	87	87	87	87	87	87	87	87	87
Capital subtotal	842	87	87	87	87	87	87	87	87	87
Operational expenditure forecast ($000)										
Fire Suppression system inspections	12	12	12	12	12	12	12	12	12	12
Property maintenance	100	100	100	100	100	100	100	100	100	100
Routine Inspections	25	25	25	25	25	25	25	25	25	25
Substation renewals	20	20	20	20	20	20	20	20	20	20
Operational subtotal	157	157	157	157	157	157	157	157	157	157

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.

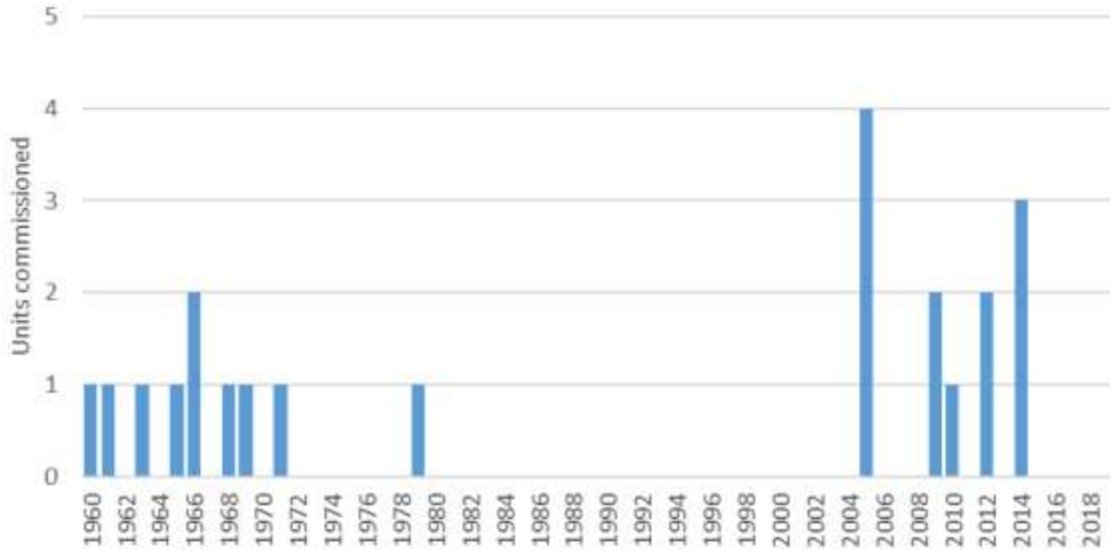


Figure 23 - Zone transformers age profile

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 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.

As can be seen from the age profile, several of our transformers will reach or surpass the standard asset life within the planning period. These assets are subject to regular condition assessment through dissolved gas analysis (DGA), which indicates that many are in good condition for their age and are likely to continue to operate safely and reliably. We investigate international good practice to ensure that our transformer condition assessment processes are delivering good outcomes.

Capacity upgrades at some substations as part of the network development plan (see chapter 6) will also influence this program, as this work may free up more modern 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	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital expenditure forecast ($000)										
Replace Power transformers										
Kurow T1					33	813				
Ohau							22	485		
Otematata		22	485							
Pukeuri T1		33	813							
Pukeuri T2				22	813					
Spare transformer					696					
Capital subtotal		**55**	**1298**	**22**	**1,541**	**813**	**22**	**485**		
Operational expenditure forecast ($000)										
Power Transformer OLTC maintenance										
3 yearly cycle - 8 per annum	120	120	120	120	120	120	120	120	120	120
Zone Tx maintenance										
Allowance for minor repairs - leaks, corrosion	10	10	10	10	10	10	10	10	10	10
Defect correction zone Tx	100	10	10	10	10					
Silica gel replacements	6	6	6	6	6	6	6	6	6	6
Zone Tx DGA	30	30	30	30	30	30	30	30	30	30
Zone Tx Maintenance	35	35	35	35	35	35	35	35	35	35
Zone Tx Oil Processing	10	10	10	10	10	10	10	10	10	10
Operational subtotal	**311**	**221**	**221**	**221**	**221**	**211**	**211**	**211**	**211**	**211**

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.

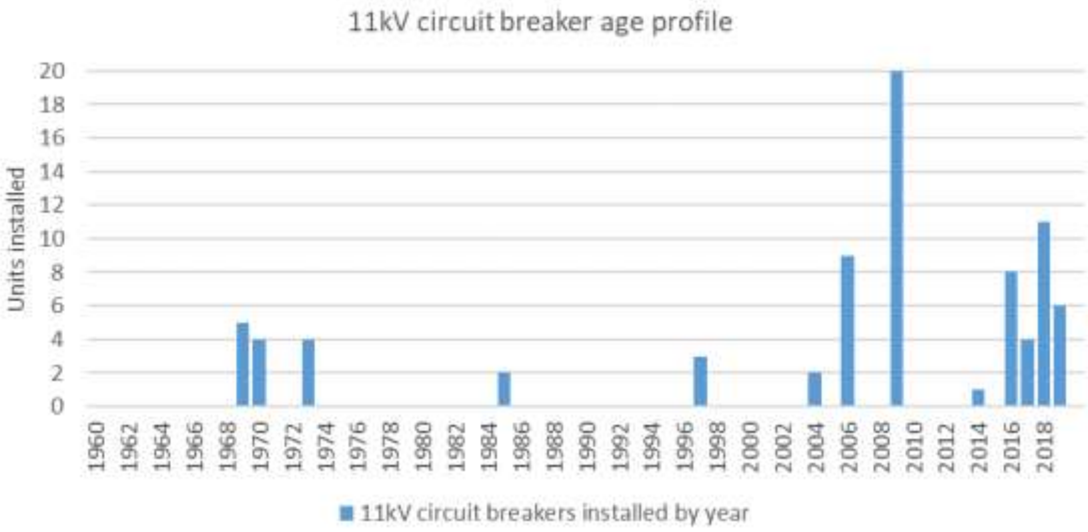


Figure 24 - 11 kV Indoor circuit breaker age profile

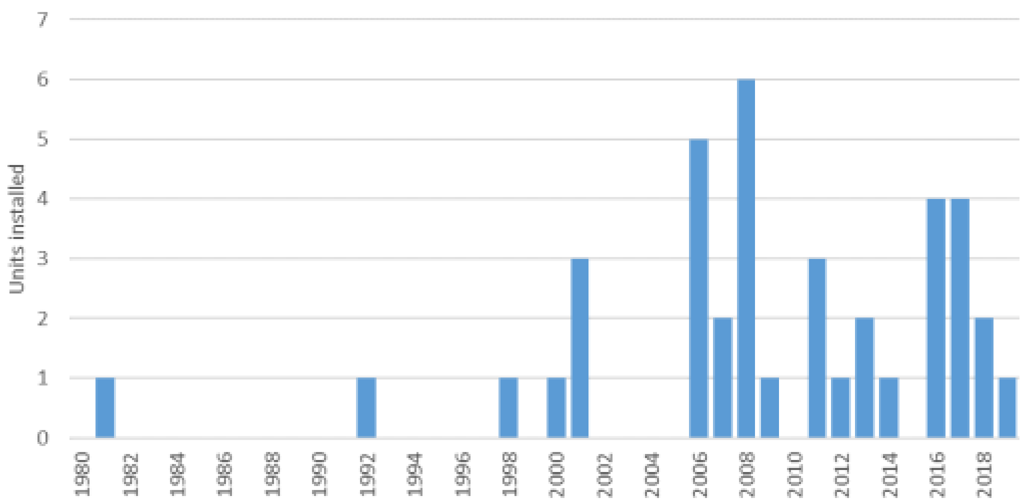


Figure 25 - 33 kV circuit breaker age profile

Common issues and risks associated with this asset group include:

- Degradation of oil insulation in older switchgear
- Gas leaks in SF6 equipment
- 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

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 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 will be replacing all examples of this type of ABS in the early years 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	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital expenditure forecast ($000)										
Replace 11kV switchboards										
Duntroon	22	327								
Hampden			22	371						
Ngapara			33	436						
Omarama					22	349				
Arc Flash Protection	43	43	43							
Ongoing Protection relay replacement							21	21	21	21
Capital subtotal	65	370	97	807	43	349	21	21	21	21
Operational expenditure forecast ($000)										
Switchgear and protection maintenance										
Redcastle, Papakaio, Black Point	12									
Ngapara, Omarama, Hampden	12									
Five Forks, Kurow, Weston		12								
Otematata, Pukeuri			12							
Parsons, Maheno, Chelmer				12						
Ongoing @ 3 x substations per annum					12	12	12	12	12	12
Operational subtotal	24	12	12	12	12	12	12	12	12	12

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

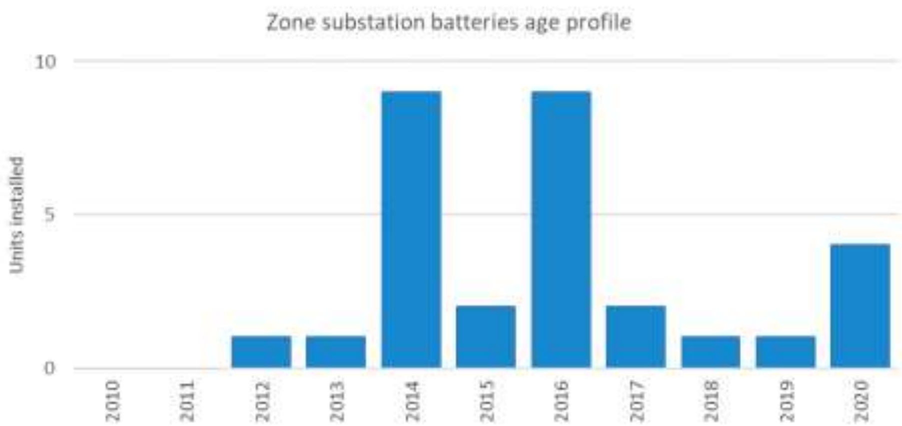


Figure 26 - Age profile data for zone substation batteries

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 considered to be 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

5.6.6.4 Expenditure Forecast

ZONE SUBSTATIONS - DC systems	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital expenditure forecast ($000)										
Battery bank replacements										
5 per annum	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										
Annual inspection and measure	4	4	4	4	4	4	4	4	4	4
Discharge test @ 5 per annum	5	5	5	5	5	5	5	5	5	5
Operational Subtotal	9	9	9	9	9	9	9	9	9	9

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

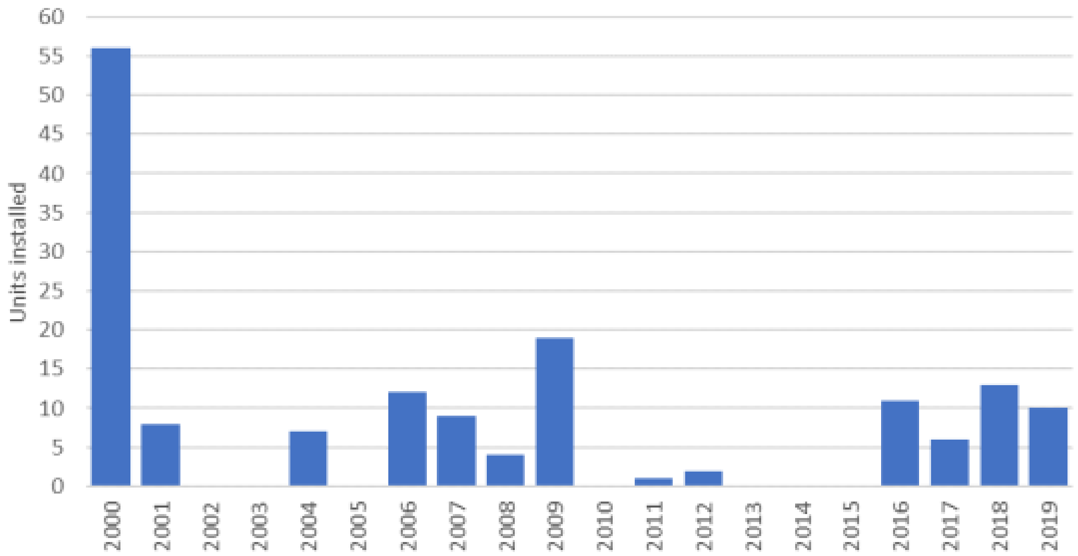


Figure 27 - Age profile data for protection relays

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 in the later years of the program.

5.6.7.4 Expenditure Forecast

Expenditure on protection relays is included in the budgets for the associated switchgear, in section 0.

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 load connected to the Waitaki GXP. We own the ripple control relays installed at customer's premises.

We will be purchasing a spare 33 kV ripple plant mounted in a transportable container for rapid deployment in the event that one of our plants has a critical failure. This will allow a single spare transmitter to support all three operational GXPs, and provide spares cover for a range of events from a major component fault through to complete loss of a ripple plant due to a HILP event.

We utilise Decabit ripple control relays at customer premises to control load in order to minimise line charge costs and control network load 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

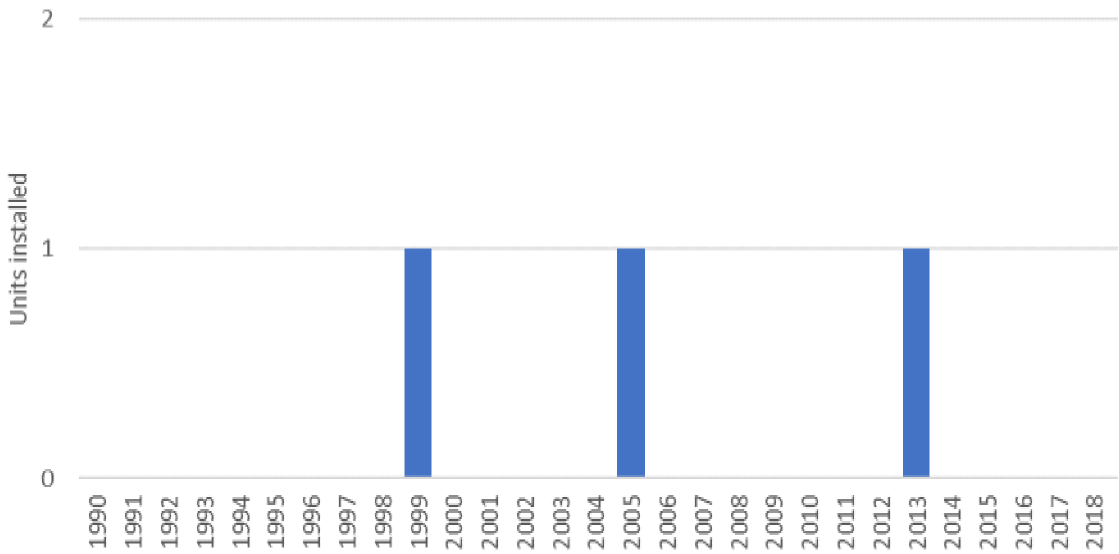


Figure 28 - Ripple control transmitters by installation date

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 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, in FY22 we will purchase a containerised ripple control transmitter to provide backup for the systems. This unit can replace any of the transmitters on our network through connection to the 33kV network.

5.6.8.4 Expenditure Forecast

ZONE SUBSTATIONS - Ripple Control Systems	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital expenditure forecast ($000)										
Spare Ripple control plant	456									
Operational expenditure forecast ($000)										
Ripple Control Maintenance	8	8	8	8	8	8	8	8	8	8

5.6.9 Total Zone Substation expenditure forecast

ZONE SUBSTATIONS	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital expenditure forecast ($000)										
Seismic resilience improvement at zone substations	570									
Substation equipment condition based replacements	87	87	87	87	87	87	87	87	87	87
Replace 11kV switchboards	22	327	55	807	22	349				
Arc Flash Protection	43	43	43							
Ongoing Protection relay replacement							21	21	21	21
Battery bank replacements	11	11	11	11	11	11	11	11	11	11
Spare power transformer				32	696					
Replace Power transformers		55	1,298	22	845	813	22	485		
Gas flood system replacement - Chelmer/Redcastle/Weston	185									
Spare Ripple Control Transmitter	457									
Total capital expenditure	**1,374**	**523**	**1,494**	**927**	**1,661**	**1,260**	**141**	**605**	**120**	**120**
Operational expenditure forecast ($000)										
Routine Inspections	25	25	25	25	25	25	25	25	25	25
Property maintenance	100	100	100	100	100	100	100	100	100	100
Substation renewals	20	20	20	20	20	20	20	20	20	20
Power Transformer maintenance	191	101	101	101	101	91	91	91	91	91
OLTC Overhaul	120	120	120	120	120	120	120	120	120	120
Ripple control plant maintenance	8	8	8	8	8	8	8	8	8	8
Switchgear and protection maintenance	24	12	12	12	12	12	12	12	12	12
Annual battery testing	9	9	9	9	9	9	9	9	9	9
Fire Suppression system inspections	12	12	12	12	12	12	12	12	12	12
Total operational expenditure	**509**	**407**	**407**	**407**	**407**	**397**	**397**	**397**	**397**	**397**

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 29

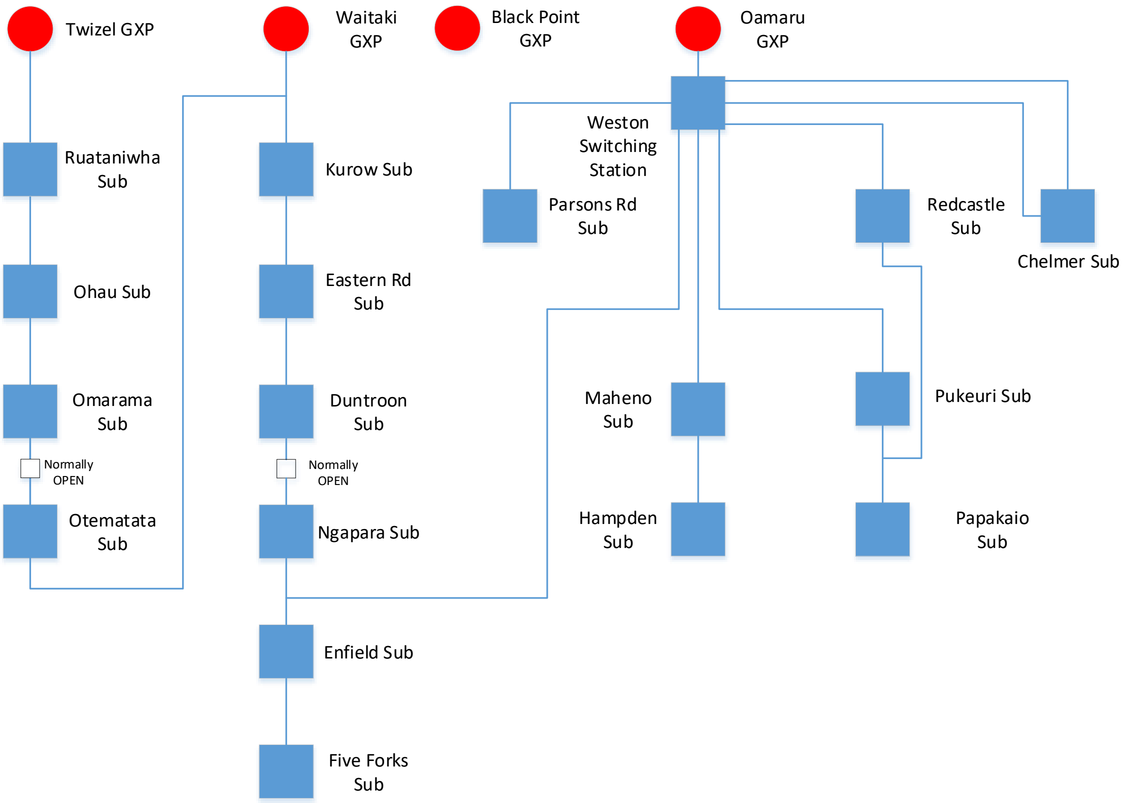


Figure 29- Subtransmission system configuration

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 - summary of subtransmission lines and cables

Asset type	Number
Wooden poles	1,985
Concrete poles	354
Overhead conductors	218 km
Cables	4.1 km

5.7.3.1 Age profile and population data

The age profile of these assets is shown in Figure 30, Figure 31 and Figure 32 below.

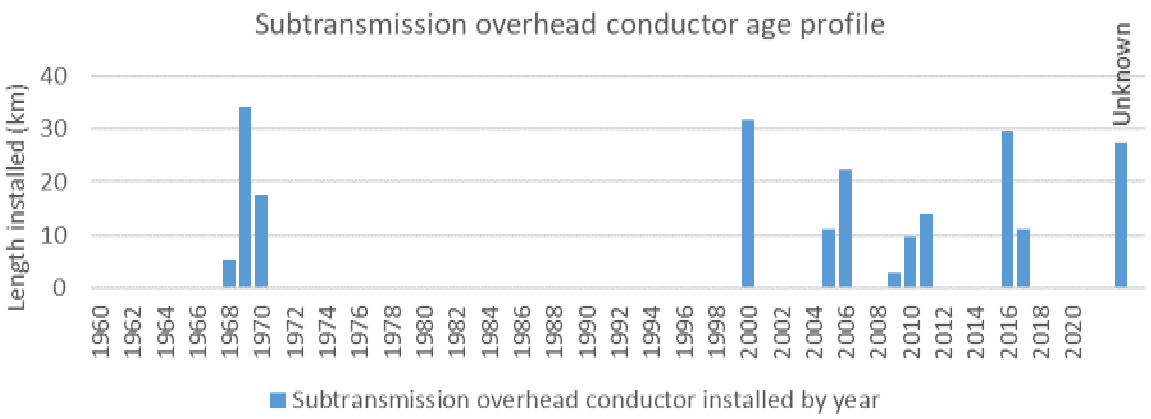


Figure 30 - Age profile of subtransmission overhead conductor

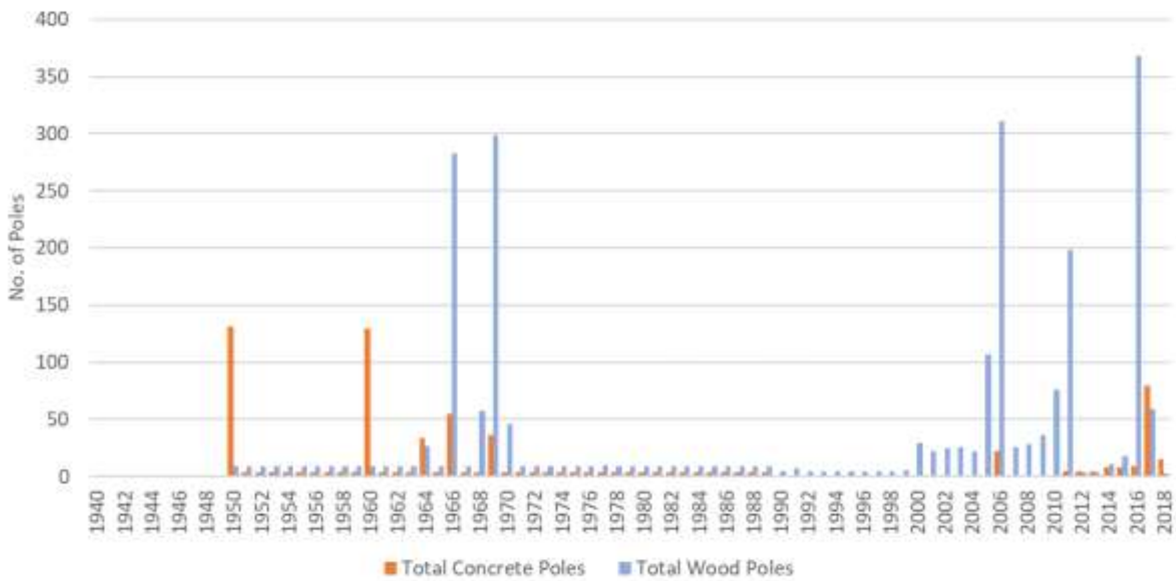


Figure 31 - Age profile for subtransmission poles

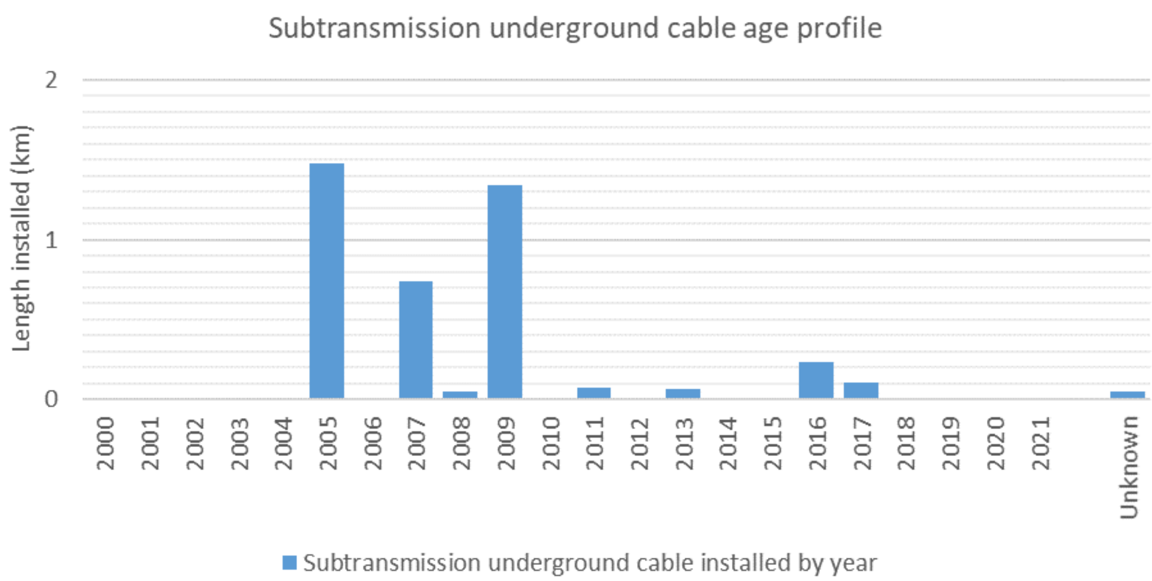


Figure 32 - Age profile of subtransmission underground cables

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.
- Longer spans can cause issues with aeolian vibration in lines constructed to older standards

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
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 Testing	Subtransmission cable terminations as part of zone substation partial discharge testing	Annual
Conductor sample testing	Special targeted testing of conductor to check for issues on older lines	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	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital expenditure forecast ($000)										
Subtransmission pole and hardware replacements	55	55	55	55	55	55	55	55	55	55
Subtransmission rebuilds due to age and condition										
Chelmer St 33kV No 2 UG Observatory Hill to Chelmer St Sub	295									
Weston to Maheno 33kV	82	818								
Weston to Chelmer St 33kV No.1		55	327							
Omarama to Twizel 33kV (waxwing replacement)					55	600				
Capital Subtotal	431	927	382	55	109	654	55	55	55	55
Operational expenditure forecast ($000)										
33kV line renewals	40	40	40	40	40	40	40	40	40	40
33kV climbing patrols	78	78	78	78	78	78	78	78	78	78
33kV ground patrols	52	52	52	52	52	52	52	52	52	52
Operational subtotal	170	170	170	170	170	170	170	170	170	170

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

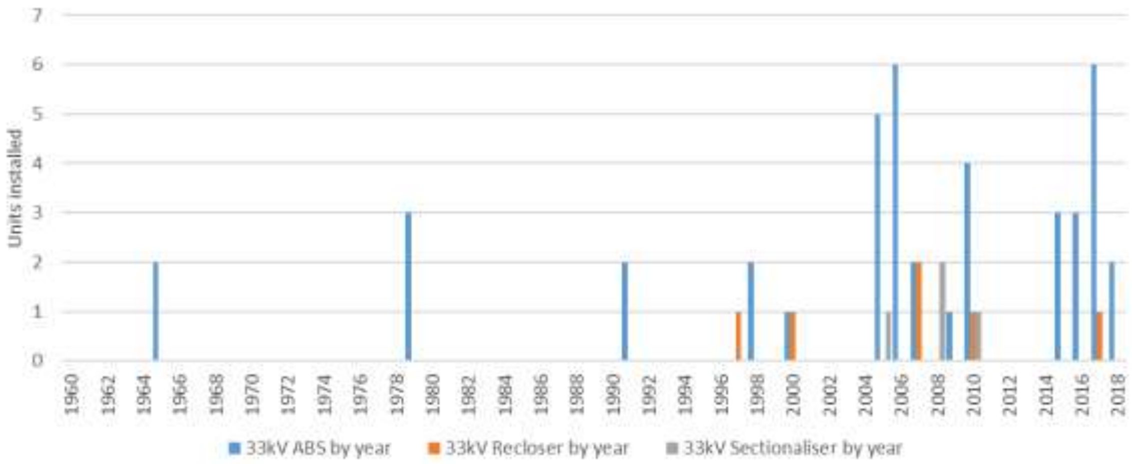


Figure 33 – Age profile of subtransmission switchgear

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	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital expenditure forecast ($000)										
Replace 33kV recloser			44				44			44
Operational expenditure forecast ($000)										
Switchgear maintenance	20	20	20	20	20	20	20	20	20	20

5.7.5 Total Subtransmission Network Expenditure forecast

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

SUBTRANSMISSION NETWORK	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital expenditure forecast ($000)										
Replace 33kV recloser			44				44			44
Subtransmission pole and hardware replacements	55	55	55	55	55	55	55	55	55	55
Subtransmission rebuilds due to age and condition	376	873	327		55	600				
Total capital expenditure	431	927	425	55	109	654	98	55	55	98
Operational expenditure forecast ($000)										
33kV climbing patrols	78	78	78	78	78	78	78	78	78	78
33kV ground patrols	52	52	52	52	52	52	52	52	52	52
33kV line renewals	40	40	40	40	40	40	40	40	40	40
Switchgear maintenance	20	20	20	20	20	20	20	20	20	20
Total operational expenditure	190	190	190	190	190	190	190	190	190	190

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 1,252 km of overhead lines and 76 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.

