Northpower

2021 – 2031
Asset Management Plan

March 2021

Northpower

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2021 – 2031
Asset Management Plan

Table of Contents

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Northpower

2021 – 2031
Asset Management Plan

Section 1
Executive summary

Table of contents

Tēnā koutou katoa

Northpower's purpose reflects our focus on generating value from infrastructure and business ownership: Rangātamiro. Kaitiakitanga ('We weave the fibres together to create strength. We are guardians of the future').

For our electricity business, our role is delivering reliable, resilient and safe electricity services today and for tomorrow for every person, family and business in our communities of Whangārei and Kaipara. This asset management plan underpins and demonstrates this commitment. It fulfils our obligation to be a responsible steward of more than $280m of Northpower electricity assets owned by our consumer owners.

This plan builds on our 2018 asset management plan and is our roadmap to build 'Your energy future' - enabling choice and flexibility for consumers on how, where and when they access and consume energy affordably. Our job is to connect customers simply and economically, in a fair way.

Here we outline how we will invest to maintain, cater for growth and transform our network over the next ten years to deliver a modern electricity service that meets the needs of all our consumers.

Ngā mihi

Andrew McLeod

Chief Executive

Executive summary

Introducing our asset management plan

This asset management plan (AMP) sets out Northpower's asset management strategy, policy, practices and forecast expenditure for the next ten years from 1 April 2021.

This plan is informed by our Statement of Corporate Intent (SCI), our company purpose and strategy, and our business plan. This AMP is our roadmap for delivering on our commitment to our consumer owners to provide a reliable, resilient, safe and affordable electricity distribution service.

Outlined is our methodology and investment plans for managing our electricity assets, and delivery of planned programmes of capital and operational work (including planned maintenance work) for the period from 1 April 2021 to 31 March 2031. This AMP complies with the requirements of the Commerce Commission's Electricity Distribution Information Disclosure Determination.

Our guiding principles outlined here, combined with our strategy and purpose, are the foundation of our AMP, ensuring we continue meeting our customers' expectations of a safe and reliable electricity supply that evolves with technology and future energy platforms.

Key investment and asset management principles underpinning our AMP are:

- Asset investment decisions consider asset condition, risk and criticality to ensure we continue to meet our customers' expectations of a safe, reliable, resilient and affordable electricity supply.
- Timely, prudent investment decisions that meet the demand for growth, as well as build the enabling foundations for an active modern network, and consider all supply options for remote areas of our network when our assets reach end of life.
- Efficient, effective operation of our network by managing quality of supply, fault response, capacity and constraints to maintain our network and service performance levels.
- A flexible energy platform, enabling customers to choose technology unconstrained by limitations in our network, and providing pricing signals and new services that enable customers to make informed decisions on their energy use.
- Pricing for connection to and use of our network is transparent, cost reflective, fair and equitable for all our consumers.

Modernising our network – progress so far

The core assets forming our electricity network have remained largely unchanged for decades, serving our customers well. Over the past three years, Northpower's asset management strategy has seen a phased programme beginning to build the foundations for a modern network. We have replaced legacy systems, improved network resiliency and safety, built our asset management capability and improved customer touchpoints.

By end of FY21 we will have completed:

- ✓ Transitioning of our electricity network onto the new Advanced Distribution Management System (ADMS) with the completion of phase 1 (core SCADA replacement) – readying our network for smart energy technologies.
- ✓ Strengthening of our subtransmission network by replacing and augmenting our key subtransmission assets at Whangārei South, commissioning of a new zone substation at Maunu and beginning the upgrade at Hikurangi and Ngunguru.
- ✓ Development of a data, system and information roadmap underpinning and supporting delivery of our asset management strategy.
- ✓ Reviewing and updating our network standards and policies including customer connection standards, aligning our network operations manual to other electricity distribution businesses and refreshing our asset management framework.
- ✓ Launch of a dedicated customer experience team and digital tools and new channels to make our customer touchpoints easy to access, use and understand.
- ✓ Assessment of our future capability requirements and gaps to fill, including digital and analytics as a core capability.

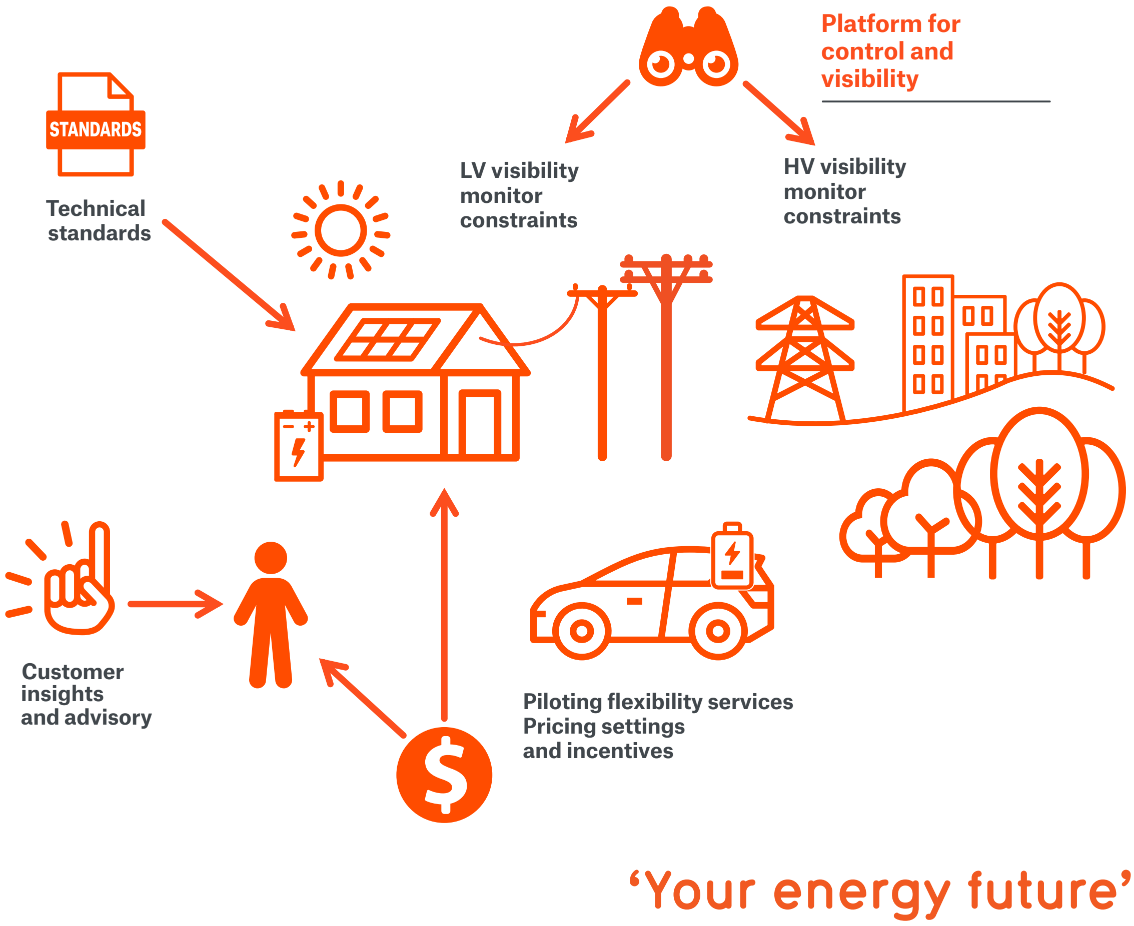
'Your energy future'

Our network needs to be 'fit for the future' – integrating a variety of energy resources and continuing to ensure capacity, constraints and power quality are managed. Technology developments and distributed energy resources (DER), such as photovoltaics (PVs), are enabling customers to generate and use their own electricity and export surplus electricity. This is changing how energy flows across our electricity network.

Our asset management strategy creates 'Your energy future'. This shifts Northpower's network operation from being 'passive' to an 'active' operation, enabling our customers to take control of their energy future. It allows them to choose where, how and when they use energy.

The uptake of new energy technologies like electric vehicles (EVs), home energy monitoring and control has been steady but currently remains low in New Zealand and on our network. We anticipate that as these products become more affordable, more customers will adopt these options.

Figure 1: Our asset management strategy – 'Your energy future'



New energy markets are expected to emerge, requiring new platforms, market operation, regulation and standards. It is still unknown how these future markets will operate and at what pace they will develop.

In preparation, we are making timely investments now to prepare our network for future market models that may evolve, while remaining prudent about over-committing to any particular outcome.

Alongside large amounts of EVs, it's possible we will support small and large DER generators operating off our distribution network (e.g. wind farms, solar farms).

This requires an uplift in our control systems, the introduction of flexibility services and new pricing models to optimise network utilisation, customer advisory services, robust technical standards and solid underlying asset management practices to incorporate these new power flows and commercial relationships.

As we prepare for the future, ensuring energy affordability and equity of pricing are at the forefront of our strategy.

Key outcome areas of 'Your energy future'

There are five key outcome areas of our asset management strategy to support 'Your energy future':

Visibility and control of our network

Active network operation requires visibility and control of our network down to LV level. We have completed the first phase of installing a new ADMS system, aiding in the operational management of our high voltage network.

Included in this AMP is expenditure for the second and third phase of ADMS, integrating our 11kV network and providing additional analytical tools to better manage operations, outages, capacity and constraints, as well as digitising access permits and switching requests. The ADMS provides the platform on which we will develop visibility of our LV network, integrating a range of LV monitoring devices, in order to monitor and manage LV connected DER.

Additionally, we are installing more automation within our high voltage network to improve network restoration and load transfer times, reducing the duration of outages.

Flexibility services and pricing

Our pricing strategy is to transition to more cost reflective network pricing that is responsive to the evolving market and the changing way consumers are using electricity. Emerging technology, such as electric vehicles, solar panels and batteries are changing how we consume, generate, and manage our electricity. We think it is important that pricing evolves to encourage efficient use of the network to minimise the cost of capacity increases, to reduce prices for consumers in the long term and ensure fair outcomes for all consumers on our network.

Building a flexible network platform offering customers choice about where, when and how they use energy.

This strategy will broadly result in fixed prices increasing, variable prices decreasing, and differentiated pricing being available based on the time of day. We also see demand response being used to efficiently manage network constraints.

We continue to support adoption of new technologies for our own needs along with 'behind the meter' technologies so our customers have greater choice.

Key to embracing this changing environment and shaping our future services and pricing structures, is expanded engagement with customers and key stakeholders to increase our understanding of their behaviours and requirements.

Helping customers navigate their energy choices

We recognise that energy hardship is a serious issue in our communities and one of our key goals is to reduce total energy costs for consumers.

Our objective is to support healthy homes in our communities with access to safe, reliable and affordable energy.

We will increase our efforts to work more closely and collaboratively with key stakeholders, community leaders, social and health organisations and government agencies to achieve this outcome.

We recognise that energy choices can be complex and our aim is to make it easier for our customers to make informed energy choices.

What customers want:

- ✓ **Easy to connect**
- ✓ **Affordable energy**
- ✓ **Security and reliability**
- ✓ **Support when things go wrong**
- ✓ **Easy to follow information to answer their questions**

Network standards

As more electric vehicles, solar panels and batteries get deployed onto our network, it necessitates upgrades to handle two-way power flows, fluctuating voltages and requires cost effective use of network resources. Developing good technical standards around these is critical to keeping our costs down and ensuring hassle free energy to our customers.

This means ensuring new connections on our network are installed correctly and do not shift costs onto others, and new equipment like solar panels and batteries meet emerging standards and do not impact power quality. It also means requiring fair contributions to network costs, and ensuring equipment is designed and connected to keep our staff, contractors and the public safe.

Northpower is continuing to develop its network standards for service connections, customer agreements, as well as our operations manuals, capital contributions and asset management related standards to adapt to the changing electricity network. This means striving to keep connection standards simple and future proofed, pricing fair and equitable across all customer groups, and working with local partners to enable new solutions that benefit our customers.

As society changes and technologies develop, standards need to evolve. Northpower is actively participating in a number of technical advisory groups examining and developing new standards and guides for EV charging, earthing, integration of inverters and voltage regulation.

Asset management

The foundation of our AMP is based on sound and robust asset and risk management principles which we are aligning to the ISO 55000 and 31000 frameworks. Factors including public safety risk, asset health, condition and criticality are used to determine asset replacement and maintenance review cycles.

Our asset inspection process and defect classification methods have improved, more accurately forecasting asset health and remaining asset lives. We are also finalising new asset fleet strategy documents outlining performance criteria against which we will manage our asset fleets in the areas of safety, reliability, cost and environment.

Our data and systems roadmap documents the core systems underpinning our operations and management of the network. We are progressively replacing legacy systems, including planning to implement a new asset management system to better meet our business needs within the next five years.

Managing external factors

An increase of low probability, high impact events such as pandemics, cyber security attacks and extreme weather events are creating greater uncertainty. COVID-19 and associated lockdowns has proven the value networks deliver as essential services.

Northpower's enterprise risk management framework provides regular review and monitoring of key identified business risks, ensuring adequate controls are operational and response plans are ready to action should the risks eventuate.

Climate change impact

Over the next ten-year planning period, we will consider our contribution to mitigating climate change and doing our part to meet New Zealand's emissions targets. With increasing frequency of severe weather events, higher rainfall, elevated temperatures and potential changes to sea levels forecasted, we will need to make our network more resilient - taking these impacts into consideration with future planning.

We will also establish our business carbon footprint baseline, including for our assets and operations, and develop plans for reduction to assist in meeting New Zealand's targets.

Cyber security

The Government Communications Security Bureau (GCSB) issued a "be prepared" advisory for all New Zealand businesses following the stock exchange suffering severe outages linked to cyber-attacks in 2020.

We have taken steps to assess our cyber security preparedness, including implementing an improvement plan stabilising and securing our network architecture.

NZ rates eighth most vulnerable to cyber attacks amongst developed countries (NordVPN 2020 Cyber Index), indicating our high percentage of online users and payments.

Pandemics

COVID-19 has highlighted the critical need for our business and operational models to withstand significant disruption, ensuring we have robust business-continuity plans in place to continue being an effective and efficient essential service provider.

As alert levels rose in response to COVID-19, we actioned pre-prepared plans to minimise risks to our network and consumers. Field staff took precautions when in public and at customers' homes, we separated our network operations centre (NOC) into two bubbles working from two separate NOC sites, we utilised digital technologies including our new ADMS, and the majority of our office staff worked from home. Lessons learnt from the pandemic, along with new capabilities developed during this time have improved our resilience for any similar future events.

Supporting our region's growth

Census figures show Northland's population increased by 18.1% from 2013 to 2019, with an additional 5,237 network connections on Northpower's network over that period – the second highest growth rate amongst the larger EDBs in New Zealand.

The network peak demand forecast shows continuing linear load growth at a rate of approximately 1.1% per annum. Residential and commercial developments around Whangārei and in east coast towns like Bream Bay, Waipu and Mangawhai are key drivers of growth. In 2020, we commissioned a new zone substation at Maunu for the growing load in Whangārei.

Whangārei and Kaipara District Councils are forecasting continued increases in population, which further influences our need to invest in our network to manage increased load growth and maintain security of supply settings.

In this AMP, we plan to spend around 30% of our capital expenditure on growth related projects. This AMP contains investment and plans to secure future zone substation sites on the east coast in Waipu, an upgrade of our Mangawhai zone substation and an additional subtransmission line to Mangawhai, catering for growth and raising our network security.

Northland's population grew by more than 27,000 people since 2013 to 179,076 with nearly 10% growth in connections on the network over that period.

COVID-19 has impacted some business operations in Northland in the short-to-medium term, with some larger businesses reviewing their future business operating models. This may impact energy demand and consequently influence our future investment plans. Catering for changes in growth and energy usage patterns is a critical element of our role in supporting economic growth in the Northland region.

The new Maunu substation is a $6.6 million investment supporting growth in the area (up to 5,000 homes and businesses) and providing an alternate supply to Whangārei hospital and CBD.

Health and safety

Our health and safety strategy focuses on developing, implementing and embedding critical controls for our critical risks, ensuring our customers, the public, our people and contractors are safe around and working on our network. We adopt "safety in design" principles for planning, building and maintaining our network to deliver healthy and safe outcomes.

Protecting life is a core commitment for Northpower and it is at the heart of everything we do.

Key aspects of our programme for safety improvements on our network include:

- A robust corrective maintenance programme to address defects arising from inspections to maintain public safety around our assets.
- Beginning an outdoor to indoor switchgear conversion at Maungatapere, improving line clearances for those working around the equipment. Conversion to indoor also reduces risk at this critical supply point from external environmental factors (particularly lightning and wildlife).
- A vegetation maintenance programme with rapid inspection and targeting of problem areas posing a public safety or damage to assets. Our sub-tropical climate promotes rapid vegetation growth, so this is an important ongoing issue.

Northpower's public safety management system is externally audited in accordance with NZS 7901, most recently in 2020, providing confidence to our community in the robustness of our internal safety management systems.

Roll out of our critical risk controls for 'live electricity' as part of our ongoing focus to manage critical risks and prevent serious harm to staff and the public.

Resiliency and reliability

Much of our asset base was constructed during the 1950's and 60's and we have planned targeted renewal of aging assets over the ten-year investment period to increase resiliency and reliability.

In this AMP, 60% of our capital expenditure is dedicated to asset renewals. Replacing these assets nearing the end of reliable service life allows us to adopt newer technologies, modernising them and providing improved safety assurances.

Combined with having a high growth rate, Northpower also has the 2nd highest industry percentage of 1950's and 1960's zone substation assets.

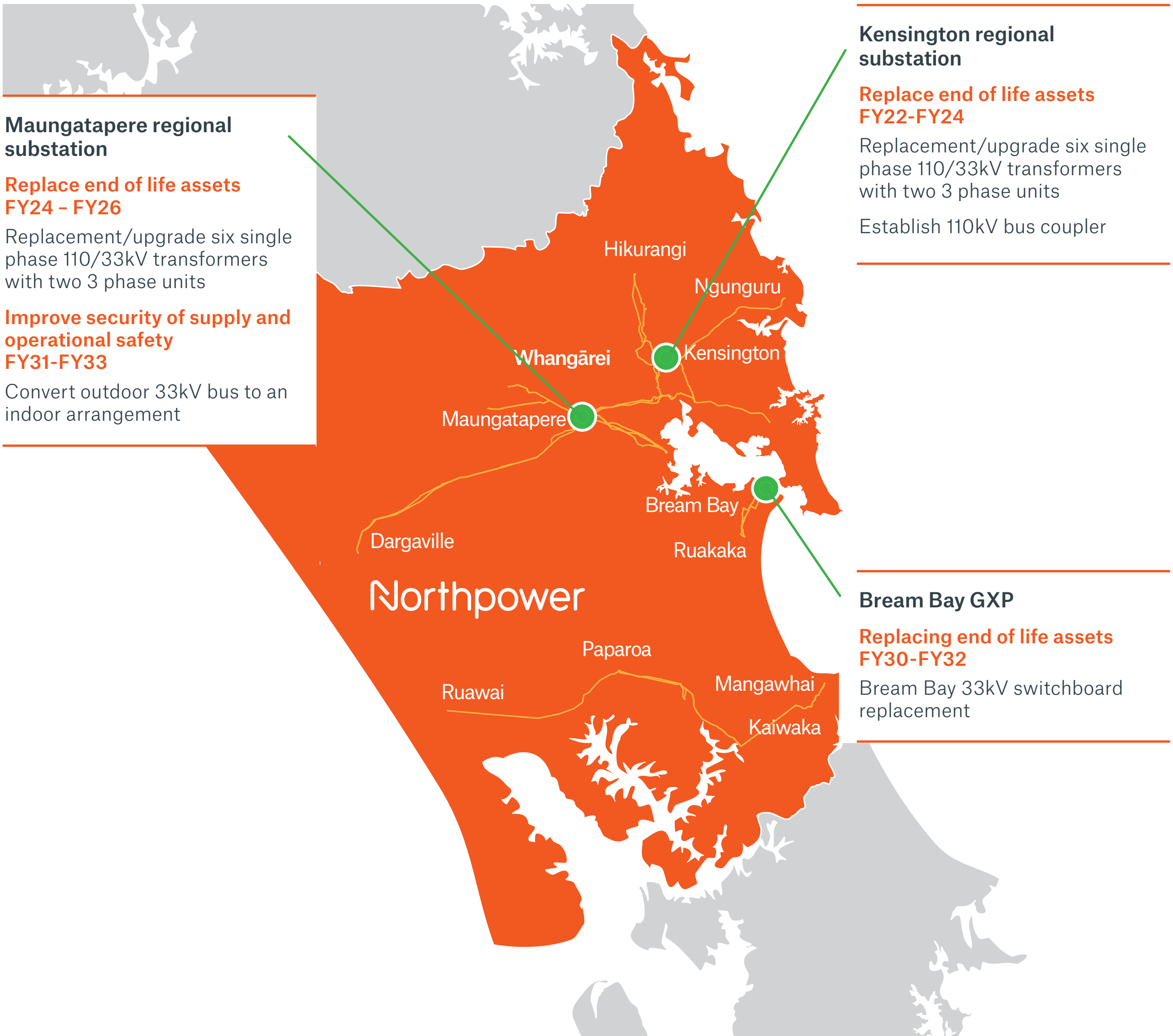
Northpower's network architecture is built around critical 110kV assets at our regional substations, which are robust, but can be vulnerable to events such as earthquakes. These assets require close management, and investment is included in this plan to strengthen our subtransmission backbone.

Network upgrades and resiliency projects in this AMP will resolve compliance with security of supply settings in Ngunguru, Parua Bay and Mangawhai over the next five years.

Reconductoring project to replace end of life assets in central Dargaville including undergrounding a portion of the 11kV line to improve reliability and resiliency.

Our investment and work programmes are additionally prioritised by considering the types and numbers of customers that are supplied by a particular asset. We also consider the specific asset fleet strategies of each of our main asset categories in the timing of asset replacement.

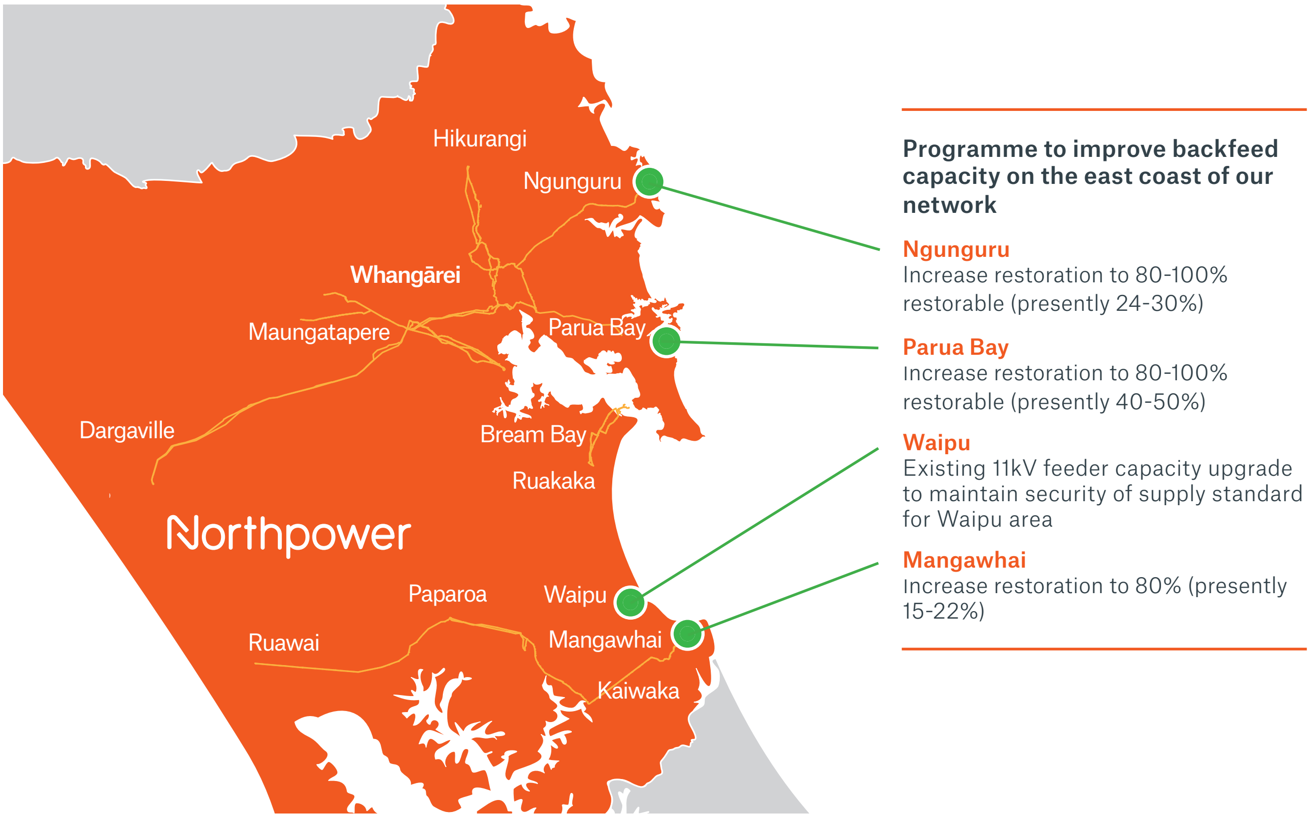
Figure 2: Our programme to enhance resiliency of our key 110kV substations



Distribution assets

Faults on our overhead line assets have one of the largest impacts on reliability and security of supply. This also poses a risk to public safety in the event of a pole failure or fallen conductor. This AMP continues our pole and conductor replacement programme and includes 11kV feeder augmentation to improve back-feeding capacity and improve network reliability. Integral to maintaining reliability levels are our asset inspection and follow up asset replacement programme. In total, we expect to spend $75m on replacing end of life overhead assets.

Figure 3: Programme to lift network security and improve back-feed capacity



Substation transformers, switchgear and circuit breakers

The next seven years will see many of our critical assets that entered service in the 1950's and 60's renewed, such as zone substation power transformers and 33kV and 11 kV switchboards. Our forecast renewals for these asset categories are $52m - providing strong investment in Northland's energy infrastructure future.

Subtransmission cables

Our subtransmission cable network conveys a sizeable amount of energy to homes and businesses in the Whangārei central area and has a large potential impact on reliability and availability of supply. The failure risk of our oil filled cables is increasing with age. We are commencing a programme to replace these aging 1960's oil filled subtransmission cables over this planning period.

Connecting customers

We expect approximately $48m total investment (customer and network funded) to enable new house and business connections.

New services aimed at 'active' homes and businesses connected to our low voltage network are expected to grow as more people purchase EVs, solar and battery systems. We are building readiness to support these types of services, helping our customers and Northpower control costs and mitigate network risks.

Environmental management and climate change

Our purpose, Kaitiakitanga expresses the importance of guardianship of the environment for current and future generations.

Northland's spectacular natural landscapes, extensive coastlines, and indigenous flora and fauna need preserving and protecting. Our environmental management system (EMS) aims to ensure our network and activities do not adversely impact the environment.

Northpower's EMS is certified to ISO14001, we track and review performance, seeking ways to further minimise environmental risk and impact. Our understanding of environmental best practice is maturing, and in 2021 we are undertaking a comprehensive review of our EMS.

Northpower recognises that climate change represents a material risk to the environment, our communities and our network. We have many roles to play in fronting this challenge.

- Our network plays an important role in electrifying our local economy as New Zealand transitions to a zero emissions future – reflected in our AMP.
- In 2021 we will complete a baseline assessment of the carbon footprint of our network, planning our path to carbon reduction.
- Climate change is a material risk to our asset's performance. As a lifeline utility, and under the new Climate Change Response (Zero-Carbon) Amendment Act 2019, we have reported our adaptation readiness, including consideration of possible scenarios and the actions required to mitigate climate change impact (detailed in Section 9).

Our planned investment aims to strengthen network security and resiliency to better withstand high impact/low probability events, including the increase in extreme weather events due to climate change.

The July 2020 storm was a one in 500 year event, some gauges reporting over 250mm rain in 24 hours. Our network received damage from landslides affecting pole foundations and caused water ingress in distribution assets.

In June 2020 a storm brought thousands of lightning strikes to Northland's coast with lightning hitting a 33kV pole mounted switch on the Mangawhai feeder causing major disruption - 27.68 SAIDI minutes recorded.

NZ Herald report 18 July 2020 Photo / Adam Pearce BP Service Station Riverside Drive, Whangārei.

Expenditure forecasts

Capital expenditure

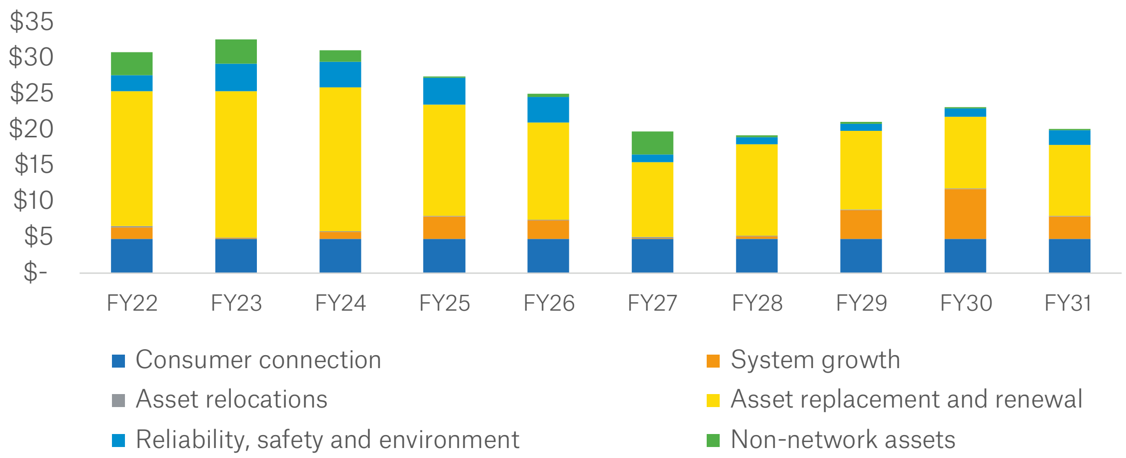
This AMP seeks to match investment to our core drivers and strikes a balanced approach to asset risk; replacing strategic subtransmission assets prior to failure, investing for growth and future technology as necessary while maintaining network performance levels.

Our ten-year capital expenditure profile of $251m represents an increase of 4.5% compared to our 2020 AMP update, largely impacted by the timing of key investment projects and a higher forecast for customer connections. The total capital expenditure profile is based on:

$143m	$23m	$23m	$48m
Asset replacement and renewal	Targeted reliability and safety improvements	System growth	Customer connections

The annual capex forecast over the ten years is shown in Figure 4.