It should be noted that the 10 worst performing feeders found through analysis for this AMP are the same as those highlighted in the last AMP. In part this is due to the overall rate of faults per feeder per year being low enough that the ranking will generally be slow to change. We will continue to monitor this trend, as it may also indicate that there is some specific targeted work such as the reconfiguration of open points, focussed vegetation management or particular asset replacement that would be cost effective in reducing outages on these particular feeders.

5.8.2.2 Feeders 406, 408, 409 and 427: Aging urban feeders

CB406 Reed St, 408 Solway St and 409 Towey St are urban feeders in the Central and South Hill areas of Oamaru, CB 416 is a semi-rural feeder that supplies into the township of Weston. They are typically older sections of network, and feature a high density of ICPs, with an associated amount of aging overhead low voltage equipment. This can also lead to outages on these feeders having a higher SAIDI and SAIFI impact due to the number of customers that can be affected.

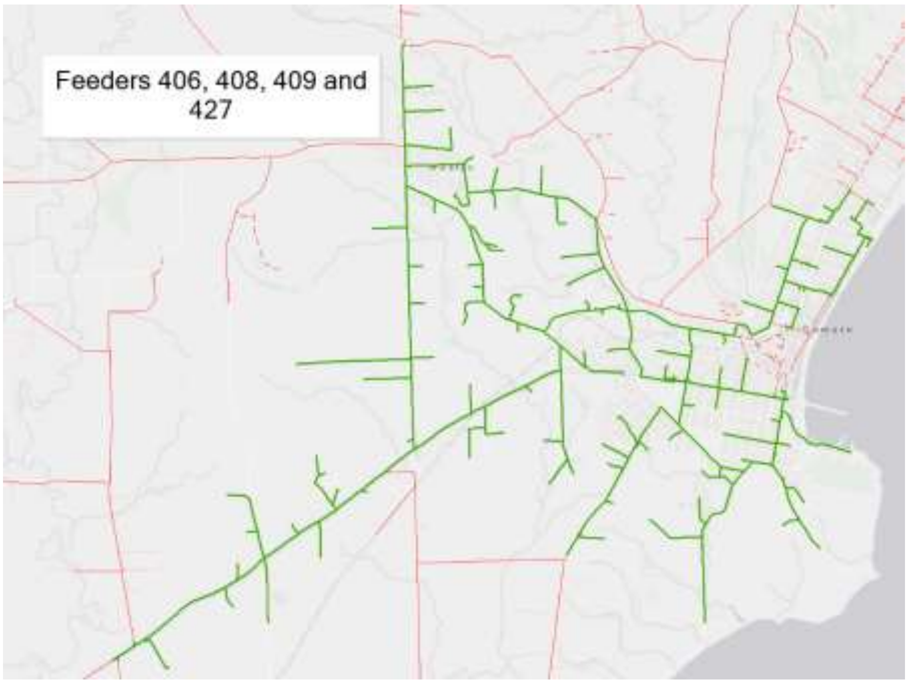


Figure 34 - Urban feeders in the worst performing group

The predominant cause of faults on these feeders is defective low voltage fuses, associated with older pole mounted fuses supplying single customers, as well as some J-type fuses supplying multiple customers. The few faults that have occurred since the last AMP have been consistent with these issues.

To target reduction of this fault type we have budget allocation for the inspection, identification and replacement of suspect low voltage fuses and switchgear. We have also instigated annual patrols of distribution transformers and ground mounted distribution switchgear within the urban network, and 5 yearly patrols for service fuse boxes. Many low voltage faults are difficult to detect prior to failure, but we will continue to investigate ways to make these inspections more effective.

The replacement of J-type fusing in older distribution switchboards around the urban network will not necessarily reduce the incidence of faults at individual premises but will reduce the impact through allowing quicker switching and providing more options for back-feeds in the event of a fault.

5.8.2.3 Feeders 416 Kakanui, 479 Waianakarua and 480 Hampden

CB416, CB 479 and CB 480 are primarily rural feeders that supply the townships of Kakanui, Herbert, Hampden and Moeraki. These feeders are characterised by being near to the Pacific coast in the southern part of our network. They are primarily rural and feature some older sections of HV lines. The terrain ranges from reasonably flat, clear farming land at the coast through to steep and rugged terrain to the west. Vegetation grows well in this area due to favourable climatic conditions and good soil. This area can also be more exposed to weather events moving up from the South. These feeders are located in proximity to State Highway One, with parts of them subject to some of the highest traffic flows in our area.

The predominant faults on these feeders are:

- defective LV fuses and switchgear
- third party activities
- vegetation faults.

Figure 35 - Coastal feeders in the worst performing group

Budget has been allocated in the planning period to rebuild many sections of older line in this area, including older copper and galvanised steel conductors, which should help the resilience of lines in these areas to weather events and improve outcomes regarding wildlife interference. Our ongoing program to install reclosers and sectionalisers based on the impact of outages will help reduce the effect of any future faults.

Motor vehicle accidents make up approximately 70% of the third-party interference events. 40 km of state highway run through this section of network, and there is a relatively high traffic flow. There is little that we can do about the actions of drivers, but we will continue to consider the placement of our assets with respect to the road, and as our GIS tools improve, we will be able to analyse crash patterns to try and identify any pre-emptive changes to the network that may improve performance. We have been working with NZTA to reduce the vulnerability of roadside lines in this area by discussing guarding options and the possibility of moving particular poles as part of this work.

With the movement of our vegetation management service to an in-house delivery model the treatment of defects is being more closely managed. Proactive patrolling is being targeted to known problem areas such as the Waianakarua area. We will be monitoring the effect of this work on the occurrence of vegetation faults across the network, but especially on these three feeders.

5.8.2.4 Feeders 411 Kurow, 413 Hakataramea and 421 Island Cliff

These feeders are all located in the central area of our network, in the area between Kurow and Ngapara. As can be seen in Figure 36 below, feeder 411 Kurow and 413 Hakataramea are contiguous, with feeder 421 Island Cliff located some distance away. They have been grouped together because they all demonstrate similar performance, and a common set of strategies will be used.

Figure 36 - Central feeders in the worst performing group

The predominant faults on these feeders are:

- Wildlife contacts
- Vegetation and weather-related faults

This area of the network can be subject to bad weather due to the prevailing winds and the topography of valleys and hills, and high winds blowing branches around is often the cause of vegetation related outages on our equipment. Significant portions of these feeders including river crossings have been rebuilt in the last few years, and there is significant reconductoring planned in this area of the network during the planning period.

A major rebuild of the Kurow township 11kV network is programmed for early in the planning period, which will help make the distribution network in that area more resilient to future weather events.

The changes to delivery of our vegetation management are likely to have a positive outcome in this situation, although we cannot control all trees that pose a falling hazard due to the limitations of the Electricity (Hazards from Trees) Regulations 2003. We will be working on an education program for tree owners to help them better understand the risks involved with improper management of their trees.

Wildlife contacts are common due to proximity to the Waitaki river and good abundant food sources for pests, due to the combination of farming and vegetation. We expect that the change in delivery model for our vegetation management will assist to reduce these issues, as access to the lines for pests should reduce. During any line work the wildlife protection such as possum guards will be updated.

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:

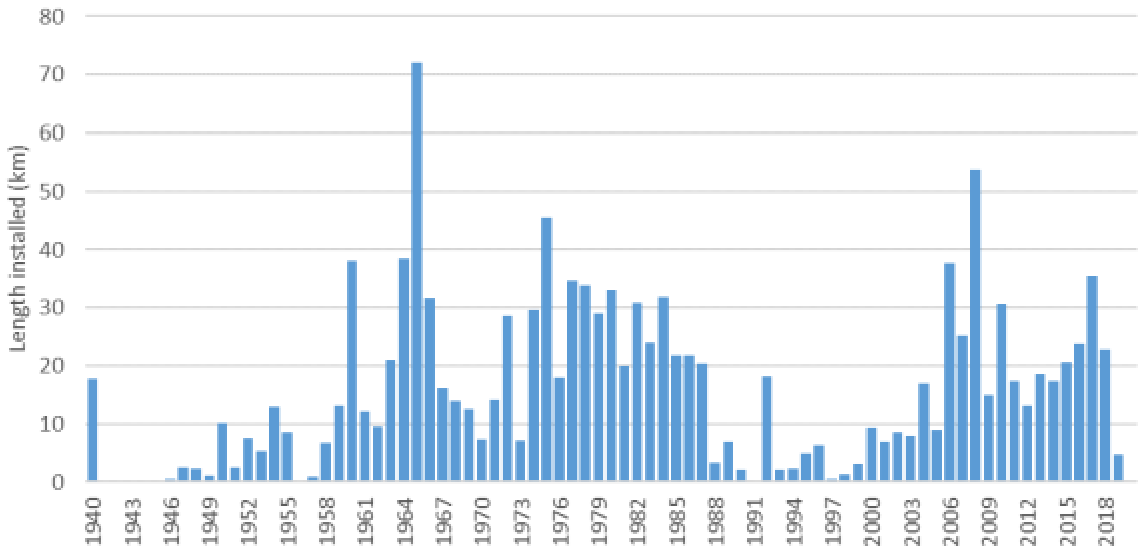


Figure 37 - Age profile of 11 kV overhead lines

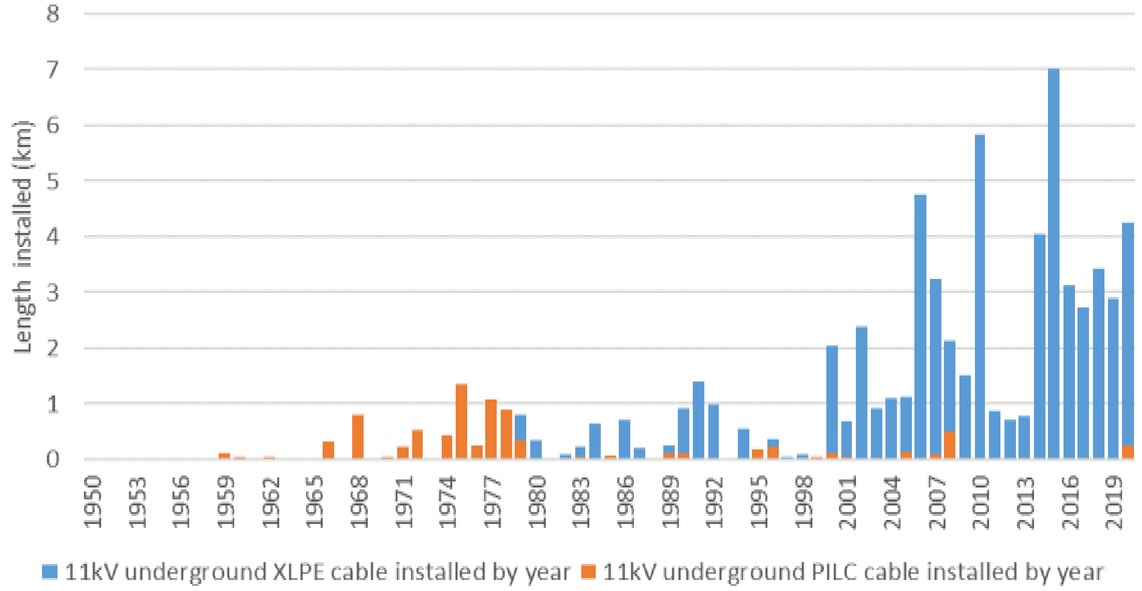


Figure 38 - Age profile of distribution cables

Of the nearly 22,000 poles on our network, approximately 40% are of unknown 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.

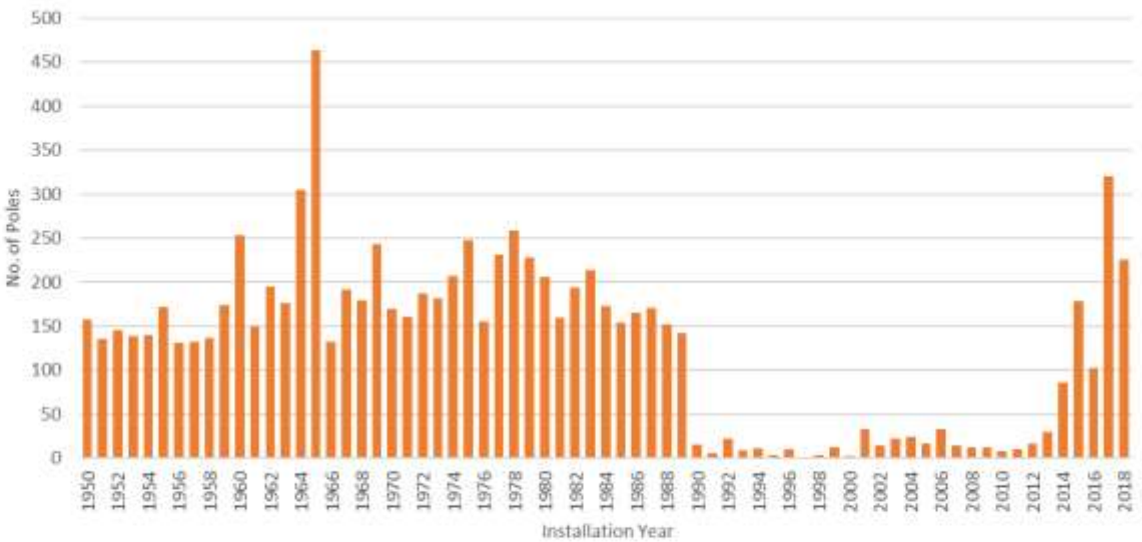


Figure 39- Age profile of wooden poles

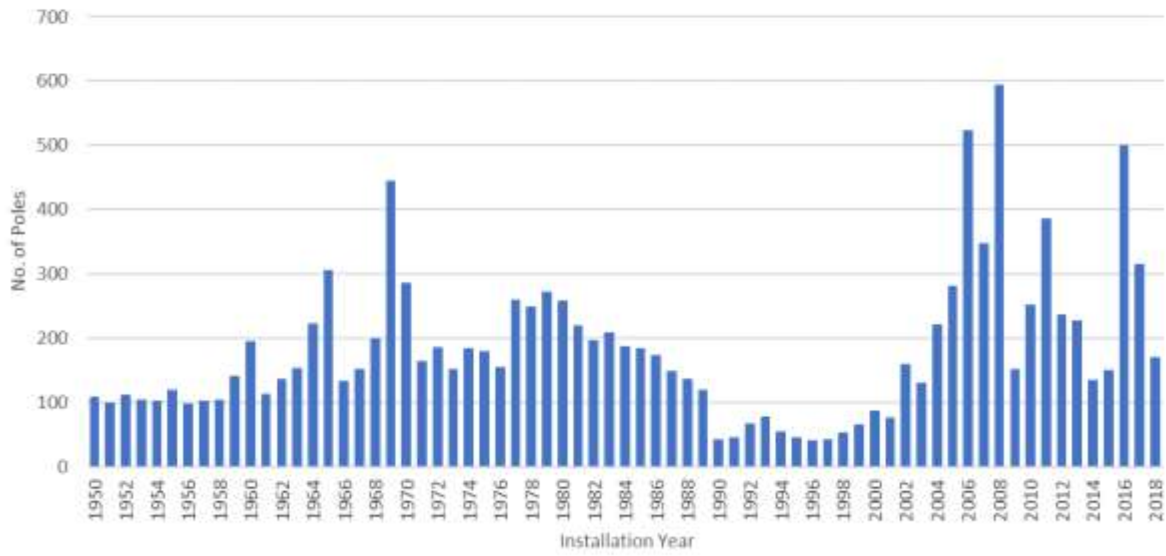


Figure 40 - Age profile of concrete poles

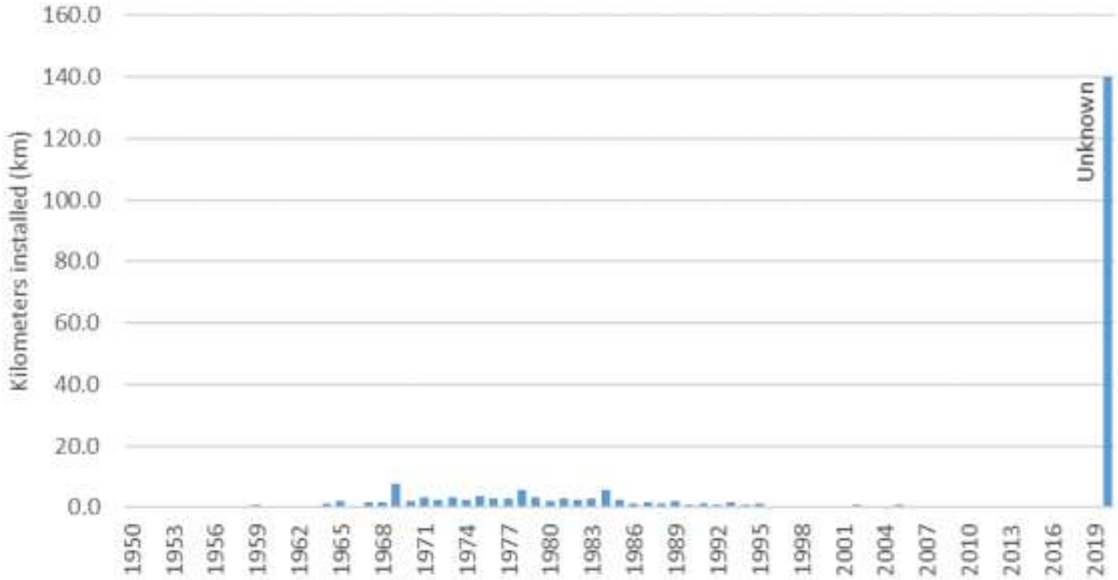


Figure 41 - Age profile of LV overhead network

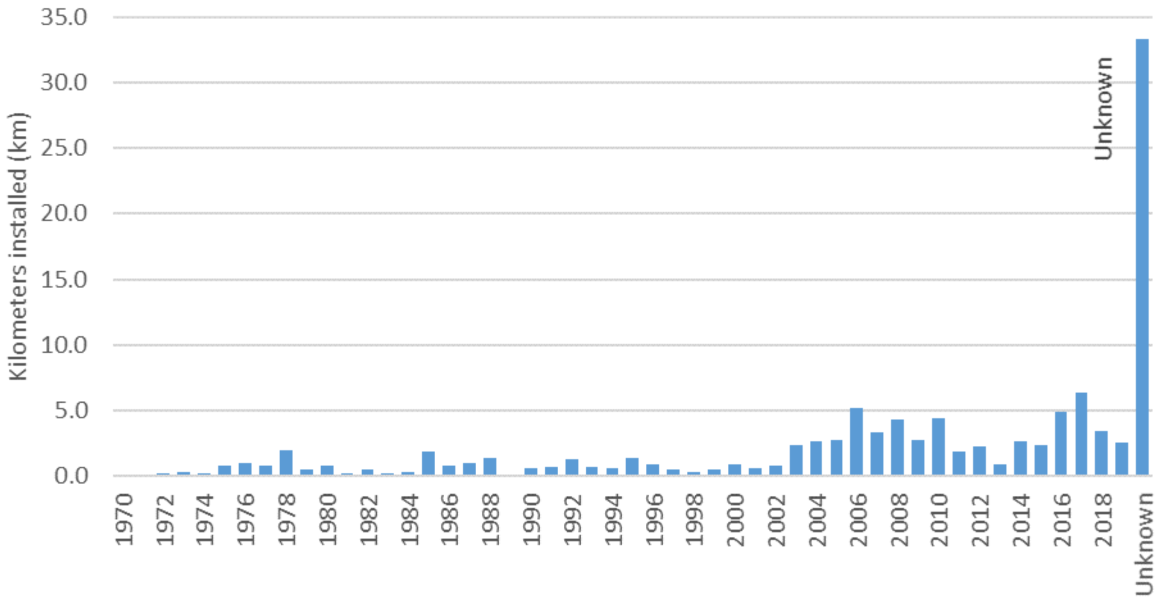


Figure 42 - Age profile of LV cables

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	Inspection of vegetation clearance by specialist vegetation management staff	Minimum of 5 yearly, timed to occur between line patrols. More regular patrols for problem areas

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.

As described in section 4.5.4 the Lake Ohau area in the Mackenzie basin was hit by an extreme weather event in October 2020 that, together with a large wildfire, caused widespread damage to property, devastating the Lake Ohau village and causing significant damage to our network. Given the elevated fire risk in this area due to generally dry ground conditions and the large quantities of wild vegetation we will be undertaking more frequent asset condition and risk assessment surveys as a precautionary measure. For the first three years of the planning period we will carry out annual line patrols for our distribution lines in the Mackenzie basin, rather than our standard five yearly patrols. Tracking the condition, any defects and maintenance requirements annually will provide insight into whether there are particular areas or types of equipment that suffer more damage from the weather conditions in that area. We are mindful of the changing climate conditions including stronger winds which can cause more wear and tear on assets, and hotter and drier summers (which increases fire risk), and as such we will adapt our asset management practices to the changing environment.

We have 228 km of copper and galvanised steel overhead distribution conductors that will be older than the standard expected life of 60 years. Some sections have been in service since the 1930's. Although most of these survivors do 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.

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

- 20 km of old 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.

In FY22 we will be carrying out a trial of Lidar scanning technology to investigate whether this can be successfully used for vegetation inspection and capture of asset location information for the Distribution network.

5.8.3.4 Expenditure Forecast

DISTRIBUTION NETWORK - Lines and cables	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital expenditure forecast ($000)										
Distribution pole and hardware replacements due to condition	1,200	982	982	1,309	1,309	1,309	1,309	1,309	1,309	1,309
Distribution rebuilds due to line age and condition										
Weston to Ngapara 11kV Cu replacement (19.8 km)	693	638								
Kurow Township rebuild 7/16 Cu (3000m)	589									
Ngapara No. 8 GS (2900m)	190									
Danseys Pass No. 8 GS (850m)		56								
Kauru Hill Rd No. 8 GS (500m)		33								
Pig Island Rd No. 8 GS (1800m)		118								
SH1 Pukeuri North to Waitaki Bridge (11600m)			813							
Tussocky Rd No. 8 GS (3000m)			196							
Windsor No. 8 GS (2900m)			190							
Ongoing rebuild of lines based on conductor type and age				764	1,527	2,836	3,818	1,745	2,727	3,272
Remove road crossings on transport corridors to create higher clearances	55	55	55							
Replace old cable terminations	55	55	55	55	55	55	55	55	55	55
Capital subtotal	2,780	1,935	2,291	2,127	2,891	4,200	5,181	3,109	4,091	4,636
Operational expenditure forecast ($000)										
11kV Patrols	200	200	200	135	135	135	135	135	135	135
Distribution line renewals	296	296	230	230	230	230	230	230	230	230
Conductor sample condition testing	100	100	100	100						
Trial of data capture using Lidar	20									
Operational subtotal	616	596	530	465	365	365	365	365	365	365

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:

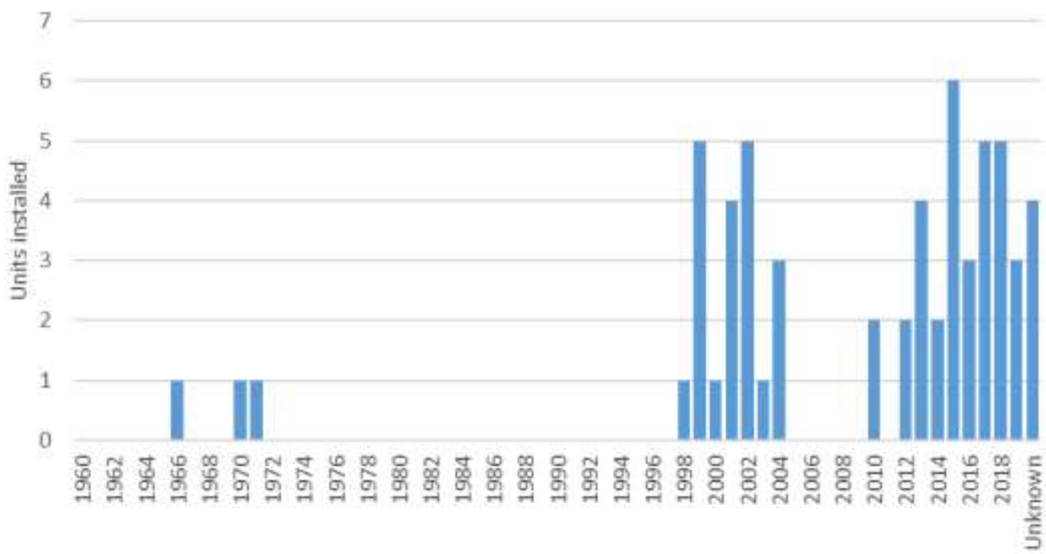


Figure 43 - Age profile of distribution sectionalisers and reclosers

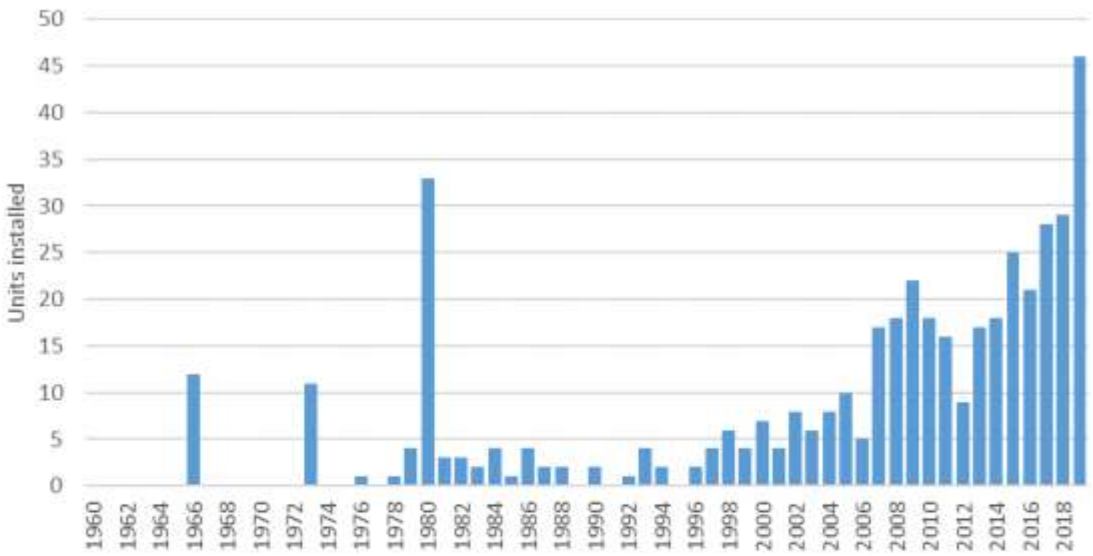


Figure 44 - Age Profile of Pole Mounted ABS

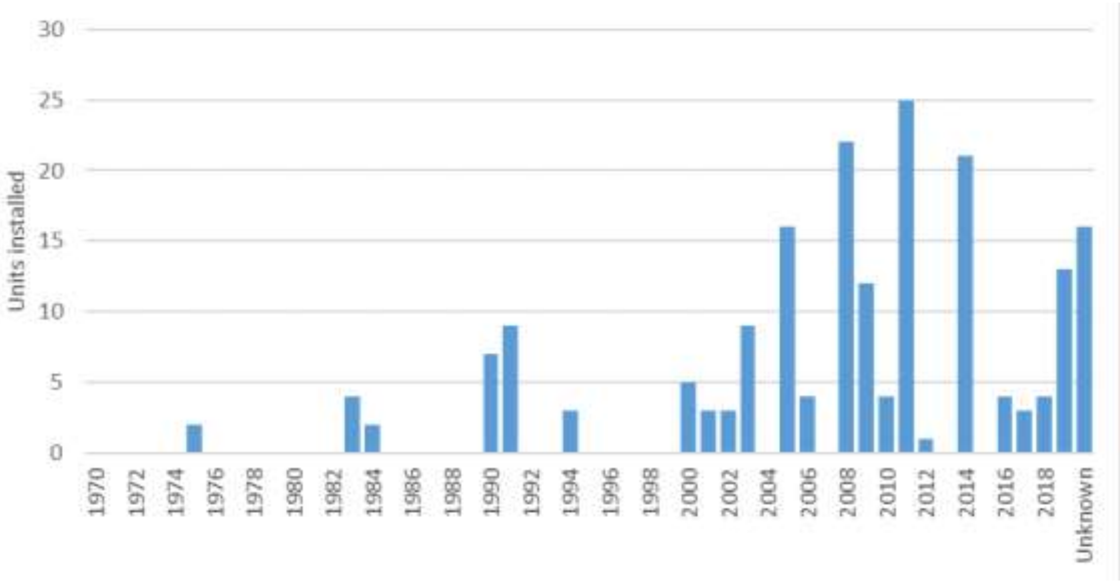


Figure 45 - Age profile of ground mounted distribution switchgear

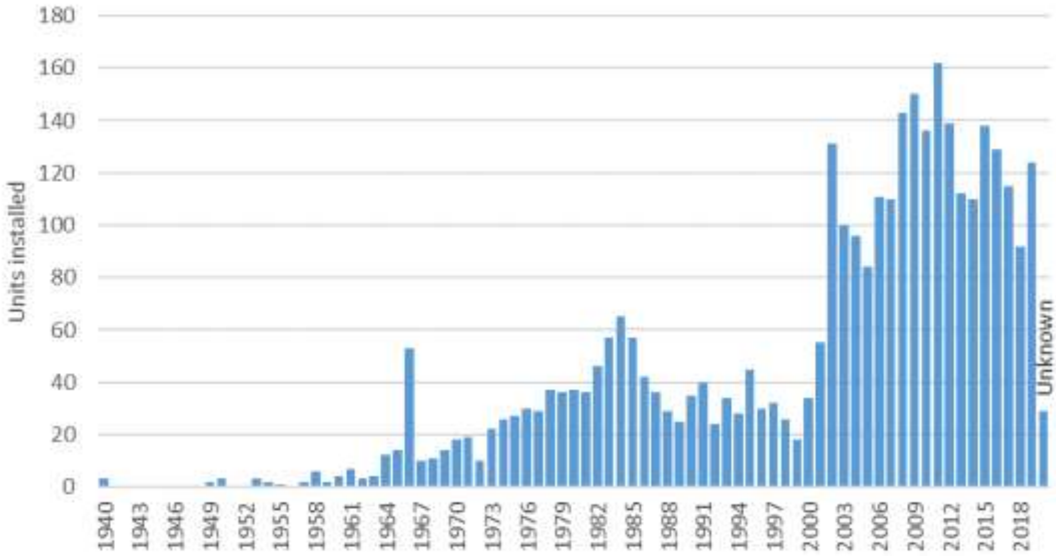


Figure 46 - Age profile of 11 kV fuses

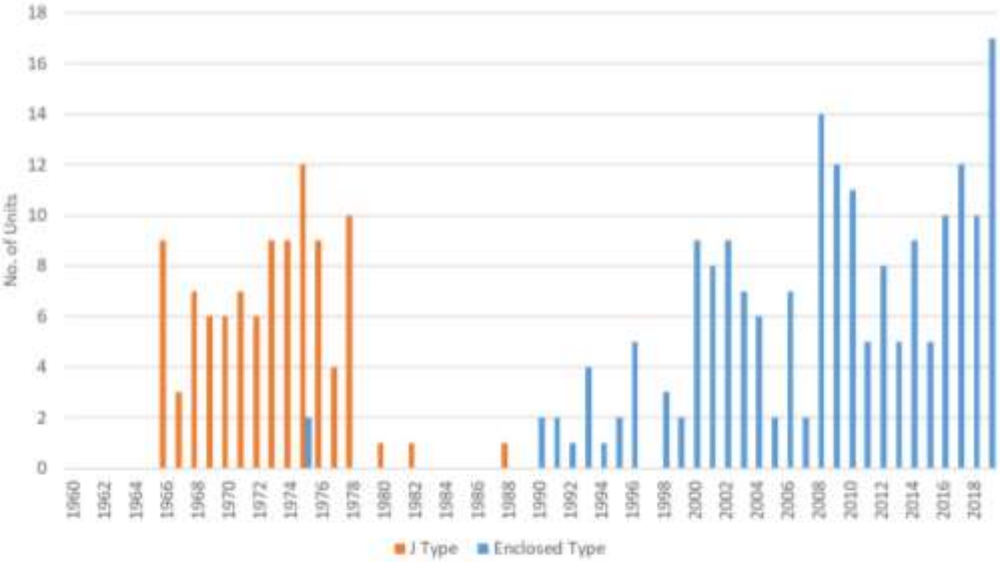


Figure 47 - Age profile of low voltage switch gear

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 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
- Failure of older fuse gear during operation

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.

5.8.4.4 Expenditure Forecast

DISTRIBUTION NETWORK - Switchgear	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital expenditure forecast ($000)										
Distribution switchgear replacement due to age and condition										
ABS age and condition based replacement	33	33	33	33	33	33	33	33	33	33
EDE ABS Replacement	273	273	273	273	273	273	273	109		
Recloser/sectionaliser/tie switch replacement	131	131	38	38	38	38	38	38	38	38
Replace Oil filled RMUs										
Awamoa Park, Ribble St		218								
Taward, RSA, Regina Lane	327									
Two conversions per year ongoing			218	218	218	218	218	218	218	218
Install Reclosers/Sectionalisers/Tie Switches for automation										
West Belt automation	75									
Ongoing reliability and automation work		75	75	75	75	75	75	75	75	75
Install ABS and spur fusing	46	34	34	34	34	34	34	34	34	34
LV Distribution Box Replacement										
J-type replacements	109	109	109	273	273	109	109	109	109	109
Over Veranda distribution boxes @ 4 per annum	44	44	44	44	44	44	44	44	44	44
Streetlight Control Replacement	22	22								
Capital Subtotal	1,059	938	824	987	987	824	824	660	551	551
Operational expenditure forecast ($000)										
Ground mount equipment safety and compliance inspections										
Distribution Boxes - annual	20	20	20	20	20	20	20	20	20	20
RMU visual inspections	4	4	4	4	4	4	4	4	4	4
SFB Trial & Patrol - 5 yearly	10	10	10	10	10	10	10	10	10	10
Distribution switchgear maintenance										
ABS maintenance	45	45	45	45	45	45	45	45	45	45
Distribution CB's & Protection	12	12	12	12	12	12	12	12	12	12
Switching Station Maintenance	32	32	32	32	32	32	32	32	32	32
Operational Subtotal	123	123	123	123	123	123	123	123	123	123

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 load growth due to dairy conversions and irrigation. They are often used as an interim measure until the load 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.

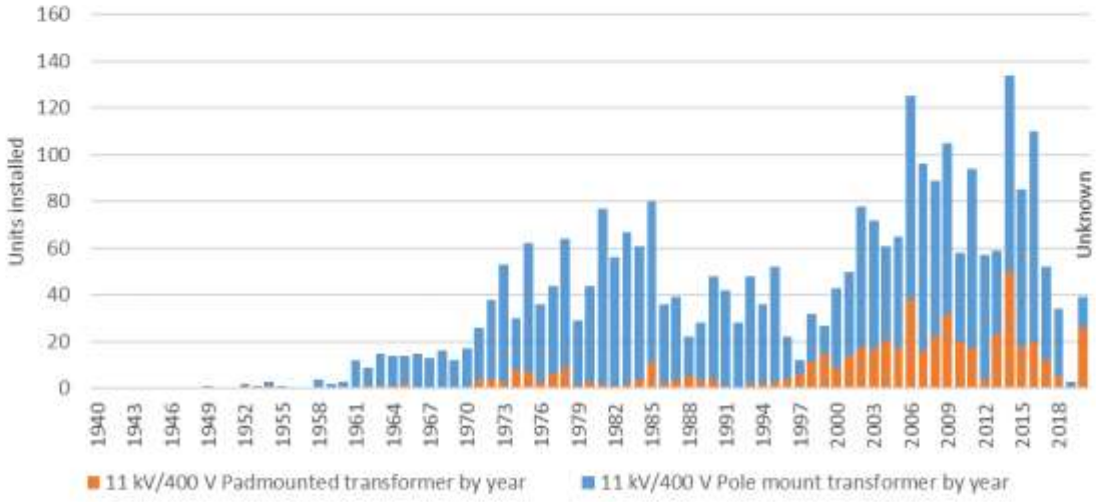


Figure 48 - Age profile of distribution transformers

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.

The 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 5.6.

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
- Overhaul regulator transformers as required

We are planning to maintain a steady number of transformer replacements throughout the planning period, to maintain the average age of the fleet to a reasonable figure.

5.8.5.4 Expenditure Forecast

DISTRIBUTION NETWORK - Transformers	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital expenditure forecast ($000)										
Distribution Transformer replacement due to age and condition	218	218	218	218	218	218	218	218	218	218
Upgrade/renew distribution earths	33	33	33	33	26	26	26	26	26	26
Capital Subtotal	251	251	251	251	244	244	244	244	244	244
Operational expenditure forecast ($000)										
Dist. Tx. Maintenance	25	25	25	25	25	25	25	25	25	25
Earth Testing - 5 yearly	140	70	70	70	70	70	70	70	70	70
Ground mount equipment safety and compliance inspections										
Dist. Tx. MDI's, inspection	25	25	25	25	25	25	25	25	25	25
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
Operational Subtotal	210	140	140	140	140	140	140	140	140	140

5.8.6 Total Distribution Network Expenditure Forecast

DISTRIBUTION NETWORK	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31
Capital expenditure forecast ($000)										
Distribution Box Replacement	153	153	153	316	316	153	153	153	153	153
Distribution pole and hardware replacements due to condition	1200	982	982	1309	1309	1309	1309	1309	1309	1309
Distribution rebuilds due to line age and condition	1472	844	1,200	764	1527	2836	3818	1745	2727	3272
Distribution switchgear replacement due to age and condition	436	436	344	344	344	344	344	180	71	71
Distribution Transformer replacement due to age and condition	218	218	218	218	218	218	218	218	218	218
Install ABS and spur fusing	46	34	34	34	34	34	34	34	34	34
Install Reclosers/Sectionalisers/Tie Switches for automation	75	75	75	75	75	75	75	75	75	75
Remove road crossings on transport corridors to create higher clearances	55	55	55							
Replace cast iron cable terminations	55	55	55	55	55	55	55	55	55	55
Replace Oil filled RMUs	327	218	218	218	218	218	218	218	218	218
Streetlight Control Replacement	22	22								
Upgrade/renew distribution earths	33	33	33	33	26	26	26	26	26	26
Total capital expenditure	4,091	3,124	3,365	3,365	4,122	5,268	6,249	4,013	4,886	5,431
Operational expenditure forecast ($000)										
11kV Patrols	200	200	200	135	135	135	135	135	135	135
Conductor sample condition testing	100	100	100	100						
Dist. Tx. Maintenance	25	25	25	25	25	25	25	25	25	25
Distribution line renewals	296	296	230	230	230	230	230	230	230	230
Distribution switchgear maintenance	89	89	89	89	89	89	89	89	89	89
Earth Testing - 5 yearly	140	70	70	70	70	70	70	70	70	70
Ground mount equipment safety and compliance inspections	59	59	59	59	59	59	59	59	59	59
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
Trial of data capture using Lidar scanner	20									
Total operational expenditure	949	859	793	728	628	628	628	628	628	628

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 are undertaking a strategic review of our communications equipment, including SCADA system and radios. We expect to upgrade these systems based on the outcomes of this review in the first year or two of the planning period.

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 automated low voltage monitoring systems to assist in fault detection and outage recovery
- 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	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**
Capital expenditure forecast ($000)										
LV Monitoring	200	250	300	400	400					
SCADA access to Engineering data at substations	50									
Demand Response Trial	30									
Radio Link Upgrade (PC Sums, project development in FY22)		160								
Fibre/Comms Projects (Dependent on overall comms plan)	285	545	290	230	330	265	141	535		
SCADA/OMS replacement				1,255						
Relocation of Cloud Hill repeater	231									
Total capital expenditure	**796**	**955**	**590**	**1,884**	**730**	**265**	**141**	**535**	**0**	**0**
Operational expenditure forecast ($000)										
LV Monitoring OPEX		15	40	70	110	150	150	150	150	150
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	**79**	**94**	**119**	**149**	**189**	**229**	**229**	**229**	**229**	**229**

5.10 RENEWALS AND MAINTENANCE EXPENDITURE SUMMARY

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

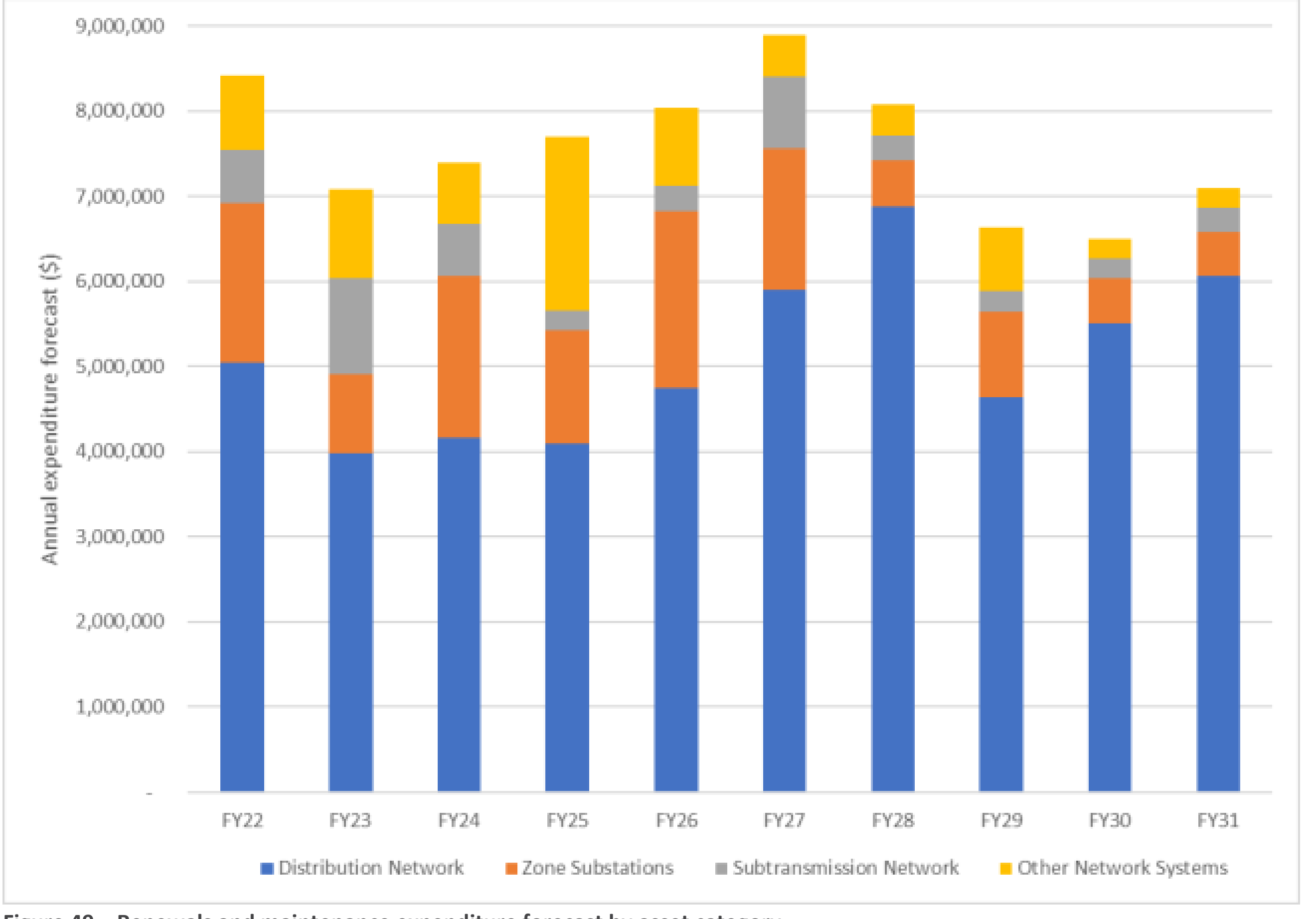
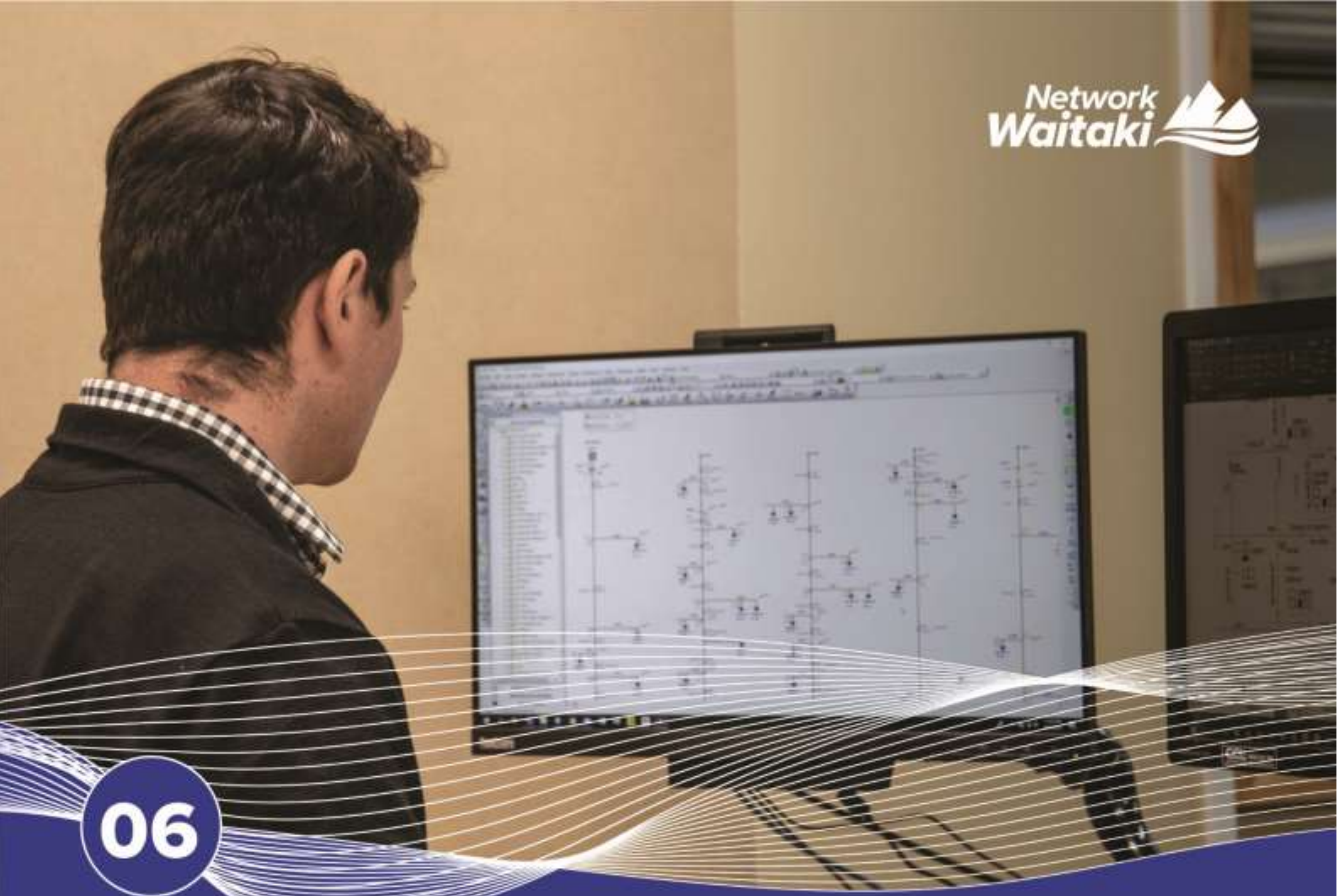


Figure 49 – Renewals and maintenance expenditure forecast by asset category

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.

Development programs. Each network area has been analysed for forecast demand, forecast constraints and options to solve constraints.

Summary of expenditure forecasts

6. Network development plan

6.1 PLANNING APPROACH

6.1.1 Network Development Plan (NDP) focus

Our NDP is focused on:

- Setting and maintaining appropriate security and reliability levels.
- Forecasting future demand and identifying capacity constraints on our network.
- Analysing and selecting solutions to deal with future constraints.

6.1.2 Planning process

- A development driver is triggered.
- A business case is prepared detailing options (including non-network options), costs, benefits, risks, and recommendations.
- Business case approval is requested subject to delegation levels.
- After business case approval, a design is prepared for the selected option, and the project is scheduled into our works program.
- After completion, the project is reviewed for effectiveness.

6.1.3 Development drivers

The main drivers for network development projects are:

- Safety
- Security of supply
- Regulatory compliance
- Quality of supply
- System reliability
- Readiness for the future
- New customer connections

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

6.1.4 Planning criteria

6.1.4.1 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.

6.1.4.2 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 is often a driver for network upgrades rural areas due to the combination of significant irrigation loads and long feeders.

Distributed generation

We welcome the connection of distributed generation (DG) on our network. If the DG has an approved inverter and is in an uncongested area, we aim to approve the connection within two working days.

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 2021 and do not forecast any areas to become congested in the following 12 months.

Conductor heights

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

6.1.4.3 Security of supply criteria

Security of supply refers to the ability of our network to meet customer 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 load. 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 load may have a security level determined by customer requirements.
- The security criteria are based on the ability to interrupt irrigation load 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 23- Security of supply - deterministic criteria

Class	Description	Load 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 2hrs
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 2hrs
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 - Probabilistic criteria

A probabilistic assessment is based on the quantification of risk via the following formula:

> ***Risk ($) = probability of outage x cost of unserved energy***
>
> *Probability of outage = risk period (yr) x equipment failure rate (failures/yr)*
>
> *Cost of unserved energy =repair time (h/failure) x load at risk (MVA) x VoLL ($/MVAh)*

This allows financial analysis of any proposed change to network security using a net present value (NPV) calculation. This will feed into a business case which will also consider factors such as sustainability, operational flexibility, maintainability, and asset longevity.

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 following values of lost load (VoLL), which were developed based on Transpower's Value of Lost Load Study 2018.

6.1.4.4 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*.

6.1.4.5 Reliability criteria

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

6.1.4.6 Environmental and sustainability criteria

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

6.1.4.7 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 loadings, provided the incremental cost of upsizing is less than the cost to upgrade the equipment in the future.

Depending on the timeframe of projected loads, distribution transformers may be sized for medium-term loads and upgraded as required for ultimate loads. This approach minimises system losses and the risk of over investment if the projected load 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 can be used (or adapted for re-use).

6.1.4.8 Energy efficiency criteria

At times of maximum demand, the network is configured to minimise voltage drop and maximise efficiency.

At feasibility stage for new builds or for network strengthening projects, the 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 cost of network power losses is passed through to our connected customers so Network Waitaki does not enjoy the financial benefit of the loss reduction but 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.

6.1.5 Demand forecast

Over the past decade a significant portion of network investment has been driven by load growth and related security and quality of supply upgrades.

A large portion of this growth has been due to the increased uptake of spray irrigation, either new schemes or the conversion of existing gravity-fed schemes to electric pumping.

Since 2003, our network has been summer peaking network, with peaks usually between December and February.

6.1.6 Demand forecast methodology

- Growth rates have been analysed for the period 1990-2021. These have been categorised into three groups based on the premise type.
    1. Domestic
    2. Farming (Dairy sheds, irrigation pumps)
    3. Commercial and Industrial (Not domestic or farming)

- Customer load types at each substation have been analysed and a percentage share of the substation summer maximum demand allocated to each group.

- New load that has been signalled to us with reasonable certainty has been added separately at the relevant substation. Large process heat conversion loads have been included under the high load growth scenario.

- Due to lack of coincident demand data at ICP level, the load growth rates are based on numbers of new connections rather than maximum demand. For this reason, we have also compared the five[6] and ten-year average GXP maximum demand growth rates. (Calculated across all GXPs to remove the effect of previous load transfers between GXPs.)

Table 24 - Historic maximum GXP demand growth rates

5 year maximum-demand average growth rate	1.5%
10 year maximum-demand average growth rate	2.2%

- 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 loading day of the year and assumed for all loads. For the FY21 period the power factor recorded at system maximum demand was 0.97 lagging.

- FY21 GXP demand data has been sourced from Transpower's metering data. Substation demand data has been sourced from NWL's SCADA system.

[6] It is noted that FY19 was wetter than average which means that the 5-year average may tend to underestimate recent irrigation growth.

6.1.7 Demand forecast inputs

6.1.7.1 Domestic load growth

Environment Canterbury predicts average annual population growth for the period from 2013 to 2043 (updated February 2017) in the Waitaki District for three scenarios.

Table 25 – ECAN population growth forecast

ECAN Scenario	Annual growth
Low	-0.1%
Medium	0.6%
High	0.9%

NWL's historical annual growth rates in numbers of new domestic dwelling connections are +0.75% (five-year average) and +0.61% (ten-year average). The growth in domestic dwellings directly relates to an increase in maximum demand.

We have derived our domestic demand growth rates as follows:

- The low growth scenario has been aligned with ECANs population figures.
- The expected growth scenario aligns well with both the ECAN medium growth projection and NWL's ten year average connection growth rate.
- The high growth scenario has been aligned with the ECAN high growth figure which is higher than our three year average but is considered prudent especially with the possibility of increased immigration from New Zealanders returning home and other nationalities seeing New Zealand as a safe haven from Covid 19.

Table 26 - Domestic growth forecast rates

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

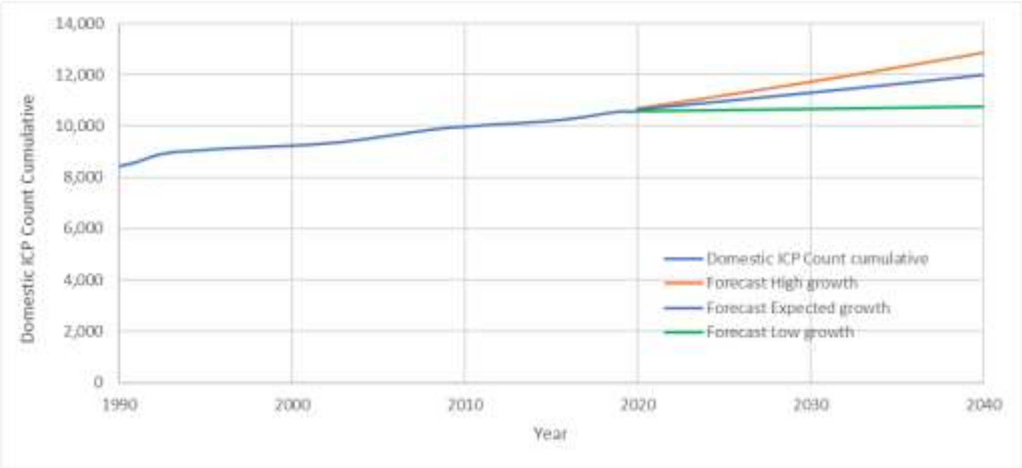


Figure 50 - Historical and forecast domestic growth

6.1.7.2 Commercial & Industrial load growth

Annually, commercial new connections have grown at +1.0% (five-year average) and +0.7% (ten-year average). Growth is expected to continue in line with the ten-year average rate.

Table 27 - Commercial growth forecast rates

Growth Scenario	Annual Growth
Low growth	0.5%
Expected growth	0.7%
High growth	1.0%

Note: these growth rates do not include process heat decarbonisation as this is added separately into our model and is subject to different assumptions.

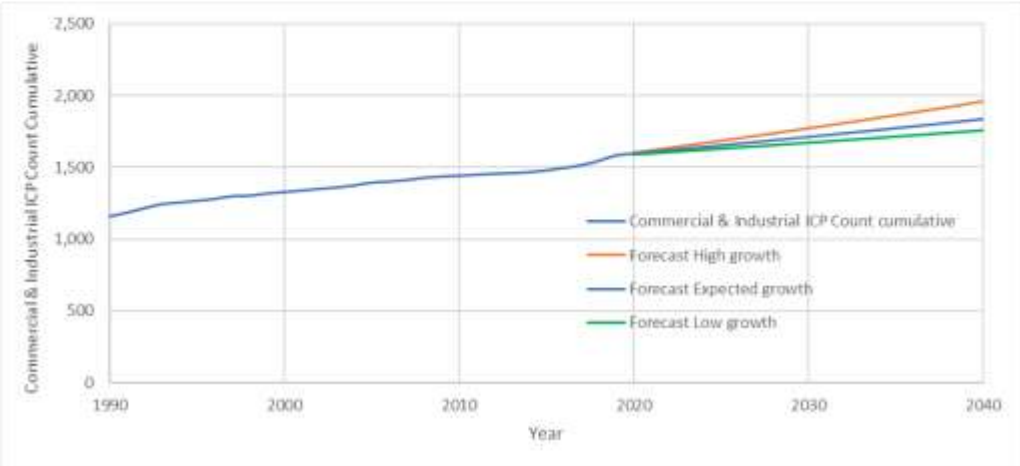


Figure 51 - Historical and forecast commercial growth

6.1.7.3 Decarbonisation of process heat

Two large industrial customers in our supply area have recently signalled that they plan to move away from coal-based process heat within the next ten years.