Figure 4: Ten-year capex forecast (FY2022-FY2031) $000,000's - 2020 dollars



Operational expenditure

The ten year opex forecast for FY22 – FY31 has reduced by $4m compared to the 2020 AMP Update (FY21 – FY30). Material changes over the ten years include:

$6.1m ↓	$2.52m ↓	$5.9m ↑
Business overheads	Corporate allocations	Reactive maintenance

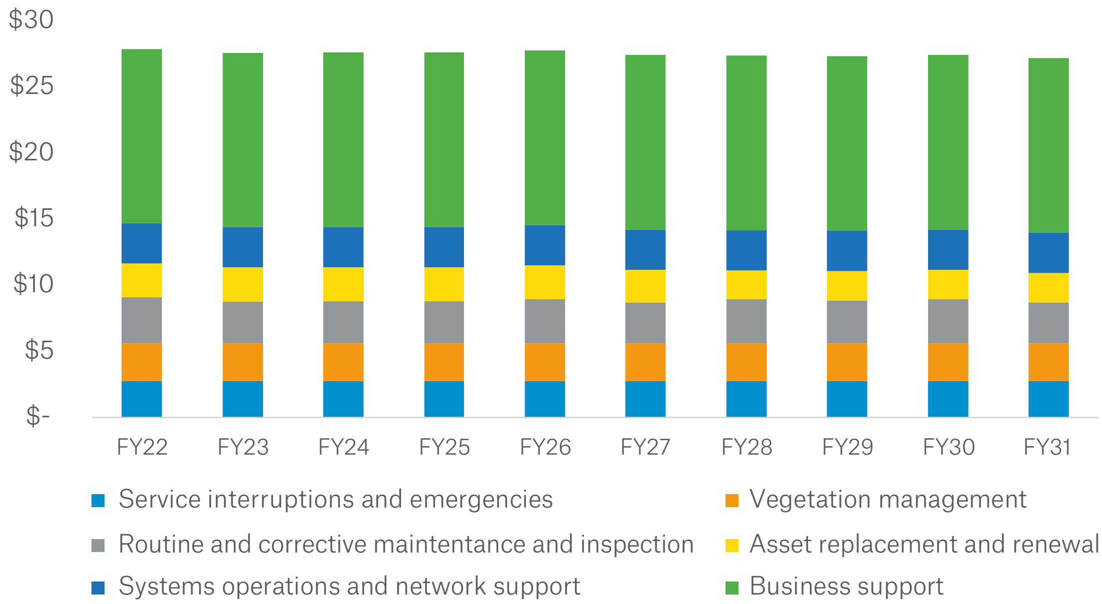
Key areas of improvement for operating and managing our assets include:

- Continuing implementation of improved asset inspection and condition assessments to inform asset replacement profiles.
- Continuing revised levels of vegetation management investment and roll out of enhanced vegetation management practices using a risk-based approach to achieve improved sustainable outcomes while reducing the impact of vegetation on the network.
- Promoting efficiencies in the planning and scheduling of work, with monitoring of established performance metrics to gauge delivery.

The increase in reactive maintenance reflects the prior three year average, impacted by the number and unpredictability of weather events on an ageing network.

The ten-year opex forecast for the ten-year period is shown in Figure 5.

Figure 5: Ten-year opex forecast (FY2022-FY2031) $000,000's - 2020 dollars



Services and performance

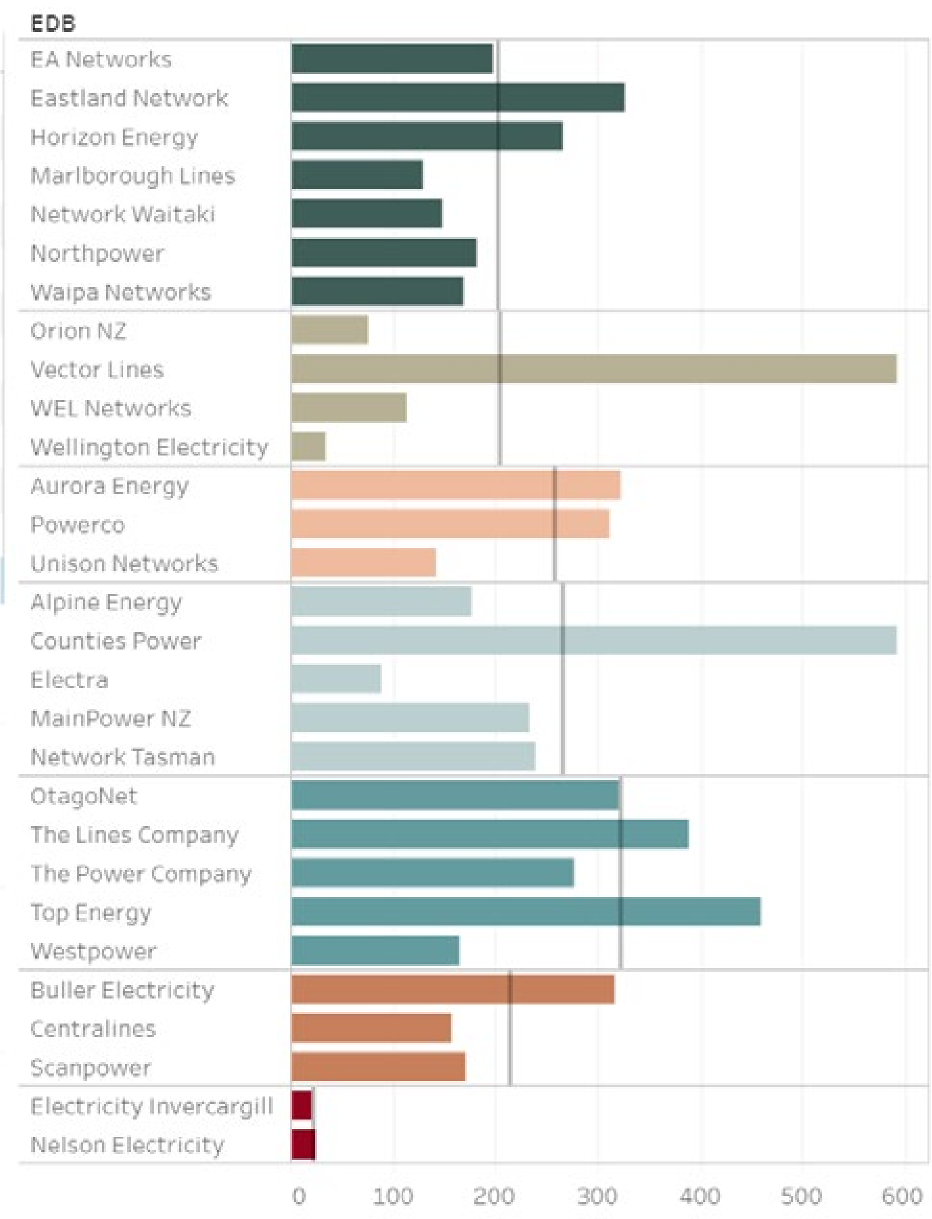
Over the last seven years, Northpower's unplanned System Average Interruption Duration Index (SAIDI) is under the average for its Commerce Commission peer group (see Figure 6).

Since 2019, however, unplanned and planned SAIDI has risen on our network. The increase in planned SAIDI represents our uplift in renewal work to reduce the number of defects and faults on our network, as well as the impact of less live work being undertaken by our service providers.

Northpower performs well against its peers for network reliability; but we are increasingly seeing extreme events skew performance results.

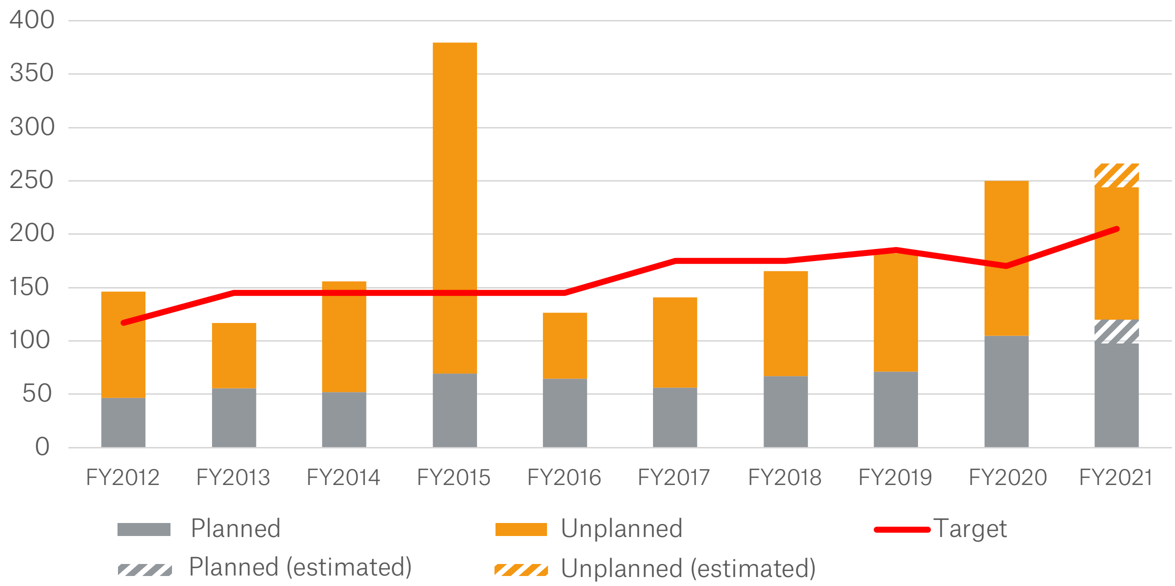
More recently we have experienced significant SAIDI impacts from outages on the sole 33kV line to Kaiwaka and Mangawhai, and a marked increase in third party incidents resulting in performance targets not being met.

Figure 6: Commerce Commission. Performance Accessibility Tool for electricity distributors. Average Total System Average Interruption Duration Index (SAIDI) 2013 – 2019 by peer group



While Northpower is exempt from price quality regulation, we are shifting our network performance measures in FY22 to align with regulated Electricity Distribution Businesses (EDBs). Going forward, these performance metrics will normalise extreme events (such as the 2015 storm as shown in Figure 7) and will provide a clearer view of underlying reliability.

Figure 7: Northpower total SAIDI FY2012 – FY21 (actual to 1 January 2021, forecast to 31 March 2021)



Section five takes a closer look at defects on an asset grouping basis on the network. Defects associated with overhead line assets comprise more than 64% of the total number of defects. As we implement our improved defect remediation programme - which includes higher quality asset inspection and defect classification processes to analyse in more detail root causes of failures - we expect faults due to defects on the distribution network to decrease.

Section five also discusses our customer satisfaction performance, network reliability and performance. We conduct an annual residential and commercial customer survey to measure satisfaction. The 2020 customer survey shows continued high-level of overall satisfaction with Northpower, with improvement in 2020 from the previous year.

Northpower's overall customer satisfaction improved from 88% to 91% for commercial customers and 92% for residential customers in 2020, which is underpinned by improvements in customer service and communications.

Transforming capability underpinning our asset management

We have increased our capability and resourcing across all core asset management functions. Improving customer experience has been a key area of focus. We have created a specialised customer experience team supported by a customer management system and digital communication channels - including for planned and unplanned outages.

Modern networks, however will require additional capabilities. Going forward we will establish greater digital and analytical capability to have this 'native' within our business. In sharp focus are our engineering and analyst roles, requiring modelling capability to navigate greater uncertainty, expanding technology and commercial challenges.

The services and supporting capability required to support active network management and DER integration will come from across our organisation, as well as external partners. Northpower will reshape and repurpose our capability as we activate this strategy over time.

We have built a data and systems roadmap to visually display the key system capability stacks and data flows to manage and operate our network assets. Across our business we are progressively replacing legacy systems with fit for purpose systems and tools. The most recent investment has been in an ADMS, as well as a new billing system and CRM. A modern faults management system is due for implementation in early FY22 and will form part of our CRM and ICP management system providing a 'single view' of all customer services.

One of the last remaining foundational systems to be replaced is our asset management system (AMS). In 2021, we will define user requirements for a new AMS to replace the existing enterprise asset maintenance system (WASP), for implementation by 2024.

Northpower's investment in ADMS is a key platform enabling a shift from 'passive' to 'active' network operation providing visibility and enabling control of our network.

Northpower

2021 – 2031 Asset Management Plan

Section 2

About our business

Table of contents

2.1 Purpose of our asset management plan (AMP)

Our AMP sets out Northpower's key asset management principles, our network planning techniques, asset management practices and investment forecasts for our electricity distribution business.

The AMP looks ahead to the next ten years from 1 April 2021. Greater focus is on the next three to five year horizon with more certainty of projects over this period. Beyond five years, while our forecasts and project schedules provide a firm indication of our requirements, a degree of change and adaption is anticipated as we respond to the changing needs of our customers and our community.

Northpower's AMP is updated and published annually, describing the methodology adopted to manage the assets in accordance with information disclosure requirements under Part 4 of the Commerce Act for Electricity Distribution Businesses (EDB's).

These requirements include:

- A summary
- Background and objectives
- Target service levels
- Details of assets covered and lifecycle management plans
- Load forecasts, development and maintenance plans
- Risk management, including policies, assessment and mitigation
- Performance

Our AMP, however, goes beyond these base regulatory requirements. It provides our stakeholders with a view of how we develop and operate our networks for the good of our community. It sets out our commitment to responsible stewardship of intergenerational assets and in doing our part to prepare our networks for the energy markets of the future.

We test and challenge our thinking and calibrate our plans against stakeholder feedback to ensure we continue to efficiently and effectively meet the current and future needs of our communities.

Our asset management objectives focus on prudent management of the life cycles of every asset class on our network to achieve agreed levels of service and meet current and future demand. Each year we strive to improve our AMP by reflecting on customer insights, considering shifts in external factors and incorporating advances in new technology and practices to enhance outcomes for our customers.

Development of our AMP is a collaborative effort combining the skills, experience and knowledge of our staff, the practical experience of our service delivery teams and the technical expertise of our key suppliers and advisors. Our plans are the result of working together, testing and challenging our thinking and calibrating our plans against customer and stakeholder feedback and changing consumer behaviour. Public comment and feedback is welcomed and carefully considered. Internal review by senior engineers and managers, external expert review by asset management specialists and scrutiny by our board to approve our investment plans ensures our network continues to efficiently and effectively meet the future needs of the communities we serve.

2.2 Our business – who we are

Our business provides residential and business customers with a safe and reliable electricity distribution service. Our networks span the Whangārei and Kaipara districts and provide the physical link between Transpower's national grid and our customers' homes and premises.

The key activities we undertake as a network business include:

- Maintaining network assets to ensure they are safe, secure, and provide reliable service.
- Building new assets and replacing assets as they reach the end of their service life, or when they need to be upgraded as our region grows.
- Overseeing the operation of our networks in real time, to ensure their effective operation and the safety of those interacting with them.
- Connecting new customers to the network.

Northpower has been serving the Kaipara and Whangārei districts for over 90 years with provision of a safe, reliable and affordable supply of electricity.

2.2.1 Our local communities we serve

Kaipara and Whangārei districts showed some of the highest growth rates in New Zealand in the 2018 census. Increased migration to regions has been a key contributing factor as housing affordability continues to be a major issue in New Zealand.

In the past three years we have added 2,900 new customer connections to our network. Development along the coastal regions, in particular Tutukaka / Matapouri, Marsden Cove, Waipu and Mangawhai continue to attract new subdivisions and businesses requiring additional infrastructure to support.

Against this backdrop of growth and migration, our inland communities continue to fuel our local economy via horticulture and agriculture, with the Whangārei district adding marine services, manufacturing, and processing industries. While the mix of industries continues to develop, longer term prospects for the region remain positive.

As our region changes and evolves, we recognise the importance of gaining a deeper understanding of the customers and communities we serve. This is a core part of our strategy so that we carefully plan investment in our network to ensure we continue to provide resilient and reliable infrastructure supporting our communities and the future growth of Northland.

Whangārei District

Population **98,300**
Increase ↑ **17.4%**
(2013 to 2020)

Kaipara District

Population **22,200**
Increase ↑ **22.9%**
(2013 to 2020)

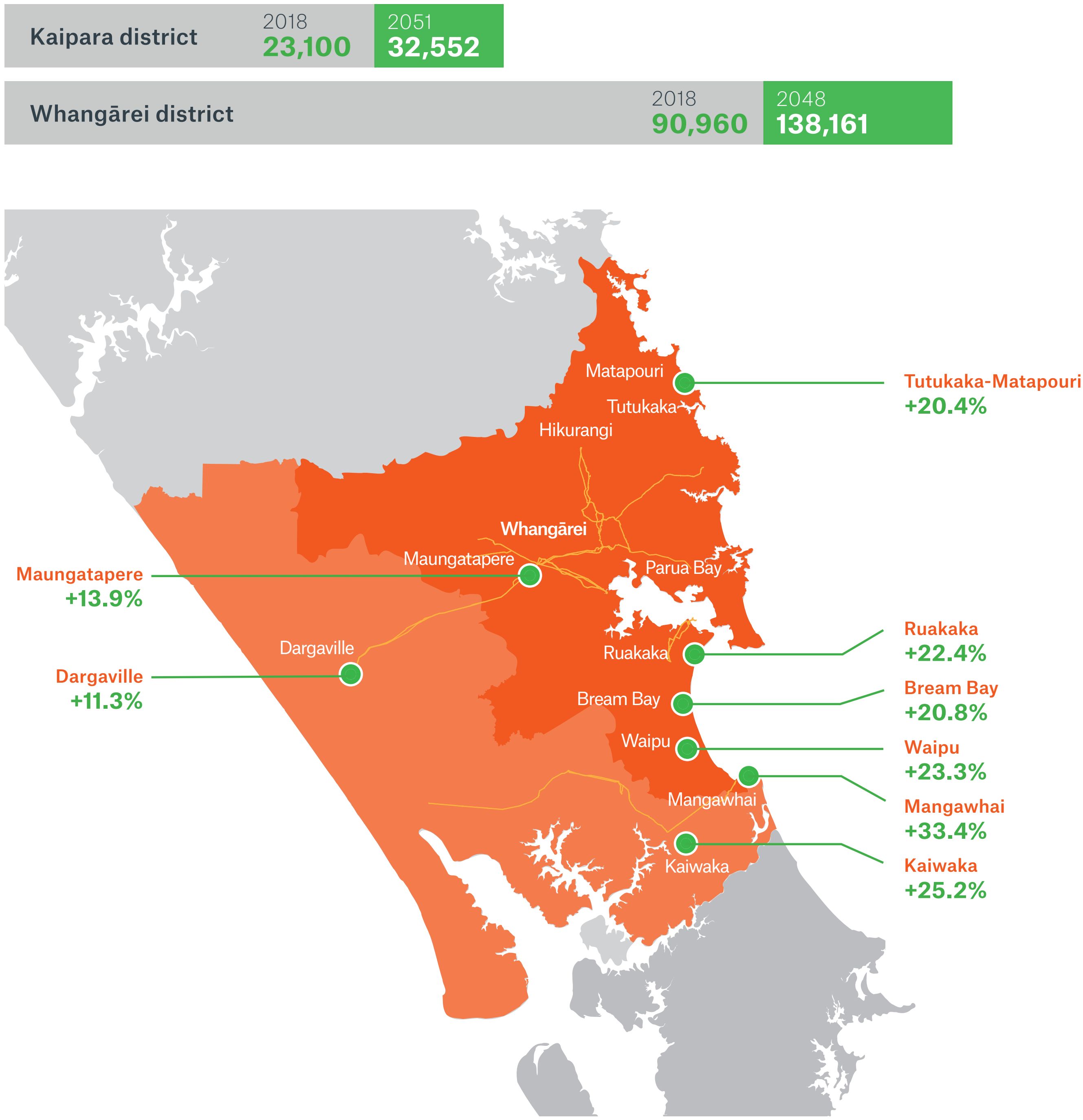
Whangārei
is the only city and major service centre for Northland.

Primary industry
is the largest employer in Northland (agriculture, fishing and forestry).

2.3 Our business strategy

Our AMP is underpinned by our Statement of Corporate Intent (SCI) and business plan which sets out Northpower's strategy, objectives and performance measures for each of our businesses comprising the Northpower Group. Our AMP is aligned to and supports the achievement of Northpower's strategy.

Figure 8: Population Growth 2013 to 2018 census and population projections for Kaipara and Whangārei Districts



2.3.1 Statement of Corporate Intent

Our SCI is our governing document setting Northpower's performance commitment to the Northpower Electric Power Trust (NEPT) and our consumer owners.

The operations of the Northpower Group are overseen by a board of directors, and directors use this SCI to guide the direction and deliverables from the Group. It is the reference point for discussions on performance between NEPT trustees, and Northpower directors.

The targets in the SCI, include financial and non-financial measures along with measures of network reliability and customer satisfaction. These KPIs reflect discussions between NEPT trustees, and Northpower directors on the purpose, outcomes and our community role.

2.3.2 Our group purpose

Northpower's purpose reflects our focus on generating value for the regions of Kaipara and Whangārei from infrastructure and business ownership: Rangitāmiro. Kaitiakitanga - 'We weave the fibres together to create strength. We are guardians of the future'.

More specifically our activities support delivery of our purpose:

- Our electricity assets deliver safe, secure and reliable electricity supply across Kaipara and Whangārei districts servicing Northland's growing economy and communities.
- Our fibre optic networks deliver high-speed communications services to Whangārei and towns in the region.
- Our contracting group supports many of the other electricity distribution businesses in the North Island giving access to diversified revenue and insight into best network practice.

These business holdings are complementary and essential long-term enablers of the Northland economy.

2.3.3 Our electricity strategy and business plan

Underpinning our AMP is our electricity business plan and strategy. Our plan reflects the emergence of new renewable energy supply options, such as roof top solar and electric vehicles, which are complementary to our current energy supply arrangements. Such developments herald a new phase in electricity supply, with options for customers to take an increased role in generating, balancing, and tailoring their electricity use.

Northpower is committed to supporting this natural integration of new energy solutions, and our networks are a key community platform to support their implementation.

Our electricity strategy is creating 'Your energy future' and we are preparing for this future in a number of key ways:

- We are **lifting investment in our electricity network** to ensure it continues to provide a safe, secure, and reliable supply of electricity, accommodating growth in our region, and supporting integration of new energy solutions. We have allocated $251 million over the next ten years to this purpose.
- We are **refining the way we charge our customers** to ensure the charges we impose are reflective of actual cost, ensure equitable and fair charges as new energy solutions emerge, and put a focus on managing our wider business operations in a way that will enable us to lift the level of rebate we provide our customers over time.
- We are **improving the way we work with customers** by streamlining and modernising the way our customers communicate with us, creating new options locally for completing work associated with our network, and taking an active stake in understanding, enabling, and providing advice on new energy options.

Our direction and priorities strike the right balance of investments that support the safe and cost effective supply of electricity and address the current and future needs of the Kaipara and Whangārei communities.

2.4 Asset management plan development process

The AMP development process is robust, involving internal peer review by senior management, external review by asset management specialists and testing against customer and stakeholder feedback. Our board approve the AMP to ensure it meets our performance commitments and expectations of the trust and our consumer owners. Specific expenditure proposals are reviewed and approved as a top down process with significant expenditure requiring formal business case and supporting asset management reports.

Risk management is a fundamental element of our AMP development. Northpower's legal, audit and risk framework sets out the approach we adopt to manage risk and achieve compliance. This framework includes a requirement to, on at least an annual basis, conduct a risk workshop to assess key network risks, determine any action that is required, captured in our risk register. Risks related to asset management within the risk register inform Section 3 of the AMP. Key mitigations and preparedness are captured in our emergency response plan, crisis management plan and business continuity plan.

Planning the development of our network is primarily determined by load growth and the changing behaviours and needs of our customers. Developments at subtransmission level tend to have more long-term inertia and therefore tend to be less dynamic and more predictable than those at distribution level. This means projects relating to the former tend to have longer planning lead times and can normally be fairly accurately defined five years ahead. Projects at distribution level are more closely linked to shorter-term economic activity, housing development and changes in consumer demand, with the result that we expect some flexibility in our near term plans.

Our maintenance programmes reflect industry norms relating to inspection and renewal and we are increasingly moving to a condition and criticality based approach in these areas. Our inspection and condition assessment processes provide us confidence that renewal and corrective maintenance activities are appropriately considered.

Presented in this AMP are Northpower's best estimates of optimal solutions based on projections of present day drivers, technologies and available network data. Given that drivers and network data will change over time, inclusion of specific activities and projects, particularly towards the second half of the ten year planning horizon, do not represent a firm commitment by Northpower to proceed with those activities and projects, which will be subject to ongoing review justification.

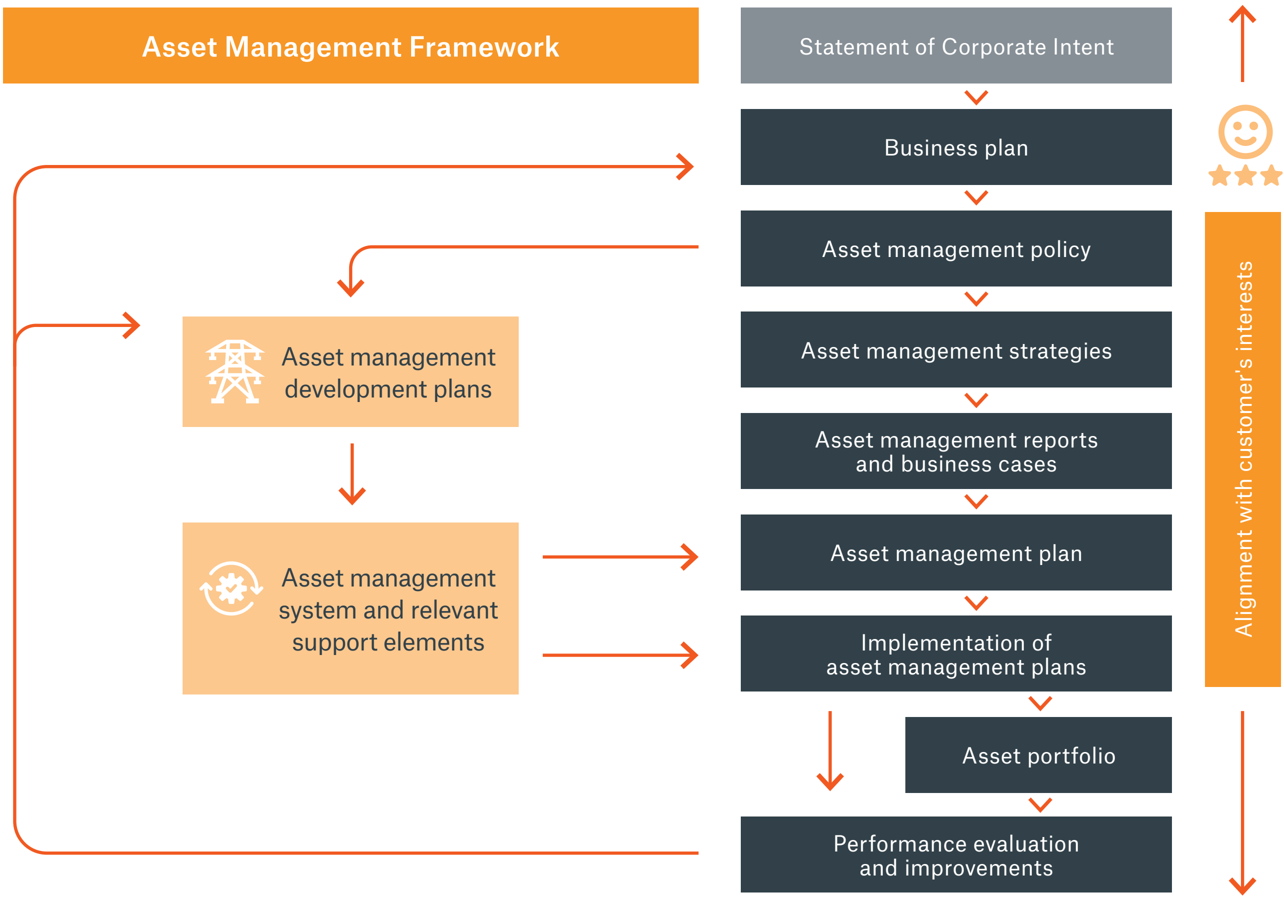
Figure 9 shows our AMP development process and role of our board, management and consultation with our customers and stakeholders.

Figure 9: AMP development process

	Board	Management	Customer/stakeholders
Strategy Aligns our strategy, business plan and asset management policy with our SCI, shareholders' expectations and feedback from customers and key stakeholders	Strategy review session and review of asset management focus (October)	Analyse external factors, performance, capability and risk. Plan strategic response (August - October)	Consider shareholders' expectations in developing strategy (November – January)
	Approve the SCI, business plan and expenditure budgets (February)	Align business strategy and asset management policy and strategy (October – February)	Stakeholder consultation
Continuous improvement Monitor and analyse performance and service levels, report and adjust operations to improve outcomes	Review progress on AMP and expenditure plans	Review/report progress on AMP and expenditure, network performance, failure modes and re-set of condition based risk maintenance	Stakeholder consultation and consider shareholders' expectations
	Confirm service level assumptions	Review load growth, capacity constraints, security, network and non-network solutions	
Reports and business cases Ensure appropriate and prudent investment decisions based on data, evidence and sound engineering judgement	Consider asset management reports and business cases and ensure appropriate investment decisions made	Prepare asset management reports and business cases and ensure necessary capability is available	Stakeholder consultation and consider shareholders' expectations
	Approve asset management investment business cases	Peer review asset management reports and business cases and gain external review as appropriate	
Asset management plan (AMP) Communicate our asset management policy, strategies and expenditure plans to ensure best practice stewardship of our electricity network	AMP key parameters, strategy, focus areas and expenditure principals (October - December)	Prepare asset management plan, strategy, focus areas, signal significant investment and improvement plans and prepare expenditure budgets	Stakeholder consultation and consider shareholders' expectations
	Approve AMP, expenditure budgets and information disclosures (February - March)	Peer review and external review of AMP, expenditure budgets and information disclosures	

Figure 10 shows our asset management framework and the relationship between governance, strategic framework and operations. It shows how the SCI, Group business plan, the key stakeholders and other strategic inputs influence the AMP.

Figure 10: Northpower's asset management framework



2.5 Asset management policy

Northpower's asset management policy provides the framework for Northpower's management of its electricity networks, and associated supporting assets and systems. The policy sets out guidance for the development of asset management strategies and objectives. It shapes priorities for efficient and safe delivery of electricity to consumers, to meet their expectations of our performance.

2.5.1 Objectives

Northpower's vision is to deliver enduring value by enabling customer choice. A key to delivery of our vision is to exercise robust asset management and ensure appropriate investment in our network and our capability to provide sustainable network services. Effective asset management is at the core of our approach across all levels of our company.

Achieving this objective requires effective management of our urban and rural based power distribution infrastructure assets and supporting assets such as disaster and communication technology, plant and equipment. Northpower is committed to providing effective asset management in order to achieve our legislated, community and strategic business objectives.

2.5.2 Delivery

In order to achieve these objectives, we will:

- Ensure the public, contractors, and our staff experience a safe network.
- Be proactive, engage with customers, ascertain their needs and develop the network to meet the changing needs of our customers.
- Develop new tools and skills enabling ongoing flexibility to meet changing customer expectations.
- Ensure appropriate levels of security and resiliency are maintained.
- Ensure that our asset management provides a cost-effective service, and provides ongoing relevance of the networks to consumers.
- Meet all statutory and legislative obligations.
- Maintain the asset management objectives in alignment with Northpower's organisational objectives.
- Ensure we develop efficient work programmes and make decisions based on complete, timely, and accurate information.
- Ensure new technologies are understood and implemented where customer value is enhanced.
- Develop and maintain an asset management system that complements and supports our business, consistent with ISO55001 and which maximises the investment in our power distribution infrastructure.
- Develop asset management planning processes that facilitate the balancing of performance, risk and cost across the asset portfolio, consistent with the objectives of our management framework and meet customer expectations of network resilience and performance.
- Ensure relevant data and information is captured and stored in a common and systematic manner, enabling informed and timely decision making.
- Invest in our workforce to ensure it is resourced and suitably skilled to meet our asset management objectives.
- Develop and maintain a continual improvement mechanism for all processes, procedures, documents, systems and principles within the asset management system.

Our asset management practices and capabilities are externally reviewed and validated and tested against international standards.

2.6 Asset management strategy

Our asset management strategy describes the key principles that guide us in making our day to day investment and operational decisions. It ensures our decisions, plans and actions are consistent with our purpose, and our actions work efficiently and effectively towards achieving our business plan as well as our asset management policy objectives.

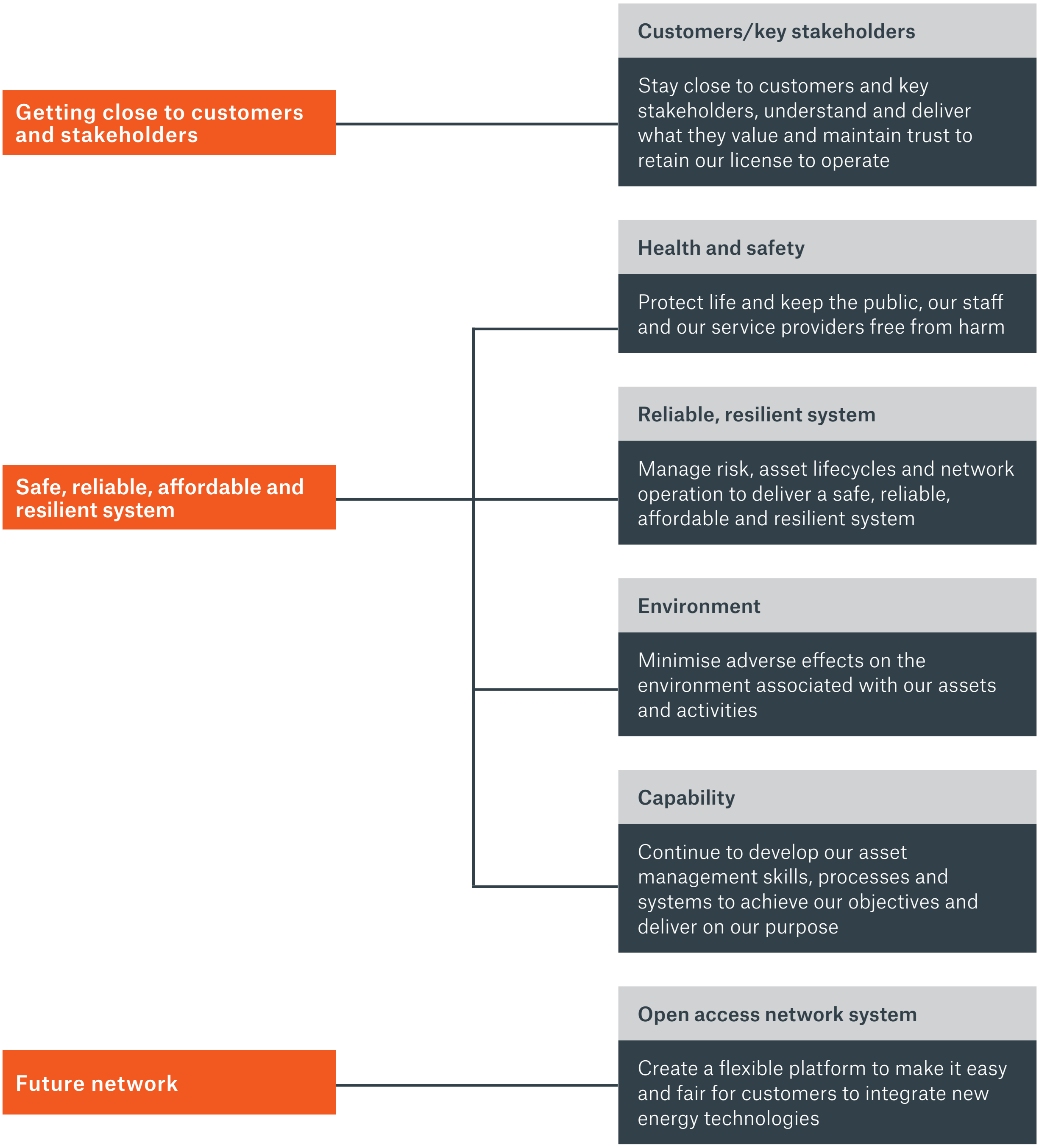
Asset management principles underpinning our AMP are:

- Asset investment decisions consider asset condition, risk and criticality to ensure we continue to meet our customers' expectations of a safe, reliable, resilient and affordable electricity supply.
- Timely, prudent investment decisions that meet the demand for growth, as well as build the enabling foundations for an active modern network, and consider all supply options for remote areas of our network when our assets reach end of life.
- Efficient, effective operation of our network by managing quality of supply, fault response, capacity and constraints to maintain our network and service performance levels.
- A flexible energy platform, enabling customers to choose technology unconstrained by limitations on our network, and providing pricing signals and new services that enable customers to make informed decisions on their energy use.
- Pricing for connection to and use of our network is transparent, cost reflective, fair and equitable for all our consumers.

2.6.1 Asset management focus areas

In executing our asset management strategy we have set asset management focus areas. Our initiatives in each of these focus areas support our electricity strategy and strategic objectives. The following pages detail how our asset management strategy is aligned to create "Your energy future" - ensuring we provide enduring value for our customers and stakeholders.

Figure 11: Our focus areas for asset management



Customers/ key stakeholders	Core objective	Strategic objective
	Deliver services customers want and value, maintain trust to retain our license to operate	**Support healthy homes in our communities with access to safe, reliable and affordable energy**
	We will do this by:	**We will do this by:**
	• Achieving our performance targets as set out in our Statement of Corporate Intent • Actively seeking to understand and meet our customers' needs, now and in the future • Continually improving our customer engagement and our customer service • Being socially responsible in our actions	• Ensuring our pricing is fair, transparent and equitable for all consumers • Helping customers navigate their energy choices and make informed decisions • Working more closely with key stakeholders, community leaders, social and health organisations and government agencies to achieve this outcome
	Key initiatives:	**Key initiatives:**
	• Lift our engagement and connection with customers to better understand their evolving behaviours/needs • Research to gain deeper insight into customer segments and key trends • Promote/champion fair transmission charging and regulation	• Public consultation and development of our pricing tariffs • Programme to help customers reduce their total energy costs • Education and advisory service to help customers navigate energy choices

Safe, reliable, affordable and resilient system:

Health and safety

Core objective	Strategic objective
Protect life and keep the public, our staff, and our service providers free from harm work on and around our assets	**Challenge ourselves to protect life and put people's safety and wellbeing at the heart of Northpower**
We will do this by:	**We will do this by:**
• Ensuring our network and our activities do not cause harm to the health and safety of the pubic, our staff and service providers • Adopting "safety in design" principles for planning, building and maintaining our network to deliver healthy and safe outcomes	• An operationally disciplined approach to our work • A tight focus on the management of critical risks • Simple and effective systems to support that approach • Staff at every level that are trained and competent to work in that way
Key initiatives:	**Key initiatives:**
• Robust corrective maintenance programme to address defects arising from inspections to maintain public safety around our assets • Identify, design and invest in improvements to our network to improve health and safety • Vegetation programme to target areas of our network posing public safety and risk to our network	• Develop, implement and embed critical controls for our critical risks, ensuring our customers, the public, our people and contractors are safe around and working on our network

Safe, reliable, affordable and resilient system:

Reliable and resilient system

Core objective	Strategic objective
Manage risk, asset lifecycles and network operation to deliver a safe, reliable, affordable and resilient system	**Timely, prudent investment decisions that meet the demand for growth and build the enabling foundations for an active modern network**
We will do this by:	**We will do this by:**
• Achieving our performance targets as set out in our Statement of Corporate Intent • Complying with security of supply settings • Planning and investing to replace end of life assets and cater for growth • Considering asset condition, risk, criticality and whole of life costs in making asset management decisions. • Maintaining our network to prevent outages • Managing quality of supply, fault response, capacity and constraints	• Adopting new technology and methods where proven to add value • Developing and implementing supply options for remote areas of our network
Key initiatives:	**Key initiatives:**
• Programme to enhance resiliency of 110kV substations • Programme to lift security and address security compliance at Ngunguru, Parua Bay and Mangawhai • Replacement programmes for end of life subtransmission assets • HV automation programme	• Evaluate non-network alternatives to address constrained areas of our network • Develop and implement a remote area power supply (RAPS) alternative for remote areas of our network

Safe, reliable, affordable and resilient system:

Environment

Core objective	Strategic objective
Practice stewardship ensuring our assets and activities do not adversely affect the natural environment	**Enable our communities to transition to a low carbon future**
We will do this by:	**We will do this by:**
• Ensuring our network and our activities do not cause harm or adversely impact the natural environment • Fulfilling our legal responsibilities • Maintaining a health and safety work environment in accordance with ISO114001	• Enabling the adoption of EVs in our community • Enabling integration of new energy resources on our network • Working to reduce our carbon emissions
Key initiatives:	**Key initiatives:**
• Comprehensive review of our environmental management system • Climate change risk mitigation reporting and regular review	• New network standards for distributed generation and distributed energy resources (DER) • Monitor and publish hosting capacity for distributed generation (DG) on our network • New subdivision design standards which cater for DER • Complete emissions baseline measurement and develop a plan to reduce emissions

Safe, reliable, affordable and resilient system:

Capability

Core objective	Strategic objective
Robust asset management skills and capability to deliver a safe, reliable, affordable and resilient system	**Transition from a 'passive' network to an 'active network operator**
We will do this by:	**We will do this by:**
• Aligning our asset management and risk management capability with the ISO 55000 and 31000 frameworks • Continuing to develop our asset management skills, processes and systems to achieve our objectives and deliver on our purpose	• LV and HV visibility (short term) and control (medium) of our network • Ensuring we have the skills and capability to operate a modern active network • Implementing and integrating modern systems providing visibility and functionality for active management and control of the network
Key initiatives:	**Key initiatives:**
• Address our gaps in capability • Repurpose capability to focus on core and strategic objectives • Lifting the level of digital and analytical capability • Staff development and training	• ADMS phase two implementation for HV visibility of our network • Solutions to provide LV visibility of our network • Plan and implement control functionality of our network • Plan for replacement of final legacy systems and completing integration • Build greater digital and analytical capability

Future network

Open access network system

Strategic objective
A flexible energy platform, enabling customers to choose technology unconstrained by limitations on our network
We will do this by:
• Enabling customers to choose technology unconstrained by limitations on our network • Providing pricing signals and new services that enable customers to make informed decisions on their energy use.
Key initiatives:
• Explore options to alleviate network constraints for hosting DG • Develop flexibility services and pricing options for customers • Monitor evolving energy market developments and opportunities for improving value for our consumer owners

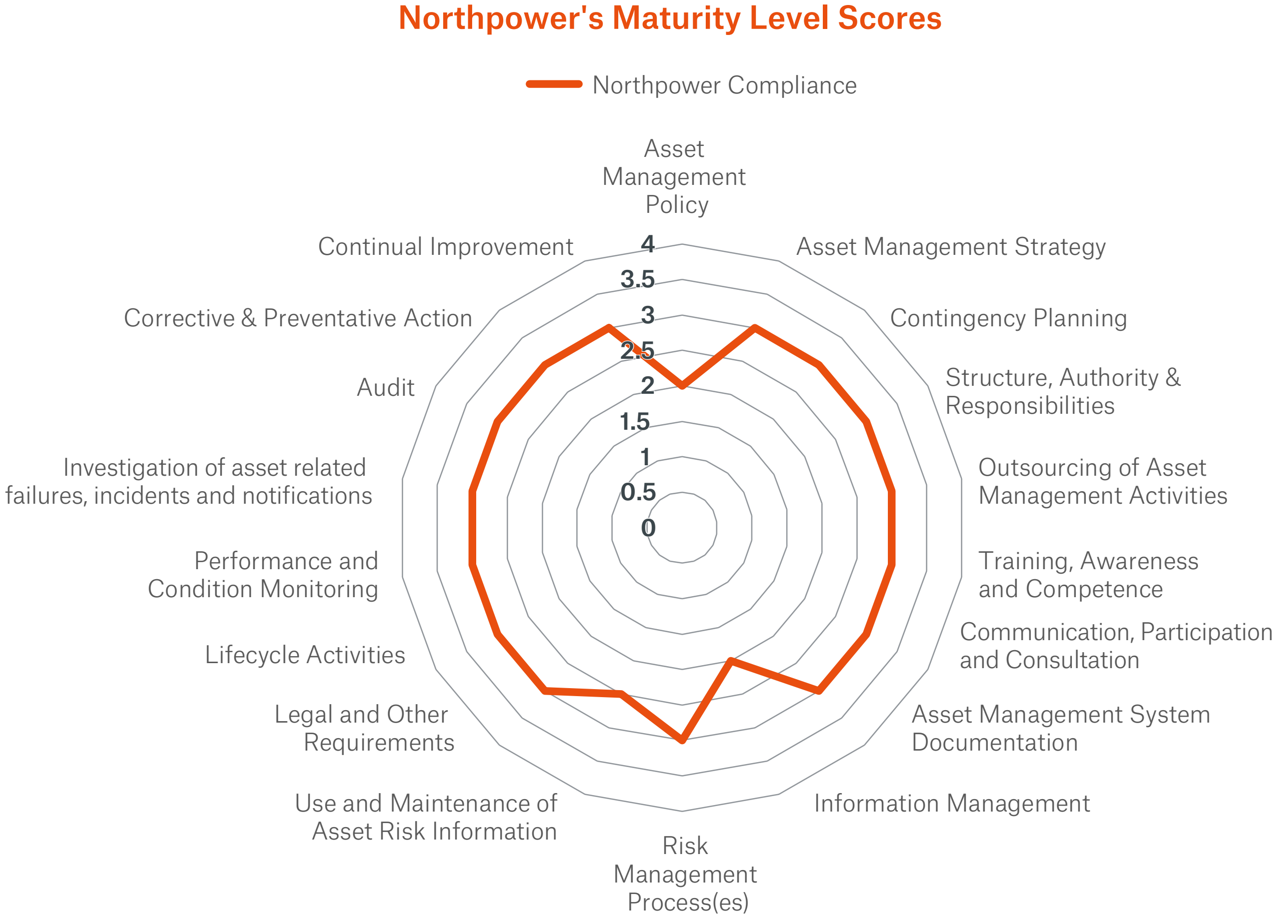
2.6.2 Asset management maturity assessment

As part of the Commerce Commission's Information Disclosure requirements we must provide an overview of asset management documentation, controls and review processes using an instrument known as the Asset Management Maturity Assessment Tool (AMMAT).

This tool provides a clear, detailed and consistent approach to assessing the maturity of an EDB's asset management. We completed a self-assessment in March 2021, which shows an improvement in some areas from our prior self-assessment in March 2018.

Maturity level 0 (Innocence)	Maturity level 1 (Aware)	Maturity level 2 (Developing)	Maturity level 3 (Competent)	Maturity level 4 (Excellent)
The elements required by the function are not in place. The organisation is in the process of developing an understanding of the function.	The organisation has a basic understanding of the function. It is in the process of deciding how the elements of the function will be applied and has started to apply them.	The organisation has a good understanding of the function. It has decided how the elements of the function will be applied and work is progressing on implementation.	All elements of the function are in place and being applied and are integrated. Only minor inconsistencies may exist.	All processes and approaches go beyond the requirements of PA55. The boundaries of Asset Management Development are pushing to develop new concepts and ideas.

Our self assessment score is outlined below and we are largely competent in all areas.



We acknowledge we are still developing in some areas of our asset management maturity and have action plans to move all aspects to at least "competent" over the next two to three years.

Asset management function	Plan
Asset management policy	Communications and engagement plan to increase awareness within the team and wider organisation of the asset management policy, and how it informs asset management decisions.
Information management	The asset management information system has limitations in its ability to support our asset management requirements. We have a programme of work in the AMP in FY22 to undertake a ground up review of the current asset management information system, with implementation of a new asset management information system in the following years.
Use and maintenance of asset risk information	As part of our asset management system review discussed above, we plan to more fully integrate asset risk information into asset management decisions.

Northpower's asset management maturity roadmap is shown in Figure 12. Our focus is on moving our investment decisions for asset fleets from a time and age-based system with some elements of condition-based input, to a condition-based system with elements of risk and criticality.
Our objective is to use a more centralised and controlled asset management system to store and interrogate all asset condition and attribute data, and move to an almost fully automated system to determine future intervention triggers and a rolling ten year asset investment plan. This is one of the key aspects of the new asset management platform we will be progressing in 2022, to replace the present maintenance management system (WASP). The following diagram indicates our assessment of where we currently sit along the asset management continuum.

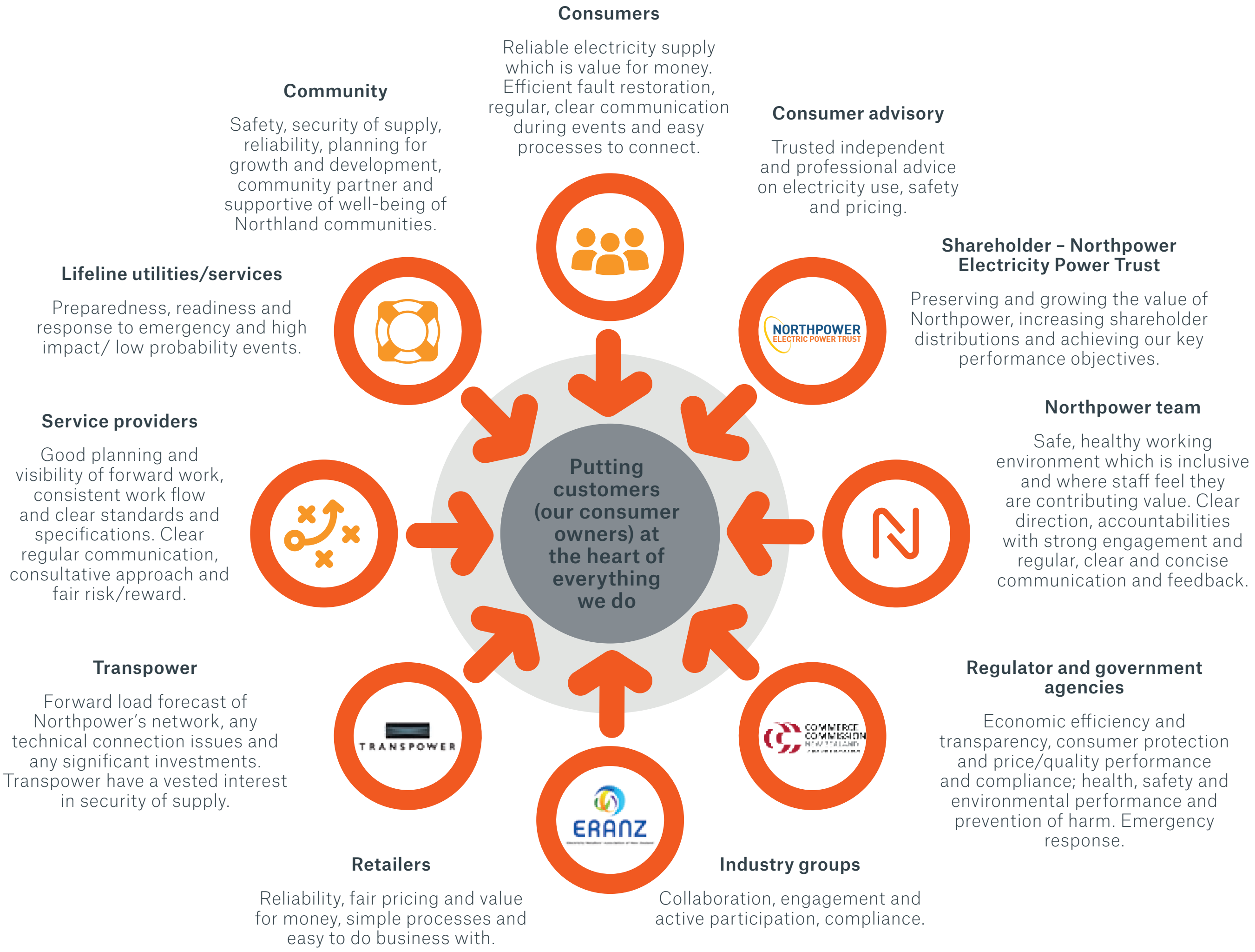
Figure 12: Northpower's asset management roadmap

	Time based	Condition	Risk based	Automated
Data collection	• Specified by defects manual • Recorded what observed • Interpretation by inspectors	• Specified by asset engineers • Records systematised • Interpretation guided by asset engineers	• Specified by asset engineers • Documented with thresholds • Recorded in risk terms	• Specified by asset engineers • Documented with thresholds • Recorded in risk terms • Stored against assets
Data analysis	• Depends on what's reported • Analysed on ad-hoc based • Analysis stored irregularly	• Follows asset management framework • Analysed regularly • Analysis stored irregularly	• Feeds into risk framework • Results stored, managed • Results categorised by risks and their levels	• Data feeds to system • Interpretation of data adjusted by system operator • Possible machine learning • Automatic feed to planning
Asset health	• Age is the only factor • G1 to G2 categorisation	• Condition based • New H1 to H5 condition scale being adopted • For some assets, age will remain in the formula	• Defined for every asset • Aligned with asset risks • Directly feed to risk levels • Stored against assets	• Defined by conditional data flow in the system • Probabilistic base for asset network performance
Asset criticality	• Not established/ad-hoc	• Considered generically • Considered for assets with deteriorated health • Used to smooth out defect remediation as required	• Defined for every asset • Aligned with asset risks • Directly feed to risk levels • Stored against assets	• Set by the system based on the performance preferences • Asset and network risks are interrelated and integrated
Prioritisation	• By contractor • Based on perceived urgency and workflow suitability	• By asset management • Based on known urgency	• By asset management • Presented as a dashboard • Defined by combination of criticality and health	• By system • Adjustable to individual asset and their complex groups • Integrated with other it
Budgeting	• Based on historic data • Forecast by asset age • Managed by expenditure	• Based on a combination of historic and conditional data • Managed by units of work	• Based on organisational tolerance to risk • Managed by controlled risk	• Forecast generated by the system • System generates budget and work plans

2.7 Stakeholder interests

Northpower considers how others may be affected or can be affected by our actions, activities and/ or performance. Development of our AMP considers interests of our key stakeholders into shaping our strategies and plans. Figure 13 summarises interest from our key stakeholders.

Figure 13: Key stakeholder interests



2.7.1 Managing stakeholder interests

Northpower understands the importance of appropriate stakeholder consultation in order to ensure proper planning coordination, dissemination of information and maintenance of good relationships. Figure 14 shows how we manage stakeholder interests.

Figure 14: Managing stakeholder interests

Identify interests via engagement and research

- Customer surveys, focus groups, major customer engagement, data analysis and market research
- Review of major events and quality of supply studies
- Employee feedback and engagement surveys
- Supplier technical assessment meetings
- Service provider engagement and performance meetings

Support interest in asset management practices

- Health and safety planning, auditing and compliance
- Customer growth and demand forecast
- Coherent network planning to ensure we maintain security of supply standards
- Risk management
- Network standards and operational procedures

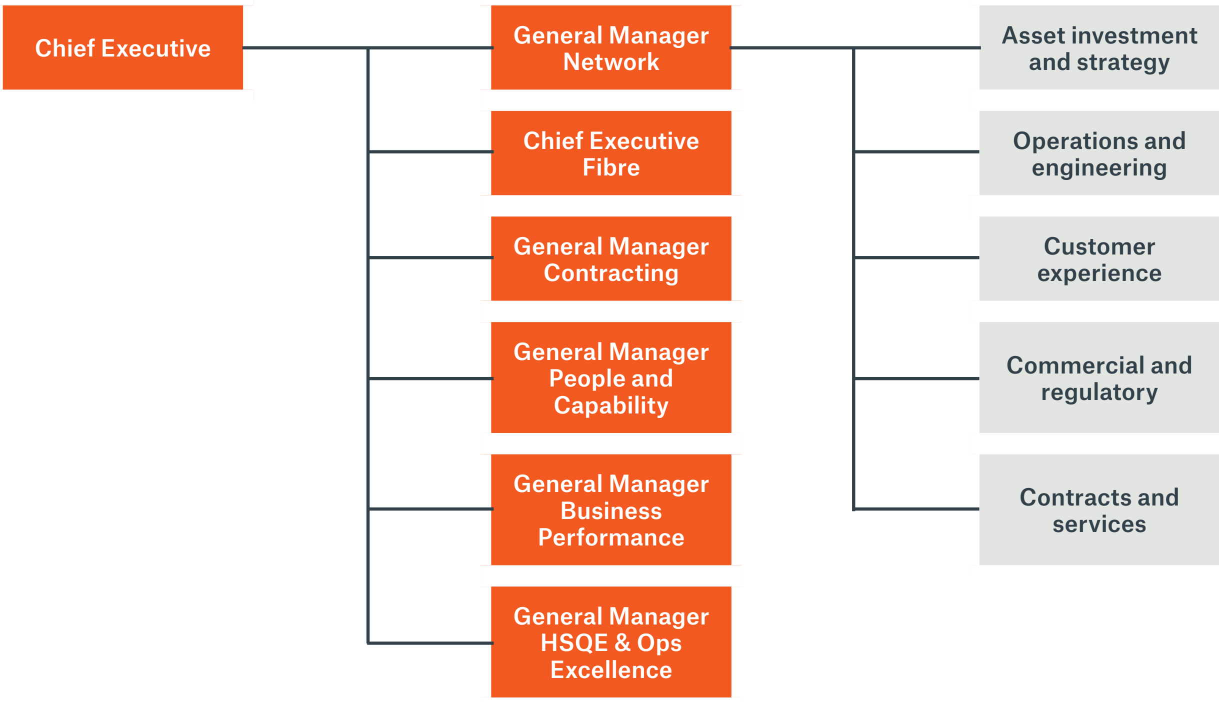
Manage conflicting interests

- Considering stakeholders' interests and needs as part of our development process of our AMP
- Balancing cost of non-supply and investment to provide security of supply
- Cost/benefit analysis
- Delivering on our commitments and objectives to our shareholder as set out in the SCI.

2.8 Accountabilities and responsibilities

Within Northpower, the network division carries responsibility for the asset management functions at Northpower. The General Manager Network leads teams to perform these functions, as illustrated below.

Figure 15: Electricity network division accountabilities



The General Manager Network oversees teams responsible for setting asset strategy and plans, engineering project delivery and operation, customer engagement and managing our relationships with regulators, retailers, contractors and external parties.

Responsibilities include managing Northpower's relations with the community and other key stakeholders, distribution network pricing, network asset management frameworks, asset fleet investment and maintenance, network operation, asset management systems, together with the network development and maintenance plans. The General Manager Network is accountable to the Chief Executive for meeting the network operational and financial targets as set in the Statement of Corporate Intent.

Shared services corporate functions support our electricity business by providing core management frameworks, processes and systems including:

- Health, safety, quality, environment (HSQE) and operational excellence
- Finance, legal and risk
- People and capability (recruitment, on-boarding, learning and development, remuneration and wellbeing)
- Business performance (strategy and planning, data and digital services, information systems, communications and marketing)

2.8.1 Governance of asset management

The board of directors is ultimately responsible for governance at Northpower. The ten year AMP requires approval from the board, which is produced and submitted annually by GM Network and Chief Executive.

Expenditure for significant projects (over $2m) or expenditure that exceeds approved budgets have board approval processes. Examples include:

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

2.8.2 Managing field operations

Northpower's in-house contracting division is the primary field service provider operating on the Northpower network. The Network Contracts and Services Manager manages the interface with the contracting division under a defined governance structure, underpinned by a service level agreement (SLA).

The schedules to the SLA have defined task-based activities determining scope, resources and time required to complete the activities. This provides the ability to benchmark performance and ensure efficiency.

The advantage of this arrangement is the alignment of values, standards and operating practices with Northpower's asset management practice and governance. Secondly, Northpower Contracting is one of the largest electricity distribution contractors in the North Island giving our electricity business access to a wide breadth of capability, a large and mobile workforce should additional resources be required and extensive purchasing power for subcontractors and materials.

Some large value capital works are subject to a competitive tender and evaluation process. This enables benchmarking and ensures that services are delivered at a fair market cost. External contractors and our internal contracting division are subject to the same health, safety, quality and environmental management policies and standards and must be authorised to work on the Northpower network.

2.9 Asset management supporting systems and processes

2.9.1 Overview

Network data is managed across a number of core operational and supporting systems. Data is replicated into a data warehouse environment with analysis and operational visibility provided via structured reports and ad-hoc queries.

Since our 2018 AMP, we have:

- Replaced our end of life legacy SCADA system as part of our programme to shift to active network operation. The first phase of the work was completed in 2020, with the new GE PowerOn advanced distribution management system (ADMS) platform now used to operate our HV network assets.
- Deployed a new CRM system, which as described in Section 4, is progressively being developed to improve our service to customers when interacting with our network.
- Replaced Gentrack retailer billing system with the Axos cloud system.
- Adopted a 'de-coupled' integration philosophy using a 'service oriented architecture' (SOA) and industry standard tools and protocols. The result is a configurable, reusable and scalable integration architecture that supports system inter-operability and enables Northpower to easily integrate with cloud solutions.
- Developed structured reporting accessible via an intranet portal with PowerBI dashboards and Geomedia workspaces providing managers and planners with another layer of decision support.