Initial estimates indicate that electrical energy requirements could be in the order of 10 MW for these two customers alone and up to 3.75 MW could be required in the short term (accelerated by government incentives).

At the time of writing no formal application has been made for these loads, however we have held high level discussions and are working closely to understand our customers' needs and help them to determine the lifecycle costs and benefits of converting to electricity as an energy source.

Process heat decarbonisation load has been added to our model under a Decarbonisation Scenario, which is based on the high load growth scenario assumptions plus process heat decarbonisation). Loads 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 five years. The decarbonisation scenario has only been presented at zone substations and GXPs where we have identified likely decarbonisation loads. In this AMP these are Pukeuri Zone Substation, Redcastle Zone Substation and Oamaru GXP.

We will work to identify and assist customers who are considering transitioning to electricity as an energy source to ensure that we can make optimum investment decisions for network upgrades and provide the best service to our customers. Along with other South Island EDBs we are collaborating on a study which will produce an updated list of coal boilers in the South Island greater than 500 kW.

6.1.7.4 Farming load growth

Dairy shed growth

Annual new connections for dairy sheds have grown at +1.2% (five-year average) and at +2.4% (ten-year average). The three-year average has reduced to +0.6%. From the graph in Figure 52 it can be seen that the growth rate has flattened off significantly.

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.

Table 28 - Dairy shed growth forecast rates

Growth Scenario	Annual Growth
Low growth	0.3%
Expected growth	0.4%
Prudent growth	0.5%

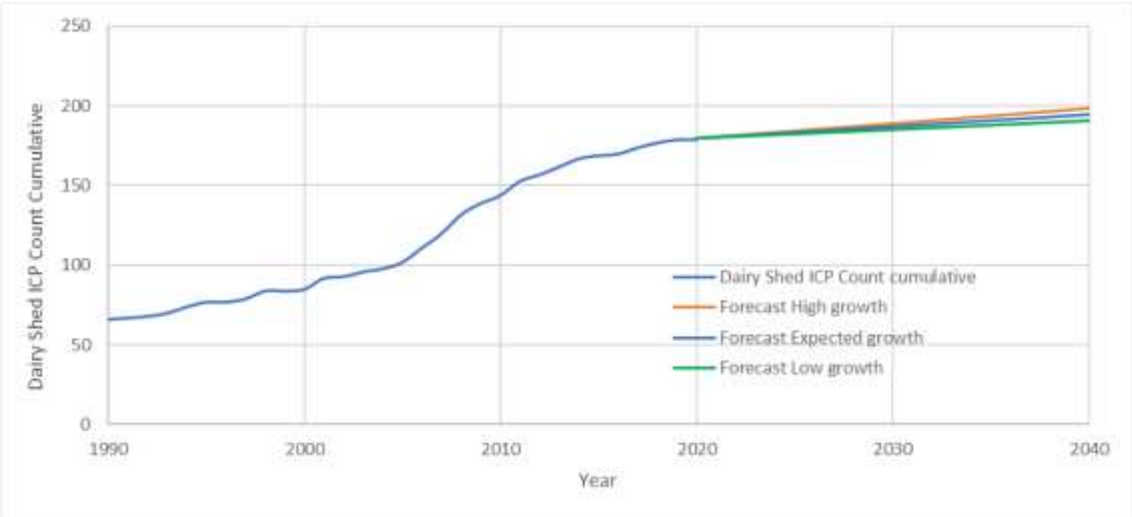


Figure 52 – Historical and forecast dairy shed growth

Fonterra's farmgate milk price[7] is forecast to be between $6.90 - $7.50 per kg of milk solids in the 2020/21 season. This is largely due to an increase in demand from China and South East Asia for skim and whole milk powder. Risk still remains around further waves of COVID-19 but this strong forecast and resulting confidence coupled with historically low interest rates may encourage farmers to bring forward investment to convert from border-dyke to spray irrigation.

The average break-even milk price is estimated at $5.95 per kg.

[7] 3 February 2021 - Fonterra Lifts Its 2020/21 Forecast Farmgate Milk Price Range | Scoop News

Irrigation load growth

Annually, new connections for irrigation pumps have grown at +3.5% (five-year average) and +3.1% (ten-year average).

The three-year average has reduced to 2.4% indicating a slight slow-down in irrigation expansion.

The following irrigation projects are proposed for the Oamaru GXP over the next 10 years and have been included as known loads.

- 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 ten years. At approximately 0.8 kVA per hectare this equates to 4 MVA of new load.
- An irrigation company indicates there may be another 1 MW of pumping load to be installed within Waiareka Valley Road, Taipo Road and Dunrobin Road areas.

We expect that total farming growth will be mainly linked to irrigation growth and will continue at similarly high rates for the next ten years. It is likely that irrigation growth rates will flatten off after 10 years.

Table 29 - Irrigation growth forecast rates

Growth Scenario	Annual Growth
Low growth	3.1%
Expected growth	3.4%
Prudent growth	3.5%

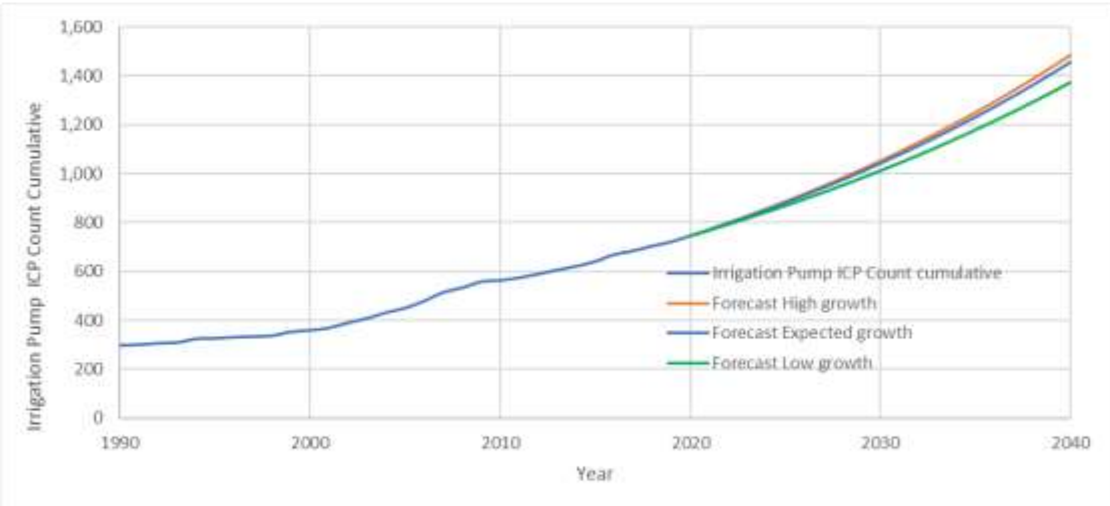


Figure 53 - Historical and forecast irrigation growth

6.1.7.5 Electric vehicles

We have low levels of electric vehicles (EVs) in our network area (32 EV and 10 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.

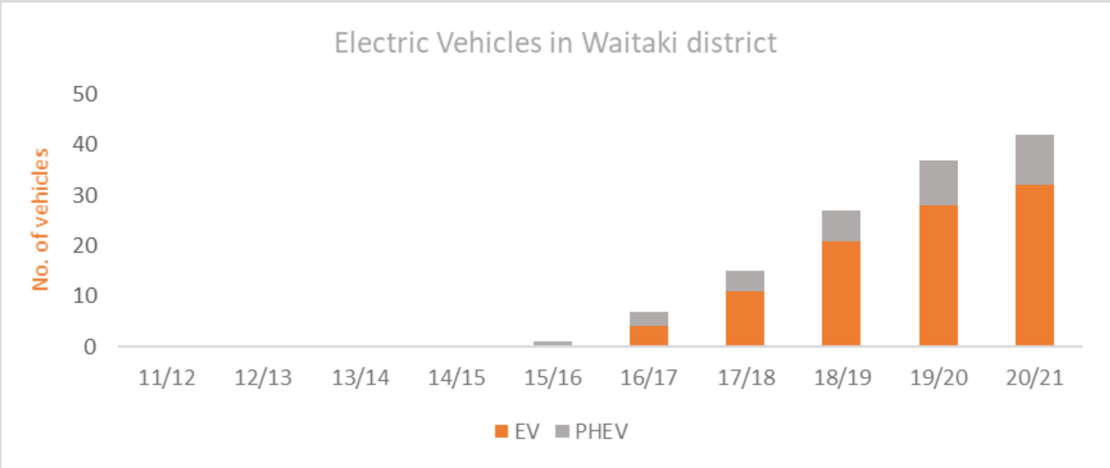


Figure 54 - Electric vehicles in the Waitaki District

We have considered the various growth projections in the table below:

Table 30 – Electric vehicle growth forecast rates

Scenario	Projection Date	Electric vehicle percentage of passenger vehicle fleet
MBIE – reference scenario - 2019	2050	44%
MBIE – growth scenario – 2019	2050	75%
NZ Ministry of Transport	2040	40%
Bloomberg (global fleet) - 2020	2030	8%
	2040	31%
IEA -2019 EV30@30 scenario	2030	30%
Transpower Whakamana I Te Mauri Hiko Accelerated electrification scenario	2030	17%[8]
	2040	70%[9]
	2050	99%[9]

Factors that will cause EV ownership to start to ramp up significantly are:

- The Labour Government has pledged to accelerate the electrification of our transport and industrial sectors in their 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 forecast to reach 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.

[8] percentage of passenger vehicle km travelled

We expect that these factors will start to significantly influence EV ownership in the second half of the planning period.

The existing New Zealand passenger vehicle fleet is comprised of about 3.8 million vehicles of which 19,000 are EVs which equates to a penetration of 0.5%.

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 32 EVs registered in the district which equates to a penetration of 0.2%. This is 40% of the national penetration and 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.

We predict that the uptake of EVs in our district, at the end of this planning period, will be lower than the rest of New Zealand and have chosen a figure closer to the Bloomberg prediction at 10% penetration by 2030 (1,800 EVs).

If 60% of these EVs, with 3 kW chargers, elected to charge their vehicles at the same time 3.2 MVA would be added to our network maximum demand. A means of optimising how EVs access our network will be required to maximise the utilisation of our distribution assets and minimise the cost of upstream upgrades.

We are a member of the ENA Smart Technology Working Group and are actively collaborating with other EDBs on low voltage network monitoring and EV control schemes. We will engage directly with EV owners in our district in FY22 to allow us to understand their needs.

We have allocated EV energy demand in our model by hour of the day based on the following assumptions[9], which assumes that a scheme will be in place to optimise EV charging.

- 80% of charging occurs between 11pm and 5am.
- 10% of charging occurs between 5pm and 11pm.
- 10% of charging occurs during the day evenly allocated between 9am and 5pm.

To allow for the uncertainty in the charging regime, the proportion of EVs charging during our summer maximum demand has been modelled for the expected growth scenario at 10% with an average 3 kW charger size and for the high growth scenario at 20% with an average 5 kW charger size.

We have not included effects of vehicle to grid (V2G) power flows in our model for the planning period but are actively watching developments in this area.

[9] MBIE, Electricity demand and generation scenarios, 2019

6.1.7.6 Distributed generation

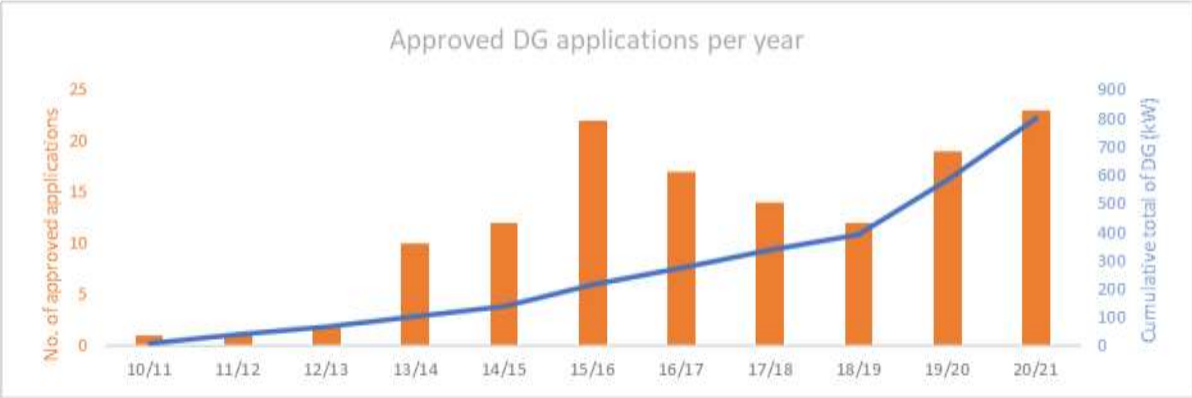


Figure 55 - Distributed generation applications

Distributed generation (DG) in our region is predominantly photovoltaic panels and this continues to grow. There are 135 DG connections approved on the network comprising 0.85% of all connections and equal to a 0.4% reduction in maximum demand (after de-rating to 50%). The average photovoltaic DG installation is 5 kW.

Distributed generation has been modelled in the low growth scenario at 10% penetration by the end of the planning period and in the high growth scenario at 8% penetration. We acknowledge that the rate of uptake for DG 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.

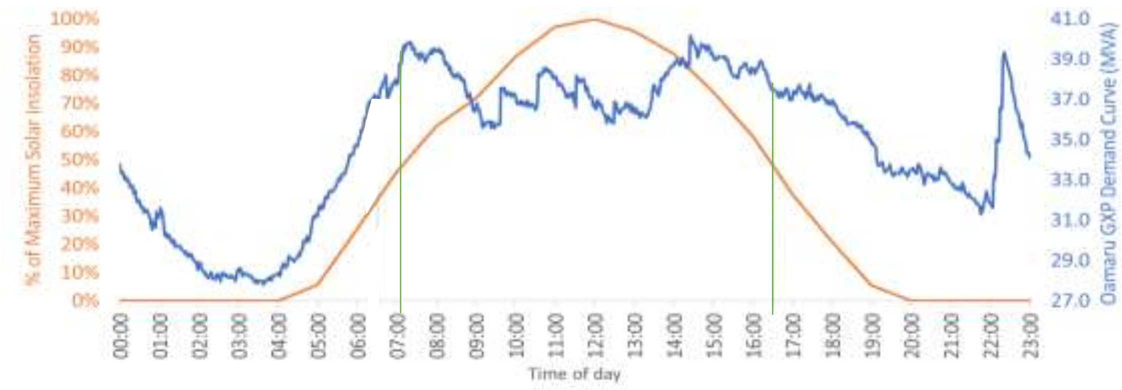


Figure 56 - Oamaru GXP load profile vs solar radiation

The graph above shows the demand (blue curve) for a typical heavily loaded summer day compared with the solar radiation figures for Oamaru (orange curve) on the same day. Taking a conservative approach and setting the start of the morning peak at 07:00 and the end of the afternoon peak to 16:30 gives an average solar output of 50% of maximum at times of system maximum demand.

6.1.7.7 Battery storage

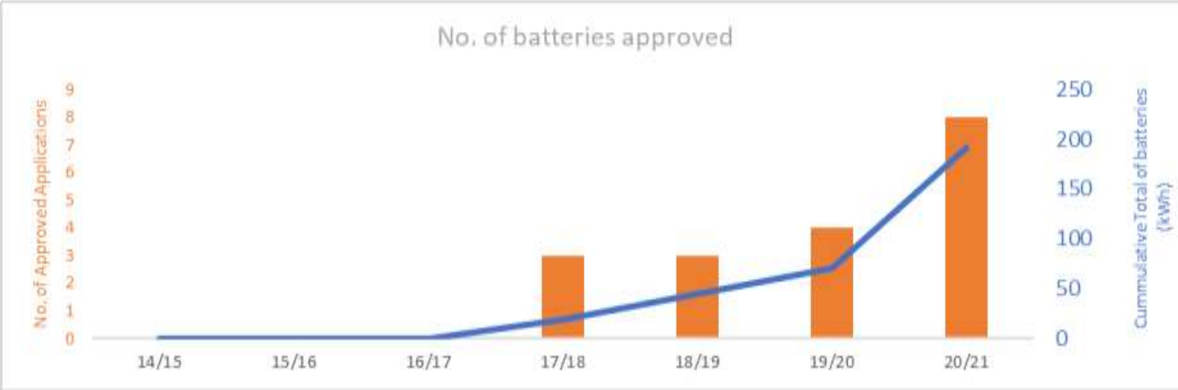


Figure 57 - Batteries approved for connection

We have low numbers (18) of customer-owned battery installations connected to our network with a total installed capacity of 200 kWh. As battery costs fall, coupled with potentially favourable regulation settings, 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 would be useful to minimise congestion and associated upgrades on our network and the upstream transmission network. To realise this we will need to develop a suitable pricing strategy and a means to communicate with our customers' technology. In conjunction with other EDBs, we are currently developing our Demand Response Management (DRM) roadmap and batteries will be included in this workstream (Further details in Section 6.2.1.6 Demand Response Management)

6.1.7.8 Energy efficiency

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

Efficiency measures that may reduce our summer maximum demand are:

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

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

Table 31 – Energy efficiency forecast rates

Growth Scenario	Annual Growth
Low growth	0.3%
Expected growth	0.2%
Prudent growth	0.1%

6.1.7.9 Demand response management

The impact of traditional network-controlled load management (storage heating and hot water) is minor during the summer peaks as the majority of hot water is already controlled off and due to the large size of each bank of load that is available for control, caution must be used as a large peak can be created when these channels are turned back on. For this reason, we have not included the effect of hot water control in the demand forecasts. We will conduct a study in FY22 to update our records of the amount of controllable water heater load on our network.

The control of irrigation load is a tool reserved for managing network loading during outage or grid emergency conditions on the network and is not available for use in the normal operation of the network.

We are yet to see the effect of customer led demand side management. With the roll-out of smart meters and the availability of spot market pricing in the domestic market, we expect there will eventually be an increase of retailer led pricing signals to customers to encourage demand management.

Transpower operate a national demand response management (DRM) program. NWL currently offer a 0.5 MW diesel genset into this program.

We are currently refining our demand response strategy and will look to complete a pilot project in FY22. There is more detail on our strategy in 6.2.1.6 Transmission Constraint Options.

6.1.7.10 Heat pumps

The largest heat pump installer in our region estimates that between 6,000-7,000 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° but many are now setting this as high as 21°C.

Heat pumps in our region are not typically used for cooling so 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 that this may have an effect on 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.

6.2 DEVELOPMENT PROGRAM – OAMARU GXP REGION

6.2.1 Transmission and GXP

6.2.1.1 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 advise 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 NWL only. Any upgrades to these circuits are required to be funded by NWL.

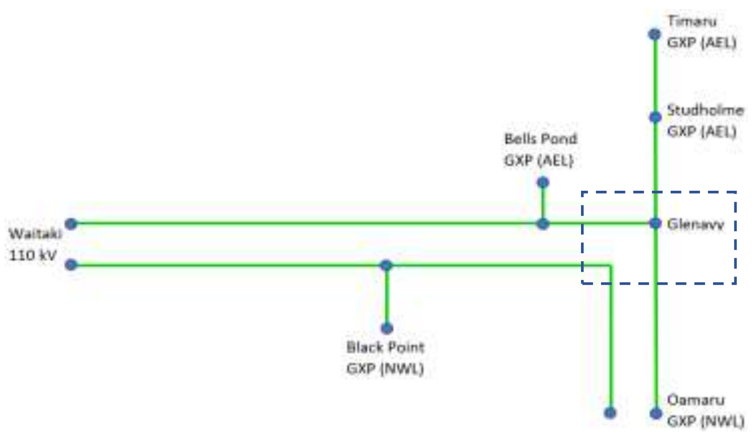


Figure 58 - Transmission single line diagram

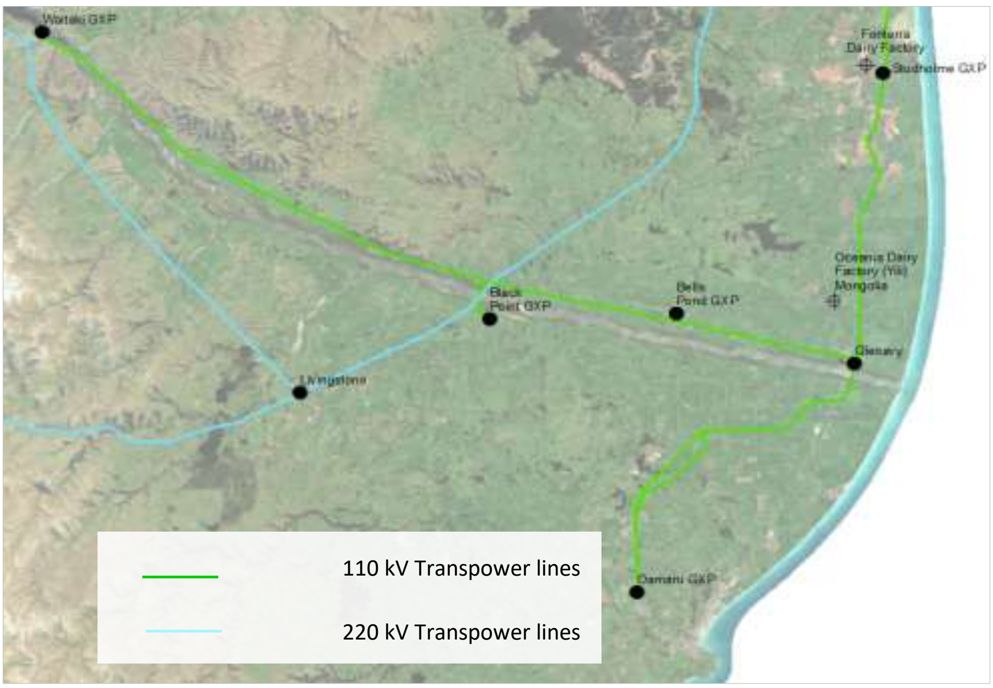


Figure 59 – Existing Transpower regional transmission network

6.2.1.2 Transmission system constraints

Table 32 – Transmission system constraints

Constraint	Type	Constraint limit	Applies pre/post contingency	Description
Waitaki 220/110 kV transformer banks	Transformer thermal rating	100 MVA (N-1)	Both	Thermal limit per transformer bank
Oamaru 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.
110 kV circuit from Waitaki via Black Point to Oamaru	Voltage stability	54 MVA	Post	There is a voltage stability constraint if Oamaru load exceeds 54 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 from Lake Waitaki to Bells Pond	Conductor thermal rating	45 MVA	Pre	When load 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 (supplying Fonterra Dairy Factory) to N security from Timaru direction only.
110 kV circuits from Glenavy to Oamaru	Conductor thermal rating	45-51 MVA	Pre	Use of Variable Line Rating (VLR) has allowed for an increase in the thermal rating of the line to 45 MVA (during selected periods of each day in Summer elsewise the limit is 51 MVA.)

The VLR determined conductor thermal rating on the Glenavy to Oamaru 110 kV transmission lines is presently the limiting constraint on the maximum demand that can be supplied from Oamaru GXP. The VLR rating has been calculated for the most constrained section of line (Black Point to Oamaru) and has been applied to both lines.

Note: 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 load from the other line should it trip out in a fault.

6.2.1.3 Oamaru GXP maximum demand

The graphs below show the Oamaru GXP demand on a heavily loaded day in December and in February for contrast. Both graphs have the corresponding monthly Variable Line Rating (VLR) constraint (red line) superimposed.

If the VLR limit curve is lowered (red dotted line) until it intersects the maximum demand curve, it can be seen in both cases that there is 7.5 MVA of spare capacity remaining. (Note: 1.5 MVA of this spare capacity is provisional on optimising the turn-on time for hot water channel boost). This approach allows us to consider that the maximum demand may not occur at maximum VLR constraint as seen in the two graphs below.

The effective Oamaru GXP limit has been calculated by adding the spare capacity to the previous Oamaru GXP maximum demand to date.

Effective Oamaru GXP Limit = 7.5 MVA + 40 MVA = **47.5 MVA**

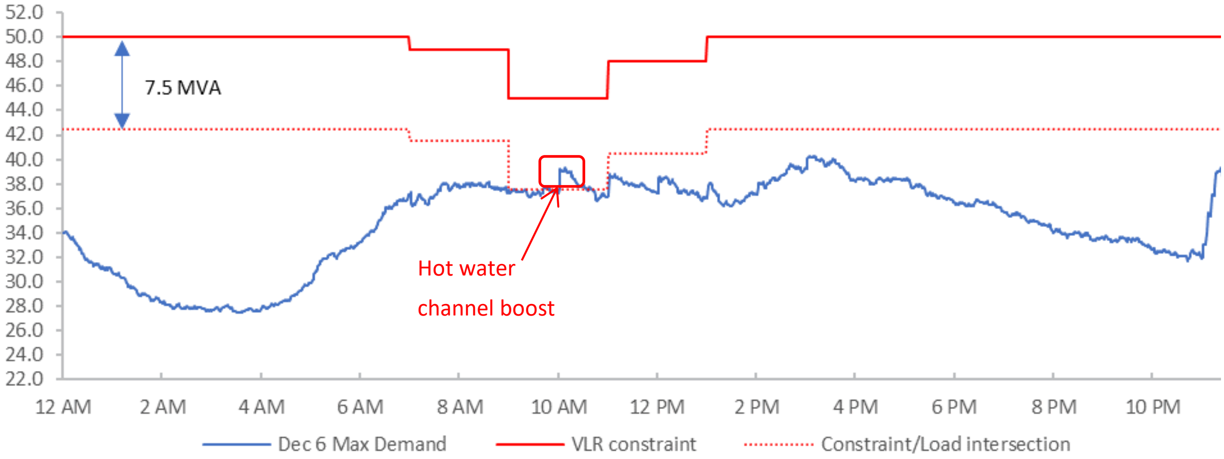


Figure 60 - December maximum demand curve vs. VLR constraint

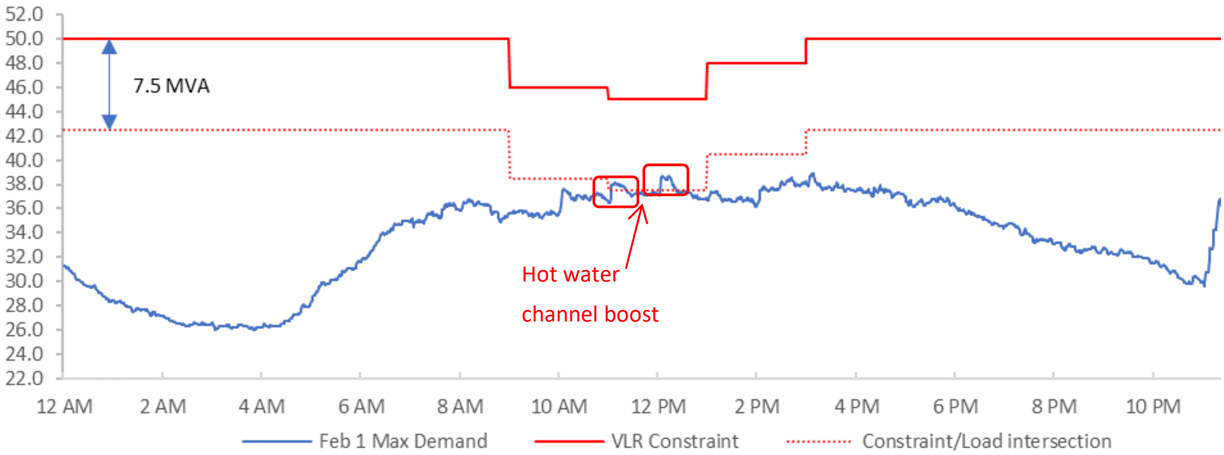


Figure 61 - February maximum demand curve vs. VLR constraint

6.2.1.4 Oamaru GXP load duration

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

① The top 10 MVA of load was present for 1233 hours per year (14%)

② The top 3 MVA of load was present for 67 hours per year (0.8%)

③ The top 1 MVA of load was present for 1 hour per year (0.01%)