The planning period covered by this AMP will see the second and third phases of our ADMS programme, which will retire legacy supporting databases, and enable sophisticated new functionality that ultimately will help us manage distributed energy resources on our network. In this planning period, we will also be upgrading our core asset management system. An overview summary of Northpower's electricity systems is illustrated in Figure 16, and further expanded in this section.

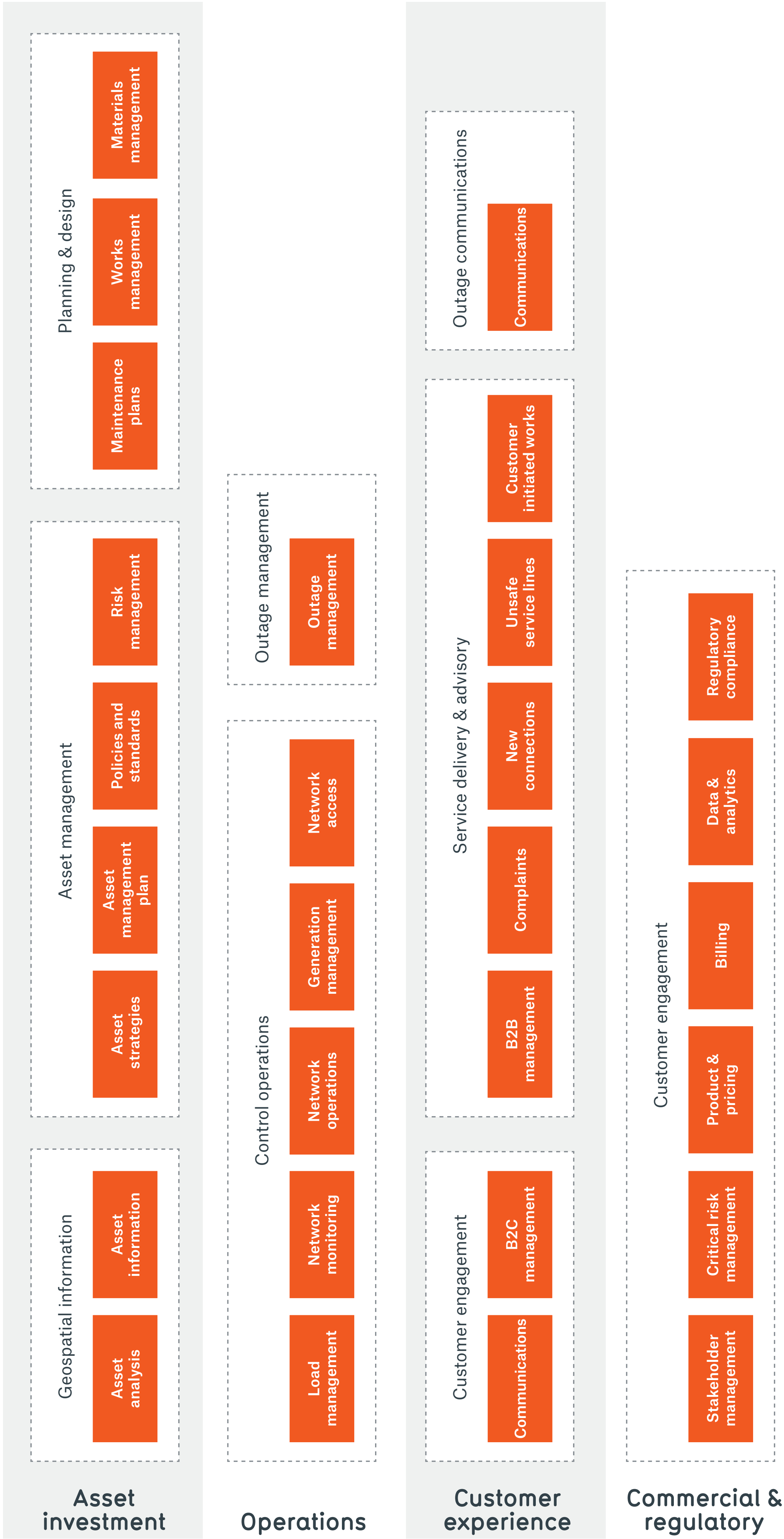


Figure 16: Electricity systems

2.9.2 Controls and integration

Access and security of Northpower systems are managed by dedicated internal staff with regular internal and external auditing.

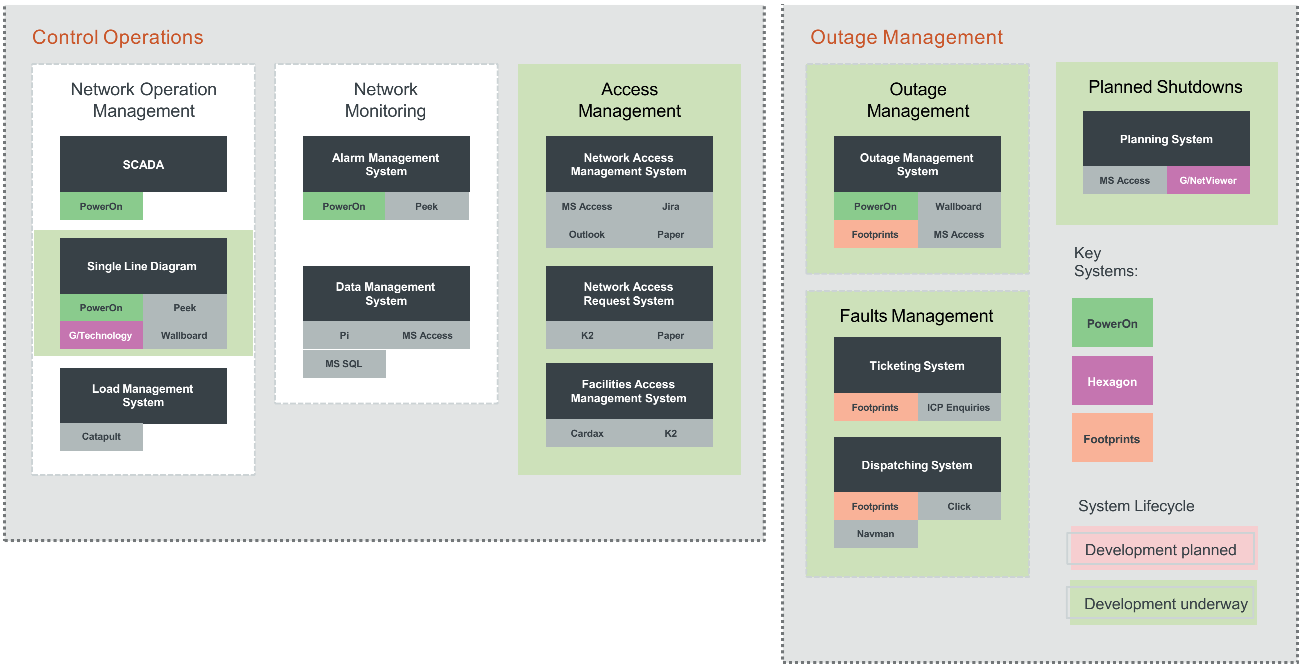
Northpower has a 'de-coupled' integration philosophy, a 'service oriented architecture' (SOA) and industry standard tools and protocols. The result is a configurable, reusable and scalable integration architecture that supports system inter-operability and enables us to easily integrate internal and cloud solutions.

Data from repositories is replicated in a data warehouse environment with analysis and operational visibility provided via structured reports and ad-hoc queries.

2.9.3 Network operations

Northpower's programme to implement an advanced distribution management system (ADMS) underpins our shift to an active network operation. These core and supporting systems and development are detailed below.

Figure 17: Network operations capability



Network operations management

Key systems	GE PowerOn ADMS, Wallboard
Purpose	Real time system control and data acquisition (SCADA). Network management systems.
Data stored	System events, plant status and loading, bus bar voltages, bulk power flows.
Function	The SCADA system records and stores time stamped event, status, loading and voltage data for the purpose of analysing system events (e.g. faults) and capturing network loading and voltage conditions for network modelling purposes.
System lifecycle	The new GE PowerOn advanced distribution management system (ADMS) was implemented to replace our legacy Siemens PowerTG system in 2020, providing a more resilient and cyber-secure solution. Work is currently underway to commission DMS modules of the new GE PowerOn system. This includes building a GIS to ADMS interface for the network model, to support for future LV operations management requirements. The wallboard and current paper based processes for switching management are being digitised.

Network monitoring

Key systems	GE PowerOn ADMS Osisoft Pi
Purpose	Alarms, events, real time system data acquisition and analysis. The Pi system provides a data historian and analysis tool kit.
Data stored	System alarms and events, plant status and loading, busbar voltages. The information is mainly used for reporting and network planning/modelling purposes.
System lifecycle	All network monitoring functions were recently upgraded with the GE PowerOn ADMS implementation.

Access management

Key systems	Access permits database (MS Access)
Purpose	Legacy database used to manage requests for permits to work on the network. This database is currently supplemented with paper, electronic calendars and front end interfaces.
Data stored	Network access requests.
System lifecycle	Work is currently underway to replace custom legacy systems for requests to work on the network (access permits) with a new DMS system integrated to the GE PowerOn ADMS.

Outage management

Key systems	Footprints HV faults database (MS SQL server)
Purpose	Network incident management, outage response management, regulatory reporting.
Data stored	Incidents, outage scope, outage events, storm management.
System lifecycle	With implementation of the ADMS functions in operations, we have scheduled implementation of PowerOn OMS features to help replace footprints and the outages database. The new OMS will enable predictive fault location identification and outage scope management. We intend to integrate this to our customer facing systems, including call taking and ticket management, to help improve customer experience during outages.

Planned shutdowns

Key systems	Shutdowns database (MS SQL server)
Purpose	Legacy Network outage notification planning system.
Data stored	ICP and customer details.
System lifecycle	With implementation of the DMS functions in operations and an extension of the CRM system for ticket management, we plan to retire the legacy shutdowns database in 2021.

Faults management

Key systems	Footprints, Click
Purpose	Faults ticketing, scheduling and dispatch.
Data stored	Customer calls, faults ticket management, crews, schedules.
System lifecycle	We are expanding our Salesforce CRM platform to handle customer calls, fault ticket management and dispatch, which will enable retirement of legacy systems, Footprints and Click.

2.9.4 Customer management

Northpower's investment in processes and a CRM system is evolving to improve core services for our customers including communications on outages and streamlining, customer initiated works and new connections processes. Figure 18 details our core customer management systems.

Figure 18: Customer management supporting systems

Outage communications

Key systems	Salesforce CRM Website, phone system (IVR)
Purpose	Customer communications, telephony, shutdown notifications.
Data stored	Current faults and outages Customer calls, interactions, planned and unplanned outages.
System lifecycle	Our Salesforce CRM system is being extended to handle faults management, replacing our legacy Footprints based system.

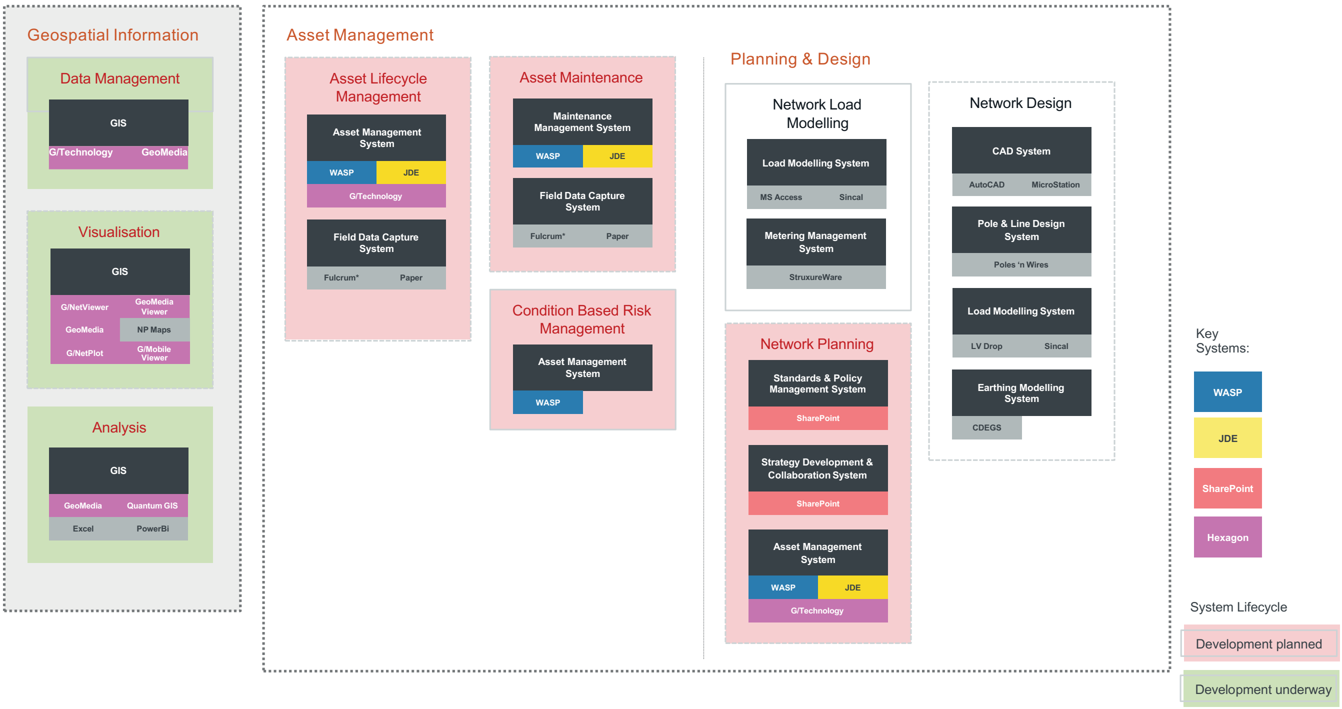
Service delivery and advisory

Key systems	Saleforce CRM
Purpose	Customer initiated works, new connections, unsafe service lines, queries, complaints and faults.
Data stored	Customers, interactions and ICP data.
System lifecycle	Our CRM is under continuous improvement, and being expanded to track and manage all customer facing interactions, engagement and management. The CRM is being integrated into our core network operations, faults management and geospatial systems to improve our service to customers.

2.9.5 Asset investment

Geospatial systems, network modelling and design tools and the WASP asset management system support our investment planning pictured in Figure 19.

Figure 19: Asset investment systems



Asset management

Key systems	EMS WASP Oracle JDE
Purpose	Asset management
Data stored	WASP holds • Asset history. • Annual plan of preventative maintenance tasks – maintenance, inspections and test. • A repository of follow up corrective maintenance tasks including defects captured from inspection. • Repository of inspection records and a record of test and inspection data. • Prioritisation and packaging of work (supported by geomedia spatial analysis toolsets). • Forward planning of capital works programmes. • JDE holds the fixed asset register, and Works Management is used to manage projects on the network.
System lifecycle	The WASP system is end of life and replacement of this system will be scoped during FY22.

Geospatial information

Key systems	Hexagon GIS
Purpose	The master repository of assets and data for all but a few zone substation assets. A fully connected model is used to maintain network topology and asset relationships in interfaced systems. asset data for distribution and most substation assets is mastered in GIS with a subset of this data replicated in the maintenance management system.
Data stored	Subtransmission, HV and LV distribution assets, most substation assets.
System lifecycle	During FY22 Northpower will be rolling out the ESRI ArcGIS suite to improve our analysis and mapping functions.

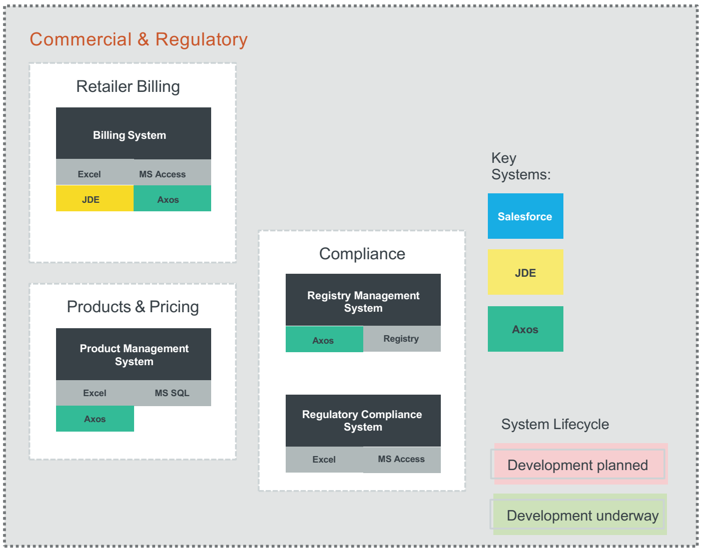
Planning and design

Key systems	PSS/Sincal Sharepoint 365
Purpose	Northpower's system analysis tool used to model the subtransmission and distribution networks. Network models are developed from GIS extracts and loading data is obtained from the SCADA system. The software is further used to simulate future loading scenarios and network strengthening options. Sharepoint is our repository for network standards, and scanned records, historically held in paper archives. Offers enhanced search and retrieval, linking to GIS.
Data stored	Sincal holds network models and case studies. Sharepoint holds Network standards, network management framework, historic construction plans and connections records.
System lifecycle	Recently updated to Sharepoint Microsoft Office 365.

2.9.6 Commercial and regulatory

In early 2021, Northpower implemented the Axos system and retired Gentrack for billing and compliance management. Our supporting systems for commercial and regulatory management are shown in Figure 20.

Figure 20: Commercial and regulatory systems



Compliance and billing

Key systems	Axos
Purpose	Axos Billing is used to calculate lines charges to retailers and direct connect customers. Axos Registry Manager is used to maintain the electricity registry.
Data stored	ICPs and billing information.
System lifecycle	Axos is a new system that replaced the older Gentrack billing system in early 2021.

Northpower

2021 – 2031

Asset Management Plan

Section 3

Risk management

Table of contents

3.1 Introduction

Diligent risk management strengthens our ability to provide a network that is reliable, safe and resilient.

We are committed to proactively and consistently manage risk to:

- Ensure a safe and secure environment for our people, partners and consumers
- Support our purpose, objectives and commitments stated in our SCI
- Pursue opportunities in an informed way, aligned with our risk appetite

Our approach to risk management is grounded in our belief that:

- Every person at Northpower has a responsibility to identify and manage risks
- A healthy and collaborative culture is a vital part of our risk management
- Effective risk management relies on sound judgment, supported by clear evidence
- We can always improve

Risk management is all about enhancing and protecting our value by delivering on our commitments (to our customers, communities and people) and meeting stakeholders' expectations.

3.2 Our risk management context

Our customers and community depend on our service, so it's essential we identify and manage the key risks to the delivery of reliable, resilient and safe electricity. We recognise that we need to be able to continue to supply electricity to our community following high impact low probability (HILP) events including natural disasters like major storms and global pandemics. Our lifelines responsibilities are set out in Section 60 of the Civil Defence Emergency Management (CDEM) Act. As a lifeline utility, we must be able to function to the fullest possible extent, even though this may be at a reduced level, during and after an emergency.

As further context, our region:

- Is at risk of tsunami
- Is subject to extreme weather events, including tropical cyclones
- Has limited reticulated natural gas

3.3 Our role and risk appetite

Our communities of Whangārei and Kaipara depend on our service all day, every day and it is critical that we assess potential risks to our business and develop and implement robust strategies to mitigate these risks. Our board and executive leadership team (ELT) are committed to ensuring that:

- Our exposure to risk is at an acceptable level
- We comply with all applicable laws and regulations

Our risk appetite statement (RAS) articulates the amount and type of risk that we are willing to take in pursuit of our strategic objectives and delivery of our company purpose.

3.4 Our approach to risk management

3.4.1 Legal compliance and risk management standards

Risk management is carried out in accordance with, or informed by, the following standards and legislation:

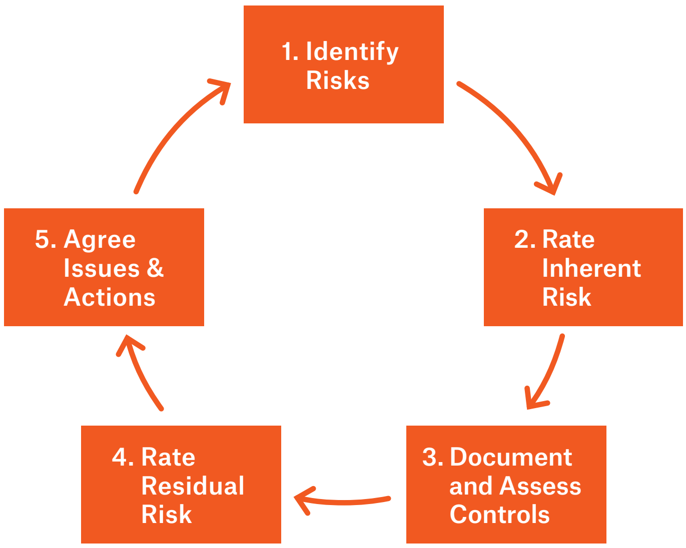
- AS/NZS ISO 31000:2009 Risk Management – Principles and Guidelines
- AS/NZS 7901:2014 Electricity and Gas Industries – Safety Management Systems for Public Safety
- EEA Resilience Guide (2020)
- EEA Security of Supply in NZ Electricity Networks Guide 2013
- EEA Asset Criticality Guide 2019
- The Health and Safety at Work Act
- Electricity Act 1992 and Regulations
- Resource Management Act
- ISO 14001:2004 Environmental Management System

We have a risk management and legal compliance policy (policy) and framework (framework) aligned to ISO 31000:2018. The policy sets out high-level principles and the framework outlines our approach to manage risk and achieve compliance.

A key objective of the framework is ensuring we operate a robust, consistent and coherent risk management and compliance process.

3.4.2 Risk assessment methodology

Figure 21: Northpower's risk management methodology



Our risk assessment methodology adopts the following approach:

1. Identify risks – appropriate stakeholders are engaged to identify new, emerging and changing risks. Specific details relating to how the risk materialises are captured, along with causes and consequences.
2. Rate inherent risk – the consequence and likelihood of each risk is assessed on an inherent basis (i.e. before consideration of the current control environment) using predefined parameters, and the rating is determined using our risk matrix below.
3. Document and assess controls – the key controls in place to mitigate these risks are identified, documented and assessed (from a design and operating perspective), determining an overall control effectiveness rating.
4. Rate residual risk – the consequence and likelihood of each risk is then assessed on a residual basis (i.e. after consideration of the current control environment) using predefined parameters, and the rating is determined using our risk matrix below.
5. Agree issues and actions – based on the residual risk assessment, stakeholders form a view on the response required. The escalation and treatment protocol (defined below) for each risk is determined based on the residual risk assessment.

Figure 22: Risk assessment matrix and risk escalation and treatment protocols

LIKELIHOOD		Low	Minor	Moderate	Major	Catastrophic
	Almost certain (at least once per year)	Medium (11)	High (16)	High (20)	Extreme (23)	Extreme (25)
	Likely (at least once every 1 to 3 years)	Medium (7)	Medium (13)	High (18)	High (22)	Extreme (24)
	Possible (at least once every 3 to 10 years)	Low (4)	Medium (9)	Medium (15)	High (19)	High (21)
	Unlikely (at least once every 10 to 50 years)	Low (2)	Low (6)	Medium (10)	Medium (14)	High (17)
	Rare (less than once every 50 years)	Low (1)	Low (3)	Low (5)	Medium (8)	Medium (12)
		CONSEQUENCE				

Risk rating	Risk escalation and treatment
Extreme	• Immediate escalation for board attention. • Detailed plans to mitigate the risk required.
High	• Immediate escalation for Chief Executive and ELT attention. • Board advised. • Detailed plans to mitigate the risk required.
Medium	• Escalation to management required. • Consideration for the implementation of appropriate cost-effective measures to further mitigate the risk.
Low	• No further escalation required. • Consideration for the implementation of appropriate cost-effective measures to further mitigate the risk.

3.4.3 Risk records

A risk record is maintained for each risk that is applicable to Northpower's electricity network business. This includes:

- A description of the risk
- The causes and consequences of the risk
- A description and assessment of the external environment relating to the risk
- The inherent risk rating
- Details of the key controls in place to mitigate the risk and an assessment of the overall control effectiveness
- The residual risk rating
- Any key issues needing addressing

3.4.4 Risk review

Risk workshops are held at least annually with senior management in our network business to assess the key risks, using the approach outlined above, to support achievement of our strategy and business objectives. Priority is given to progressing action plans that will mitigate the highest residual risks. Risks are reviewed at least quarterly to:

- Track progress of agreed management action plans
- Re-rate risks where appropriate to reflect control improvements or the identification of any new issues.

The results of the annual risk workshop and quarterly risk reviews are reported to our board.

3.5 Our key risks

3.5.1 Current key electricity network risks

The current key electricity network risks are as follows:

Risk	Description
Inadequate health and safety practices	Physical and non-physical harm to stakeholders including staff, contractors and members of the public.
Poor asset performance	Our critical equipment and property is not fit for purpose, malfunctions, is lost or is damaged. This risk primarily relates to network performance being affected by failure of a high value asset, or a series of failures of lower value assets.
Inadequate service design	Network is not adequately designed to meet current/future customer needs and fails to provide the expected level of service.
Failure of critical systems and IT infrastructure	Unavailability or poor performance of critical IT systems and infrastructure.
Cyber security breach	External parties gain unauthorised access into our systems with the intention to defraud or disrupt.
Errors, omissions or delays in internal or external reporting	External statutory/regulatory reporting and/or internal management reporting is inadequate, contains material errors/mis-statements and/or reporting is not prepared, submitted or acted upon within required timeframes.
Errors, omissions or delays in processing financial transactions	Financial transactions processing is incorrect, delayed or not carried out at all. For our network, this risk is primarily the distribution charge invoicing of retailers and large customers.
Inadequate environmental practices	Potential or actual adverse effects on the environment.

Risk	Description
Failure to deliver the strategic benefits of capital investment	Our capital investment initiatives do not deliver anticipated network performance targets.
Incorrect number of people and skillsets	We do not have appropriately qualified and experienced individuals in the right roles.
Inadequate people motivation	Our people are not motivated to deliver the strategy.
Failure to manage / respond to regulatory and compliance obligations	We are exposed to legal or regulatory sanction, financial or reputational loss arising from failure to abide by our compliance obligations.
Inadequate supplier management practices	External or internal suppliers fail to supply services to the standard required for us to meet business objectives.
Inadequate customer delivery practices	Our electricity network fails to deliver the expected level of service to our customers at a fair price.
Inadequate data management	Our critical data is unavailable or unreliable. This primarily relates to asset information, network monitoring, customer, job information and network drawings and data.

3.5.2 Asset failure risks

Equipment failure risk is assessed regularly and is a key input in forming future strategies to manage assets and estimate forward capital and maintenance expenditure.

We draw upon records of incidents, asset failures, inspection, deterioration trends, experience, as well as national and international practices, ensuring all risks associated with equipment types are understood and managed. Our asset fleet strategies provide guidance on maintenance and replacement intervention triggers.

3.5.3 Asset health and criticality assessments

Section 5 'About our network' outlines how we have undertaken analysis to apply a health grading to assets.

We have initially based asset health indicators on the age to condition ratings, however progressively over the next few years, this will be supplemented with condition-based ratings from regular asset inspections. We will then move to the principal determinant of asset health based on actual condition.

Asset criticality is intended to represent the relative seriousness of failure and our progress in its application is outlined in Section 5. We have used the EEA Asset Criticality Guide to determine our asset criticality scale.

Asset criticality has initially been based only on service levels, however criticality based on public safety, workplace safety, direct cost and environment will also be included in future strategies as relevant data is able to be extracted and utilised.

Service levels relate to the electricity supply and customer impact from loss of supply.

The risk reporting matrix we utilise for assets which considers an asset's health rating (or risk) and its criticality rating is also outlined in Section 5. The risk reporting matrix contains five risk grade zones with a combination of health and criticality indicators where intervention response is likely to be similar. The definitions and likely interventions of the risk grade in the reporting matrix are discussed in Section 5.

3.5.4 Health and safety

The Health and Safety at Work Act 2015 and various regulations outline the details of our PCBU risk management obligations. They specify that we must establish and maintain:

a. An appropriate system of risk oversight and management for the entity; and
b. An appropriate system of internal controls for the entity.

This includes implementing direct measures ensuring duty holders comply with relevant New Zealand legislation.

We have additional HSQE risk management related obligations under other legislation and guidelines including, but not limited to:

- Electricity Act 1992 and associated regulations
- Resource Management Act

Our health and safety framework seeks to enable the consistent and consolidated management of all our risk management obligations.

3.5.5 Health and safety framework, policy and strategy

Our approach to health and safety encompasses the relationships between our people, the work they do and the environment they work in, held together with leadership.

The health and safety management framework looks at three dimensions:

- Physical safety
- Physical health
- Psychological/mental health (wellbeing and resilience)

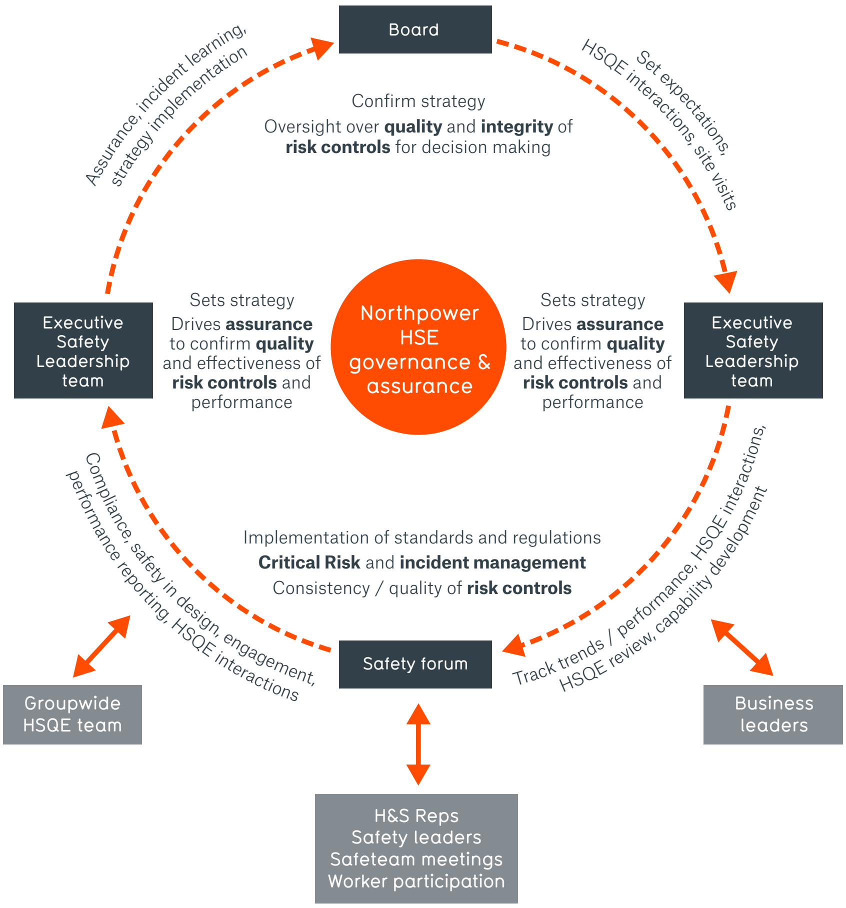
Figure 23: The three levels of Northpower's health and safety management framework

We recognise that a robust safety strategy, including health and safety plans, is essential to achieving our objective. The framework is summarised in Figure 24.

Figure 24: Northpower's health and safety management framework

Figure 25 outlines governance and assurance accountabilities, consultation and communication flows across Northpower and two-way engagement with our safety forums.

Figure 25: Northpower's health and safety governance and assurance

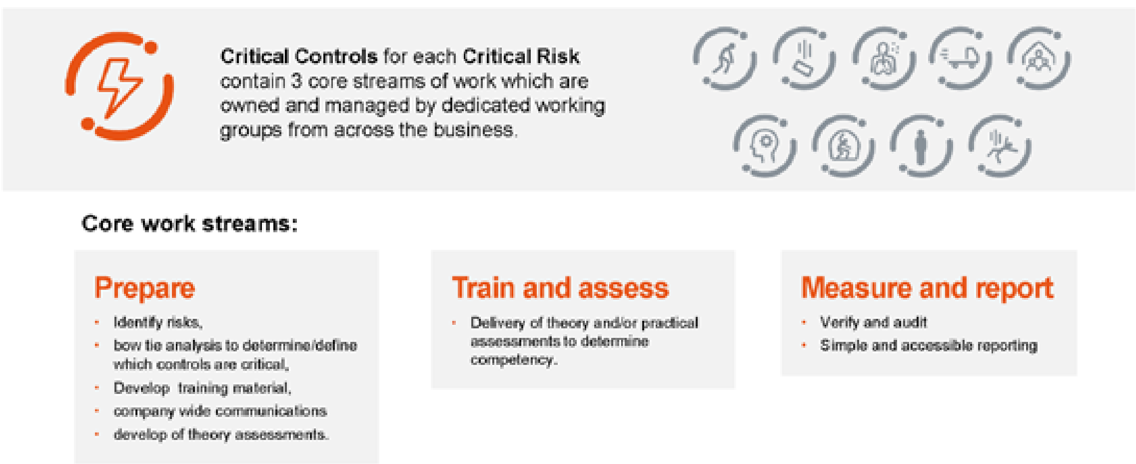


We have identified ten critical risks associated with the management and operations of our electricity network. We are now working through establishing revised and more effective controls for each of these critical risks.

Figure 26: Northpower's critical risks

In 2020, we developed and rolled out a new critical risk control framework toolkit for all employees, which includes core work streams for each of the critical controls (Figure 27).

Figure 27: Northpower's critical risk control framework



3.6 Environment management and climate change

3.6.1 Operating in an environmentally sustainable way

We value the environment we live, work and play in.

As an organisation, we challenge ourselves to consider the potential environmental impacts of our actions or inactions and through active leadership, underpinned by a culture orientated to continual improvement - seeking to identify, monitor and lessen the potential for adverse outcomes for the environment.

We have made commitments to ensure we:

- Are compliant with all statutory requirements and conditions of consents relating to environmental matters under the Resource Management Act 1991
- Constantly review and improve our environmental performance as measured by our objectives and their associated targets
- Commit to re-use, recover and recycle instead of disposing
- Identify, implement and promote ways to improve efficient use of resources, including energy and water
- Continuously improve our environmental system, processes and work practices, ensuring they become more environmentally sustainable
- Include environmental considerations in all business planning, along with options to reduce or eliminate adverse effects on the environment from our activities
- Ensure environmental risks are reviewed at the start of a project or site works and prevention/mitigation measures are established up front
- Work with all stakeholders, understanding and respecting their perspectives, reacting to their requirements where it is possible and safe to do so

3.6.2 Energy efficiency on the network

All new distribution transformers on the Northpower network are subject to MEPS Minimum Energy Performance Standards. We have a significant number of capacitor banks, to help us to manage power factor to a reasonable level – typically better than a .95 power factor.

Standards are used to ensure line and cable rating are fit for purpose on any works, factoring in voltage drop and thermal ratings. Feeders are on average less than 600 connections.

3.6.3 Environmental management

Our purpose, supported by our behaviours and values recognises the role of 'Kaitiakitanga', and our role in protecting the environment.

Our network traverses the outstanding Northland landscape and we recognise that there is potential for our activities to impact the environment. Equally, there is potential for climate change induced events to put the network and security of supply at risk. We understand these risks both require careful management.

We are certified to the international standard ISO14001:2015 Environmental Management System (EMS). This certification confirms that we operate to a compliant environmental management plan with clearly articulated policies, procedures, roles and responsibilities.

Figure 28 shows our electricity network's environmental management framework (EMS).

Figure 28: Northpower's electricity network environmental management framework

Our environmental framework demonstrates our system, its linkages, and the continual challenging and evolution of our approach. Our EMS aims to maximise the positive impacts while minimising negative impacts that our activities, products or services may have upon the environment.

3.6.4 Our contribution to a net-zero emissions economy

The New Zealand government passed the Climate Change Response Amendment Act in 2019 committing to sustained action on climate change and set reductions in emissions. The targets set require New Zealand to reduce emissions (other than biogenic methane) to net-zero by 2050.

We expect to have many roles to play in supporting the transition to a low emissions economy, the 100% production of energy from renewable sources, electrification of the transport system and process, that will generate change and opportunity for our business.

Starting in our backyard in 2021, we will determine our network's carbon footprint, establishing a baseline view of the contribution our operations make to this national (and global) challenge. This will inform future strategies and plans and see the acceleration of programmes to shrink our footprint.

3.6.5 Managing climate change induced risks, climate adaptation

Climate change has the potential to affect the way customers use electricity and may also adversely impact the performance of electrical networks. No longer solely an environmental issue, climate change is a material risk to our network's performance.

We recognise that to ensure a reliable network we need to be ready to adapt and respond to climate change impacts, particularly where there is proven risk of the potential for more extreme events.

We have undertaken a high-level review of these risks and continue to review and reset our emergency response plans accordingly. In time, more detailed modelling of climate change induced impacts through scenario analysis will be used.

The following table lists possible climate scenarios, likely impacts on our electricity assets, possible strategies and proposed actions to better understand potential impacts, and realistic options to improve preparedness.

Climate scenario	Key impacts	Possible strategies	Areas to examine
Increased air temperatures	• Reduced current carrying capacity of lines and transformers • Increased losses in lines due to operating at elevated temperature • Increased peak demand for cooling • Increased bushfire risk due to operations of electricity networks	• Increase thermal rating and capacity of assets • Underground hardware • Use of more heat-resistant materials • Implementation of more effective cooling for transformers • Peak load shedding • Revise and improve bushfire mitigation options	• Assess projected future temperature rises for Northland and where necessary adjust design parameters • Research availability of more appropriate equipment • Consider options to improve future load forecasting • Examine other bushfire mitigation strategies (operations and equipment selection)
Increase in precipitation	• Flooding of infrastructure installed at ground level or in low lying areas • Reduced and more difficult access to equipment • Increases in fault finding and restoration times • Higher and prolonged levels of humidity, reducing equipment performance • Faster growing vegetation	• Improve flood protection for equipment at vulnerable locations (i.e. low-lying areas) • Positioning of new equipment in flood free areas • Transition to more indoor equipment with humidity control	• Scan network for assets in low-lying areas and rank according to criticality of asset • Check access to critical infrastructure (e.g. KEN-MPE 110kV towers) • Consider 'outdoor to indoor' options for key outdoor infrastructure
Sea level rise / increased flooding during high tides / increased storm surge	• Flooding/damage to coastal/low-lying infrastructure • Changes to existing access route to assets	• Implement flood control around our assets (dams, reservoirs) • Improve coastal defences (seawalls, bulkheads) • Build in and/or relocate to less exposed locations • Raise structure levels • Improved drainage systems	• Contact local district and regional councils to understand their forecasted changes to sea levels and likely areas impacted and timeframes • Prepare a draft response plan with phased implementation for consideration

Climate scenario	Key impacts	Possible strategies	Areas to examine
More frequent/ severe extreme events (floods, droughts, high winds)	• Damage to exposed infrastructure from increased cyclonic conditions • Damage to facilities related to soil erosion and slips	• Implement more rigorous structural standards • Increased vegetation management and include drop zone risks • Transition to more indoor equipment	• Investigate options to reduce impact of air borne debris on critical assets (lines and outdoor switchyards) • Explore options to increased vegetation management • Review suitability of design standard for assets

We will evaluate potential impacts of credible scenarios based on what we are seeing regionally and nationally and formulate actions to address any probable shifts. We will also review our planning process, including potential credible impacts of climate change into the project development phase as well as our operations and emergency response.

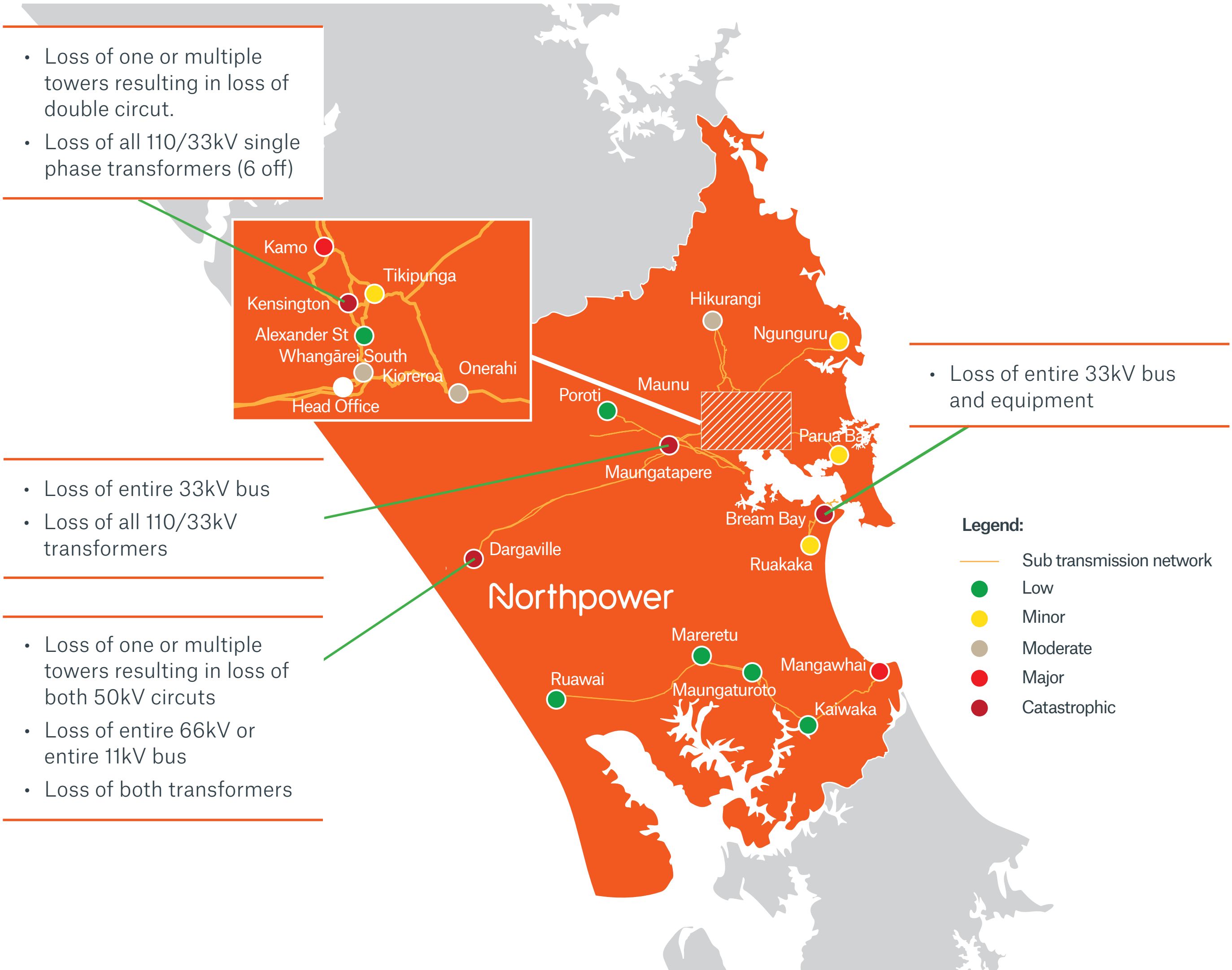
3.7 Our resilience

We operate both indoor switchrooms and outdoor switchyards at our zone substations. Both arrangements have bus coupling circuit breakers to facilitate load transfer, with additional ability to isolate individual circuit breakers. All our 11kV switchgear is the indoor type, with or without bus coupling circuit breakers.

We have used the EEA draft guide on resilience, designed to assist EDBs to assess and improve their resilience to major events. This along with other methodologies has enabled us to identify and quantify what we consider our primary electricity supply resilience risks from an external impact perspective – including earthquakes, extreme weather event, third party interference and major asset failure.

Figure 29 illustrates the Northpower network and locations showing low to catastrophic resilience vulnerabilities.

Figure 29: Heat map showing key electricity network resilience risks (low to catastrophic)



3.7.1 Emergency response and contingency

We have four plans in place for emergency response and contingency:

Coordinated incident management plan (CIMP)

This sets out actions in response to incidents that have (or may have) an impact on supply or the normal operation of the electricity network, and which cannot be managed within normal 'business as usual' operations. It outlines details about:

- Incident response strategy and procedures
- Escalation points for the initiation of the incident management team (IMT)
- Roles, responsibilities and competencies of IMT members
- Reporting required to manage and advise stakeholders on recovery plans and progress.

Network contingency plans

These detail specific actions to be taken when responding to the loss of certain strategic network assets. This includes the switching plans that should be followed, the critical spares that should be deployed, and the key specialist support to be engaged.

As we develop a greater understanding of credible HILP events, we are developing plans to document operational response, assess the feasibility of possible infrastructure resilience, and establish greater access to other strategic spares and specialist resources.

Crisis management plan (CMP)

This documents our response to a major disruptive incident. The CMP details:

- How incidents with potential to become a crisis should be assessed and escalated
- When our crisis management team should be activated
- How a crisis should be managed
- How a crisis should be closed, and the effectiveness of the response evaluated.

Business continuity plan (BCP)

Our BCP documents the key resources, infrastructure, tasks and responsibilities required to support critical business functions in the event of disruption. The BCP highlights the critical processes within each business unit and the strategies to be adopted if the facilities, people, applications, suppliers and equipment we depend on is unavailable.

We test aspects of the CMP and BCP annually, ensuring they can be successfully applied to respond to a crisis and recover critical business functions. This includes physically relocating critical staff and the testing of core systems.

3.7.2 Mitigating disruptions to supply

Every potential event is different and affects different assets - for example, loss of supply at a zone substation could be caused by a single fault on an N security sub-transmission line, or a fire. We have addressed this by creating generic contingency plans for individual assets, balancing investment cost against the impact of non-supply to various customers.

Electricity supply interruption risks are managed by ensuring adequate capacity in our assets to deliver peak power flows under normal and emergency conditions. This leads to redundancy/duplication of supply, depending on whether the additional costs of an outage to a large customer base outweigh the cost of investment. Security categories are:

- N security - a system that is unable to accommodate the full load following the loss of a single power system element
- N-1 security - a system that is still able to accommodate the full load following the loss of a single power system element
- Switched N-1 security – a system that, has a relatively short outage while alternate supplies are connected (such as switching to a back-up high voltage feeder) following the loss of a single power system element.

The following table outlines our network contingency measures to support network power flows in the event of asset failure. These are effectively the generic network risks and their treatment to mitigate.

Asset type	Target network contingencies	Other mitigation measures
Overhead line	Circuits with N-1 or N-1 switchable security: use the remaining circuit while the line is repaired. Circuits with N security: back-feed as many customers as possible through alternative 11kV feeders. Use portable generation to support distribution back-feed for sustained outages.	Large stocks of basic line hardware components are held for general use, e.g., poles, conductors, cross arms etc. We have a 500KVA mobile generator and access to other large generators from local suppliers.
Cable	Circuits with N-1 or N-1 switchable security: use the remaining circuit while the line is repaired. Circuits with N security: back-feed as many customers as possible through alternate feeds. Use portable generation to support distribution back-feed for sustained outages.	Strategic stocks of cables. We have a 500KVA mobile generator and access to other large generators from local suppliers. Access to specialist cable jointers in Auckland.
Transformers	Substation with N-1 or N-1 switchable security: supply on remaining transformer while faulted transformer is repaired or replaced.	Hold strategic spares for components such as bushings. Hold strategic spares of transformers.
Individual circuit breaker	Most zone substations can supply load with an individual feeder circuit breaker out of service. Incomer circuit breakers of N-1 or N-1 switchable security: run on remaining incomer until circuit breakers are returned to service or replaced. Incomer circuit breakers of N security substation: back-feed as many customers as possible through alternate feeds until circuit breakers are returned to service or replaced. Use portable generator to support distribution back-feed, for sustained outages.	Many of the indoor circuit breakers are "rackable", in some cases can take a circuit breaker from a less critical location. Hold strategic spares of most types of circuit breakers, allowing simple defects to be fixed relatively easily.
33kV outdoor bus	Substations with N-1 or N-1 switchable security have a bus section switch. Supply can be restored by opening this switch and re-livening the un-faulted section. Substations with N security option will vary depending on the situation: some faults can be isolated by switches and supply restored using the bypass switch. Back-feed as many customers as possible through alternate feeds until repairs have been done. Use portable generator to support distribution back-feed, for sustained outages.	We hold stocks of insulators, copper bus-bar, conductor, and other components. Consideration is given to the possible conversion of outdoor bus equipment to an indoor arrangement where warranted based on economic and security of supply considerations.
Indoor switch	Substation with bus couplers, open coupler and re-liven unfaulted section of bus: for 11kV switchboards, some configuration (by switching) of the HV distribution network will be required. For switchboards without bus couplers: back-feed as many customers as possible through alternate feeds. In the worst-case scenario, the faulty section may need to be cut away. Use portable generation to support distribution backfeed for sustained outages.	We hold some stocks of bushings and current transformers for the more critical switchboards. For Bream Bay 33kV switchboard we have complete spare cubicles and circuit breakers.

Asset type	Target network contingencies	Other mitigation measures
SCADA system	We have the capability to manually operate substations on site. Note: loss of SCADA will not cause any interruption to supply. The communication network is configured in an N-1 configuration, ensuring all key trunk communication circuits have back-up. We operate "Translay" protection using pilot wires. For pilot wire failures, steps can be taken to disable "Translay" protection and restore supply, all circuits with "Translay" protection have a back-up protection scheme.	We hold a large range of the RTUs, radio system and communication cables. We have a least one means of communication independent from the communications used by SCADA. We are in the process of removing protection that uses "copper" pilot cables.
Control room	A back up control room, fitted for SCADA services, is provided at an alternate location. Duplicate servers are provided at an alternate location. The alternate site is fully operational and duplicates all the functions of the main control room.	Man critical substations. Utilise radio and cell phone communications.

Our other supporting systems (such as our GIS, and WASP asset management systems) are hosted across dual data centres (on-site and cloud based), with real time failover capability, and robust power, comms, and backup facilities. Other systems such as our Salesforce CRM are hosted in the cloud and rely only on provision of internet access.

3.7.3 High impact low probability risks and network resilience

A high-level assessment of major and catastrophic HILP events has been carried out, identifying possible mitigation strategies. These strategies include operational actions, improved recovery strategies and resources, or infrastructure investment options.

These events are listed in the following table and detail possible mitigation options and proposed actions to improve our electricity network resilience. Unless stated otherwise, the investment required to implement these options has not been included in this AMP, as over the next few years we expect to review the mitigation options, consult with our stakeholders and assess whether to make further investments to increase our resilience to such HILP events.

Asset description	Based on financial (VOLL)	Based on SAIDI	HILP scenario	Immediately available actions (operational)	Options - preparedness infrastructure (capex)	Options - recovery (opex)	Options - strategic resources	Next steps - FY22 – FY24
2 x 110kV lines Maungatapere to Kensington	Catastrophic	Catastrophic	Loss of one or multiple towers resulting in loss of double circuit.	Perform 33kV switching to transfer load to MPE. Request Transpower to increase T2 and T4 ratings and increase 33 kV interconnections with Maungatapere and Kensington.	Build one new 110kV line from MPE to KEN. Possibly coupled with a single 110/33kV bulk supply point as a backup close to Kensington.	Deploy emergency response system (Lindsay Towers) as a temporary measure to reinstate 110kV supply to Kensington. Assess and commence works to rebuild tower(s).	Purchase new tower components to the spec of the existing tower.	1) Commission an assessment at each tower site: access, stability, vulnerability to impacts that would de-stabilise, suitability for the deployment of emergency response system (ERS). 2) Define scope of works to improve any shortfalls in 1. 3) Increase surveillance of towers.
Kensington 33kV bus	Catastrophic	Catastrophic	Loss of entire 33kV bus.	Perform 33kV load transfers to adjacent centres. Deploy generators to strategic services first, then others. Carryout sufficient repairs to get half the bus operational.	Design and install a third 33kV bus in a strategic location as a backup. Reinforce supply to Whangārei from Maungatapere GXP.		Purchase spare bus components and equipment to repair bus.	1) Investigate option to build a separate 33kV bus arrangement as a backup. 2) Investigate 33kV augmentation options to increase transfer capacity from Maungatapere regional substation to Whangārei substations that could supply loads to Kensington. 3) Investigate risk scenarios at site and options to mitigate.

Asset description	Based on financial (VOLL)	Based on SAIDI	HILP scenario	Immediately available actions (operational)	Options - preparedness infrastructure (capex)	Options - recovery (opex)	Options - strategic resources	Next steps - FY22 – FY24
Kensington 110/33kV transformers	Catastrophic	Catastrophic	Loss of all 110/33kV single phase transformers (six off).	Same as above.	Install third 110/33kV transformers in nearby location as a backup that are seismic rated.	Install 3rd 110/33kV transformers in nearby location as a backup, that are seismic rated.	Secure a 110/33kV 3 phase strategic spare TX.	1) Investigate purchase and possible installation as a hot spare, and additional 110/33kV TX. 2) Assess risks associated with Kensington site and mitigate as far as practicable.
Bream Bay 33kV bus	Catastrophic	Catastrophic	Loss of 33kV bus and equipment.	Carryout repairs that are feasible to reinstate 33kV to refinery. Trustpower diesel generators to supply 11kV to 11kV network.	Install bypass and divert 33kV cables into new RMU arrangements if possible, to supply refinery direct from GXP.	Continue with project to separate 33/11kV Northpower transformers and switchboard from Northpower 33kV buses.	Establish mobile 33kV switch room/ control centre and connect to 33kV incomers and exit cables to refinery.	1) Continue with projects to separate the 33kV and 11kV switch rooms as per AMP. 2) Investigate how our 33kV switch room could be bypassed so the refinery is supplied directly from GXP as a backup option. 3) Investigate mobile 33kV switch room/ control centre.

Asset description	Based on financial (VOLL)	Based on SAIDI	HILP scenario	Immediately available actions (operational)	Options - preparedness infrastructure (capex)	Options - recovery (opex)	Options - strategic resources	Next steps - FY22 – FY24
Maungatapere 33kV bus	Catastrophic	Catastrophic	Loss of entire 33kV bus.	Perform whatever 33kV load transfer possible. Deploy generators to strategic services first, then others.	Design and install a third 33kV bus in a strategic location as a backup. Consider an outdoor to indoor (ODID) conversion.	Reinforce the 33kV supply to Whangārei from Maungatapere GXP.	Secure spare switchgear and equipment to rebuild bus.	1) Investigate option to build a separate 33kV bus arrangement as a back-up. 2) Investigate 33kV augmentation options to reinforce 33kV supply from KEN to ALE substations that could supply loads to Maungatapere. 3) Investigate risk scenarios at site and options to mitigate. 4) Consider outdoor to indoor (ODID) conversion.
Maungatapere regional substation 110/33kV transformers	Catastrophic	Catastrophic	Loss of all 110/33kV transformers.	Same as above Carryout sufficient repairs, if possible, using parts from other 110/33kV transformers.	Install third 110/33kV transformers in nearby location as a backup that are seismic rated.		Secure a 110/33kV 3 phase strategic spare TX.	1) Investigate purchase and possible installation as a hot spare a third 110/33kV TX. 2) Assess risks associated with Maungatapere site and mitigate as far as practicable.

Asset description	Based on financial (VOLL)	Based on SAIDI	HILP scenario	Immediately available actions (operational)	Options - preparedness infrastructure (capex)	Options - recovery (opex)	Options - strategic resources	Next steps - FY22 – FY24
Dargaville 66kV bus.	**Major**	**Catastrophic**	Loss of entire 66kV bus	Perform whatever 11kV backfeeding is possible. Deploy generators to strategic services first, then others. Carryout whatever repairs are possible to get half of the 66kV bus online or build a temporary outdoor 66kV bus.	Examine option to use proposed distributed energy resource (DER) on West Coast to supply 66kV and route to a repaired portion of the bus, or onto a temporary bus to get 66kV to at least one transformer. Requires 11kV switchboard to be operational.	Rebuild the 66kV bus.	Secure spare switchgear and equipment to rebuild bus	1) Investigate if 66kV from a large distributed energy resource (DER) in the region could become the generator if the 66kV from Maungatapere GXP is lost. 2) Examine an arrangement that enables the 66kV bus to be bypassed if existing 66kV bus is not operational.
Dargaville 11kV bus.	**Major**	**Catastrophic**	Loss of entire 11kV bus	Same as above.	Establish sites in order to establish RMUs and reclosers in order to bypass the 11kV bus.	Bypass the 11kV bus and establish suitable arrangement of RMUs and reclosers as temporary 11kV feeder circuit breakers.	Secure spare switchgear and equipment to rebuild bus.	1) Investigate the option to bypass the existing 11kV bus by deploying RMUs and reclosers to connect the secondary side of the 66/11kV TXs to the network. 2) Consider other options to improve security of the existing 11kV bus arrangement.

Asset description	Based on financial (VOLL)	Based on SAIDI	HILP scenario	Immediately available actions (operational)	Options - preparedness infrastructure (capex)	Options - recovery (opex)	Options - strategic resources	Next steps - FY22 – FY24
Dargaville 2 x 15MVA transformers	Major	Catastrophic	Loss of both 15MVA transformers.	Same as above.	Secure and install at least one spare 66/11kV TX in a temporary location close to 66kV bus and 11kV bus - deploy as a hot spare.	Inject 33kV into one of the MPE to Dargaville 66kV lines and power on loan 33/11kV mobile substation to supply 3.75 MVA. Shortfall in capacity to be restored by deployment of strategically located generators. Proceed with proposal for establishment of our own 33/11kV mobile substation (FY22-24).	Purchase one 66/11kV strategic spare TX.	1) Examine the purchase of a spare 66/11kV power transformer. 2) Consider its installation as a hot spare in a secure location. 3) Continue with the establishment of a 66/33/11kV mobile substation FY22-24.
2 x 50kV lines Maungatapere to Dargaville	Major	Catastrophic	Loss of one or multiple towers resulting in loss of both 50kV circuits.	Perform whatever 11kV load transfer possible. Deploy generators to strategic services first, then others.	Build new 66kV line from MPE to DAR to establish an alternate 66kV ring. Possibly coupled with a single 50kV bulk supply point as a backup close to Dargaville.	Deploy emergency response system (Lindsay Towers) as a temporary measure to reinstate 50kV supply to Dargaville, or build a temporary or permanent 66kV bypass.	Purchase components to build one new tower or purchase as an assembled item.	1) Commission the assessment of each tower site in terms of access, stability, vulnerability to impacts that would de-stabilise, suitability for the deployment of ERS. From this, develop mitigation plans to address. 2) Increase surveillance of towers. 3) Investigate bypass options in tower locations as a contingency plan.


ECEPTION

Northpower

2021 - 2031

Asset Management Plan

Section 4

Customer experience

Table of contents

4.1 Introduction

Our owners are also our customers – every customer connected to our network is an owner, represented by the Northpower Electric Power Trust (Northpower Trust). Trustees are elected by the community and represent the customers through defining the desired outcomes to be achieved by Northpower on behalf of our consumers, and engage with directors on long term matters affecting Northpower's business strategy.

This is reflected in the service level targets which we set and monitor. Our targets are classified into two groups - customer orientated and network reliability performance. These measures include subjective service levels (measured by surveys) along with quantitative technical service levels.

'Getting close to our customers' is one of our key focus areas of our asset management strategy. Our aim is to better understand the views of our customers and stakeholders and what they want so we evolve our services and network to best meet their changing needs.

This section outlines how we engage with our customers, understand their needs and what they expect from us in terms of service levels. We'll outline how we measure our performance and our plans to further develop our customer engagement and service in the future. We also review our performance against service levels and the initiatives we have underway to ensure a continuing high level of service to our community.

Every connected customer is one of our owners. We work hard to better understand our customers to give them a voice in our decision-making.

What customers want:

- ✓ **Easy to connect**
- ✓ **Affordable energy**
- ✓ **Security and reliability**
- ✓ **Support when things go wrong**
- ✓ **Easy to follow information to answer their questions**

4.2 Customer engagement

In addition to operating and maintaining our network, keeping our network operating sustainably is also about knowing our customers, understanding their needs and aspirations so that we can ensure our service remains relevant in their lives.

We do this by actively consulting with our customers. We seek out customer views on future investment plans -what matters most to them and their experience in dealing with us. In 2018 we launched our dedicated customer experience team with the focus of putting customers at the heart of all we do. Customer views and feedback are incorporated into our strategies through regular monthly and annual surveys, market research, and engagement with special interest and community groups, direct consultation and ongoing customer feedback.

We are also looking to better understand customers' views and behaviours for adopting new technology and their aspirations for managing their energy use in the future. We see a role for us in helping our customers get the most from their energy choices to help them drive down the total cost for their energy.

Figure 29: Northpower's customer engagement model

4.2.1 "Always on" customer contact centre

Our Customer Experience and Network Operations teams provide a 24/7 customer contact centre. We talk to around 3,500 customers per month over the phone and in person. We're also available through social media and web chat channels where approximately 4,500 customers per month engage with us.