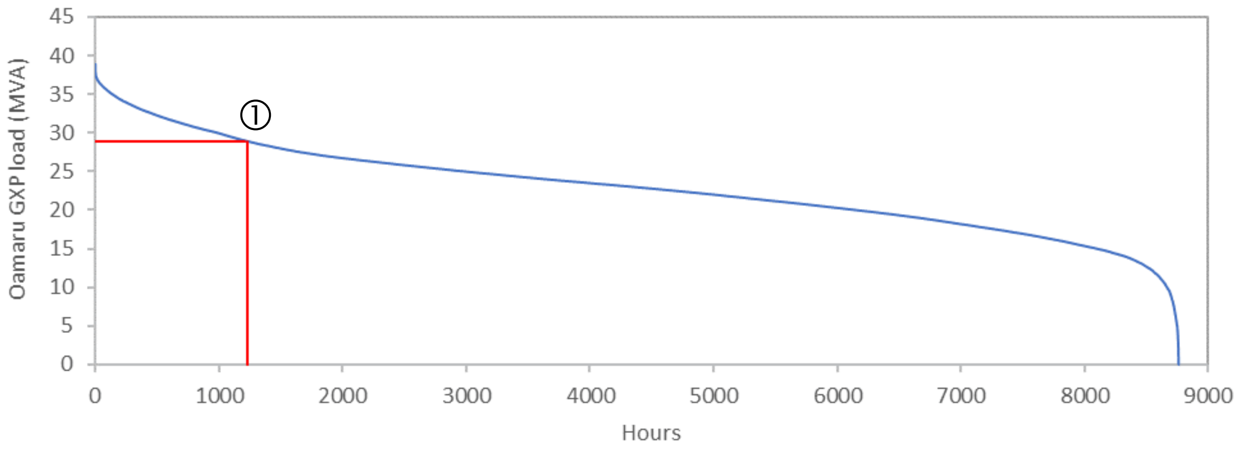


Figure 62 - Oamaru GXP FY20 Full year load duration curve

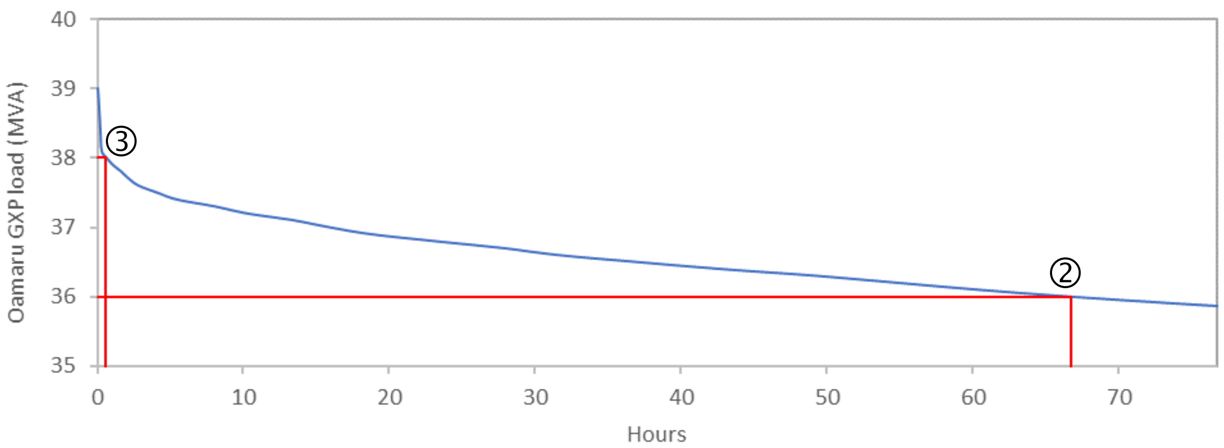


Figure 63 - Oamaru GXP FY20 load duration curve - Top 3 MVA

6.2.1.5 Oamaru GXP demand forecast

Table 33 - Known likely loads

Substation	Load Type	Scenario	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32
Pukeuri	Industrial customer	A	0.44	0.07			0.30						
Pukeuri	Gravity to Spray Irrigation	A	0.20	0.20	0.20		0.04		0.33	0.33	0.33		
Pukeuri	remove compound growth	A											
Papakaio	Gravity to Spray Irrigation	A	0.23	0.20	0.20	0.25	0.25	0.25	0.10	0.10	0.10		
Papakaio	remove compound growth	A											
Awamoko	Gravity to Spray Irrigation	A				0.25	0.25	0.25	0.10	0.10	0.10		
Awamoko	remove compound growth	A											
Chelmer	New subdivision	A	0.05	0.05									
Chelmer	EV Chargers	A					0.05		0.05		0.10		
Redcastle	Meat Processor	A	0.50										
Five Forks	On farm Irrigation	A		0.15	0.15	0.10							
Maheno	On farm Irrigation	A		0.15	0.15	0.10							
Hampden	Poultry farm	A	0.25										
Pukeuri	Decarbonisation	H		0.75			5.00						
Redcastle	Decarbonisation	H		3.00									
	Total New Load (MVA)		**1.7**	**4.6**	**0.7**	**0.7**	**5.9**	**0.5**	**0.4**	**0.3**	**0.4**	**-0.2**	**-0.2**

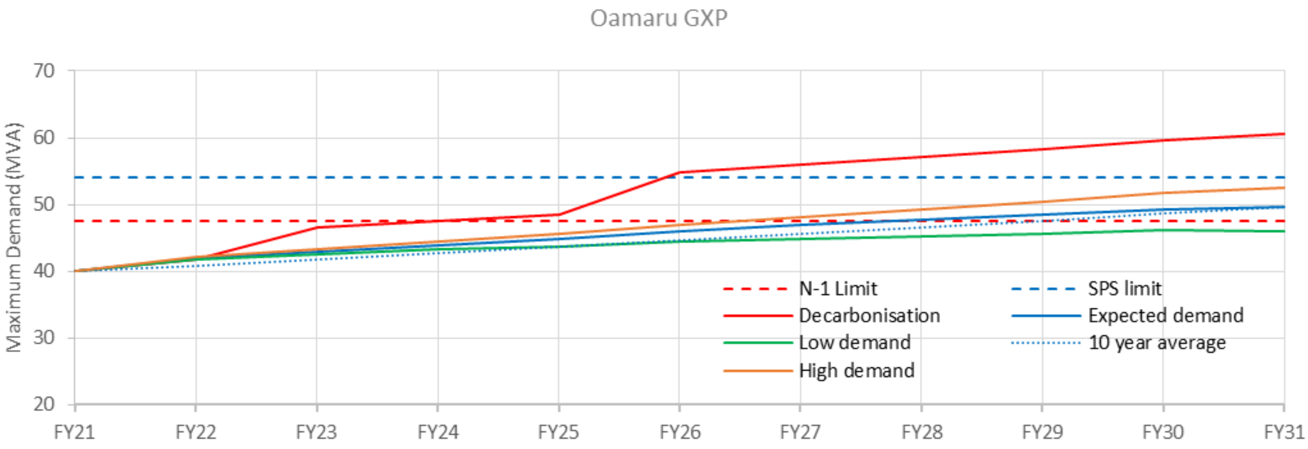


Figure 64 - Oamaru GXP demand forecast

Table 34 – Oamaru GXP demand forecast

Grid Exit Point (GXP)	Load Growth Scenario	N-1 Security Limit (MVA)	N Security limit (MVA) (SPS)	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Average Annual Growth Rate
Oamaru GXP	Low demand	47.5	54	40.0	41.8	42.6	43.2	43.7	44.5	44.8	45.3	45.6	46.1	46.1	1.4%
OAM GXP	Expected demand	47.5	54	40.0	42.0	43.0	43.9	44.8	46.0	46.9	47.7	48.4	49.3	49.6	2.2%
OAM GXP	High demand	47.5	54	40.0	42.2	43.3	44.4	45.5	47.0	48.1	49.2	50.3	51.7	52.6	2.8%
OAM GXP	Decarbonisation	47.5	54	40.0	41.8	46.5	47.4	48.5	54.9	56.0	57.1	58.2	59.6	60.5	4.2%
OAM GXP	10 year average	47.5	54	40.0	40.9	41.8	42.7	43.6	44.6	45.6	46.6	47.6	48.7	49.7	2.2%

For the low demand scenario, Oamaru GXP will have sufficient capacity for the remainder of the planning period.

For the expected demand scenario, demand will exceed the GXP firm rating in FY28. Implementing a Special Protection System in FY22 will allow demand to be supplied for the remainder of the planning period with 2 MVA of load at N level security for an estimated 20 hours each year.

For the high demand scenario, the demand will exceed the GXP firm rating in FY27. Implementing a Special Protection System in FY22 will allow demand to be supplied for the remainder of the planning period with 5.5 MVA of load at N level security for an estimated 100 hours each year.

The decarbonisation scenario is dominated by large customers potentially converting from coal to electricity for their process heat requirements. Implementing a Special Protection System in FY22 will allow demand to be supplied until FY26 with up to 2 MVA of load on N security for an expected 20 hours per year in FY25. This projection is based on 3.75 MVA of new load being required in the next two years and 5 MW of process heat being required in FY26 and is very sensitive to the size and timing of this load, both of which are presently uncertain. The trigger for major investment into the upstream transmission grid will be commitment from our customers of this new load. Our preferred option will be selected, costed, and designed in FY22/23 to allow for the best possible project build time. It is estimated that a transmission system upgrade could take up to five years to implement and demand response/load transfer may be required in the short term to manage Oamaru GXP load.

6.2.1.6 Transmission constraint options

A capacity constraint can be alleviated by either increasing supply capacity or reducing demand requirements for the period the constraint is present. This section will compare the following options:

Reduce demand with non-network options

- Optimise timing of water heater load.
- Special Protection Scheme (Some load at N Security)
- Demand Response Management – Incentivise customers to reduce demand at peak times.
- Grid-scale photovoltaic system to reduce demand at Oamaru GXP.
- Diesel generation to reduce demand at Oamaru GXP

Reduce demand with traditional network options

- Reactive support (capacitors) to reduce reactive demand at Oamaru GXP
- Upgrade subtransmission to a higher voltage and transfer load from Oamaru to Waitaki GXP.

Increase capacity with traditional transmission options (Grid investment)

- New Transpower GXP.
- Collaborative transmission or GXP investment.

Reduce demand with non-network options

Optimise timing of hot water heater load

1.5 MVA of additional capacity can be gained by optimising the hot water channel morning and afternoon boost timing out of the most constrained VLR period (refer Figure 60 and Figure 61). This can be achieved at short notice and at very low cost by changing the timing of the ripple control channel in the SCADA system. This could be further optimised by breaking the hot water control channels into smaller subgroups to allow more granular control.

Note: This additional capacity has already been included in the spare capacity calculation for Oamaru GXP as this can be achieved by manual intervention immediately.

Special Protection Scheme

Transpower have advised that a Special Protection Scheme (SPS) is feasible on the 110 kV circuits supplying Oamaru GXP. We have engaged Transpower to produce a scope and costs for detailed design and implementation of this scheme.

This would allow Oamaru GXP to be loaded to 54 MVA pre contingency. If an outage occurs on one of the two 110 kV circuits supplying Oamaru GXP, NWL would be required to reduce load to the lowest VLR rating (45 MVA) within 7.5s or the SPS will remove supply to Oamaru GXP. Due to the limited time available, it is possible that an entire zone substation would be required to be automatically shed, followed by an appropriate amount of irrigation load shed, and then the zone substation supply restored.

This means that all load over the VLR rating in force at the time (45 to 50 MVA) would be subject to N security. The first three MVA would be at risk for 67 hrs per year and if 10 MVA of load was at N security, this would be at risk for 1233 hrs per year.

Transpower advise that, due to the short duration of peak loads at Oamaru GXP, statistically this scheme would be expected to operate once every thirty years.

Transpower advise that the lead time to design and install this scheme is in the order of 18 months and is estimated to cost $430,000 which would be funded under a Transmission Works Agreement. Transpower have commenced design work and we expect that the SPS will be operational in FY22. An estimated $80,000 will be required to be spent within the NWL network.

Control details will be confirmed once Transpower complete detailed design, however, it is intended that this scheme would only be enabled during periods when load is predicted to exceed the lowest VLR rating and once all other options such as demand response have been fully utilised.

Demand Response Management

Overview

A Demand Response Management (DRM) scheme would allow an offer to be made to subscribers to reduce their load via a phone app or email. Subscribers can reduce their load by turning it off, running generation, or utilising battery storage.

Ideally a DRM scheme would only control demand that is able to be shifted in time. This suits demand with an element of thermal storage, such as hot water cylinders, refrigeration, heating and cooling, or load that is available to be scheduled outside of times of network constraint such as electric vehicles and potentially irrigation load.

In Q1 FY22 we will consult with our irrigation customers to quantify their appetite for irrigation demand response and feed this into a feasibility study. We aim to have our demand response roadmap developed by Q3 FY22. Once developed, demand response measures will be fed back into our security and capacity studies.

Pilot trial costs are expected to be in the order of $30,000.

Grid-scale photovoltaic system

The output from a grid-scale photovoltaic system will largely coincide with the VLR constraint on the 110 kV circuits supplying Oamaru. High level investigations indicate that 4.2 MW of grid scale photovoltaic system could reduce demand and thus increase spare capacity by between 2 and 3.5 MVA.

While it is noted that output under full cloud cover will be significantly reduced, in conjunction with a SPS, a grid-scale PV system could reduce the probability of a SPS being called to drop load.

Further investigation is required to refine interaction with a SPS (once detailed SPS design is complete), costs, potential energy revenue, and to quantify risks to energy return such as closure of the Tiwai Aluminium Smelter and the impact of the Transmission Pricing Methodology changes. It is proposed that further high level investigation is carried out in FY22.

Diesel generation

Installing large-scale diesel gensets to provide security at GXP level does not align with the sustainability requirements of our strategic plan and mission statement. Diesel gensets may be considered as an option to increase security at the zone substation level and below. The cost for 1 MW of diesel installed is estimated at $450,000.

Reduce demand with traditional network options

Reactive support

Initial calculations indicate that 9 MVAr of reactive support (capacitors) would be required to free up 1 MVA of capacity on the 110 kV transmission lines. The costs to supply and install 9 MVAr of 11 kV capacitor banks is estimated at $1 million.

At $1 million per MVA, the option of correcting for the last 1 MVA of capacity on this line is not as cost effective as other options considered. The option may become more cost effective if additional benefits are gained such as smaller distributed units to increase subtransmission line capacity. Further study is required in this area.

Some reactive support could also be supplied to the system from inverters on a grid scale photovoltaic system.

Upgrade subtransmission voltage

Overview

The existing 33 kV subtransmission system between Waitaki GXP and Ngapara Zone Substation could be converted to a higher voltage. This would allow feeders or zone substations to be offloaded from Oamaru GXP onto Waitaki GXP. This expenditure is forecast for the end of the planning period and may not be required if a GXP solution is selected.

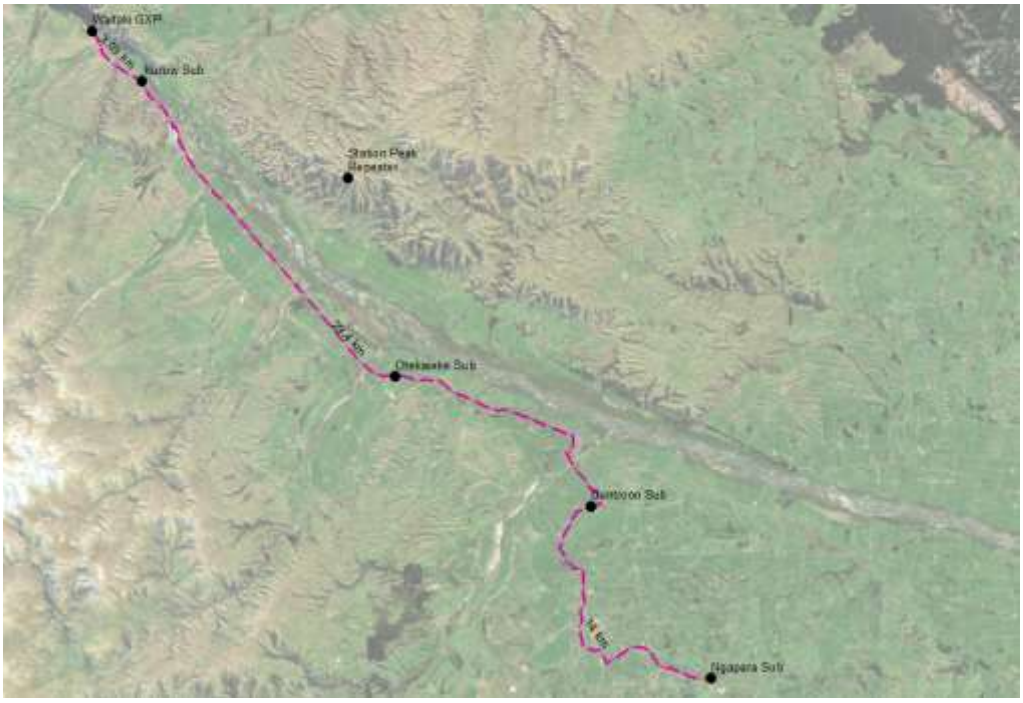


Figure 65 - Proposed subtransmission system subject to voltage upgrade

- The section of 33 kV line between Duntroon and Ngapara zone substations would be reinsulated to allow for operation at a higher voltage.
- A second subtransmission line would be installed between Lake Waitaki and Kurow to increase supply capacity and security to Kurow Zone substation.
- Step up transformers with On Load Tap Changers (OLTC) would be installed at Kurow and Duntroon substations.
- Eastern Rd and Duntroon zone substation transformers would be replaced with units designed for the new subtransmission voltage.

Table 35 – Upgrade subtransmission to higher voltage – Cost and timing

Project Name	Components	Timing	Budget cost (000's)
Duntroon/Ngapara voltage conversion	Reinsulate line for higher voltage Retighten line	FY27 FY28	\$600 \$43
Install 2nd line Lake Waitaki to Kurow	New subtransmission line Retighten line	FY28 FY29	\$680 \$43
Kurow -Ngapara voltage conversion	Stage 1 and 2 design Stage 1 conversion	FY28 FY29 FY30	\$75 \$2,150 \$1,100
Kurow -Ngapara voltage conversion	Stage 2 conversion	FY30 FY31	\$1,600 \$1,600
	Total estimated cost		**\$7,891**

This option initially frees up 6 MVA of capacity at Oamaru GXP with the option to free up another 3 MVA once Awamoko substation and subtransmission are constructed. The cost of this option is estimated at \$0.8m per MVA. This option also provides additional security benefits to NWL's zone substations.

Increase capacity with traditional network options

New Transpower GXP

Overview

A new 220 kV GXP would be constructed at Livingstone. Detailed design and any resource consents would be completed in advance to allow the shortest possible build time.

As load at Oamaru GXP approaches the constraint, we would progressively transfer feeders and then zone substations from Oamaru GXP onto the new Livingstone GXP.

We are mindful that transferring load between GXP's creates spare capacity in other parts of the transmission grid which may be used by others, creating a 'free rider' problem with other beneficiaries not paying their share.

Cost Estimate

NWL would pay for any new GXP investment through a Transmission Works Agreement. The capital cost of this scenario is estimated at \$21m. This option would provide an extra 60 MVA of capacity at an estimated cost of \$0.35m per MVA.

Timing estimate

Transpower advise that a new GXP solution would take between three and five years to design, consent and build. This timeframe may be reduced if design and consenting is completed in advance.

Collaborative Transmission or GXP investment

Over the past ten years, Network Waitaki has actively engaged with Transpower and Alpine Energy to jointly investigate solutions to our shared capacity issues on the transmission lines feeding our districts. We remain committed and open to a collaborative approach to solving these capacity issues together. We hold that the costs of any investment should be shared by those who benefit from the investment.

Proposed development plan

Option	Capacity gained	Cost estimate (000's)	Timing
1. Optimise water heating channels - Part 1 – Investigate moving channel timings Part 2 – Reprogram ripple receivers	1.5 MVA	\$0 \$50	FY22 FY23
2. Demand Response Management trial	TBC	\$30	FY22
3. Grid-scale photovoltaic system Further investigation into feasibility.	TBC	\$0	FY22
4. Special Protection Scheme Commission detailed design and implement SPS scheme in FY22.	9 MVA (N security)	\$80	FY22
5. Select and design long-term solution. Engage Transpower to review and reissue the SSR for GXP Perform study to select best transmission solution Produce roadmap for full design, land purchases, and easements to decrease build time.		\$5 \$50 TBC	FY21 FY22 FY22
6. Commence long-term solution Once the appropriate trigger level is reached long-term solutions should be re-evaluated against options and a business case submitted for project commencement.	60 MVA	\$20,000-\$30,000 Paid by means of TWA	Dependant on load growth (3-5 year build time)

6.2.2 Subtransmission and substations

6.2.2.1 Oamaru GXP zone substation overview

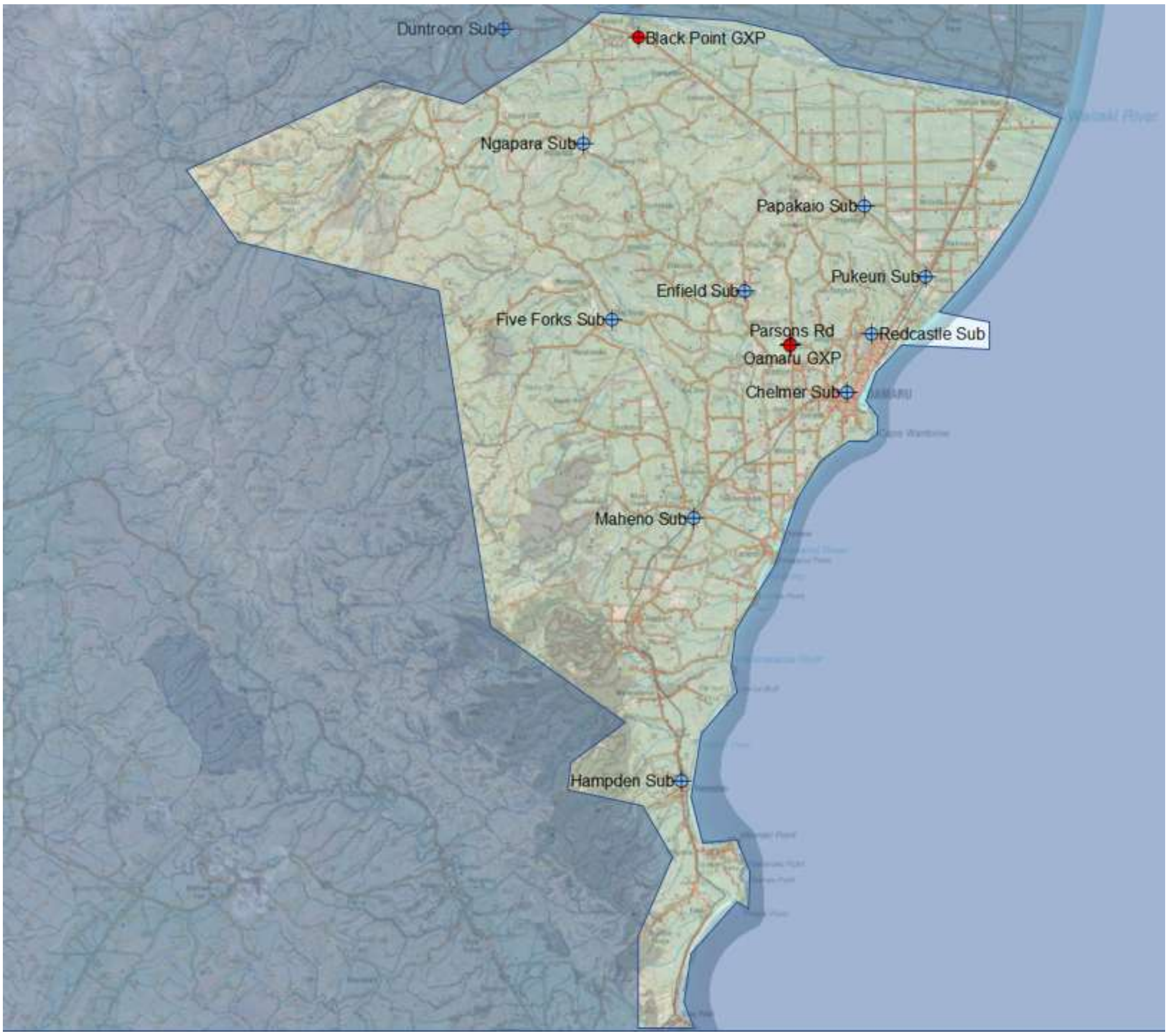


Figure 66 - Oamaru GXP zone substations

6.2.2.2 Ngapara Zone Substation

Security

Table 36 – 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 load supply at 33 kV can only be provided from Oamaru GXP.

Load details

Table 37 - Load 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 load. No capacity related upgrades are proposed at Ngapara in the planning period.

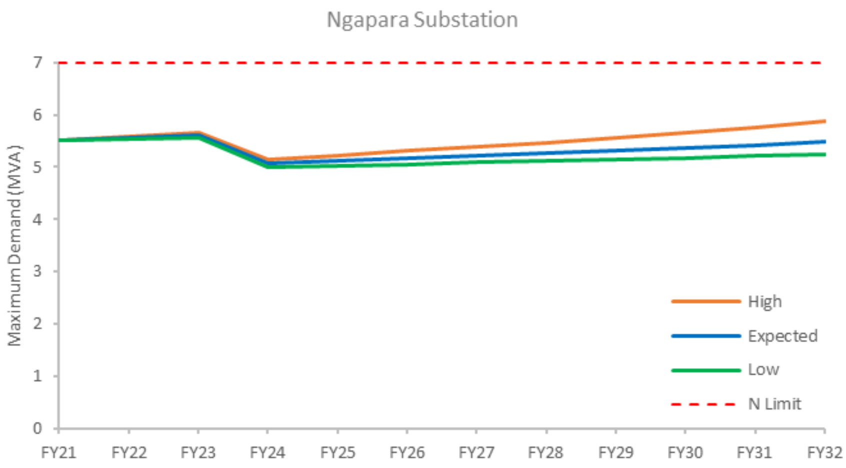


Figure 67 - Ngapara Zone Substation - load forecast

Security Analysis

During summer peak demand, B4 security may not be able to be achieved for outages of N Security components due to load 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 load 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 load 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.

6.2.2.3 Papakaio Zone Substation

Security rating

Table 38 - 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

Load details

Table 39 - Substation load 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 load. If nothing were done to address this constraint maximum demand is forecast to exceed the zone substation rating as early as FY25 for the high load growth scenario. (Note: the graph below includes the effect of transferring load onto a new Awamoko Zone Substation in FY24)

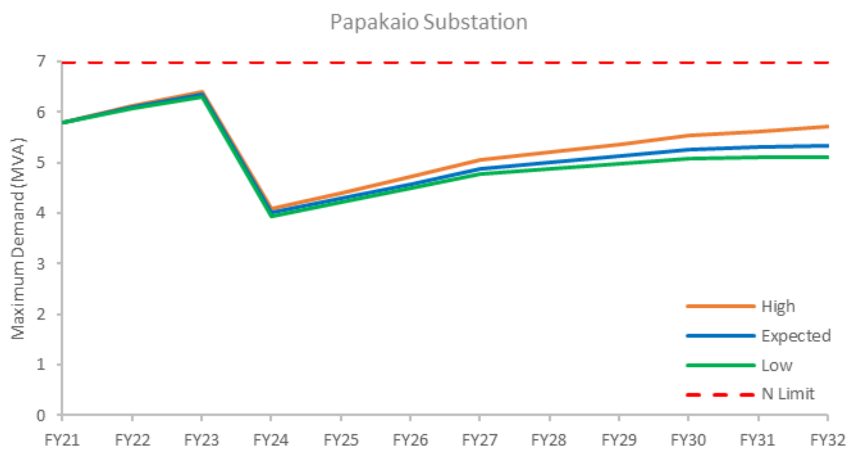


Figure 68 - Papakaio Zone Substation demand forecast

Security Analysis

During summer peak demand, B4 security may not be able to be achieved for outages of N Security components due to load 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 load 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 load 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.

Development plan

A new Awamoko Zone Substation is proposed to be commissioned in FY24 to reduce loading 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 will increase security to Awamoko and Papakaio Zone Substations.

Recent buoyant milk price forecasts and historically low interest rates could influence farmers to bring irrigation conversion projects forward. If this is signalled, we may need to bring this project forward into the FY23 period. We are currently working with irrigation companies to refine forecasts and will procure land and complete design in FY22.

Table 40 - 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	FY22 FY23 FY24	$210 $750 $1,100
Papakaio/Awamoko subtransmission	Design and procure easements New subtransmission line Stage 1 New subtransmission line Stage 2 Retighten line	FY22 FY23 FY24 FY25	$50 $1,300 $1,300 $45
Duntroon/Awamoko subtransmission	Design and procure easements New subtransmission line Stage 1 New subtransmission line Stage 2 Retighten line	FY24 FY25 FY26 FY27	$50 $1,620 $1,620 $54

6.2.2.4 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 a 16 km of new subtransmission line from Duntroon to Awamoko.