While responding to requests and helping customers get the information they require, we are able to keep track of key trends and concerns through our customer relationship management (CRM) system. Reviewing these trends helps us identify and improve our processes. Emails to customers include a survey button with a simple satisfaction score and comment area. This feedback is considered and valued to further enhance our service to customers.

4.2.2 Customer engagement on major projects

Customers affected by major projects are consulted and their views are taken on board during the project planning phase. Changes to planning dates or the provision of generation are often considered and provided where appropriate.

Prior to the recent build of Maunu substation, we invited local iwi and all neighbouring property owners to an information sharing event and sod turning. On completion, all stakeholders, neighbours and the public were invited to come and tour the new substation. This was a valuable learning exercise for our team who were able to better understand customers' views and questions.

Members of the community, iwi, council and Northpower team during the Maunu substation blessing and sod turning at the commencement of the project.

4.2.3 Monthly customer surveys

We engage an independent customer research agency to carry out monthly surveys on all customers who have had contact with us in the prior month – either a new connection, customer initiated works or where they have requested a fault response. Customer satisfaction is measured across key touchpoints and verbatim comments are reported along with net promoter score and satisfaction results. Feedback is reviewed by customer and operations staff and performance scores are reported to the board monthly. Changes are made when required to ensure continual improvement.

4.2.4 Annual survey

An annual survey of 400 customers (both commercial and residential) across the region is undertaken by an independent research company. Customers are called and invited to give their views on a range of questions, around what is most important to them and how we are doing in those areas. The results of this survey are discussed in section 4.2.6 What customers have told us and in Section 4.6 Performance.

4.2.5 Stakeholder engagement

We have recently enabled a wider range of approved contractors to undertake customer connections to the network. This has resulted in positive change for our stakeholders and customers – providing customers with a choice and new business opportunities for stakeholders.

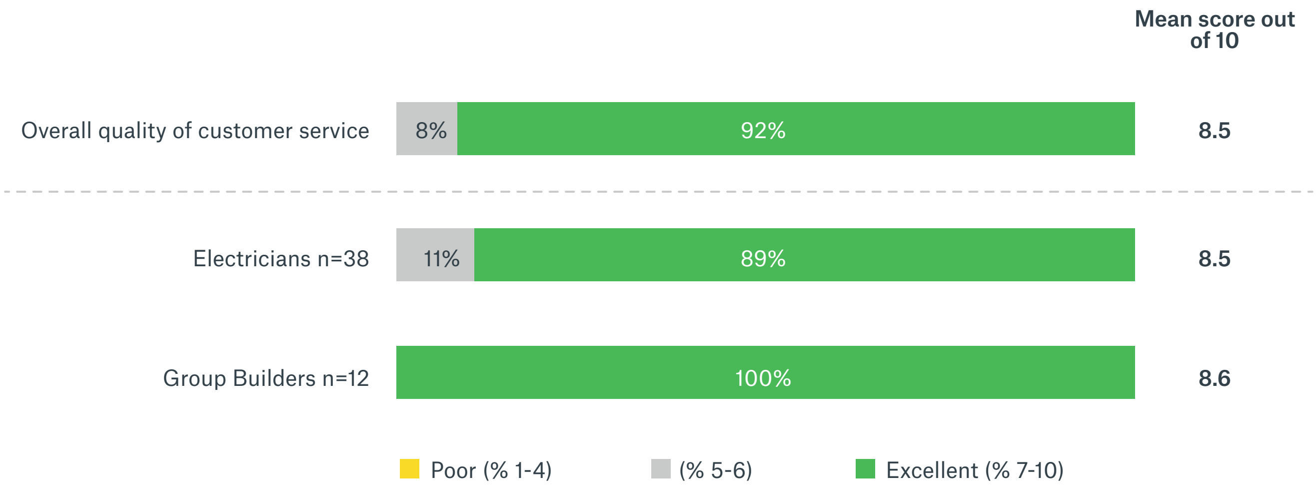
Ongoing meetings with key stakeholders in the new connections area, such as electricians, builders, developers and community groups, helps us understand what is important to them and how we can improve our service. This has been instrumental in directing the changes to our processes and services.

Following this period of change we commissioned an independent research organisation to understand how changes had been received by stakeholders, and it showed that 92% of our stakeholders are satisfied with our level of service.

71% of electricians who have completed new connections rate their recent experiences as better than before

Source: Stakeholder Satisfaction Survey – New Connections, August 2020

Figure 31: Stakeholder Satisfaction Survey – New Connections, August 2020



We are planning to increase our commitment to seek our customers' views through establishing stakeholder and customer panels, as well as continued formal surveys and community engagement around major projects.

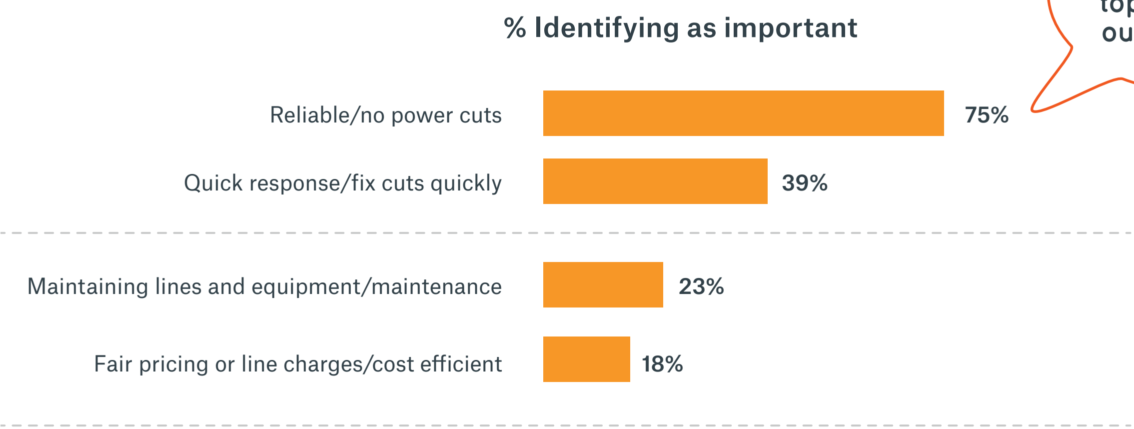
Our key stakeholder engagement also includes consultation and feedback from our electricity network team, shared services teams and our contracting partners. An annual survey of network staff and our service provider, Northpower Contracting, seeks feedback on service delivery performance and areas for improvement. This feedback helps prioritise improvement initiatives.

4.2.6 What our customers have told us

Through engagement, survey and conversations, our customers are consistent on what matters to them most. Our customers continue to rate reliability as their highest priority. Responsiveness (quick restoration of power) is also highly important. They recognise that an investment in maintaining the lines is important to achieve this, but want to ensure we balance this with being cost-efficient so that pricing remains fair. They've told us their key priorities are:

These priorities are fundamental to how we manage and operate our network.

Figure 32: Customers' top priorities as identified in annual customer survey, March 2020



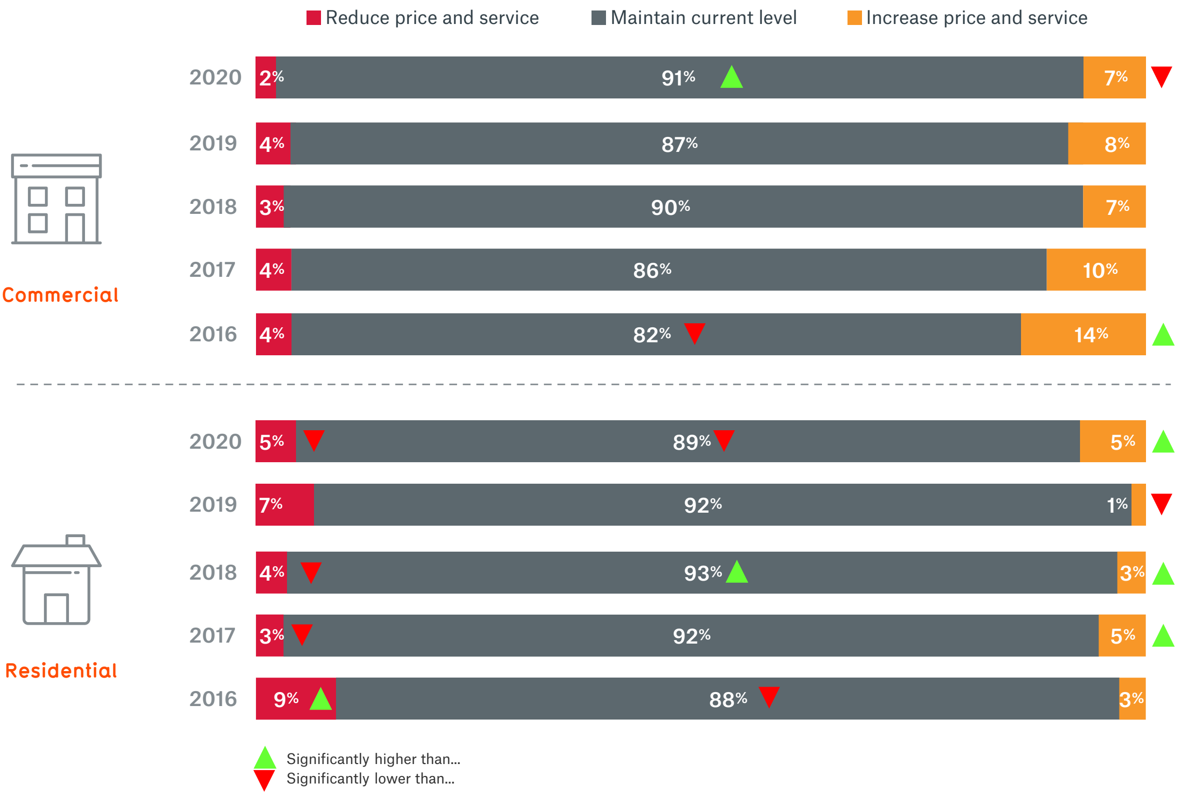
Network reliability is the top priority for our customers

4.2.7 Customers are happy with existing reliability levels

When surveyed, the vast majority of customers want existing service levels maintained, and these results have been reasonably consistent over the last five years. This is an important input when determining the level of network investment into reliability associated projects.

Customers would like our current levels of reliability and responsiveness to be maintained, but costs managed.

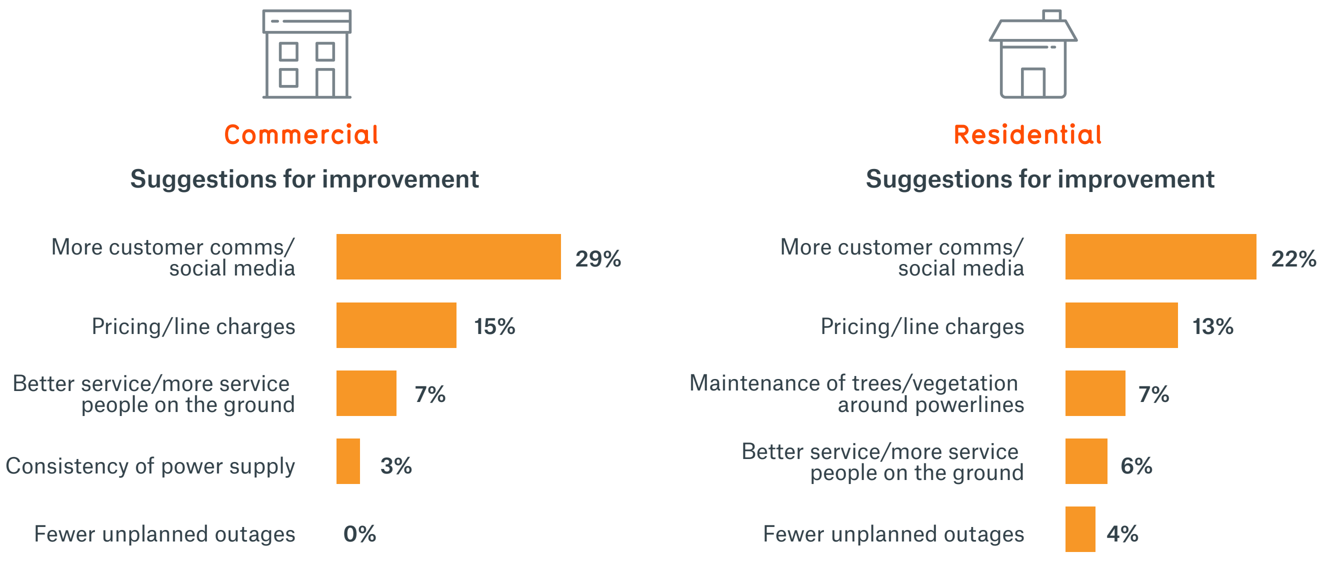
Figure 33: Preferred level of service, annual customer survey March 2020



4.2.8 Communication is increasingly important

In the last annual survey, when asked what we could do better, the most common response was a desire to see more customer communications, including the use of social media.

Figure 34: Suggestions for improvement, annual customer survey March 2020



The customer feedback we receive reinforces the increasing expectations of real-time information about network outages and planned works. As well as advising customers of planned outages well ahead of time, we now publish both planned works and unplanned outages on our website. For large unplanned outages, or events such as storms, we also utilise social media channels like Facebook.

This is becoming a preferred communication channel for many customers and is utilised for updates around network plans, investment news and outage information sharing, as well as keeping customers engaged.

4.2.9 Investing in technology to improve customer service

We are furthering our investment in our customer experience team to improve customer service. We have recently invested in a new customer relationship management (CRM) system which allows us to keep track of all interactions and requests, ensuring we are keeping our promises to our customers.

One of the key touchpoints that customers identified could be improved was our new connections process. We have used CRM to help better manage this process and feedback around the improvements has been positive. It has also resulted in reduced time to get a connection livened.

We have introduced a new customer transaction portal known as Northpower Service Central following customer feedback around making it easier to connect with us online. From the website www.service.northpower.com customers can request multiple services online at once from new connections through to cable locations.

Figure 35: Northpower faults and outages on line information

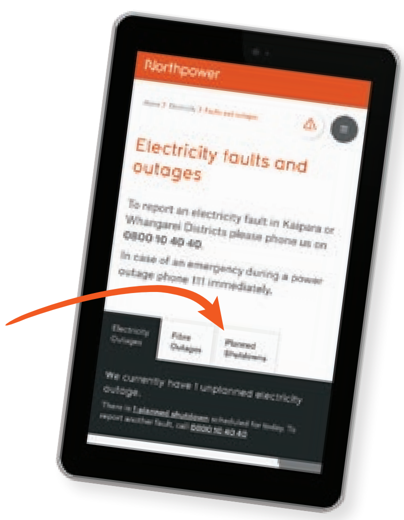
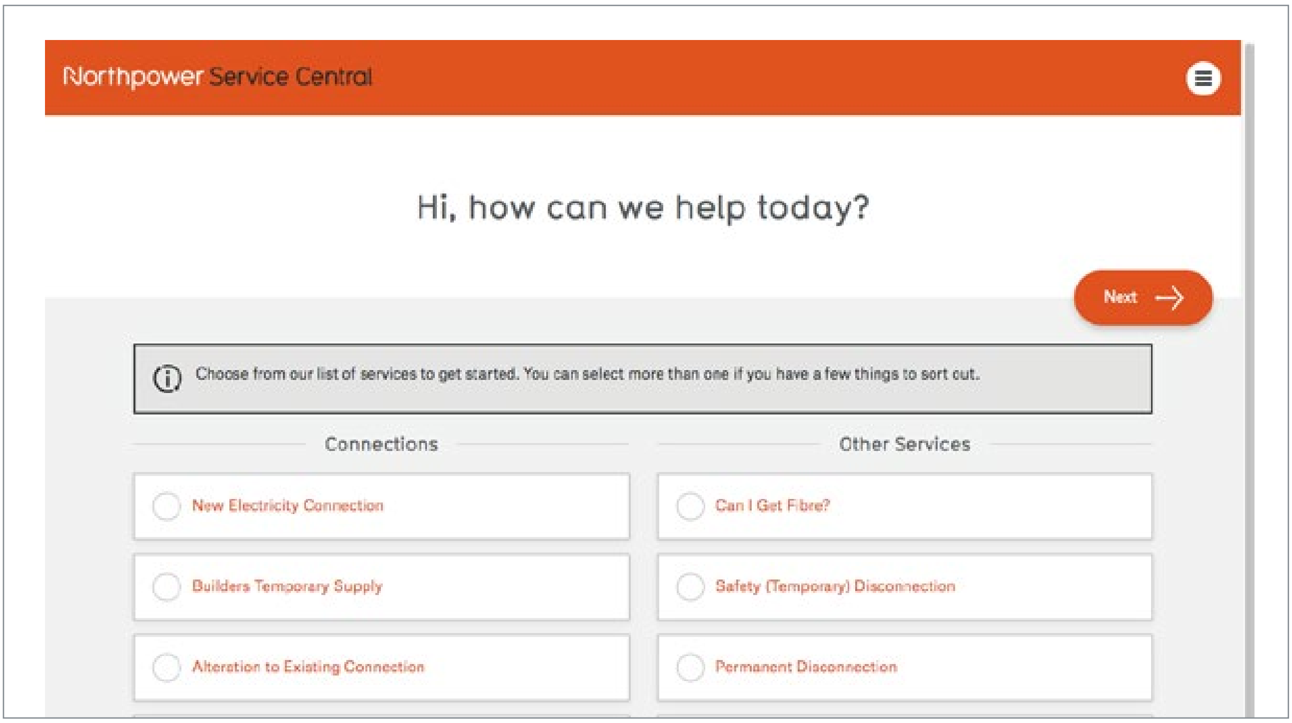


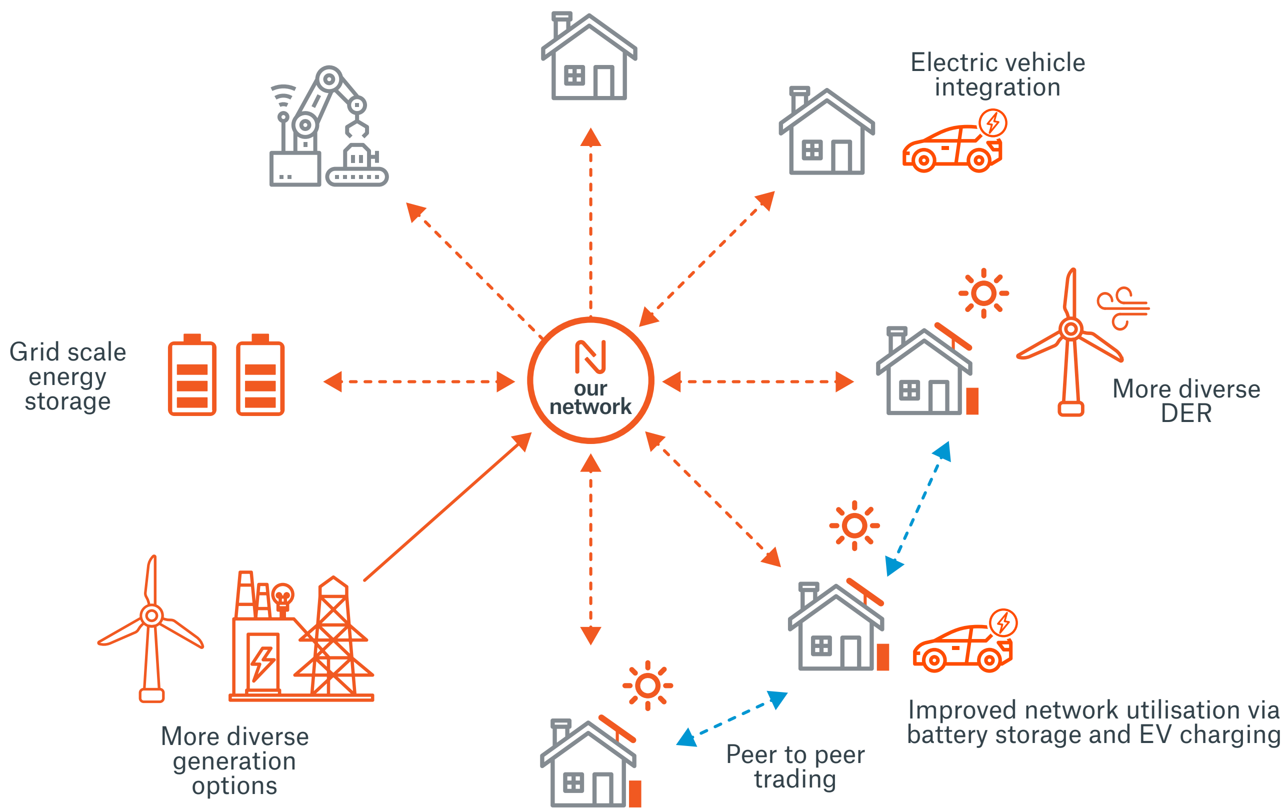
Figure 36: Northpower Service Centre portal enabling customers to order services and connections online



4.3 Looking to the future

Customers have told us that ensuring the network is able to manage their future energy needs and choices is important. We're investing and preparing for the expected changes to ensure our network is resilient and able to cope with these changes, whilst ensuring pricing remains fair.

Figure 37: Supporting our customers' energy future



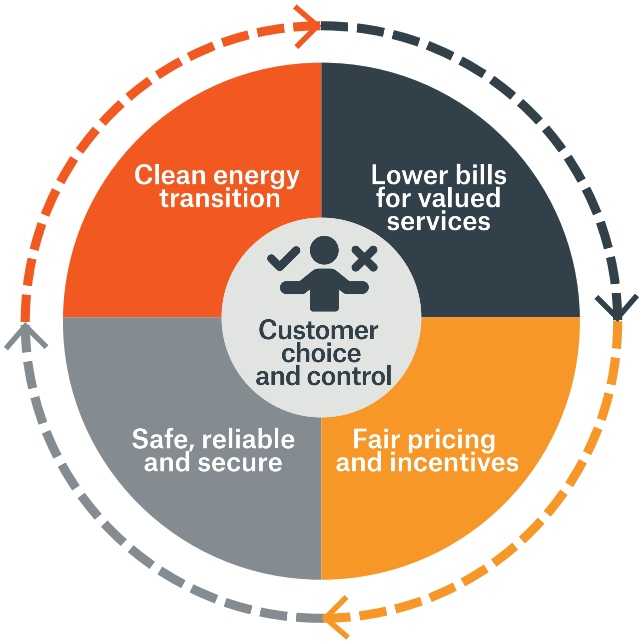
Our strategy to support our customers' energy future includes:

- Engaging with customers, supporting their journey to new energy markets, and making it easy for them to access new solutions.
- Supporting and educating consumers so they can maximise the value they receive from their energy use, by continuing to provide independent, trusted advice.
- Ensuring fair and equitable pricing across all customer groups.
- Partnering with providers, other distribution businesses and industry parties to avoid complexity and creating a 'plug and play system'

We take a balanced approach to supporting our customers' energy future, acknowledging we need to balance a range of customer outcomes.

- Customer choice and control
- Clean energy transition
- Safe, reliable and secure electricity supply
- Lowering total cost of energy
- Fairness and incentives in our network pricing

Figure 38: Our approach to supporting our customer's energy future



4.4 Performance measures

In this section we set out how we measure our performance. Consistently, customers have told us that a reliable electricity supply remains their top priority and this is a key measure of our service performance. We also monitor other key performance indicators such as safety and customer satisfaction as set out in our SCI. Additionally, we monitor key measures aligned more directly to our asset management strategy and objectives,in public safety, environmental management, efficiency and legal compliance.

We also discuss the targets for these measures and our performance. It is noted that for some measures we have not set a specific target as we believe in some instances this would be counter-productive.

4.4.1 Network reliability

Northpower recognises that network reliability is a key priority for our consumers. Ensuring a safe, reliable and resilient system is a key focus area of our asset management strategy and a cornerstone of our company's purpose.

We measure our network reliability using the Commerce Commission measures to assess EDB network performance - SAIDI and SAIFI. We have also historically used "faults per 100km" as an indicator of network health.

4.4.2 Public safety

We are committed to collaboration across Northpower to provide a safe reliable network and a healthy work environment around our assets. We take all practical steps to minimise the risk of harm to the public, our service providers and our people. Maintaining a safe and healthy working environment while working on and near our assets benefits everyone and is achieved through collaborative effort.

To ensure our network does not present significant risk in terms of public safety we measure compliance with the Electricity Safety Regulations 2010. We certify to NZS7901:2014 Electricity and Gas Industries - Safety Management Systems for Public Safety. Compliance requires an audit by an accredited auditor to be carried out at least once every three years. Surveillance audits are carried out annually between the accreditation audits. We passed our last accreditation audit in January 2021.

The following key performance indicators are used to provide assurance of the public safety management system. Events that may cause the public harm are investigated and the measures are reviewed annually.

- Number of public harm events
- Number of known near misses that could have caused public harm

4.4.3 Environmental

We are committed to being environmentally responsible. This is consistent with our purpose - 'Kaitiakitanga'. Northpower's environmental management policy communicates our principal commitments to ensuring we do not cause harm to the environment.

The environmental measures in relation to the operation of our network are:

- The number of incidents that result in permanent or ongoing environmental harm due to the failure of an asset, associated containment system or our work practices.
- Compliance with environmental legislation as it relates to our operations.

These measures are reviewed by the electricity leadership team on a quarterly basis.

SF6 gas

Sulfur hexafluoride (SF6) is a potent greenhouse gas that is used as an interruption medium for switchgear. We are committed to minimising Northpower's SF6 emissions and carefully monitor and report losses in order to comply with the compliance level set by the Ministry for the Environment of 1% losses as stated in the "Memorandum of Understanding relating to Management of Emissions of Sulphur Hexafluoride (SF6) to the Atmosphere".

Oil spills

Northpower operates oil containment facilities, has oil spill mitigation procedures and staff are trained in mitigating this risk.

4.4.4 Efficiency

Economic efficiency

Economic efficiency reflects the level of asset investment required to provide network services to customers, and the operational costs associated with operating, maintaining and managing the assets. We benchmark ourselves against our peers and the industry average using the following measures of economic efficiency:

- Operating expenditure per annum per customer
- Operating expenditure per annum per line length

Network utilisation

We calculate network utilisation as the maximum demand experienced on the network, divided by the distribution transformer capacity on the network.

Our strategy aims to ensure maximum return on investment by ensuring good design and lifecycle management practices. If we specifically target levels of transformer utilisation rather than transformer utilisation and low voltage reticulation design together, there could be an incentive to build the network inefficiently. Therefore we don't have a specific target.

4.4.5 Customer satisfaction

Getting close to our customers to understand what matters most to them and their satisfaction with our delivery and services helps to ensure our service remains relevant customers. This is a key focus area of our asset management strategy and is a key commitment in our SCI.

We monitor customer satisfaction monthly and annually to gauge overall customer satisfaction for residential customers and commercial customers. This is determined via an annual survey of 400 customers across our network conducted by an independent research company as described in Section 4.2.4.

4.4.6 Summary of measures and definitions

The following table summarises our performance measures aligned to our asset management strategy and focus areas.

SAIDI minutes (System average interruption duration index)	The average duration of interruptions to supply consumers on average in the year, split by planned and unplanned interruptions
SAIFI (System average interruption frequency index)	The average number of interruptions to supply experienced by consumers Generally regarded as an indicator of customer inconvenience (frequency of outages)
Average number of faults per 100 km	This measure calculates faults per 100km averaged for subtransmission and HV distribution; generally regarded as a good measure of network health
Public safety	• Number of public harm events related to our assets • Number of known near misses that could have caused public harm
Environmental	The number of incidents that result in permanent or ongoing environmental harm due to the failure of an asset, associated containment system or our work practices. This measure monitors our compliance with environmental legislation as it applies to network operations.
Customer satisfaction	Percentage of customers satisfied with our service compared with the total number of customers surveyed via annual survey
Economic efficiency	No specific measures
Network utilisation	Network peak demand in comparison to network capacity

4.5 Targets

4.5.1 Network reliability targets

Our AMP is designed to be deployed in a way that ensures unplanned reliability is held in line with long term averages, recognises an increase in planned works, and ensures performance will be kept stable over time. The targets we have set ourselves remain below the 'midpoint' for the distribution industry in New Zealand.

Network reliability and performance targets have historically been set for the entire network, rather than establishing different targets for each asset type. We are moving towards more detailed capability to analyse and report on asset trends moving forward, understanding that some areas are more challenging to manage and could require additional investment, resources or effort.

Our performance targets have historically considered trends over the past three to five years and our upcoming work programme. These forecasts exclude Transpower outages and those from extreme weather events. Set out below are our reliability forecasts for the next five financial years (also see Schedule 12d of Appendix C). SAIDI and SAIFI are based on "raw" results and we will monitor our performance against these forecasts.

Northpower electricity network reliability forecasts	FY22	FY23	FY24	FY25	FY26
SAIDI minutes - planned	≤120	≤120	≤120	≤120	≤120
SAIDI minutes - unplanned	≤105	≤100	≤100	≤100	≤100
SAIFI	≤ 3.25	≤ 3.25	≤ 3.25	≤ 3.25	≤ 3.25
Average faults per 100 km	≤ 10	≤ 10	≤ 10	≤ 10	≤ 10

The increase in these forecasts from prior forecasts reflects the realities of an aging network, increased planned outages to accommodate asset renewal, and more limited application of live line work practices.

We anticipate unplanned SAIDI will start to reduce marginally from FY23 as targeted investment programmes begin delivering reliability improvements. We are mindful of the vulnerabilities posed by the sole 33kV subtransmission line to Kaiwaka and Mangawhai, and are increasing our maintenance on this line to minimise the risk of future interruptions, as we plan future investment to improve security to this area of our network.

4.5.2 Future measures – Statement of Corporate Intent

Under our SCI, we are moving to adopt performance and reliability metrics that reflect the applicable measures if we were subject to price/quality regulation under the default price quality path.

Using the default price quality methodology for 1 April 2020 to 31 March 2025 (DPP3) we have applied the ten-year reference dataset (2010 to 2019) to simulate relevant performance targets. These measures will apply from 1 April 2021 and across the DPP3 period.

- Consistent with DPP methodology, calculations for unplanned SAIDI and SAIFI will be normalised to reduce the impact of extreme events in order to provide a robust view of the underlying performance of our network.
- Planned and unplanned SAIFI will be reported separately to provide greater transparency of the impact of outages on our consumers.

Our forward performance metrics and targets are shown following, of which the first three years are reflected in our SCI. Measures and targets for average number of faults per 100km and customer satisfaction remain the same and apply for the ten-year planning period.