Security

Table 41- 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

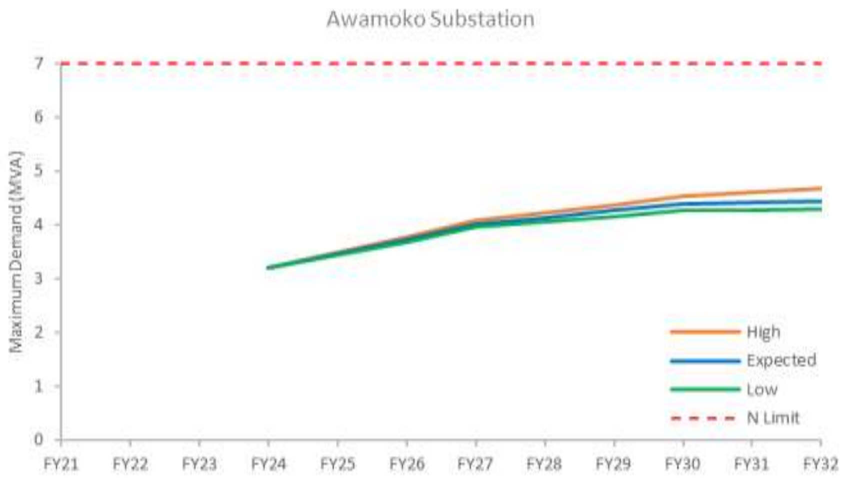


Figure 69 - Awamoko Zone Substation demand forecast

6.2.2.5 Pukeuri Zone Substation

Security

Table 42- 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

Load details

Table 43- Substation load 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 9.2 MVA in Summer with the difference being predominantly due to irrigation load. Pukeuri Zone Substation is predicted to exceed the N-1 security limit in FY29 under the low, expected and high scenarios. Under the decarbonisation scenario, which allows an allowance for conversion of a large amount of process heat from coal to electricity the N-1 security limit could be exceeded by FY26.

The two Papakaio transformers are scheduled for condition based replacement within the planning period and before the expected constraint is reached. The new units would be rated to cater for the future projected load. If the decarbonisation scenario eventates, this replacement will be brought forward. Subtransmission upgrades may also be required and this will be modelled and quantified in FY22.

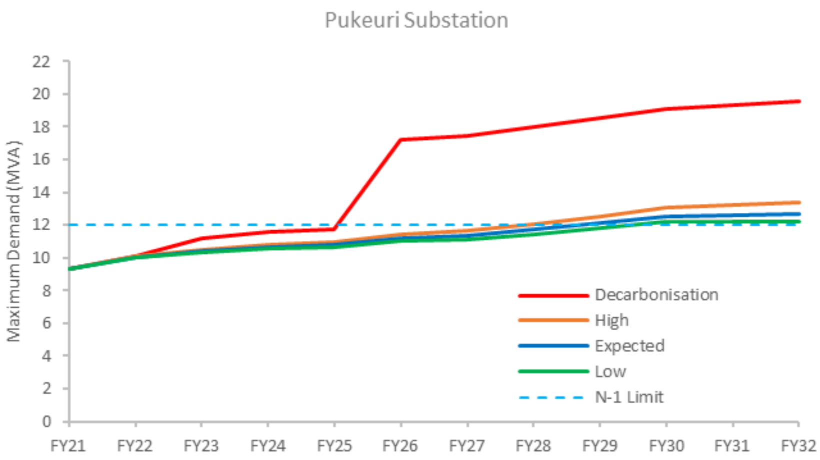


Figure 70 - Pukeuri Zone Substation demand forecast

6.2.2.6 Enfield Zone Substation

Security

Table 44- 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 load, supply at 33 kV can only be provided from Oamaru GXP.

Load details

Table 45- Substation load 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 load. No capacity related upgrades are proposed during the planning period.

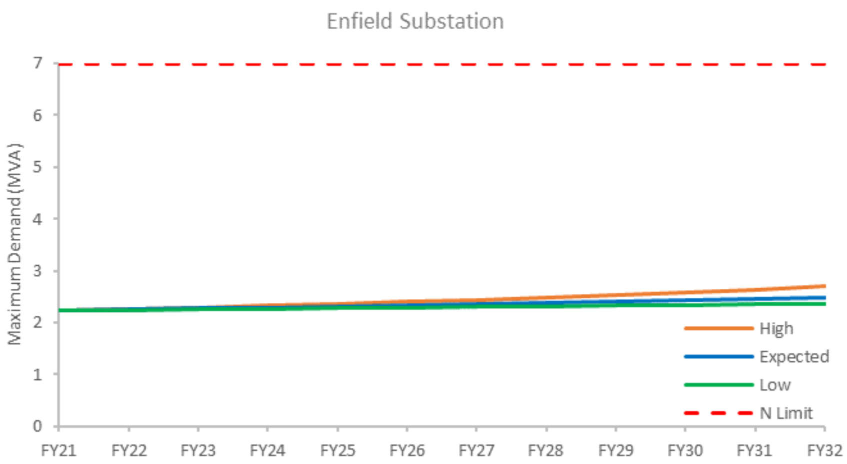


Figure 71 – Enfield Zone Substation demand forecast

6.2.2.7 Parsons Zone Substation

Security

Table 46- 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

Load details

Table 47- Substation load 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 load. No capacity upgrades are proposed during the planning period.

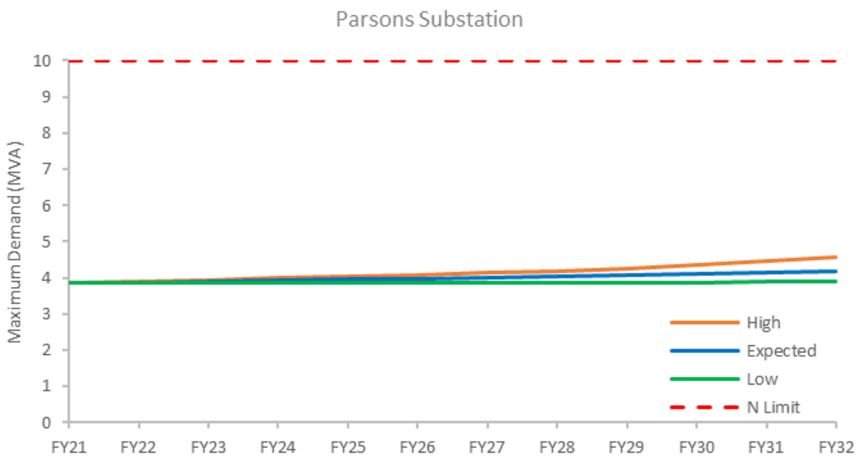


Figure 72 – Parsons Zone Substation demand forecast

6.2.2.8 Five Forks Zone Substation

Security

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 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

Load details

Table 49- Substation load 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 load. No capacity upgrades are proposed during the planning period.

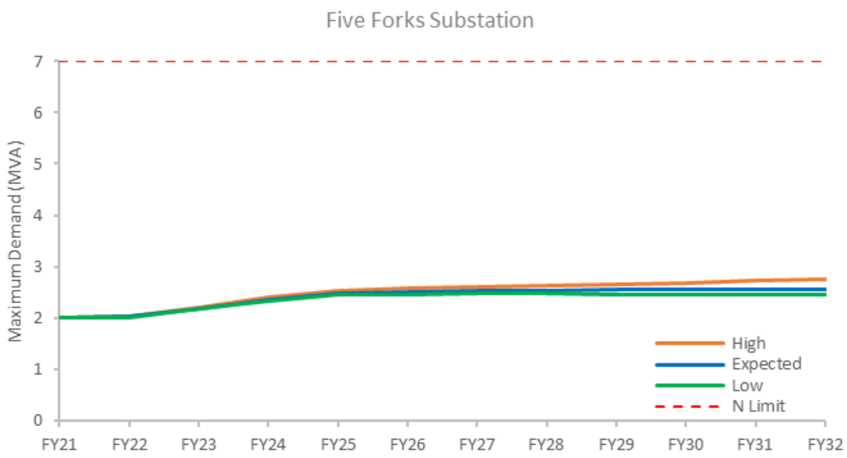


Figure 73- Five Forks Zone Substation demand forecast

6.2.2.9 Chelmer Zone Substation

Security

Table 50- 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

Load details

Table 51 – Substation load 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.

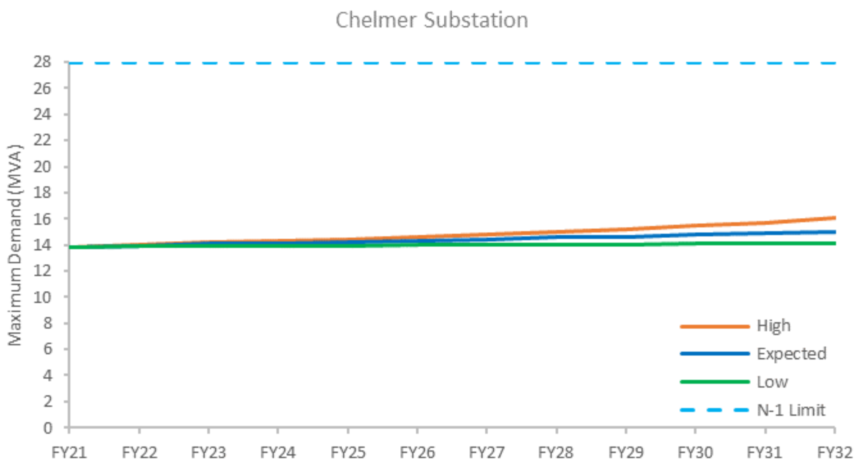


Figure 74 - Chelmer Zone Substation demand forecast

6.2.2.10 Redcastle Zone Substation

Security

Table 52- 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

Load details

Table 53- Substation load 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. Existing maximum demand varies from 9.3 MVA in Winter to 7 MVA in Summer. The decarbonisation scenario includes an allowance for conversion of a large amount of process heat from coal to electricity. No capacity related upgrades are planned during the planning period. In the decarbonisation scenario, subtransmission upgrades may be required and this will be modelled and quantified in FY22.

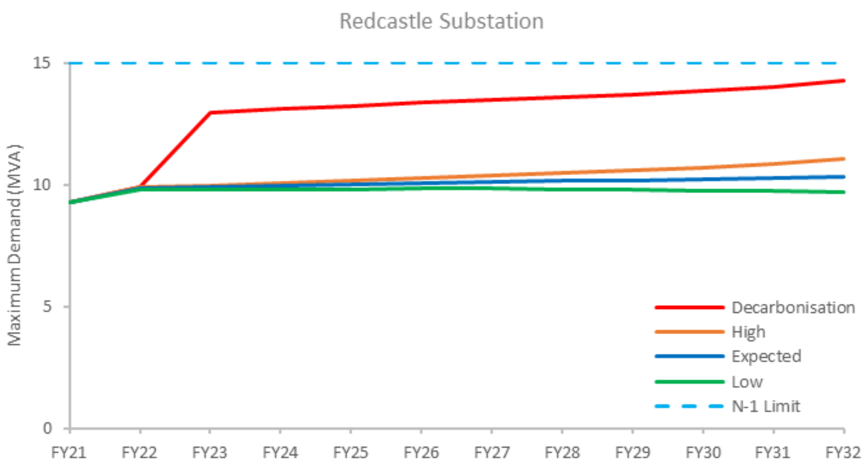


Figure 75 - Redcastle Zone Substation demand forecast

6.2.2.11 Maheno Zone Substation

Security

Table 54- 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

Load details

Table 55- Substation load 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 load. No capacity upgrades are proposed during the planning period.

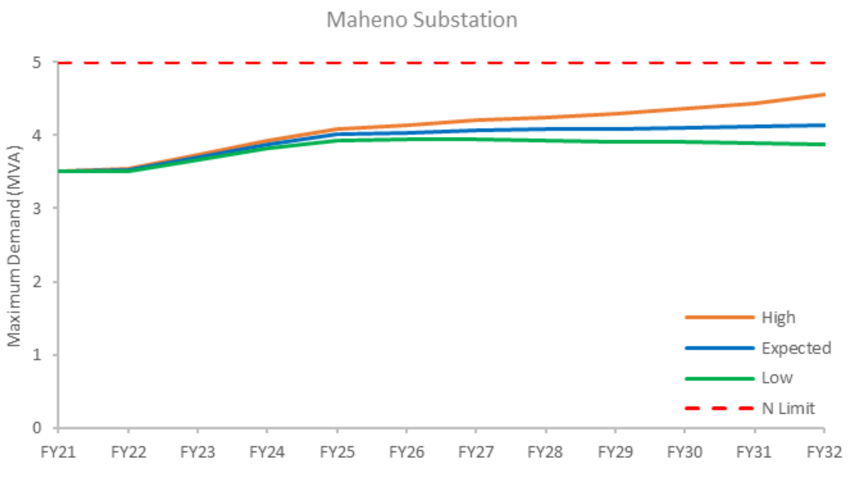


Figure 76 – Maheno Zone Substation demand forecast

6.2.2.12 Hampden Zone Substation

Security

Table 56- 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

Load details

Table 57- Substation load details

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

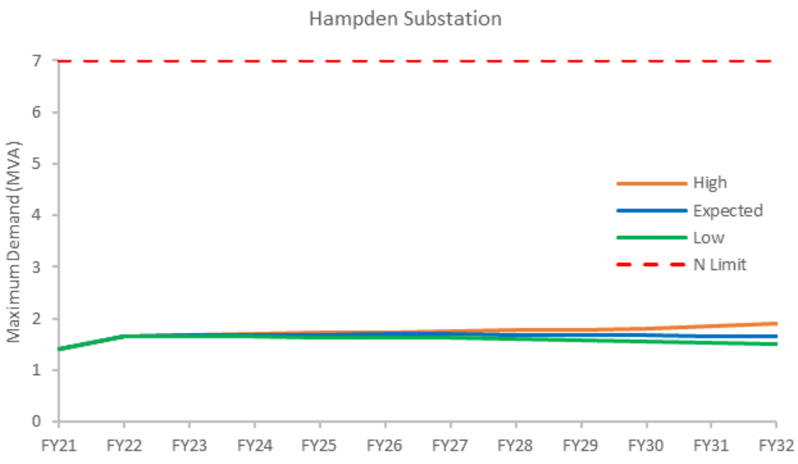


Figure 77 – Hampden Zone Substation demand forecast

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

At present, an outage on the Weston-Maheno 33 kV line takes both Maheno and Hampden substations out of service. The load at Hampden cannot all be supplied via the 11 kV network from Parsons or Five Forks zone substations due to excessive voltage drop.

A 17 km, 66 kV/11kV line (operated at 33 kV) will provide backup to Maheno substation and allow Hampden to be supplied at 11 kV from Maheno in the event of a subtransmission fault between Maheno and Hampden. This will also increase security to Maheno and Five Forks substations. The construction of this line commenced in FY21 and is proposed to be completed and commissioned in FY22.

Table 58 - Project cost estimate - Five Forks Maheno subtransmission upgrade

Project Name	Components	Year (s)	Budget cost (000)
66/11 kV line Five Forks to Maheno	New 66 kV subtransmission line Stage 2	FY22	$1,800
	Retighten line	FY23	$54

6.2.2.13 HV and LV distribution

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 load transfer between substations. Business cases will be completed for any proposed upgrades.

During the FY22 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)	2020/21	$350

6.2.2.14 Network Transformation

Our low voltage network development has historically been based around customer load growth and an expectation that domestic customer loads would not change significantly after design.

Typically, the only performance data collected for our low voltage networks has been from transformer Maximum Demand Indicators (MDIs) which are recorded manually on a yearly basis. MDIs record the maximum current experienced on a transformer during the year but can present false high readings if a transformer is called to provide back up to a neighbouring transformer and the MDIs are not reset. MDIs also do not provide any information about the time and duration of load. Relying on this data for asset upgrade can result in unnecessary capital expenditure.

Emerging technologies such as electric vehicles, distributed generation, and battery storage all have the potential to significantly change the load profile on our low voltage systems. The timing of this change is uncertain, but government regulation is evolving quickly to remove barriers and encourage uptake of these technologies. To determine the impact on our low voltage networks we need to start collecting data and monitoring the performance of our assets. This will allow us to develop a base-line of our existing load profiles, to predict when sections of the network will become congested, and to optimise the timing and quantity of any investment required.

There are also safety and customer service benefits from LV Monitoring devices such as:

- Broken neutral detection
- HV wire down detection
- Confirmation that an area is deenergised before commencing work
- Detection of unauthorised generation
- Detection of unintended parallel LV feeds into an area
- Early outage detection and location
- Early detection of supply quality issues

Our approach is to firstly gain visibility of our LV networks at distribution transformer level, starting with transformers with the highest number of connected urban customers and then to monitor selected rural transformers to best provide visibility of the rural network for operational and planning benefits. We have already trialled ten distribution transformer monitoring (DTM) units on our larger urban transformers and plan to complete this trial and integrate the data from these units into our business in FY22.

A parallel workstream is to work with Metering Equipment Providers (MEPs) in our area to gain access to customer smart meter data with an expectation that limited non-real time data may be available as soon as FY22.

NWL is a member of the Smart Technology Working Group and support the recommendations and roadmap laid out in the Network Transformation Roadmap (NTR) which was released in April 2019. We are actively collaborating with other EDBs to define use cases, share trial information, and standardise our approach to LV monitoring.

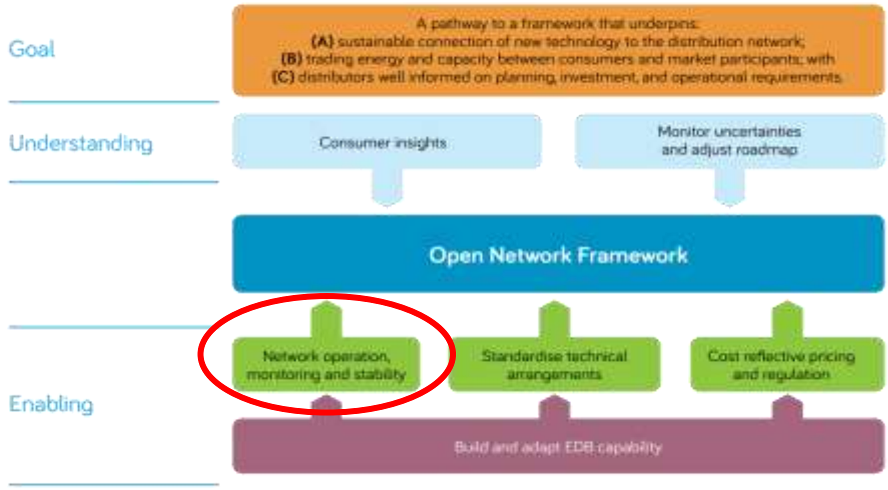


Figure 78 - NTR structure and relationship

Presented below is our interim roadmap for the network operation, monitoring and stability programme of the NTR. We will conduct a gap analysis of our network against the NTR in conjunction with our LV monitoring business case which is scheduled to be completed in Q3 FY22. In our business case we will identify and value customer and network benefits that could be gained from an LV monitoring programme. We will integrate content from the recently published *Business case for investment in low voltage network monitoring* which was commissioned by the Smart Technology Working Group.

We are working as a business to progress towards cost reflective pricing and will work with the industry and the STWG to standardise technical arrangements between EDBs and incorporate these into our business.

Table 59- Network operation, monitoring and stability roadmap

Network operation, monitoring and stability roadmap			
Actions	2 years	2-5 years	5-10 years
LV network monitoring and visibility	Real time low voltage monitoring installed at 3% of distribution transformers (extra 40 transformers), data systems in place to receive this data, and initial integration into the business	Real time low voltage monitoring installed at 10% of distribution transformers (extra 270 transformers), data systems in place to receive this data, and initial integration into the business Optimum final state number of transformers to be monitored agreed.	Full integration of real-time LV Monitoring and AMI data into operations and planning processes within the business.

Network operation, monitoring and stability roadmap

Actions	2 years	2-5 years	5-10 years
	Agreements and data systems in place to receive AMI data (real-time if available). Ability to access this data for planning and operational usage Review current state of SCADA system, define future state, compare options, and develop roadmap. Investigate ADMS, OMS, DERMS[10].	Access to real-time AMI data. Dependent on roadmap	Integration of real-time AMI data into business Dependent on roadmap
Network stability	Develop network model, integrated with GIS system, to distribution transformer LV bus level. Investigate DER control schemes with other interested parties.	Develop network model, integrated with GIS systems, to ICP level. Ability to model DER penetration scenarios and forecast congestion on network assets Trial DER control schemes in collaboration with other parties	Implement control schemes for DER.
Provision of network information	Investigate and trial provision of network information to operators with other EDBs (on request from operators)		

[10] ADMS – Advanced Distribution Management System
OMS – Outage Management System
DERMS – Distributed Energy Resource Management System

Our provisional budgetary costs are :

Table 60 - Provisional budgetary costs

Project Stage	Components	Year (s)	Capital Budget cost (000)	Annual OPEX cost (000)
	Negotiate access to MEP data	FY22	-	TBC
Investigate	Develop strategy, objectives, and use cases	Q4 FY21	-	-
	Compare systems and select vendor for trial	Q4 FY21	$20	-
	Integrate existing LV monitoring into the business	Q2/Q3 FY22	$50	$10
	LV monitoring business case to Board	Q3 FY22	-	-
	Vendor selection	Q3 FY22	-	-
Rollout	Phase 1 (30 transformers)	Q3/Q4 FY22	$150	$50
	Phase 2 (50 transformers)	FY23	$250	$135
	Phase 3 (60 transformers)	FY24	$300	$240
	Phase 4 (80 transformers)	FY25	$400	$375
	Phase 5 (80 transformers)	FY26	$400	$510

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

6.3 DEVELOPMENT PROGRAM – WAITAKI GXP REGION

6.3.1 Transmission and GXP

6.3.1.1 Waitaki GXP

Figure 79 - Waitaki GXP supply area

6.3.1.2 Waitaki GXP capacity

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

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

6.3.1.3 Waitaki GXP demand forecast

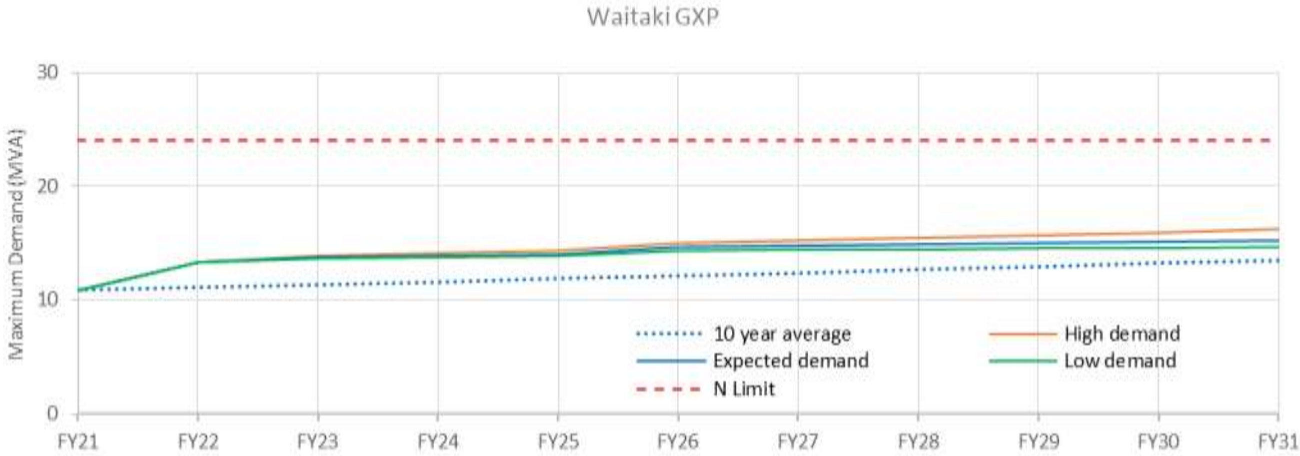


Figure 80 - Waitaki GXP demand forecast graph

Table 61 - Waitaki GXP demand forecast

Load Growth Scenario	N-1 Security Limit (MVA)	N Security limit (MVA)	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Average Annual Growth Rate
Low demand	5.5	24	10.9	13.3	13.7	13.8	13.8	14.4	14.4	14.5	14.5	14.6	14.6	3.0%
Expected demand	5.5	24	10.9	13.3	13.8	13.9	14.1	14.6	14.8	14.9	15.0	15.1	15.3	3.4%
High demand	5.5	24	10.9	13.4	13.9	14.1	14.3	15.0	15.2	15.5	15.7	16.0	16.3	4.1%
5 year average	5.5	24	10.9	11.1	11.2	11.4	11.6	11.7	11.9	12.1	12.3	12.5	12.6	1.5%
10 year average	5.5	24	10.9	11.1	11.4	11.6	11.9	12.1	12.4	12.7	13.0	13.2	13.5	2.2%

6.3.1.4 Waitaki GXP constraints

Waitaki GXP has sufficient capacity to meet our load within the planning period. A security constraint is forecast in FY29 when the high forecast demand is expected to reach 15 MVA although a loss of this transformer from FY22 would result in up to 4 MVA of load unable to be supported from Waitaki GXP until the transformer can be repaired or replaced. A business case will be produced in FY22 to propose the installation of a second transformer at Waitaki GXP. Investment at this GXP will not be committed until we have confirmed the optimum supply configuration for our complete network. Once the security constraint is relieved, no further constraints are forecast at this GXP during the planning period.

6.3.1.5 Waitaki GXP security upgrade

Installation of a second transformer to increase the security of the GXP to *24 MVA N-1 Security.*

Table 62 - Project budgetary cost

Project Name	Components	Year (s)	Cost (000)
Waitaki GXP upgrade	Detailed design and transformer deposit	FY22	$162
	Transformer purchase, install and commission	FY23	$1,910

6.3.2 HV and LV distribution

This has been included under a provisional budget under the Oamaru GXP. Refer to section **6.2.2.13** for details on HV and LV distribution.

6.3.3 Subtransmission and substations

6.3.3.1 Otematata Zone Substation

Security

Table 63- 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

Existing maximum demand is 0.5 MVA (98.5% percentile) for the majority of the year rising to 0.8 MVA for the two weeks after Christmas as many of the houses in this area are holiday homes. NWL is contracted to provide a 1 MVA, N Security, 11 kV backup supply to Benmore Power Station.

Due to the location and lack of 11kV interconnections, NWL has a 0.5 MW backup diesel genset installed at this site to provide security of supply to all load for most of the year and to restore power to 50% of ICPs within switching time during the Christmas period. Network Waitaki owns a truck mounted 0.5 MW genset which will be relocated to Otematata Zone Substation to supplement the existing genset in the event of an outage during the Christmas period.

Load details

Table 64- Substation load details

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

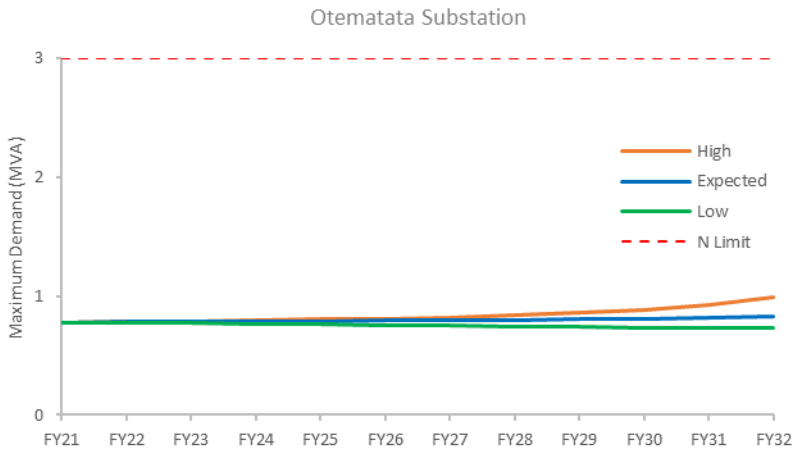


Figure 81 - Otematata substation demand forecast

6.3.3.2 Kurow Zone Substation

Security

Table 65- 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 load, supply at 33 kV can only be provided from Waitaki GXP.

Load details

Table 66- Substation load details

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

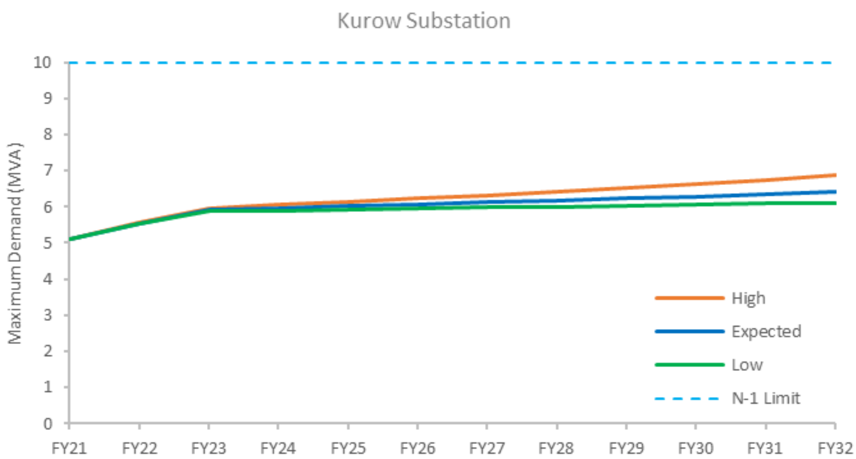


Figure 82 - Kurow substation demand forecast

Existing maximum demand varies from 1 MVA in Winter to 5.1 MVA in Summer which is predominantly due to irrigation load.