		FY22	FY23	FY24	FY25	FY26	FY27 - FY31
Network interruptions (SAIDI minutes)[2]	- planned	≤162.05	≤162.05	≤162.05	≤162.05	≤162.05	
	- unplanned	≤93.31	≤93.31	≤93.31	≤93.31	≤93.31	
Average number of network interruptions/customer (SAIFI)[3]	- planned	≤0.7231	≤0.7231	≤0.7231	≤0.7231	≤0.7231	
	- unplanned	≤2.2843	≤2.2843	≤2.2843	≤2.2843	≤2.2843	
Average number of faults per 100 km		≤10	≤10	≤10	≤10	≤10	≤10
Customer satisfaction (residential)		≥85%	≥85%	≥85%	≥85%	≥85%	≥85%
Customer satisfaction (commercial)		≥85%	≥85%	≥85%	≥85%	≥85%	≥85%

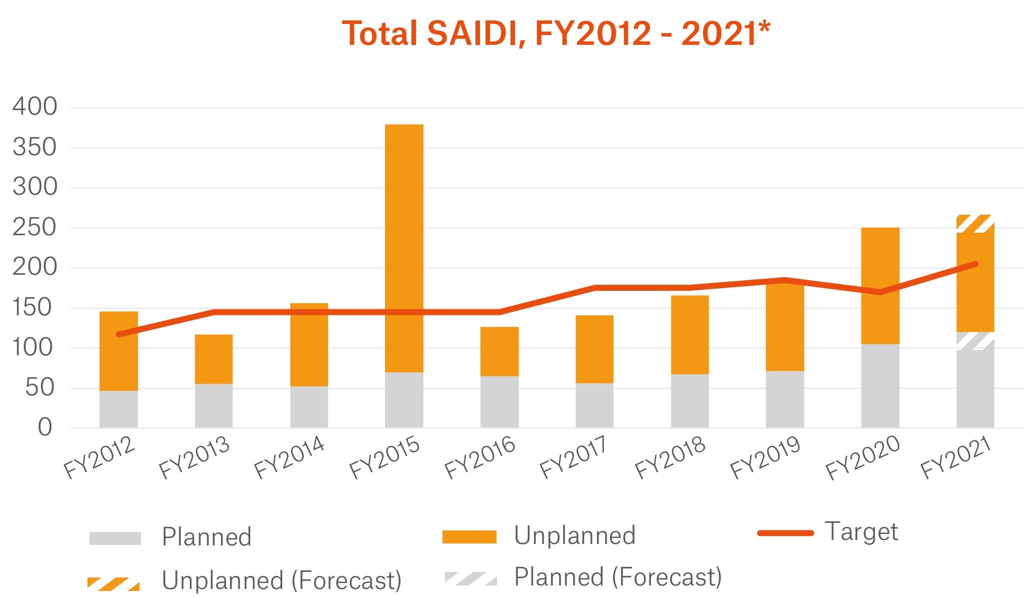
[2] *These performance metrics are based on the simulated DPP3 cap.*
[3] *As per above.*

4.6 Performance

4.6.1 Network reliability

Historically, network reliability has generally been achieved against our targets, except for an extreme storm event in 2015. In the last two years however, equipment failure combined with volatile weather patterns and interference from third parties and vegetation have caused our reliability outcomes to fall outside our target range.

*Figure 39: Total SAIDI versus target FY12 – FY21**



**FY21 - 1st April 2020 to 1st January 2021, plus forecast Q4.*

4.6.2 Performance results - unplanned SAIDI

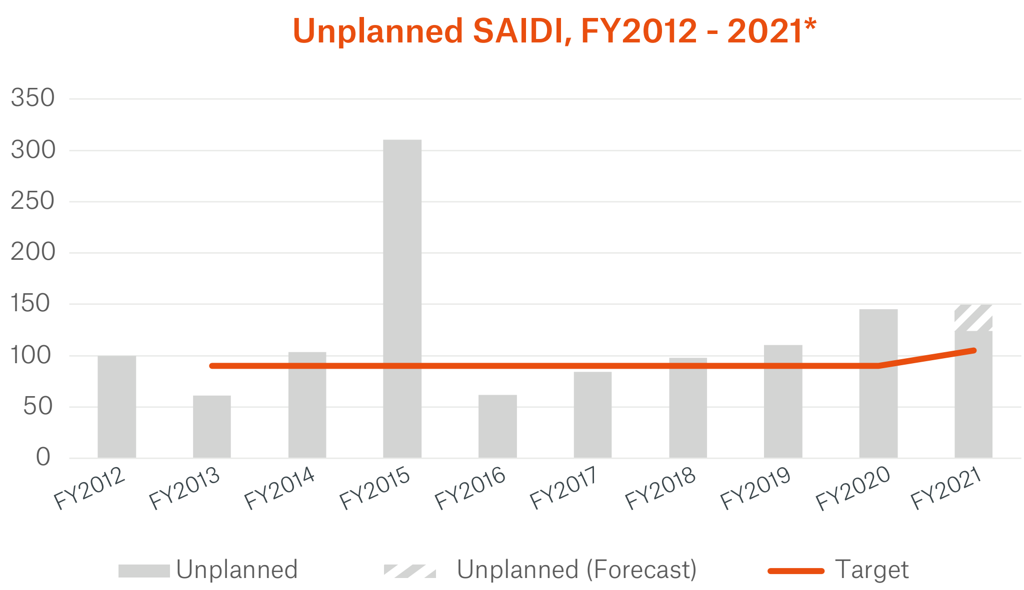
Total unplanned SAIDI has shown an increasing upward trend since 2016, with FY21 forecast to be a similar full year result as FY20, as shown in Figure 40. This variance has primarily been driven from events outside our direct control – including lightning events, adverse weather and recent increases in car vs. pole events.

The results in FY20 and FY21 have also been skewed by the impact of rare events on the single 33kV subtransmission line to Mangawhai:

Outages on 33kV line to Mangawhai	
FY20	Two separate vegetation events (10 and 12 SAIDI minutes) from fall zone trees contacting 33kV line.
FY21	27 SAIDI minutes - lightning strike on an overhead switch.

The following graphs show annual unplanned SAIDI raw results, against performance targets. These results include extreme events including storms (the impact of an extreme weather event on SAIDI in 2015 is apparent).

*Figure 40: Unplanned SAIDI actual versus target FY12 to FY21**



**FY21 - 1st April 2020 to 1st January 2021, plus forecast Q4.*

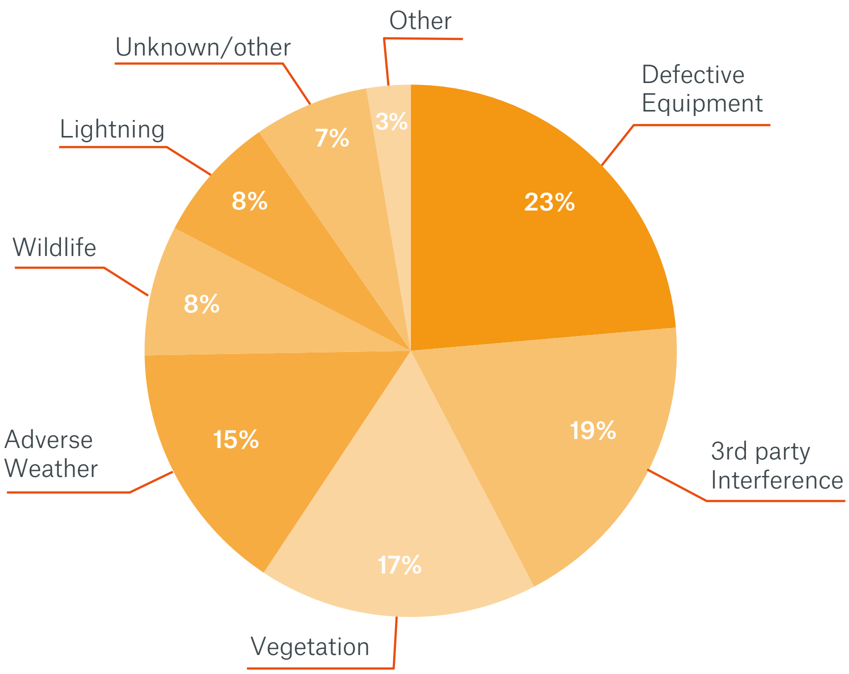
4.6.3 Key drivers of unplanned SAIDI

We are continually improving our root cause analysis of unplanned interruptions to better understand reliability and performance across the network. This provides details about the lower performing parts of our network and informs decision making about where to direct available funds and prioritise defect remediation.

Given the adverse variance in recent performance we have put in place remedial actions to understand causes and incorporate improvement actions in our operation and management of the network.

Expressed as an average over the last five years, 80% of all SAIDI can be attributed to one of four high-level causes: adverse weather, defective equipment, third party interference and vegetation.

*Figure 41: Unplanned SAIDI by cause FY17 to FY21**

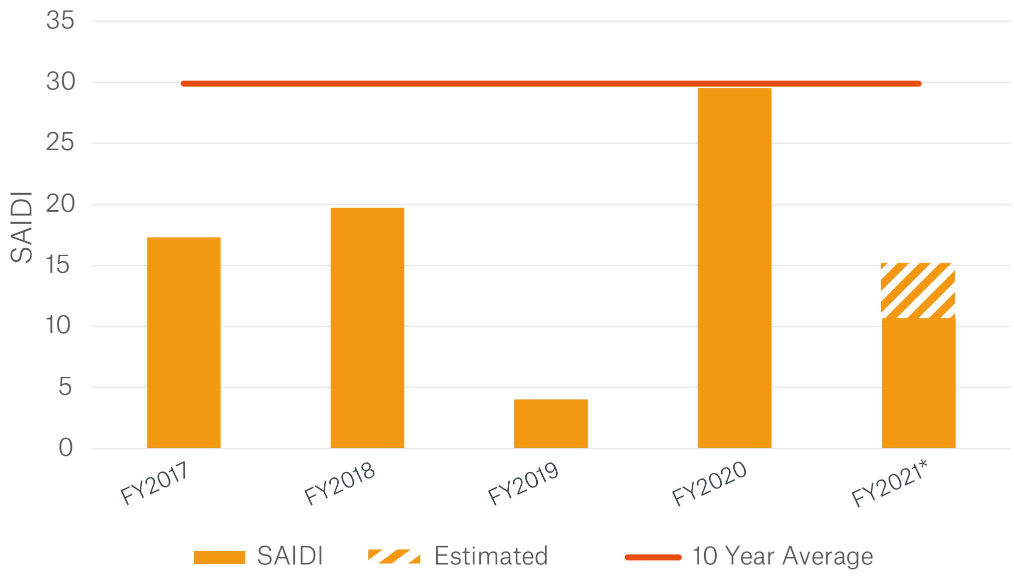


**FY21 as at 1 January 2021.*

4.6.4 Adverse weather

While major weather events are infrequent, as shown below they produce major fluctuations in SAIDI and can have a significant impact on the frequency and duration of unplanned outages.

*Figure 42: SAIDI minutes attributed to adverse weather annual and ten-year average FY17 – FY21**



**FY21 as at 1st January 2021, plus forecast Q4 based on FY12-FY20.*

Our strategy to mitigate storm impacts is focused on better identification and management of fall zone trees and reducing wind-blown vegetation debris. We have increased our focus on the subtransmission network to ensure the backbone of our network is increasingly resilient to weather related events to reduce the risk of high impact events.

4.6.5 Defective equipment

The impact of defective equipment faults has risen in the last four years and last year exceeded the ten-year average.

*Figure 43: SAIDI minutes attributed to defective equipment annual and ten-year average FY17 – FY21**

**FY21 as at 1 January 2021, plus forecast Q4 based on FY12-20.*

This continues to be a key area of focus, and we have put in place the following initiatives:

- Introduction of a revised overhead inspection standard, improving consistency amongst inspectors as well as enhancing the quality of inspection of our overhead assets for defect classification. This will assist with inconsistencies in defect capture and prioritisation of replacing end of life assets as the network continues to age. We have seen slight improvements however the full benefit of this will not be realised until completion of the current full round of asset inspection in 2024.
- Increased resourcing of maintenance team, including increased monitoring to ensure high priority works are delivered within specified timeframes.
- Increased corrective maintenance budgets, ensuring expenditure on defect remediation and asset renewal is sufficient to maintain the health and resilience of our network.
- From FY21 we returned to full structure maintenance and acoustic testing for substation assets supported by timely remediation of defects.

We expect to see SAIDI from defective equipment remain at or below the long-term average over the planning period.

4.6.6 Third party interference

Outages caused by vehicles hitting poles has continued to trend upwards and are now featuring significantly in unplanned SAIDI statistics. This appears to be an industry-wide trend.

*Figure 44: SAIDI minutes attributed to third party interference annual and ten-year average FY17 – FY21**

**FY21 as at 1 January 2021, plus forecast Q4 based on FY12-20.*

We routinely review pole locations when a vehicle collides with a pole to identify improvements to reduce the vulnerability of the assets.

4.6.7 Vegetation

Except for two major vegetation related outages on the subtransmission network in FY20 (totalling 22 SAIDI minutes), SAIDI caused by vegetation has remained reasonably consistent year on year.

*Figure 45: SAIDI minutes attributed to vegetation annual and ten-year average FY17 – FY21**

**FY21 as at 1 January 2021, plus forecast Q4 based on FY12-20.*

Helicopter surveys and line patrols of subtransmission networks focus on identifying risks from fall zone trees and wind-blown vegetation debris. We use a risk-based approach to continue to reduce the impact of vegetation on our network, and actively engage with landowners to get their agreement to remove vegetation that provides an elevated risk of interference with the network.

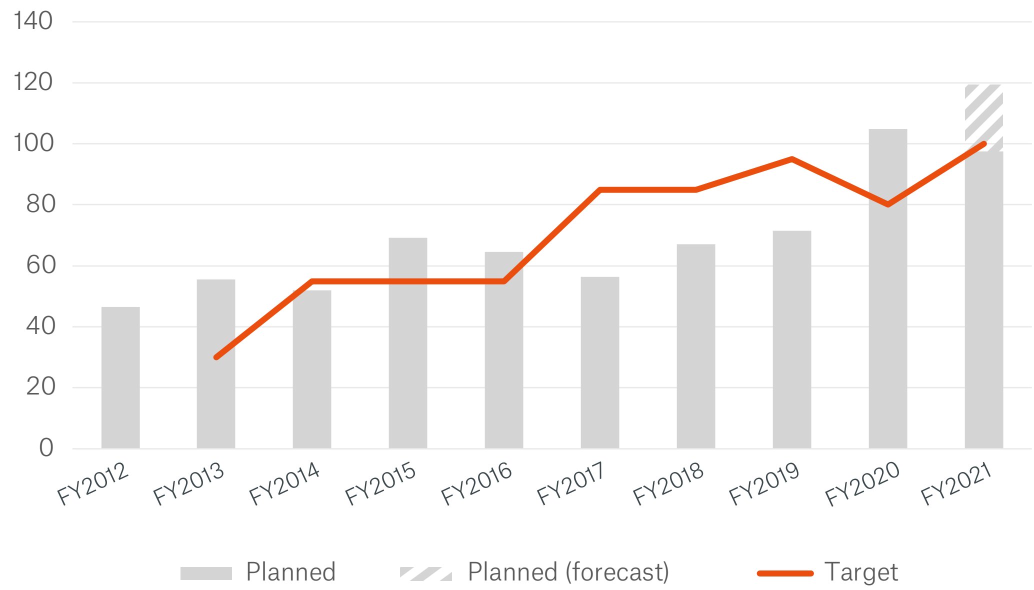
4.6.8 Performance results – planned SAIDI

Our planned SAIDI has historically been lower than industry average. In line with an uplift in our asset replacement programmes, our planned work programmes have risen in recent years in response to the need to improve reliability and strengthen resilience to the increasing frequency of severe weather related events.

Reducing live work has also influenced network reliability KPIs, although this is difficult to quantify. We have progressively lifted our planned SAIDI targets since 2017 reflecting an expected increase in planned works. Planned SAIDI for FY20 was above the industry average and will remain at elevated levels reflecting increased volumes of work to renew an ageing network. To minimise customer impacts we proactively bundle and blend work to lessen the number of planned shutdowns where possible.

Our performance for planned outages compared to our target is shown in Figure 46.

Figure 46: Planned SAIDI against target - FY12 – FY21



**FY2021 as at 1 January 2021, plus forecast Q4.*

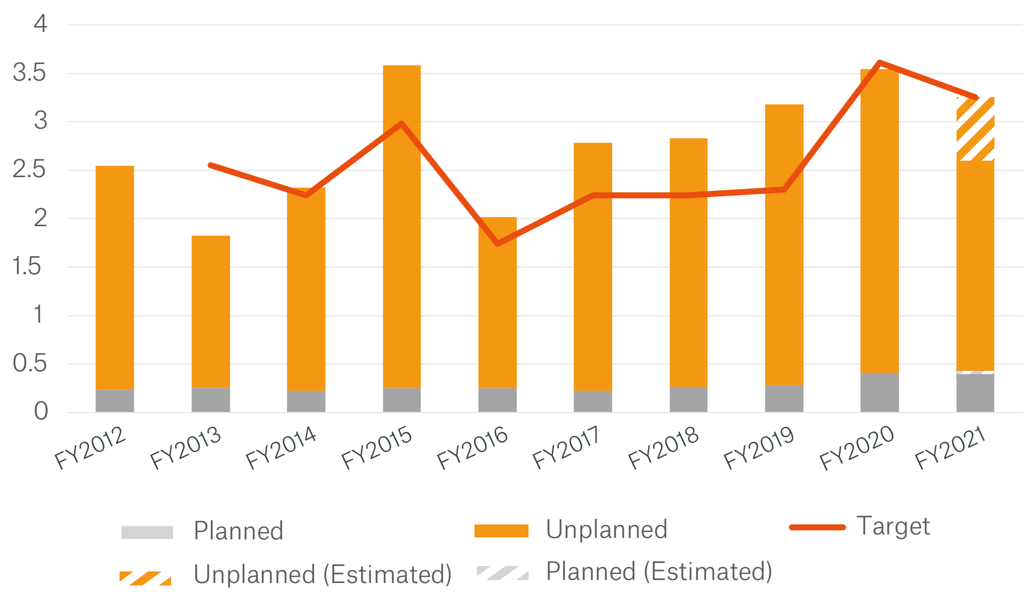
4.6.9 Performance results – SAIFI

Planned and unplanned SAIFI has not historically been a performance measure in our SCI, but we monitor our performance against our forecasts.

The uplift in recent years in planned SAIFI reflects the same drivers as those for planned SAIDI - an increase in our planned work programme, focussing on defect remediation and targeted end of life asset replacement.

We expect unplanned SAIFI to be lower in FY21 than FY20, due to a focus on vegetation clearance and defect remediation on critical subtransmission circuits.

*Figure 47: Planned, unplanned and total actual SAIFI FY12 to FY21 with extreme events removed**



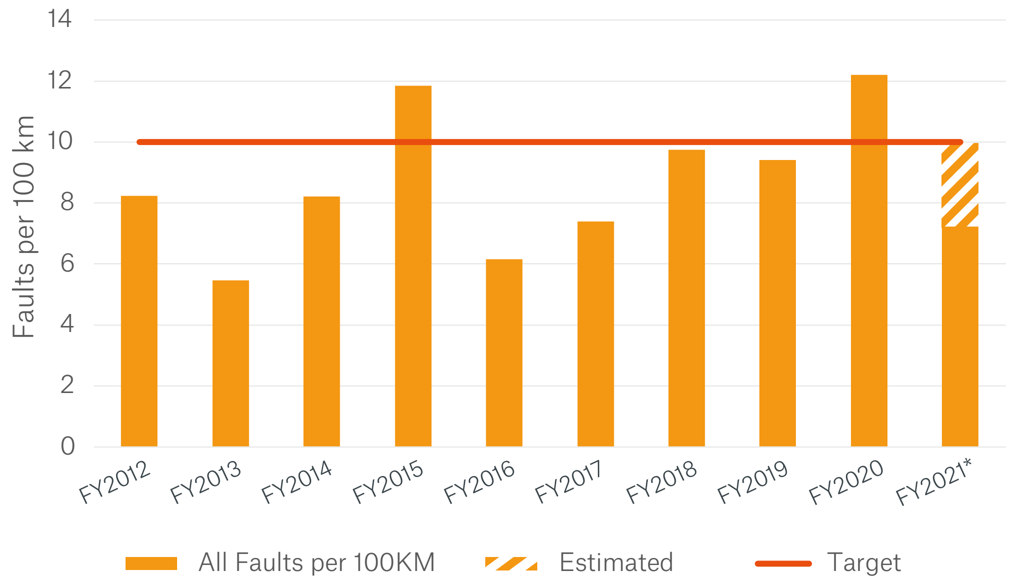
**FY2021 as at 1 January 2021 plus forecast Q4. Targets as per historical AMP forecasts.*

4.6.10 Performance results – faults per 100km

We report on a performance measure of number of faults per 100km of network length (excluding low voltage). Our target for faults per 100km is ten or less per year. The average number of faults per 100km is generally higher on the distribution network than the subtransmission network due to more assets on the distribution network, making up the greater proportion of length and exposure of our network. We met this performance target in eight of the previous ten years.

A spike in the number of faults in 2015 was caused by several major weather events resulting in considerable storm damage from gales and wind-blown vegetation. A significant rise in the frequency of lightning strikes in 2020, combined with a higher than average number of equipment faults, pushed the frequency of faults over this target.

*Figure 48: Faults per 100km actual versus target FY12 – FY21**

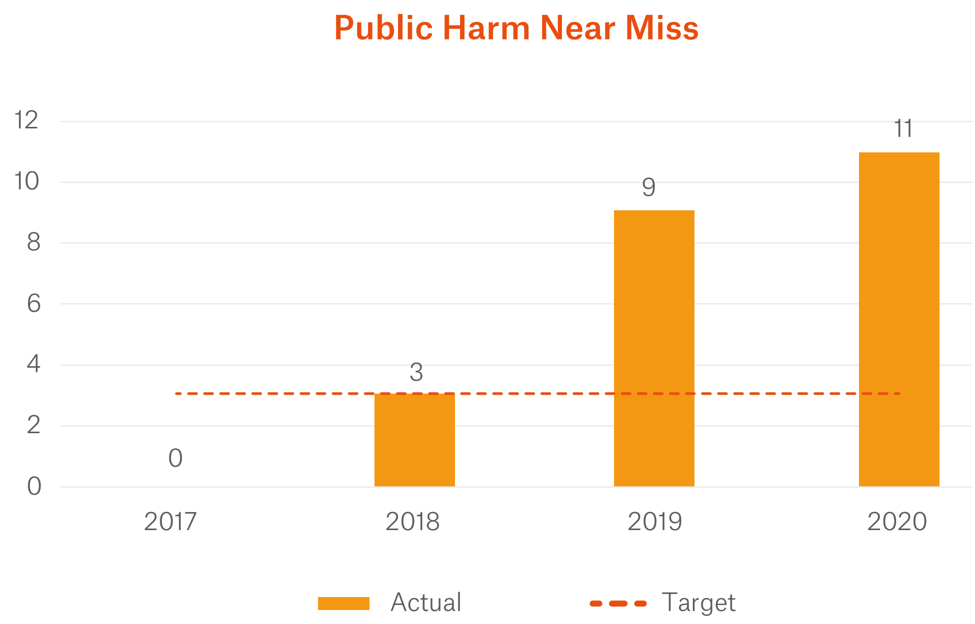


**FY2021 as at 1 January 2021, plus forecast Q4.*

4.6.11 Public safety

The Northpower network is committed to the health and safety of the public in respect to the operation of our assets. The network continues to have no incidents of public harm reported due to the operation of our network since 2017*. This data excludes motor vehicle versus power pole data.

Reporting of potential public harm through near misses has increased year on year since 2017*. Analysis of these events indicates that this is driven by an improvement in reporting with increased reporting of events rather than an increase in actual events.



** 2017 is reported as nine months.*

4.6.12 Environmental

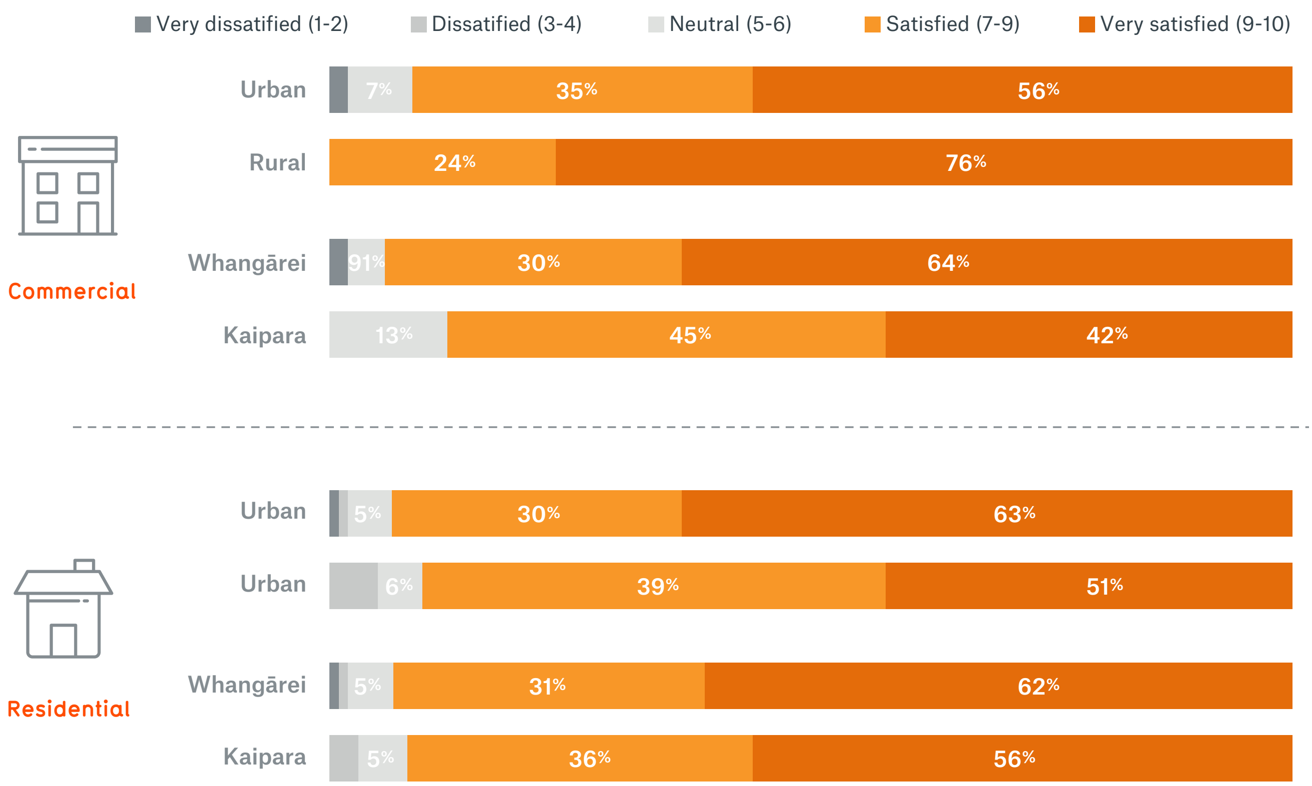
Continued monitoring of these two key measures confirms that our network attends to our environmental responsibilities.

Measure	FY18	FY19	FY20	FY21 ytd
Target	0	0	0	0
Environmental breaches	0	1	0	0
Legislative non-compliance	1	0	0	0

4.6.13 Customer satisfaction

Our performance target for customer satisfaction is >85% - a target which we consistently meet. The last annual survey in March 2020 showed our overall customer satisfaction is high – overall 92% of residential customers and 88% of commercial customers are satisfied or highly satisfied.

Figure 49: Annual customer satisfaction, annual customer survey March 2020



4.6.14 Efficiency

Asset utilisation

Based on Commerce Commission disclosure data for FY19, Northpower has 31% utilisation of its distribution transformers, against an industry average of 28%, indicating above average utilisation. Transformer monitoring devices are selectively used to record actual utilisation each day, which is particularly useful in areas with greater PV and EV uptake. This has the potential to help us improve utilisation across the network.

The average 11 kV feeder utilisation (based on the feeder's high alarm limit) is 54%. Four projects have been proposed to help mitigate the 11 kV back feed constraints, at Mangawhai and Parua Bay in FY22 plus Ngunguru and Ruawai in FY25.

Economic efficiency

Economic efficiency reflects the level of asset investment required to provide network services to customers, and the operational costs associated with operating, maintaining and managing the assets. There are inherent limitations when comparing performance with other EDBs. A direct comparison of data cannot be made appropriately without a full understanding of the local context, asset history, and business purpose and drivers of each EDB being compared. For this reason, the comparisons provided below are for guidance only.

Economic efficiency compared to other EDBs

We monitor and benchmark our regulatory operational expenditure indicators including expenditure per kilometre circuit length and expenditure per customer connection.

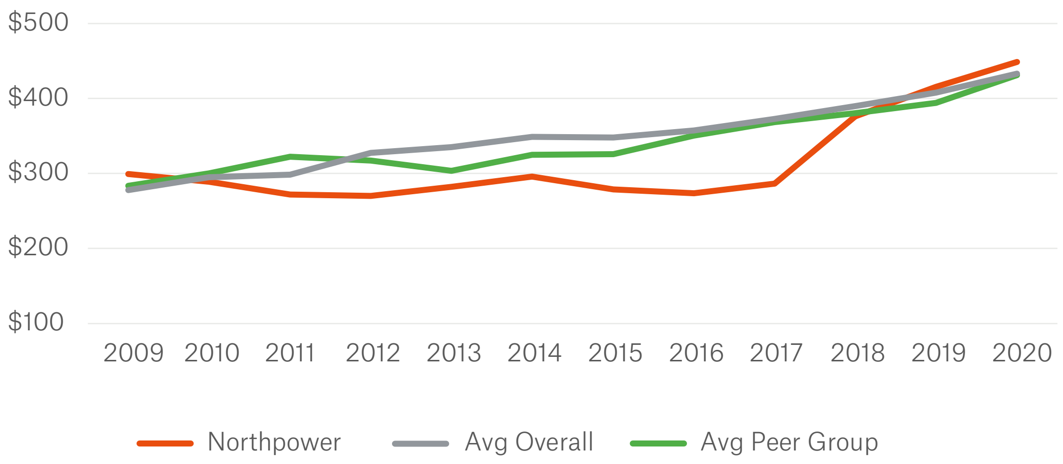
Since 2017, Northpower's electricity business has undergone considerable change across all functions, including a lift in asset operational expenditure programmes to address overhead defects, increased vegetation management spend, and additional capability across asset management and operational functions to support increased delivery and significant change programmes. This is reflected in the operational benchmarking analysis below.