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

6.3.3.3 Eastern Rd Zone Substation

Security

Table 67- 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 load, supply at 33 kV can only be provided from Waitaki GXP

Load details

Table 68 - Substation load details

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

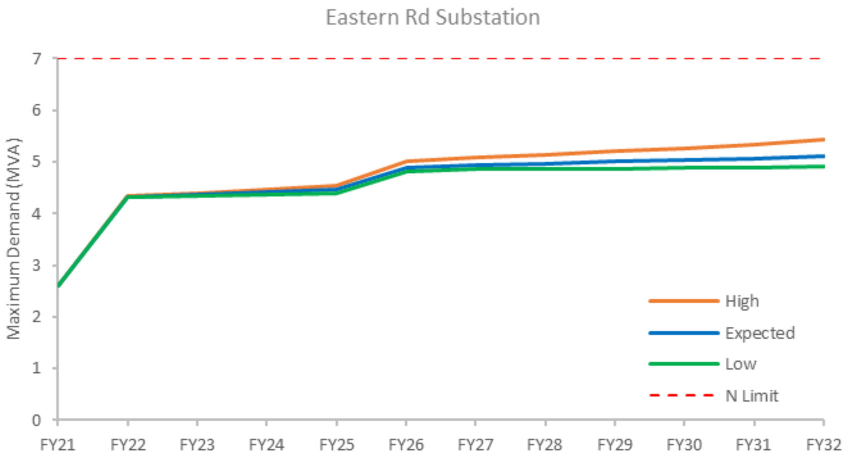


Figure 83 - Eastern Rd substation demand forecast

Existing maximum demand varies from 0.7 MVA in Winter to 2.6 MVA in Summer which is due to effects of irrigation load.

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

6.3.3.4 Duntroon Zone Substation

Security

Table 69- 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 load, supply at 33 kV can only be provided from Waitaki GXP.

Loading

Table 70- Substation load details

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

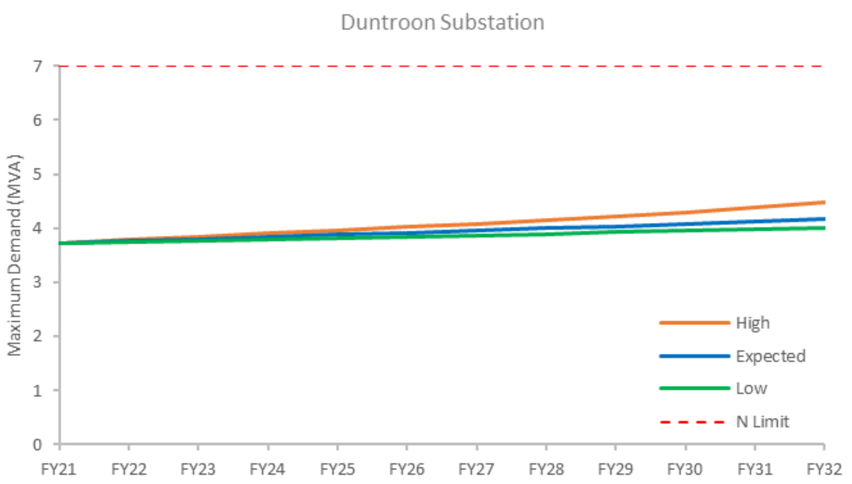


Figure 84 - Duntroon substation demand forecast

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

6.4 DEVELOPMENT PROGRAM – TWIZEL GXP REGION

6.4.1 Transmission and GXP

6.4.1.1 Twizel GXP capacity

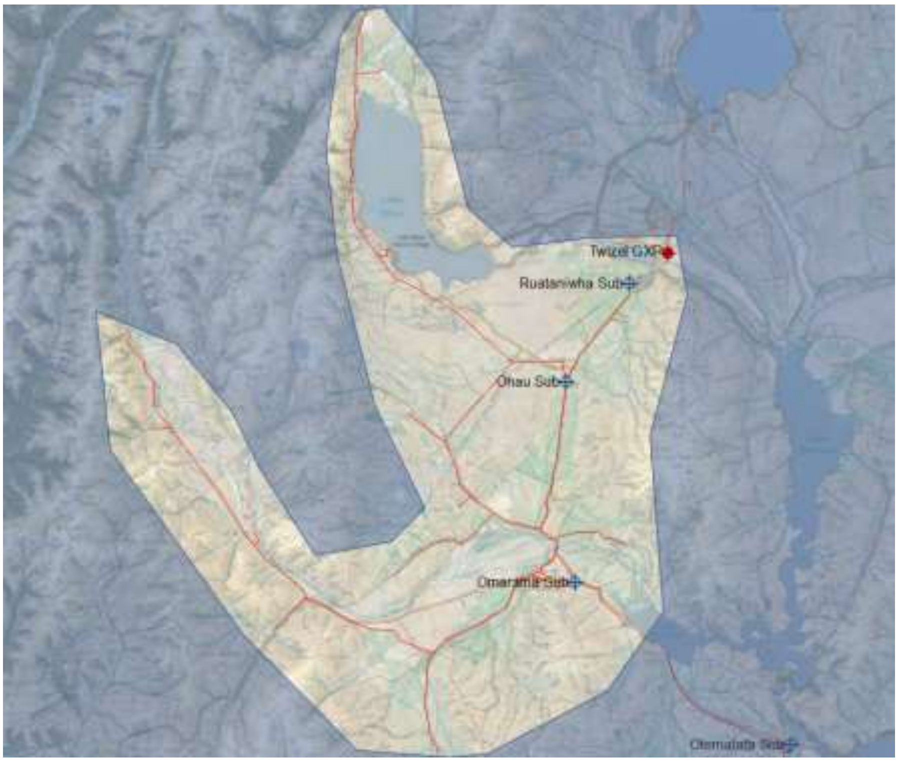


Figure 85 - Twizel GXP supply area

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. 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 change the security level to *27 MVA, N-1.*

6.4.1.2 Twizel GXP demand forecast

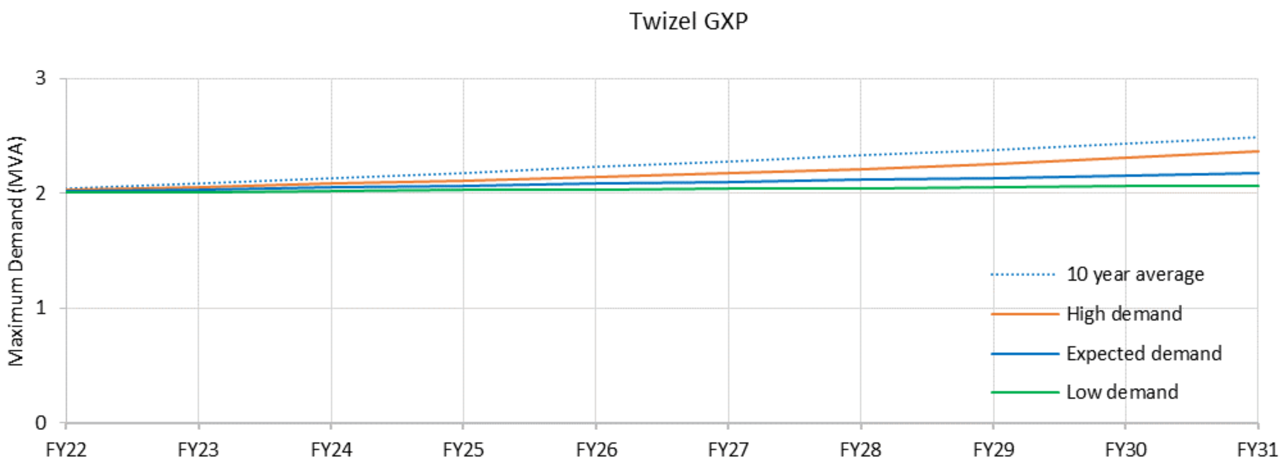


Figure 86 - Twizel GXP demand forecast

Table 71 - Twizel projected load growth

Grid Exit Point (GXP)	Load Growth Scenario	N-1 Security Limit (MVA)	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Average Annual Growth Rate
Twizel GXP	Low demand	27	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	-0.2%
Twizel GXP	Expected demand	27	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.1	0.5%
Twizel GXP	Prudent demand	27	2.0	2.0	2.1	2.1	2.1	2.2	2.2	2.2	2.3	2.3	1.5%
Twizel GXP	5 year average	27	2.0	2.1	2.1	2.1	2.2	2.2	2.2	2.3	2.3	2.3	1.5%
Twizel GXP	10 year average	27	2.0	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.5	2.2%

6.4.1.3 Twizel GXP constraints

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

There are no constraints forecast at the Twizel GXP during the planning period.

6.4.2 Subtransmission and substations

6.4.2.1 Ruataniwha Substation

Security

Table 72- 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.

Loading

Table 73- Substation load details

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

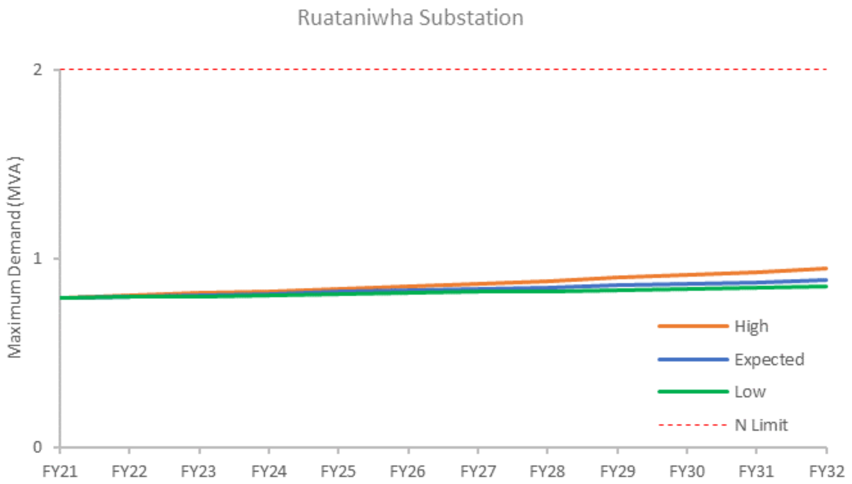


Figure 88 – Ruataniwha Substation demand forecast

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

6.4.2.2 Ohau Zone Substation

Security

Table 74- 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

Loading

Table 75- Substation load details

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

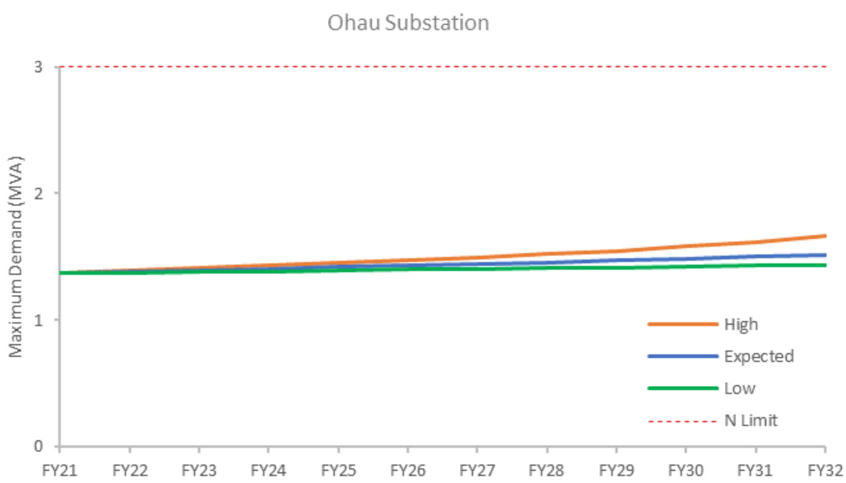


Figure 89 - Ohau Substation demand forecast

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.

6.4.2.3 Omarama Zone Substation

Security

Table 76- 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

Loading

Table 77- Substation load 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 load.

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

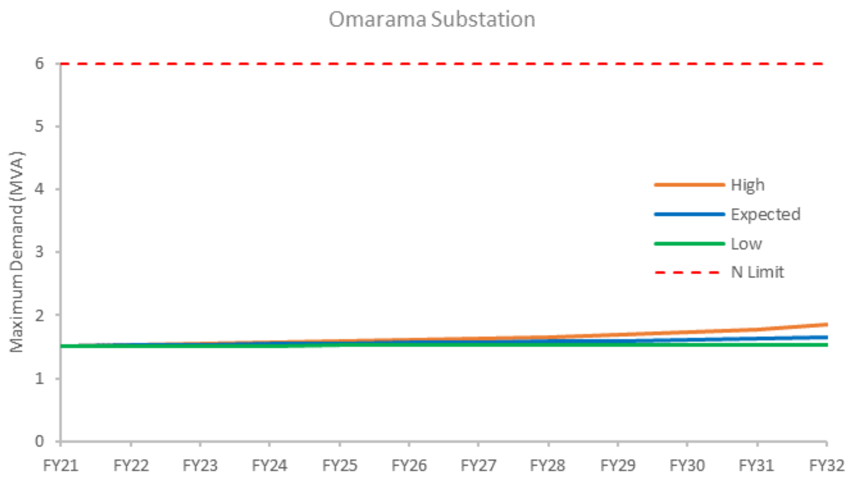


Figure 90 – Omarama Substation demand forecast

6.4.3 HV and LV distribution

This has been addressed under a provisional budget under the Oamaru GXP. Refer to section **6.2.2.13** for details on HV and LV distribution.

6.5 DEVELOPMENT PROGRAM – BLACK POINT GXP

6.5.1 Transmission and GXP

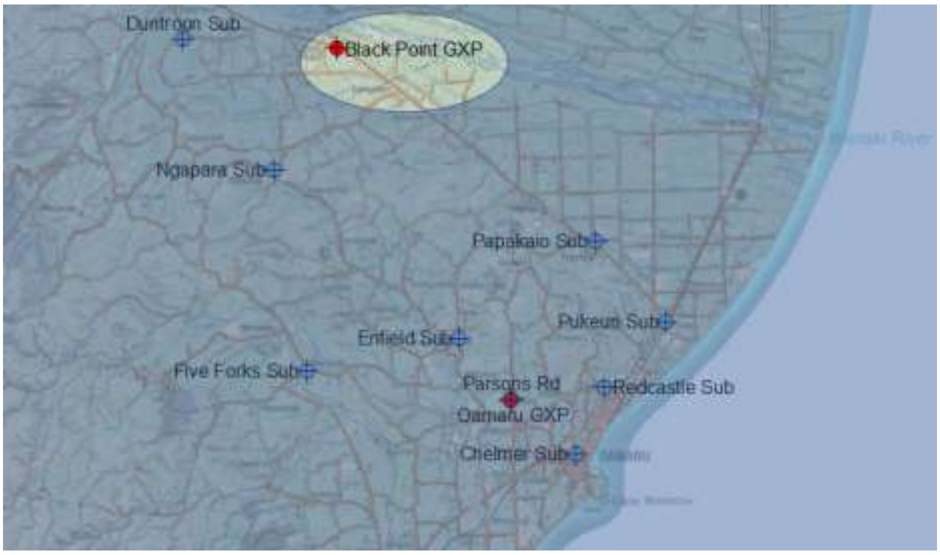


Figure 91 - Black Point GXP location

6.5.1.1 Black Point GXP capacity

This GXP is dedicated to the NOIC Irrigation Scheme, which was commissioned in 2006 and is rated as *25 MVA, N security*.

6.5.1.2 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 (load control) scheme between Waitaki GXP, Oamaru GXP, Black Point GXP, Bells Pond and Studholme to allow NOIC to increase their load 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 load below the constraint.

6.5.1.3 Black Point GXP demand forecast

NOIC advise that they are in the process of selling the remaining shares on the scheme and as a result expect that maximum demand at Black Point GXP will reach 20 MVA by FY24.

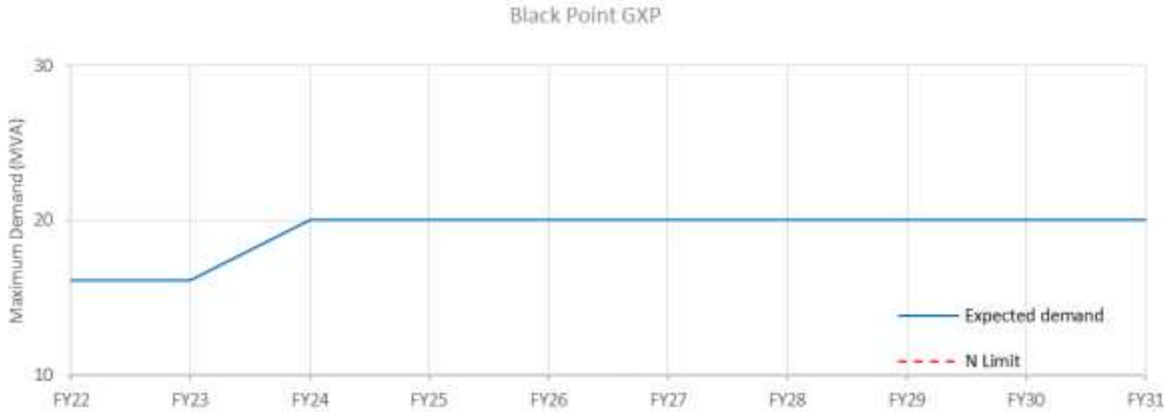
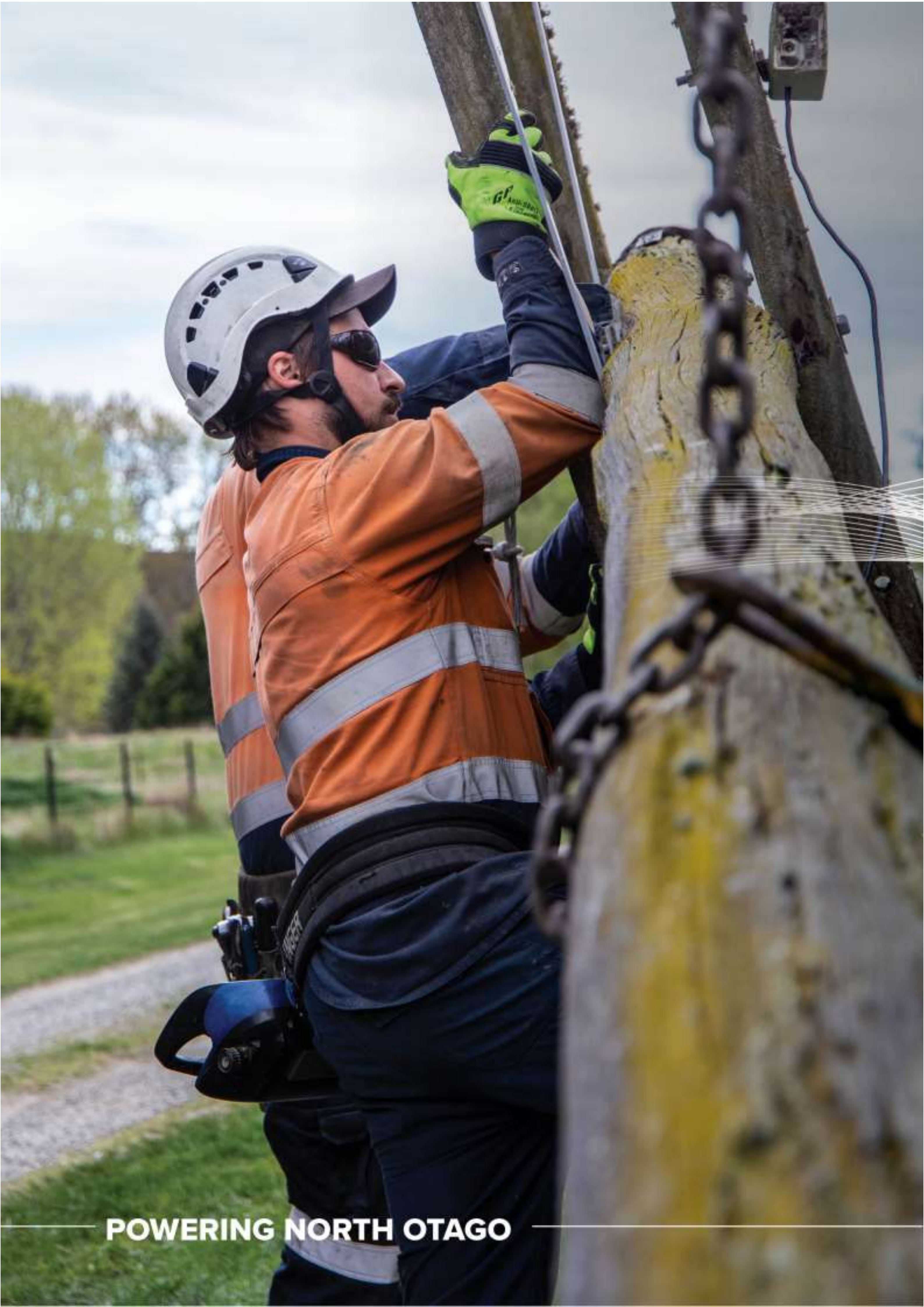


Figure 92 - Black Point GXP demand forecast

6.6 NETWORK DEVELOPMENT EXPENDITURE FORECAST

Table 78 - Summary of system growth projects

System Growth	FY22 ($000)	FY23 ($000)	FY24 ($000)	FY25 ($000)	FY26 ($000)	FY27 ($000)	FY28 ($000)	FY29 ($000)	FY30 ($000)	FY31 ($000)	Total ($000)
Distribution Development											
Unspecified HV and LV reinforcement	350	350	500	500	500	500	500	500	500	500	**4,700**
SPS at OAM GXP											
Special protection scheme - NWL protection changes	80										**80**
Subtransmission and Substation Development											
66/11 kV Line from Duntroon to Awamoko			50	1,620	1,620						**3,290**
66/11 kV Line from Five Forks to Maheno - Part 2	1,800										**1,800**
66/11 kV Line from Papakaio to Awamoko - design	50										**50**
66/11 kV Line from Papakaio to Awamoko - install part 1		1,300									**1,300**
66/11 kV Line from Papakaio to Awamoko - install part 2			1,300								**1,300**
66/11 kV Line from Waitaki GXP to Kurow							680				
Kurow to Ngapara 66 kV conversion Stage 1							75	2,150	1,100		**3,325**
Kurow to Ngapara 66 kV conversion Stage 2									1,600	1,600	**3,200**
New Awamoko substation - detailed design - transformer purchase		750									**750**
New Awamoko substation - installation and commission			1,100								
New Awamoko substation - land purchase and prelim design	210										**210**
Post construction - retightens		54		45		54	43	43			**239**
Reinsulate Ngapara -Duntroon to 66 kV						600					**600**
WTK GXP Development											**-**
Detailed design, transformer procurement 15% deposit	162										**162**
New bay and installation		1,100									**1,100**
Pay transformer balance		810									**810**
Grand Total	**2,652**	**4,364**	**2,950**	**2,165**	**2,120**	**1,154**	**1,298**	**2,693**	**3,200**	**2,100**	**24,696**


POWERING NORTH OTAGO

NON-NETWORK INVESTMENT PLAN

This section details our non-network investment program.

7. Non-network investment plan

7.1 TEN YEAR FORECAST

Component	FY22 ($000)	FY23 ($000)	FY24 ($000)	FY25 ($000)	FY26 ($000)	FY27 ($000)	FY28 ($000)	FY29 ($000)	FY30 ($000)	FY31 ($000)
Private Networks	1,012									
Buildings	2,971	3,689								
Vehicles	827	945	910	1,895	1,580	932	997	1,004	1,016	1,028
Plant	146	111	81	191	191	246	242	251	257	264
Information Technology	454	237	250	207	218	310	298	314	323	334
EV Charger	86									
Total	**5,496**	**4,982**	**1,241**	**2,293**	**1,989**	**1,488**	**1,537**	**1,569**	**1,596**	**1,626**

7.2 COMMENTARY

Private networks – In FY21 we purchased a private high voltage network in our supply area. In FY22 we have budgeted to provide an additional power transformer to increase security of supply.

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 FY23. 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 storage of poles and large plant and materials.

The vehicles component includes end of life replacement of fleet vehicles and additional vehicles required to cater for business growth.

The plant component includes end of life replacement of plant and additional plant and test equipment required to cater for business growth.

Information Technology includes routine replacement of server hardware, computers, and mobile devices.

In FY22 we are installing a fifth EV charger and developing a roadmap to guide the ongoing development of our EV charging strategy.

POWERING OUR FUTURE

07

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 considered to be 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 79 - Summary of expenditure forecasts

	Forecast Expenditure ($)										
Network Capital Expenditure	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**Total**
Consumer connection	1,301,000	1,301,000	1,301,000	1,301,000	1,301,000	1,301,000	1,301,000	1,301,000	1,301,000	1,301,000	**13,010,000**
System growth	2,652,000	4,364,000	2,950,000	2,165,000	2,120,000	1,154,000	1,298,000	2,693,000	3,200,000	2,100,000	**24,696,000**
Asset replacement and renewal	4,416,000	4,182,000	4,892,000	5,144,000	4,745,000	6,894,000	6,179,000	4,363,000	4,751,000	5,340,000	**50,906,000**
Asset relocations	300,000	-	-	-	-	-	-	-	-	-	**300,000**
Reliability, safety, and environment: Quality of supply	1,174,000	1,128,000	742,000	793,000	1,557,000	396,000	272,000	666,000	131,000	131,000	**6,990,000**
Reliability, safety, and environment: Legislative and regulatory	814,000	240,000	240,000	349,000	342,000	179,000	179,000	179,000	179,000	179,000	**2,880,000**
Other reliability, safety, and environment	-	-	-	-	-	-	-	-	-	-	**0**
Total capital expenditure	**10,657,000**	**11,215,000**	**10,125,000**	**9,752,000**	**10,065,000**	**9,924,000**	**9,229,000**	**9,202,000**	**9,562,000**	**9,051,000**	**98,782,000**
Operational Expenditure											
Service interruptions & emergencies	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	**4,500,000**
Vegetation management	650,000	650,000	618,000	587,000	557,000	529,000	503,000	478,000	454,000	431,000	**5,457,000**
Routine & corrective maintenance & inspection	1,225,000	1,048,000	1,073,000	1,038,000	978,000	1,008,000	1,008,000	1,008,000	1,008,000	1,008,000	**10,402,000**
Asset replacement & renewal	501,000	501,000	435,000	435,000	435,000	435,000	435,000	435,000	435,000	435,000	**4,482,000**
Total operational expenditure	**2,826,000**	**2,649,000**	**2,576,000**	**2,510,000**	**2,420,000**	**2,422,000**	**2,396,000**	**2,371,000**	**2,347,000**	**2,324,000**	**24,841,000**
Total Expenditure	**13,483,000**	**13,864,000**	**12,701,000**	**12,262,000**	**12,485,000**	**12,346,000**	**11,625,000**	**11,573,000**	**11,909,000**	**11,375,000**	**123,623,000**

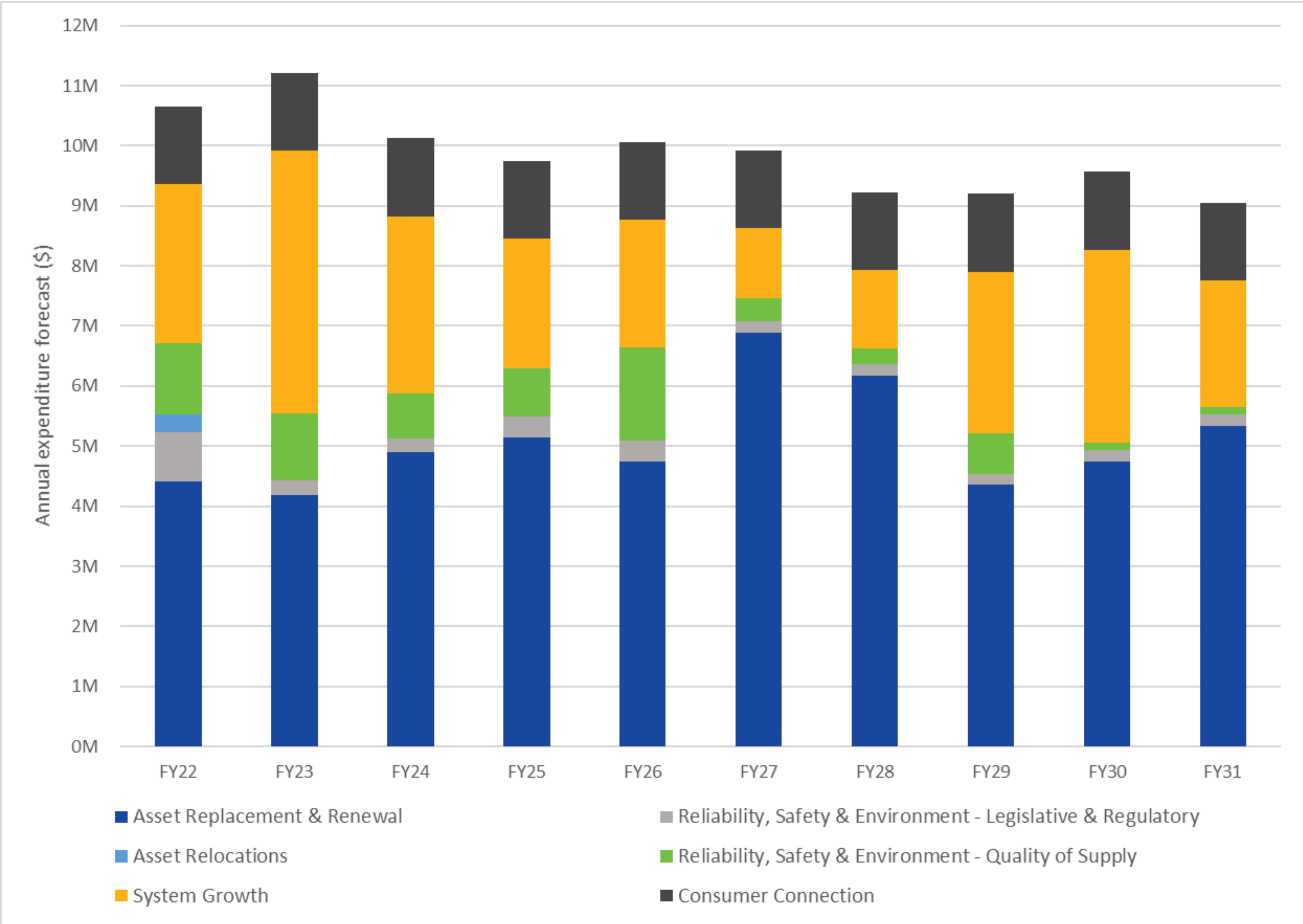


Figure 93 - Annual capital expenditure forecast by category

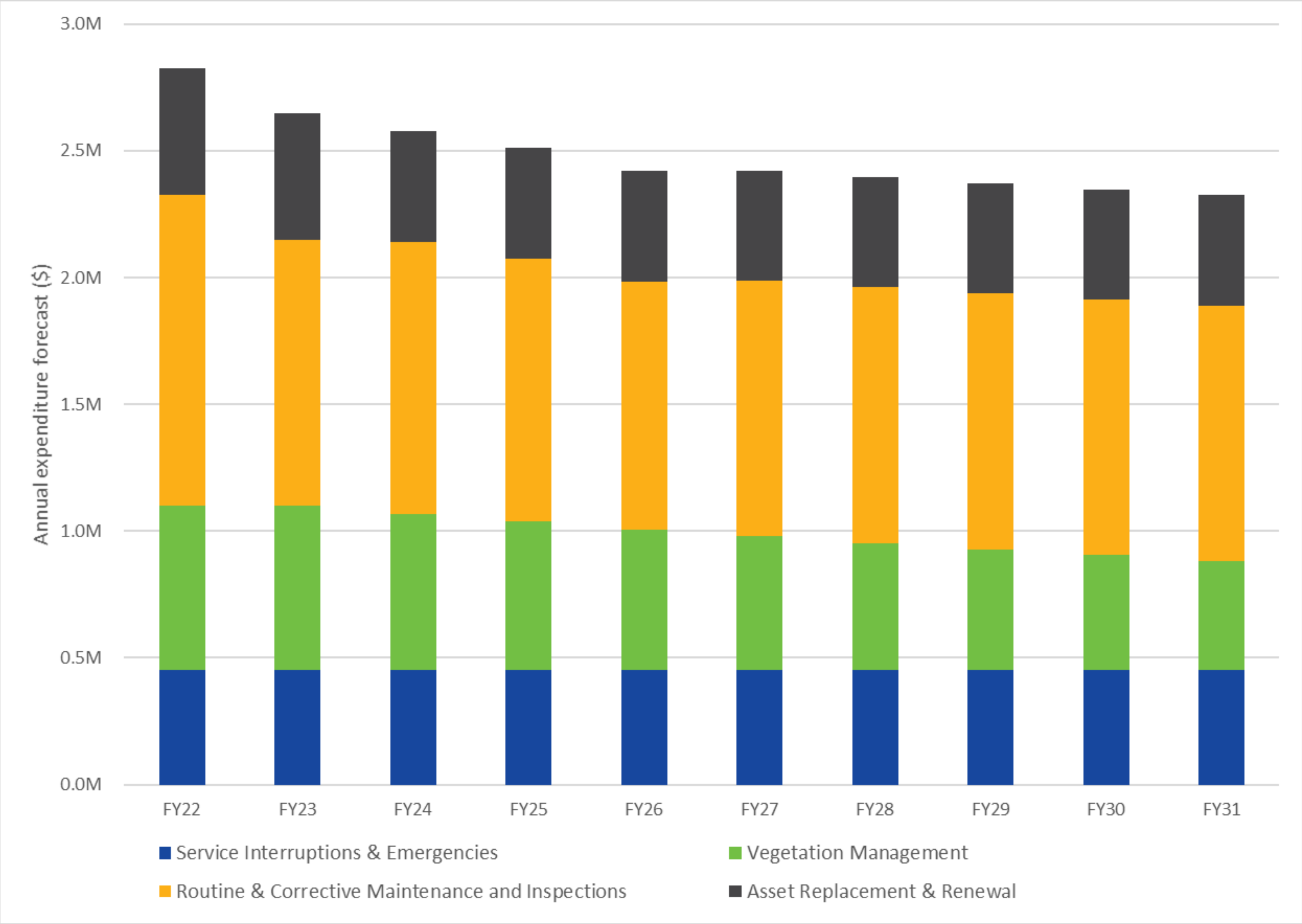


Figure 94 – Annual operational expenditure forecast by category

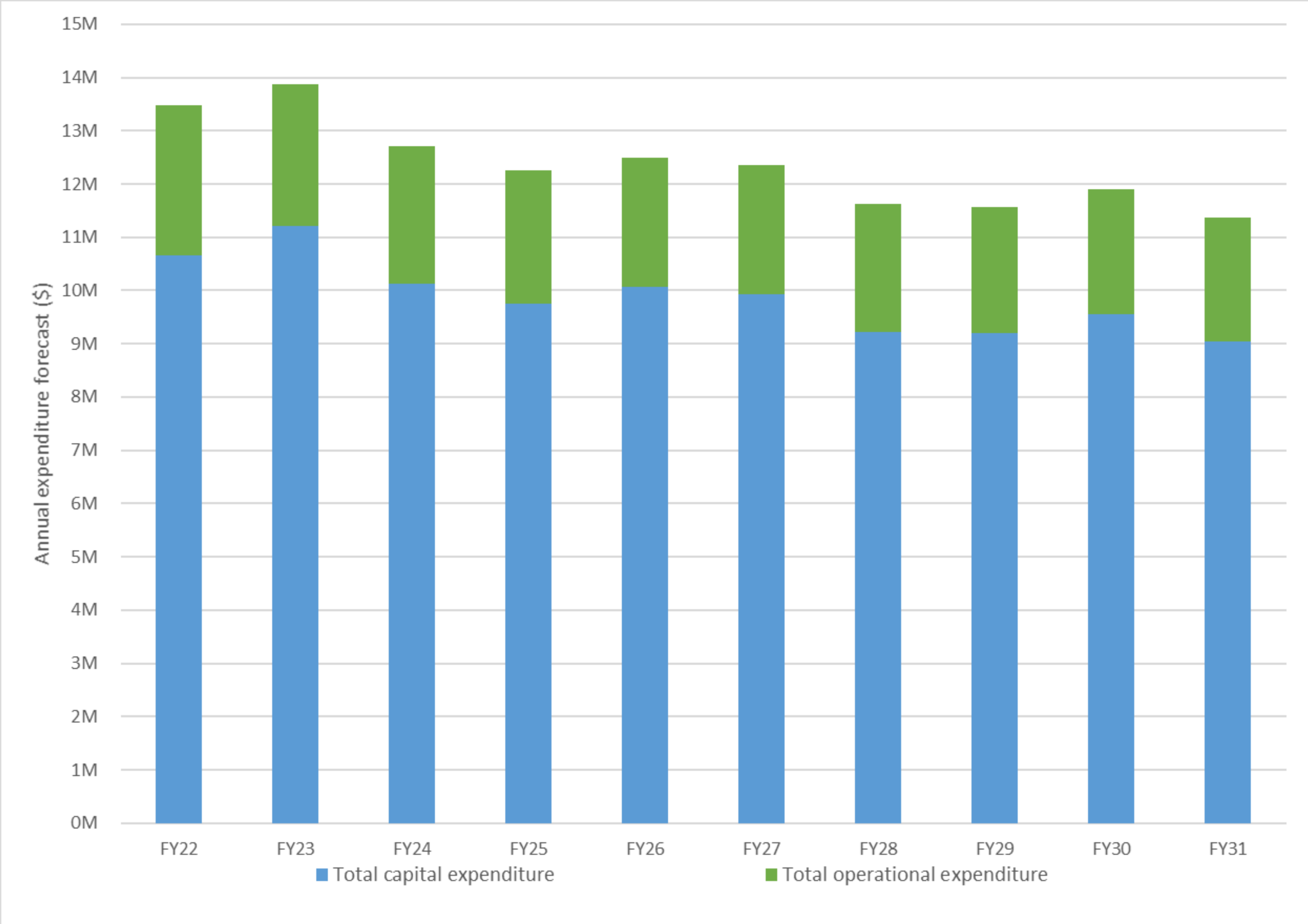


Figure 95- Summary of total network expenditure forecast across planning period

POWERING OUR FUTURE

APPENDIX

9.1 APPENDIX A - 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 2021
AMP Planning Period Start Date (first day)	1 April 2021

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

Table of Contents

Information disclosure asset management plan schedules

Company Name	**Network Waitaki Ltd**
AMP Planning Period	**1 April 2021 – 31 March 2031**

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

11a(i): Expenditure on Assets Forecast

	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 21**	**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**
	$000 (in nominal dollars)										
Consumer connection	1,495	1,321	1,343	1,370	1,397	1,425	1,454	1,483	1,512	1,543	1,573
System growth	2,205	2,692	4,505	3,106	2,325	2,322	1,289	1,479	3,131	3,794	2,540
Asset replacement and renewal	2,591	4,480	4,315	5,149	5,523	5,197	7,702	7,042	5,072	5,633	6,458
Asset relocations	357	305	-	-	-	-	-	-	-	-	-
Reliability, safety and environment:											
Quality of supply	389	1,193	1,165	782	852	1,706	442	310	773	155	158
Legislative and regulatory	280	826	249	254	376	376	200	204	208	212	216
Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
Total reliability, safety and environment	669	2,019	1,414	1,036	1,228	2,081	642	514	981	368	375
Expenditure on network assets	7,317	10,816	11,577	10,661	10,473	11,026	11,087	10,518	10,696	11,338	10,947
Expenditure on non-network assets	3,474	5,625	1,335	1,307	2,463	2,179	1,386	1,413	1,441	1,470	1,500
Expenditure on assets	10,791	16,441	12,911	11,967	12,936	13,204	12,473	11,931	12,138	12,808	12,446
plus Cost of financing	493	751	590	547	591	603	570	545	555	585	569
less Value of capital contributions	2,083	1,618	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357	1,357
plus Value of vested assets	-	-	-	-	-	-	-	-			
Capital expenditure forecast	9,201	15,574	12,145	11,157	12,170	12,451	11,686	11,120	11,335	12,037	11,658
Assets commissioned	7,101	17,154	10,515	13,207	10,570	14,051	11,786	11,120	11,355	12,662	13,258

WACC of 4.57% used, as per Comcom guidelines

	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 21**	**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**
	$000 (in constant prices)										
Consumer connection	1,495	1,301	1,301	1,301	1,301	1,301	1,301	1,301	1,301	1,301	1,301
System growth	2,205	2,652	4,364	2,950	2,165	2,120	1,154	1,298	2,693	3,200	2,100
Asset replacement and renewal	2,591	4,414	4,180	4,890	5,143	4,744	6,893	6,179	4,363	4,751	5,340
Asset relocations	357	300	-	-	-	-	-	-	-	-	-
Reliability, safety and environment:											
Quality of supply	389	1,175	1,129	743	793	1,557	396	272	665	131	131
Legislative and regulatory	280	814	241	241	350	343	179	179	179	179	179
Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
Total reliability, safety and environment	669	1,989	1,370	984	1,143	1,900	575	451	844	310	310
Expenditure on network assets	7,317	10,656	11,215	10,125	9,752	10,065	9,923	9,229	9,201	9,562	9,051
Expenditure on non-network assets	3,474	5,542	1,293	1,241	2,293	1,989	1,240	1,240	1,240	1,240	1,240
Expenditure on assets	10,791	16,198	12,508	11,366	12,045	12,054	11,163	10,469	10,441	10,802	10,291

Subcomponents of expenditure on assets (where known)

Energy efficiency and demand side management, reduction of energy losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Overhead to underground conversion	557	890	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Research and development	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

	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 21**	**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**
Difference between nominal and constant price forecasts	**$000**										
Consumer connection	-	20	42	69	96	124	153	182	211	242	272
System growth	-	40	141	156	160	202	135	181	438	594	440
Asset replacement and renewal	-	66	135	259	380	453	809	863	709	882	1,118
Asset relocations	-	4	-	-	-	-	-	-	-	-	-
Reliability, safety and environment:											
Quality of supply	-	18	36	39	59	149	46	38	108	24	27
Legislative and regulatory	-	12	8	13	26	33	21	25	29	33	37
Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
Total reliability, safety and environment	-	30	44	52	85	181	67	63	137	58	65
Expenditure on network assets	-	160	362	536	721	961	1,164	1,289	1,495	1,776	1,896
Expenditure on non-network assets	-	83	42	66	170	190	146	173	201	230	260
Expenditure on assets	-	243	403	601	891	1,150	1,310	1,462	1,697	2,006	2,155

11a(ii): Consumer Connection

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
*Consumer types defined by EDB**	**$000 (in constant prices)**					
New 11kV Network Extensions	700	325	325	325	325	325
New LV Service Connections	350	217	217	217	217	217
Installation of customer transformers	380	434	434	434	434	434
Residential Subdivisions	65	325	325	325	325	325
[EDB consumer type]						
**include additional rows if needed*						
Consumer connection expenditure	1,495	1,301	1,301	1,301	1,301	1,301
less Capital contributions funding consumer connection	2,083	1,618	1,357	1,357	1,357	1,357
Consumer connection less capital contributions	(588)	(317)	(56)	(56)	(56)	(56)

11a(iii): System Growth

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
Subtransmission	1,962	1,850	1,354	1,350	1,665	1,620
Zone substations	56	452	2,660	1,100	-	-
Distribution and LV lines	187	350	350	500	500	500
Distribution and LV cables						
Distribution substations and transformers						
Distribution switchgear						
Other network assets						
System growth expenditure	2,205	2,652	4,364	2,950	2,165	2,120
less Capital contributions funding system growth						
System growth less capital contributions	2,205	2,652	4,364	2,950	2,165	2,120

11a(iv): Asset Replacement and Renewal

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
$000 (in constant prices)						
Subtransmission	30	136	927	381	50	109
Zone substations	120	305	479	1,494	930	965
Distribution and LV lines	1,821	2,094	1,826	2,181	2,074	2,836
Distribution and LV cables	147	643	54	54	54	54
Distribution substations and transformers	180	218	218	218	218	218
Distribution switchgear	293	766	654	562	562	562
Other network assets		252	22		1,255	
Asset replacement and renewal expenditure	2,591	4,414	4,180	4,890	5,143	4,744
less Capital contributions funding asset replacement and renewal						
Asset replacement and renewal less capital contributions	2,591	4,414	4,180	4,890	5,143	4,744

11a(v): Asset Relocations

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
*Project or programme** / **$000 (in constant prices)**						
Relocate Chelmer St 33kV	-	294				
Distribution feeder undergrounding 220kV crossings	357	6				
**include additional rows if needed*						
All other project or programmes - asset relocations						
Asset relocations expenditure	357	300	-	-	-	-
less Capital contributions funding asset relocations						
Asset relocations less capital contributions	357	300	-	-	-	-

11a(vi): Quality of Supply

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
*Project or programme** / **$000 (in constant prices)**						
Arc flash protection upgrades	64	43	64	43	21	21
Install new ABS and spur fuses	18	35	35	35	35	35
Substation Fibre optic communications		285	545	290	230	330
LV Customer monitoring	20	200	250	300	400	400
SCADA Access to substation engineering data	32	50				
Install Reclosers/sectionalisers for automation	40	75	75	75	75	75
Spare ripple control plant	-	457				
Spare power transformer 10/15 MVA					32	696
Voice/SCADA Radio link upgrade			160			
Demand response trial		30				
Pukeuri substation dual TX upgrade	34					
Backup Control Room	140					
Weston to Chelmer St line differential protection	41					
**include additional rows if needed*						
All other projects or programmes - quality of supply						
Quality of supply expenditure	389	1,175	1,129	743	793	1,557
less Capital contributions funding quality of supply						
Quality of supply less capital contributions	389	1,175	1,129	743	793	1,557

11a(vii): Legislative and Regulatory

	Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
*Project or programme**	**$000 (in constant prices)**					
Seismic resilience improvement at zone substations	80	574				
Distribution Box Replacement	75	109	109	109	273	273
Distribution Box Replacement (Over Verendah)	65	43	44	44	44	44
Road crossing improvements	55	55	55	55		
Upgrade/renew distribution earths	5	33	33	33	33	26
**include additional rows if needed*						
All other projects or programmes - legislative and regulatory						
Legislative and regulatory expenditure	280	814	241	241	350	343
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions	280	814	241	241	350	343

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 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
*Project or programme**	**$000 (in constant prices)**					
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**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 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
Routine expenditure						
*Project or programme**	**$000 (in constant prices)**					
Vehicles	1,245	1,797	945	910	1,895	1,580
Technology	515	406	237	250	207	218
Contracting plant	254	255	111	81	191	191
**include additional rows if needed*						
All other projects or programmes - routine expenditure						
Routine expenditure	2,014	2,458	1,293	1,241	2,293	1,989
Atypical expenditure						
*Project or programme**						
Buildings and Depot	1,425	2,951				
Electric Vehicle charger		86	-			
Network test equipment	35	47				
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other projects or programmes - atypical expenditure						
Atypical expenditure	1,460	3,084	-	-	-	-
Expenditure on non-network assets	3,474	5,542	1,293	1,241	2,293	1,989

		Company Name	Network Waitaki Ltd
		AMP Planning Period	1 April 2021 – 31 March 2031

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

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

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8	for year ended	31 Mar 21	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
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	669	457	465	474	483	493	503	513	523	534	544
11	Vegetation management	489	660	671	651	630	610	591	573	556	538	521
12	Routine and corrective maintenance and inspection	816	1,243	1,082	1,130	1,115	1,071	1,126	1,149	1,172	1,195	1,219
13	Asset replacement and renewal	327	509	449	458	467	477	486	496	506	516	526
14	**Network Opex**	2,301	2,868	2,666	2,712	2,696	2,651	2,706	2,731	2,756	2,783	2,811
15	System operations and network support	2,783	3,409	3,399	3,434	3,588	3,760	3,835	3,911	3,990	4,069	4,151
16	Business support	2,555	3,122	3,327	3,455	3,307	3,477	3,546	3,617	3,690	3,764	3,839
17	**Non-network opex**	5,338	6,532	6,726	6,888	6,895	7,236	7,381	7,529	7,679	7,833	7,990
18	**Operational expenditure**	7,639	9,400	9,392	9,600	9,590	9,887	10,087	10,260	10,436	10,616	10,800

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 21	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
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	669	450	450	450	450	450	450	450	450	450	450
23	Vegetation management	489	650	650	618	587	557	529	503	478	454	431
24	Routine and corrective maintenance and inspection	816	1,225	1,048	1,073	1,038	978	1,008	1,008	1,008	1,008	1,008
25	Asset replacement and renewal	327	501	435	435	435	435	435	435	435	435	435
26	**Network Opex**	2,301	2,826	2,583	2,576	2,510	2,420	2,422	2,396	2,371	2,347	2,324
27	System operations and network support	2,783	3,359	3,293	3,261	3,341	3,432	3,432	3,432	3,432	3,432	3,432
28	Business support	2,555	3,076	3,223	3,281	3,079	3,174	3,174	3,174	3,174	3,174	3,174
29	**Non-network opex**	5,338	6,435	6,516	6,542	6,420	6,606	6,606	6,606	6,606	6,606	6,606
30	**Operational expenditure**	7,639	9,261	9,099	9,118	8,930	9,026	9,028	9,002	8,977	8,953	8,930
31	**Subcomponents of operational expenditure (where known)**											
32–33	Energy efficiency and demand side management, reduction of energy losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
34	Direct billing*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Research and Development	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
36	Insurance	149	262	267	273	278	284	289	295	301	307	313

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 21	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
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	7	15	24	33	43	53	63	73	84	94
43	Vegetation management	-	10	21	33	43	53	62	70	78	84	90
44	Routine and corrective maintenance and inspection	-	18	34	57	77	93	118	141	164	187	211
45	Asset replacement and renewal	(174)	74	14	23	32	42	51	61	71	81	#REF!
46	**Network Opex**	-	42	83	136	186	231	284	335	385	436	487
47	System operations and network support	-	50	106	173	247	328	403	479	558	637	719
48	Business support	-	46	104	174	228	303	372	443	516	590	665
49	**Non-network opex**	-	97	210	346	475	630	775	923	1,073	1,227	1,384
50	**Operational expenditure**	-	139	293	482	660	861	1,059	1,258	1,459	1,663	1,870

Company Name	**Network Waitaki Ltd**
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SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref												
7					**Asset condition at start of planning period (percentage of units by grade)**							
8												
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**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	
35												

Row	Voltage	Asset category	Asset class	Units	Asset condition at start of planning period (percentage of units by grade)							
36												
37												
38	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

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	Ruataniwha	1	2	N	1	40%	2	46%	No constraint within +5 years	
10	Ohau	1	3	N	2	47%	3	50%	No constraint within +5 years	
11	Omarama	2	6	N	5	25%	6	27%	No constraint within +5 years	
12	Otematata	1	3	N	2	27%	3	20%	No constraint within +5 years	
13	Kurow	5	10	N-1	5	51%	10	62%	No constraint within +5 years	
14	Eastern Road	3	7	N	4	37%	7	71%	No constraint within +5 years	
15	Duntroon	4	7	N	3	53%	7	57%	No constraint within +5 years	
16	Ngapara	6	7	N	2	79%	7	76%	No constraint within +5 years	
17	Awamoko	-	-	-	-	-	7	54%	No constraint within +5 years	
18	Papakaio	6	7	N	1	83%	7	67%	No constraint within +5 years	
19	Enfield	2	7	N	5	31%	7	34%	No constraint within +5 years	
20	Parsons Road	4	10	N	6	39%	10	41%	No constraint within +5 years	
21	Pukeuri	9	12	N-1	3	78%	12	96%	No constraint within +5 years	
22	Chelmer Street	14	28	N-1	14	49%	28	52%	No constraint within +5 years	
23	Redcastle	9	15	N-1	6	62%	15	69%	No constraint within +5 years	
24	Five Forks	2	7	N	5	29%	7	37%	No constraint within +5 years	
25	Maheno	4	5	N	2	70%	5	82%	No constraint within +5 years	
26	Hampden	1	7	N	6	20%	7	24%	No constraint within +5 years	
27	[Zone Substation_19]					-			[Select one]	
28	[Zone Substation_20]					-			[Select one]	

29 [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

7 ### 12c(i): Consumer Connections

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
8	*Number of ICPs connected in year by consumer type*		**Number of connections**					
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
11	*Consumer types defined by EDB**							
12	Small: residential and commercial to 15kVA		11,014	11,080	11,147	11,213	11,281	11,348
13	Medium: residential and commercial 16kVA to 50kVA		1,443	1,453	1,463	1,474	1,484	1,494
14	Large: commercial and industrial 51kVA and above		580	584	588	592	596	601
15	Indpendent Contract Consumers ("IND")		85	86	86	87	87	88
16	[EDB consumer type]							
17	**Connections total**		13,122	13,203	13,284	13,366	13,448	13,531
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		140	180	230	290	360	440
21	Capacity of distributed generation installed in year (MVA)		0	0	1	1	1	1

22 ### 12c(ii) System Demand

sch ref				Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
23				*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24		**Maximum coincident system demand (MW)**	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
25		GXP demand		68	73	75	80	81	83
26	*plus*	Distributed generation output at HV and above							
27		**Maximum coincident system demand**		68	73	75	80	81	83
28	*less*	Net transfers to (from) other EDBs at HV and above							
29		**Demand on system for supply to consumers' connection points**		68	73	75	80	81	83
30		**Electricity volumes carried (GWh)**							
31		Electricity supplied from GXPs		301	269	271	273	274	276
32	*less*	Electricity exports to GXPs							
33	*plus*	Electricity supplied from distributed generation							
34	*less*	Net electricity supplied to (from) other EDBs							
35		**Electricity entering system for supply to ICPs**		301	269	271	273	274	276
36	*less*	Total energy delivered to ICPs		285	256	257	259	260	262
37		**Losses**		16	13	14	14	14	14
38									
39		**Load factor**		50%	42%	41%	39%	39%	38%
40		**Loss ratio**		5.3%	4.8%	5.2%	5.1%	5.1%	5.1%

Company Name	**Network Waitaki Ltd**
AMP Planning Period	**1 April 2021 – 31 March 2031**
Network / Sub-network Name	**Network Waitaki Ltd**

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 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
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 2021 – 31 March 2031**
Asset Management Standard Applied	**N/A**

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 CEO and reviewed by top management. It is available for staff in the policy section of the document library, and the content drives the direciton of development of the AMP, and other activities. It aligns with the SCI and is reviewed in light of any changes to 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	Key items in the 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, for example in 2017 the approach to consumer engagement and the content of the surveys was extensively overhauled with the intention of getting more actionable information. The inter-relationship between corporate strategies and network asset management is understood and recognised. Changes to non-network parts of the business		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	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, adn 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. Extenisve development of systems to support the training and operational activities associated with the lifecycle of network equipment is underway at this point in time.		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

Company Name	**Network Waitaki Ltd**
AMP Planning Period	**1 April 2021 – 31 March 2031**
Asset Management Standard Applied	**N/A**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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

Company Name	**Network Waitaki Ltd**
AMP Planning Period	**1 April 2021 – 31 March 2031**
Asset Management Standard Applied	**N/A**

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.		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 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	Tthe asset management plan is developed with 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 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		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. In 2019-2020 we worked carried out a comprehensive review of these plans, including support from an external provider (Kestrel) to further develop these plans, including carrying out exercises. Our plans include working with external agencies such as the Police, Fire Service, and Civil Defence. Regular incidents such as cars hitting poles provide on-going training and opportunities to review plans. These plans have been developed as part of a		Widely used AM practice standards require that an organisation has plan(s) to identify and respond to emergency situations. Emergency plan(s) should outline the actions to be taken to respond to specified emergency situations and ensure continuity of critical asset management activities including the communication to, and involvement of, external agencies. This question assesses if, and how well, these plan(s) triggered, implemented and resolved in the event of an incident. The plan(s) should be appropriate to the level of risk as determined by the organisation's risk assessment methodology. It is also a requirement that relevant personnel are competent and trained.	The manager with responsibility for developing emergency plan(s). The organisation's risk assessment team. People with designated duties within the plan(s) and procedure(s) for dealing with incidents and emergency situations.	The organisation's plan(s) and procedure(s) for dealing with emergencies. The organisation's risk assessments and risk registers.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	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		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		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		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 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 acheived efficiently and safely. If they are not, then we will find		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 idenitified 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.		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 compentencies to carry ou t 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 compentencies, and keeping up with training requirements. However, the		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 dicsuss 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		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		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	2	We have an excellent GIS system with accurate data that assists with many oeprational aspects of our asset management. We are developing methods to accurately capture field data direct to our GIS and asset management system, with several in test. Key personnel in the field have access to digital tools via data enabled devices. We are in the process of developing links between our		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.	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 preparation provide confirmation that asset data is accurate. Field software is being adopted to maximise efficiency and reduce errors from the field. Personell in the office are responsible for recording information from teh field, with some already being electronically reported. Data		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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

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Asset Management Standard Applied	**N/A**

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 managemetn goals.		Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	3	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		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		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.		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		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 daily, 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.		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. We are developing Root Cause Analysis skills and practices 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		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		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, and less likely to get lost. Serious incidents are investigated thoroughly using root cause analysis techniques, and actions from the investigations aim at removing any systemic problems.		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 subscibe to the NEDERs equipment failure database, and incorporate information on failures into our practices. We track costs against various categories of		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 activley 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 has consistent with previous years used predictions for CPI as extracted from the Reserve Bank of New Zealand Monetary Policy Statement, February 2021.

For CY+1 and CY+2 forecasts of 1.5% and 1.7% respectively was used. From CY+3 to CY+10 a CPI forecast of 2% per annum was used.

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 has consistent with previous years used predictions for CPI as extracted from the Reserve Bank of New Zealand Monetary Policy Statement, February 2021.

For CY+1 and CY+2 forecasts of 1.5% and 1.7% respectively was used. From CY+3 to CY+10 a CPI forecast of 2% per annum was used.

9.2 APPENDIX B - 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.

c) 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: 29 March 2021

Michael C. Underhill
Director

Date: 29 March 2021