The analysis highlights that we have historically benchmarked below average across our Commission peer group comparator (intermediate regional EDBs), and across the industry average, but the recent uplift in capability and resourcing has put us in line with industry averages.

On a cost per customer basis:

- Northpower remains in line with industry averages.
- Costs have increased since FY17, largely due to an increase in resourcing after several years of a reduced cost base.
- The industry average reflects the lower cost per customer of the higher density urban networks.

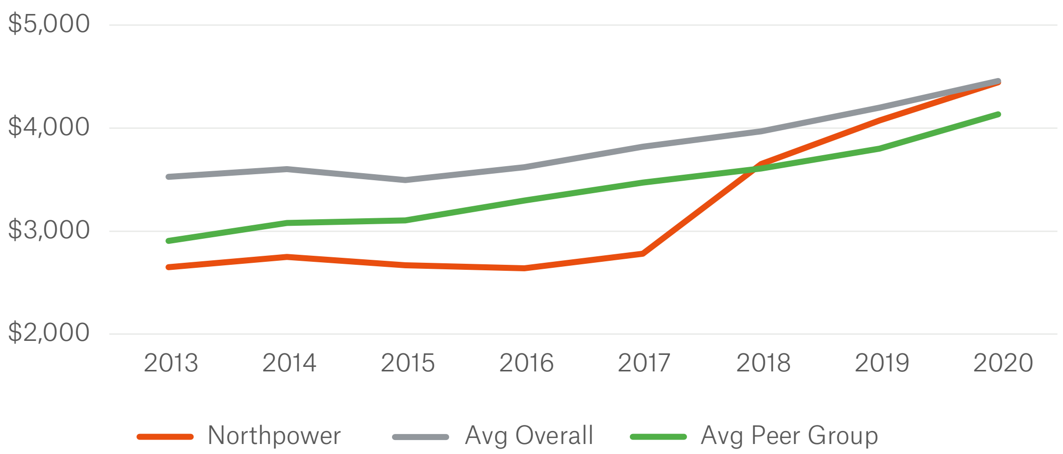
Figure 50: Total opex per number of ICPs – Northpower vs peer group and EDB average. Commerce Commission, March 2021



On a cost per km of line basis:

- There has seen a general upward trend across the peer group and industry.
- Northpower's increase, since 2017, reflects an element of catch up after five years of no increase (a decrease in real terms).

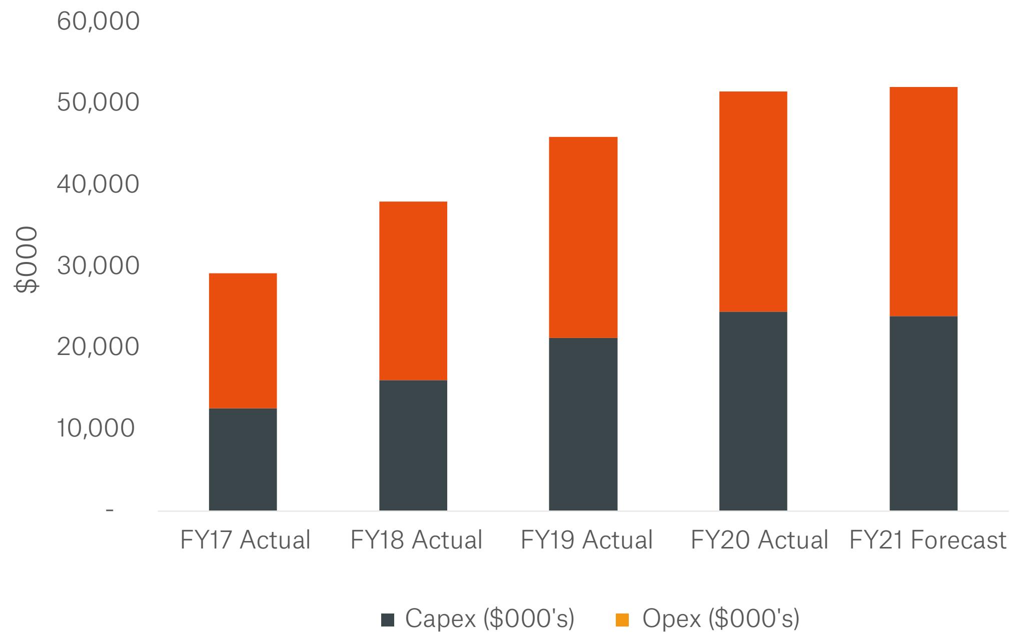
Figure 51: Total opex per total km of line – Northpower vs peer group and EDB average. Commerce Commission, March 2021



Expenditure metrics

Over the last five years we have progressively lifted our annual spend on maintaining our assets, across both operational expenditure and capital expenditure. As outlined in this AMP, this is to address the impact of aging assets and to hold network reliability at long term levels.

Figure 52: Total operating and capital expenditure FY17 – FY21



Capital expenditure delivery

We have lifted our capital expenditure from an average of $14.4M for the period FY13 to FY17, to an average of $21.4M for the period FY18 to FY21, and we are forecasting expenditure to sit around $30M for the next three years. In total we are delivering against plan, with at least 90% of annual budget delivered in each of the last two years. We are forecasting 80% delivered for FY21, as design and procurement phases of a couple of large projects has taken longer than planned.

The table below compares actual expenditure with forecast expenditure.

Capex category	FY20 actual ($000)	FY20 budget ($000)	FY21 forecast ($000)	FY21 budget ($000)
Customer connections	$4,919	$5,795	$3,993	$5,644
System growth	$3,662	$5,414	$3,118	$2,775
Asset replacement and renewal	$11,098	$10,747	$13,814	$14,915
Reliability, safety and environment	$1,914	$2,032	$1,520	$955
Asset relocations	$515	$255	$36	$945
Non-network assets	$2,359	$2,411	$1,442	$3,454
TOTAL	**$24,467**	**$26,654**	**$23,923**	**$28,688**

Operational expenditure delivery

The table below shows the budget and actual operational expenditure for the 2020 and 2021 financial years. As outlined, with the exception of routine and preventive maintenance, the actual expenditure is tracking to budget for each category given the expected easing in vegetation maintenance towards the end of the financial year.

Opex category	FY20 actual ($000)	FY20 budget ($000)	FY21 YE forecast ($000)	FY21 budget ($000)
Service interruptions and emergencies	$3,126	$ 2,819	$ 2,150	$ 2,150
Vegetation management	$3,241	$2,820	$2,820	$2,820
Routine and corrective maintenance and inspection	$3,267	$3,326	$3,320	$3,320
Asset replacement and renewal	$2,076	$2,994	$2,734	$2,734
System operations and network support	$2,712	$2,663	$3,396	$3,396
Business support	$12,624	$13,182	$13,710	$13,710
TOTAL	**$27,047**	**$ 27,803**	**$28,130**	**$28,130**

Northpower

2021 – 2031

Asset Management Plan

Section 5

About our network

Table of contents

5.1 Introduction

Northpower's network distributes electricity from the Transpower grid to our customers. The network is made up of a number key subtransmission, high voltage, distribution, low voltage and auxillary/secondary system elements.

This section summarises the network architecture – the key elements that make up our electrical network and explains the approaches we take to develop the network.

Further details of the assets that make up these parts of the network are in Section 7 Managing our assets.

5.2 Transpower grid exit points

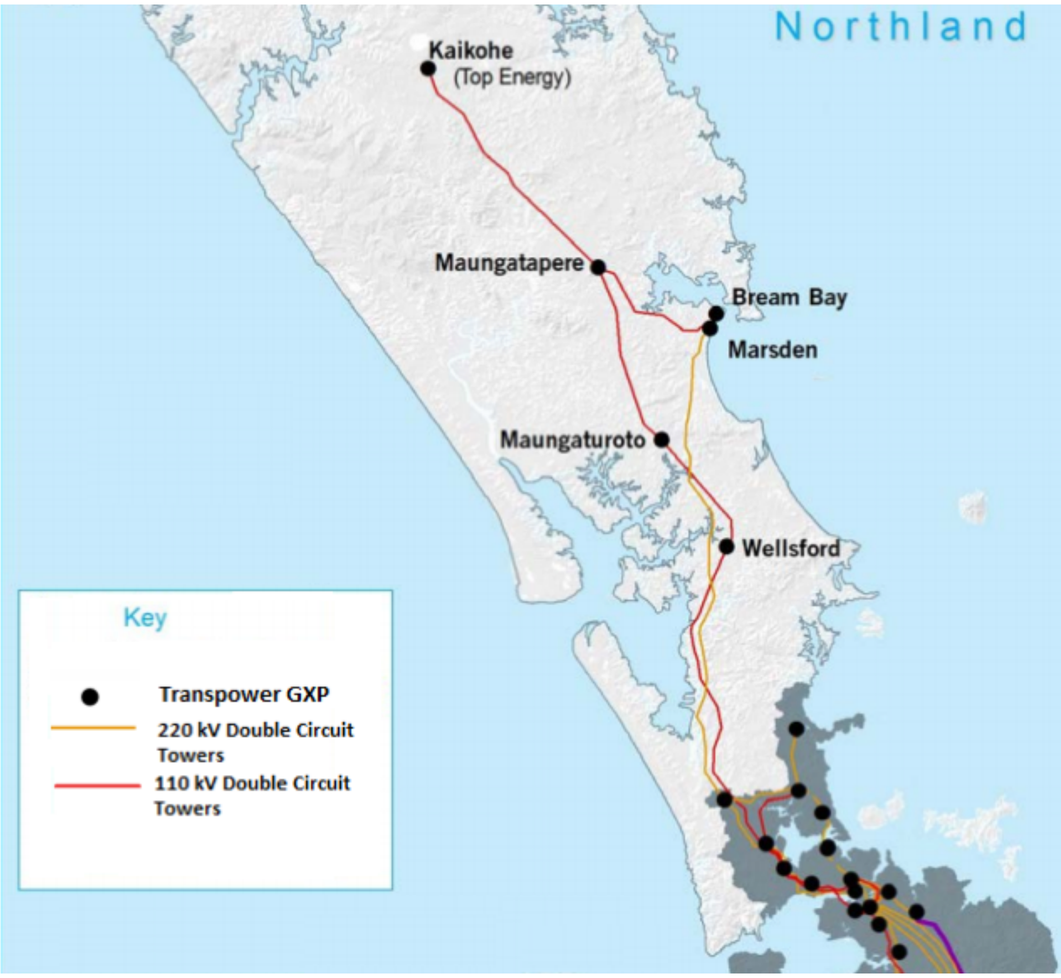
Northpower's electricity network is supplied from three Transpower grid exit points (GXP's). We take supply at 110 kV and 33 kV.

Grid exit point	Supply voltage	Customers supplied
Bream Bay	33 kV	9%
Maungatapere	110 kV	73%
Maungaturoto	33 kV	18%

Our network

23	Electricity substations
42	Substation power transformers
54,436	Overhead Poles
5,201km	Overhead lines
1,335km	Underground cables
7,415	Distribution transformers
13,184	Low voltage distribution pillars and cabinets

Figure 53: Transpower's regional transmission network



Northpower has assets located at these grid exit points, including:

Grid exit point	Supply voltage
Bream Bay	33 kV power cables and associated sheath voltage limiters (SVL) Electrical protection relays and associated pilot cables
Maungatapere	110 kV, 50 kV and 33 kV power cables 110 kV, 50 kV and 33 kV line termination structures, conductor and fittings An entire 50 kV and 33 kV outdoor buses 50 kV and 33 kV switchgear (circuit breaker and isolators) HV voltage and current transformers 110/50 kV and 110/33 kV power transformers Local supply transformer Protection and control equipment including SCADA Control and communication cables
Maungaturoto	33 kV line termination structures, conductor and fittings Part of 33 kV outdoor bus 33 kV switchgear (circuit breaker and isolators) 33 kV current transformers Protection and control equipment including SCADA Control and communication cables

5.3 Network architecture

5.3.1 Subtransmission network

The map below shows our distribution area, and geographical location of zone substations and subtransmission circuits.

Most remote zone substations are supplied via a single 33 kV line, with varying levels of back-feeding capability via the 11 kV network. Mobile generation can be deployed for voltage and load support where back-feeding capacity is not adequate.

Detailed information on substation transformer capacity, loading and security of supply is provided in Appendix B Substation data and feeder maps.

Figure 54: Northpower's substations and interconnecting subtransmission circuits

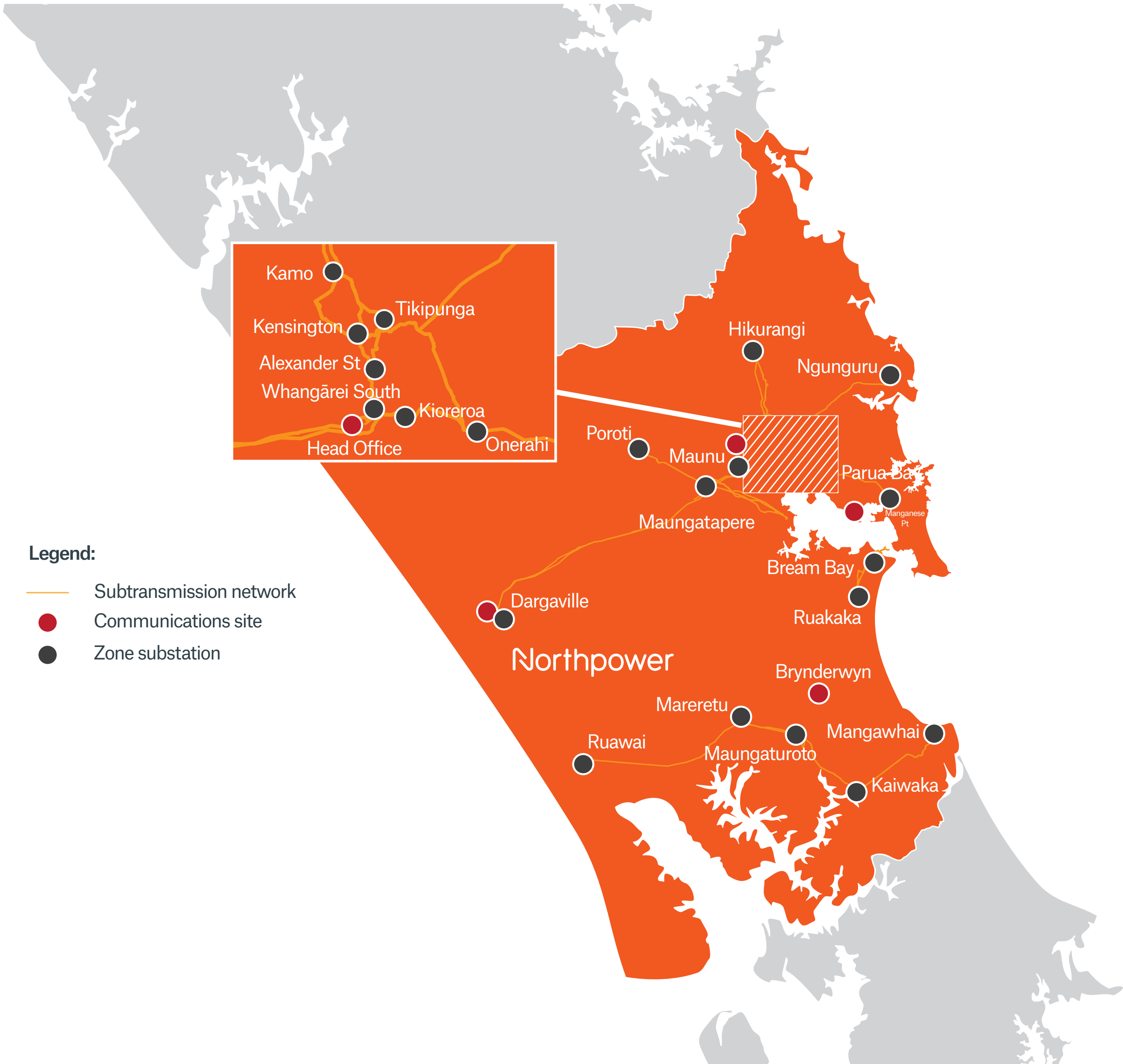
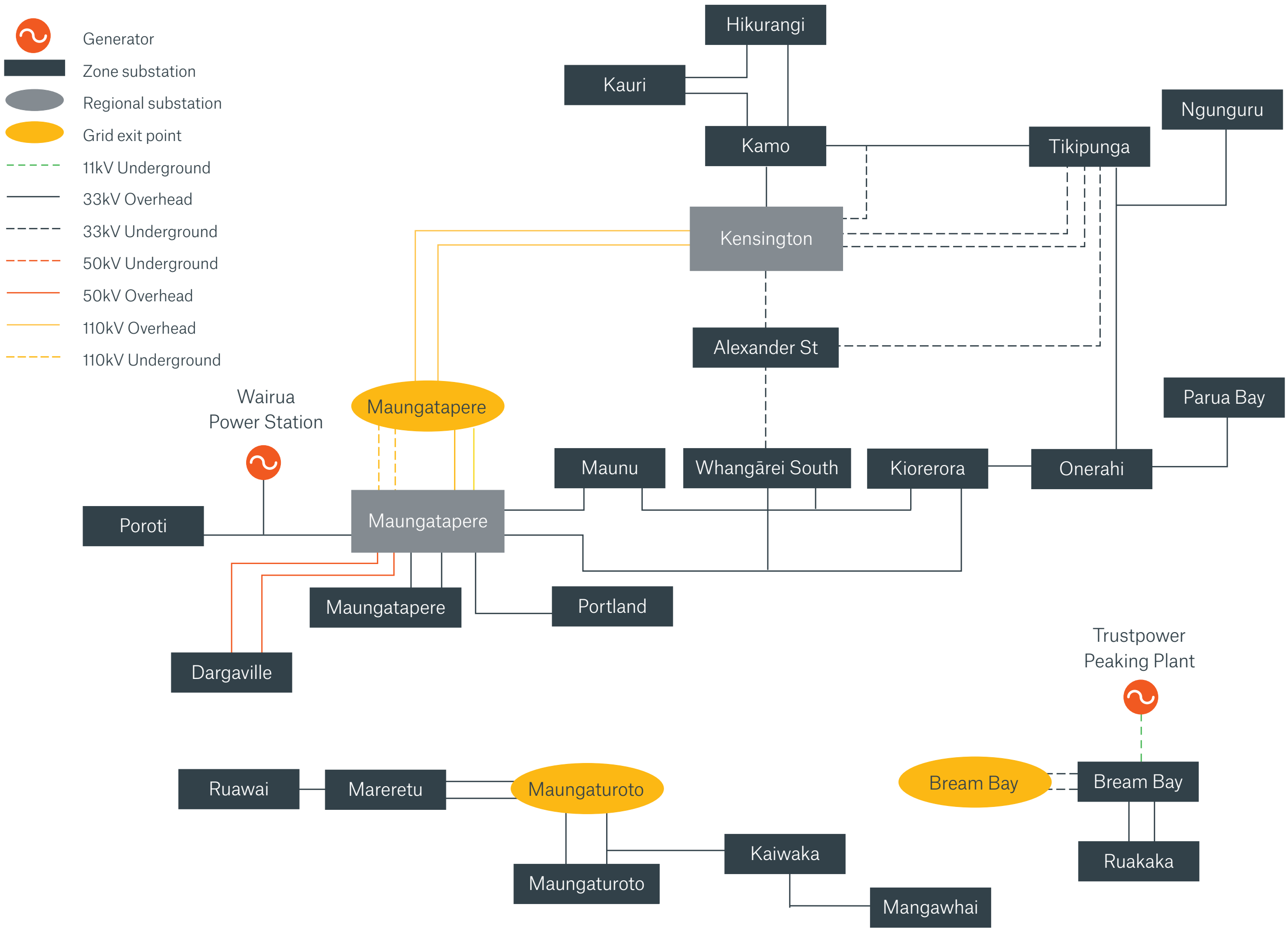


Figure 55: Northpower's subtransmission network schematic



5.3.2 High voltage distribution network

The high voltage distribution network originates from the zone substations and includes:

- Two 11 kV express lines (i.e. 11 kV feeder with no distributed load connected)
- Ninety seven 11 kV distribution feeders and associated low voltage reticulation

Most customers are supplied from 11,000/415 Volt distribution transformers however some are supplied directly at 11 kV.

There are also several large industrial customers supplied direct from the 33 kV subtransmission network.

High voltage distribution	Total (km)	Underground (km)	Overhead (km)
March 2020	3,790	288 (8%)	3,502 (92%)

5.3.3 Distribution substations

Distribution substations deployed on the network range in size from 0.5 kVA to 1,500 kVA and are either pole or ground mounted. They comprise an 11,000/415 volt transformer, high and low voltage fuses, and associated earth grids. Fuses on the high voltage side of the transformer provide fault protection for the transformer. Fuses on the low voltage side provide both transformer overload and downstream fault protection for cables or lines.

There are also a small number of 33,000/415 volt transformers supplying industrial customers.

Transformers with a rating exceeding 150 kVA are normally ground mounted due to their weight and size. Transformers with a rating of 50 kVA and below can be either 2 phase or 3 phase, while those larger than 50kVA are all 3 phase.

A distribution substation typically supplies one to 100 customers. In May 2020, there were 7,415 distribution substations installed on our network.

5.3.4 Low voltage network

Northpower's low voltage (LV) network is a mixture of overhead and underground circuits operating at 400/230 Volts. The LV feeders distribute power from distribution transformers (connected to the 11 kV network) to customers' service lines, generally from poles or pillars near property boundaries.

Each LV circuit is protected by fuses at the transformer and each customer point of connection. Electricity meters and ripple relays or pilot control contactors (for control of water heating load) are generally located at the end of the service line or cable at the installation control point (ICP) or meter station on the customer's premises.

Where increased security of supply is needed, the LV network is configured in a ring, to allow an alternative supply should it be required. This type of arrangement is common in the central business district and urban residential areas.

Low voltage reticulation	Total (km)	Underground (km)	Overhead (km)
March 2020	1,993	791 (40%)	1,202 (60%)

The point of supply between our network and our customers is generally on the road reserve (at the fusing point). We have information on our website to help customers understand the demarcation point and their responsibilities for maintaining service lines.

5.3.5 Auxiliary and secondary systems

Northpower's main network operations centre (NOC) is located at our headquarters in Raumanga and is attended 24 hours. There is a backup NOC located at Tikipunga zone substation.

The electricity network can be fully monitored, managed, and controlled from both the main and backup NOCs.

A SCADA system continuously monitors loads, alarms, and operation of equipment in all substations, including regulators and remote-controlled switches on the network.

Northpower's telecommunication network is integral to the remote monitoring and control of network equipment and utilises radio and fibre optic systems. A separate land mobile radio network gives contact with operating staff and contractors in the field.

Ripple injection plants are installed on Northpower's network providing ripple control signalling to activate load control. This is utilised for hot water load control, streetlights, tsunami warning activation and other controlled loads.

Metering is installed at Transpower GXP supply points (Maungatapere, Maungaturoto and Bream Bay) to record energy delivered to the Northpower network from the national grid.

5.4 Major customers

We have five major industrial consumers (VLIs) on our network, with loads over 4 MW, who collectively consume approximately 43% of the electricity conveyed across the network.

We work with our VLI customers to understand their security and reliability of supply requirements. In most cases these customers have a dedicated feeder supplying their site from a Northpower substation, and often have dedicated backup feeders to provide N-1 security. They receive a higher level of service reflecting their reliance on electricity to operate significant sized and often critical industrial processes.

We work with our customers to understand their capacity requirements and ensure the network meets their evolving needs.

5.5 Distributed generation

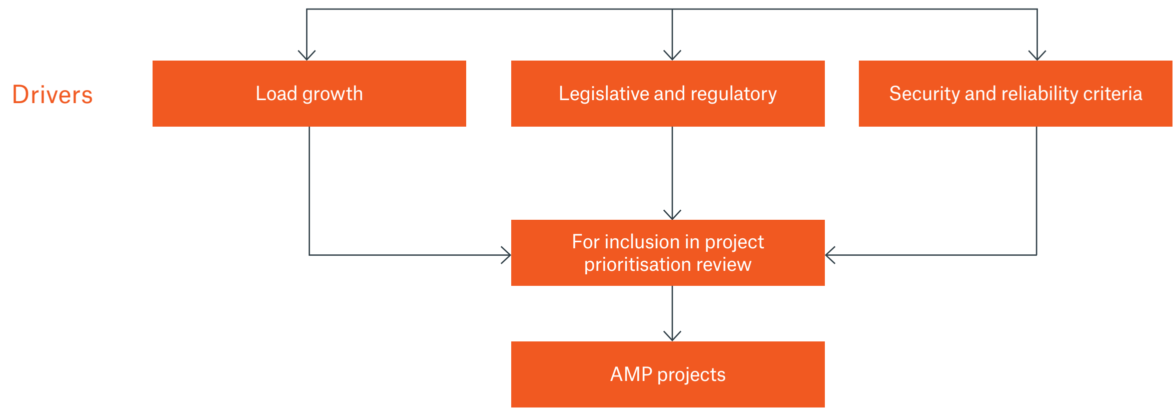
As at October 2020, there are 1,184 distributed generation systems with a total capacity of 19.5 MW connected to our network.

This includes our Wairua hydro generation plant (5 MW) and Trustpower's diesel peaking plant (9 MW). The remainder are mainly small solar PV systems.

5.6 Network development approach

Northpower's network planning process is shown in figure 56.

Figure 56: Northpower network's planning process.



We use various tools and data in validating identified network issues and constraints:

- SINCAL software – used for network modelling such as load flow calculations, outage modelling scenarios and fault level determination
- Geographic Information System (GIS) – provides detailed information of assets installed in our network
- Load forecast – used to produce ten-year load forecast for individual feeders, zone substations and Transpower GXP's
- Stats NZ – provides information regarding five-year dwelling projections used in load forecast
- Whangārei and Kaipara District Council development plans
- SCADA load and operational data
- Customer services – information on load applications
- We regularly review our regulatory environment and consider any changes in our planning process and investment decisions.

5.6.1 Options analysis

All new network investment requirements are carefully scrutinised, ensuring the appropriate long-term solution is adopted, delivering desired outcomes and service levels for the least cost.

Several options are developed, and the most appropriate option is selected based on safety, cost benefit analysis and value of lost load (VoLL), and other variables. Non-network solutions are also considered where feasible, and if they are economic compared to traditional solutions.

5.6.2 Contingency planning

Our contingency plans are updated and reviewed regularly to improve and widen the scopes included. This helps identify areas that require upgrade, and these are included in the augmentation planning process, ultimately defining projects in the AMP.

The contingency plan includes loss of significant assets or groups of assets including total loss of supply from the grid. These events are called high impact low probability (HILP) events and are discussed in more detail in Section 3 'Risk Management'.

5.6.3 Load flow calculations

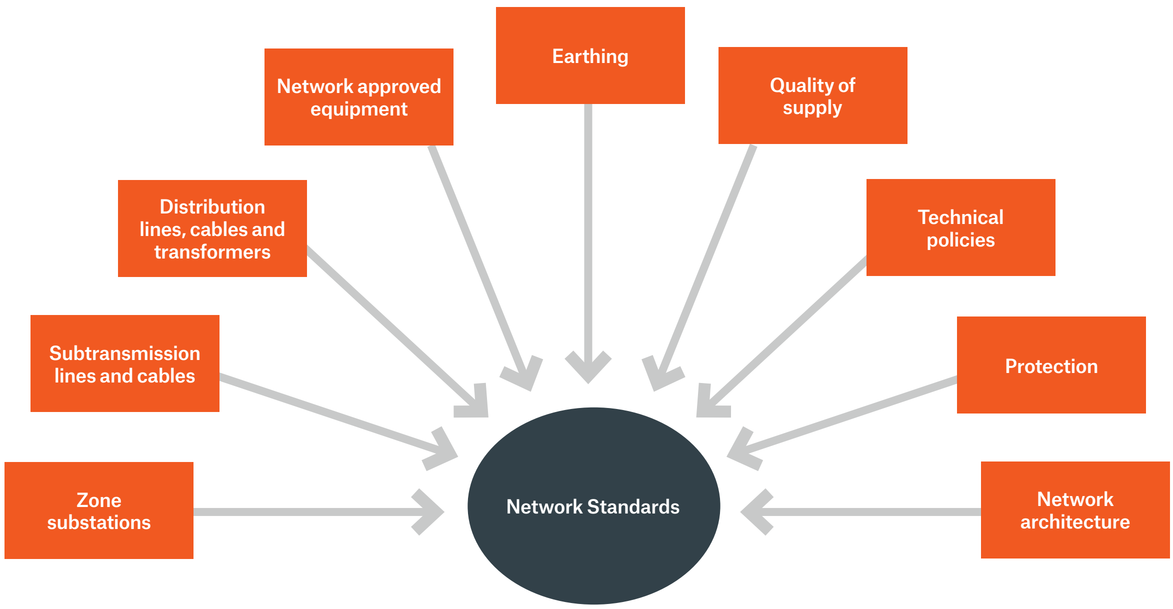
Simulation studies using SINCAL software are used at system peak load conditions for summer and winter periods. This exercise excludes generation from Wairua hydro power station and Trustpower generators.

5.6.4 Network management framework

Planning and design parameters, as well as equipment rating criteria are set out in Northpower's electricity network standards. Our standards used for the network derive from the following sources and key inputs.

This development approach is discussed in more detail in Section 6 Planning our network.

Figure 57: Northpower's electricity network standards sources of information



5.7 Asset lifecycle management approach

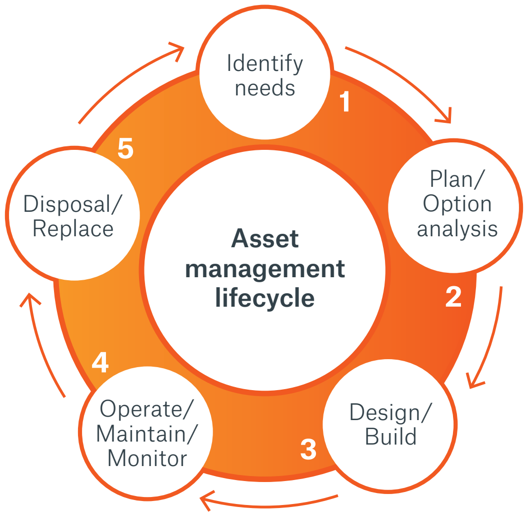
Our lifecycle asset management planning objectives support Northpower's strategy to provide a safe and reliable supply to our customers. Our customers tell us that they want us to maintain existing levels of reliability, but most customers do not want to pay more for increased reliability.

Our asset lifecycle management considers both current and future customer needs, given our role as providers of enabling intergenerational infrastructure. This optimises the performance of an asset between the time of commissioning and its eventual renewal.

We consider the following criteria in determining our approach to asset maintenance and renewal:

- Safety and environment – minimising future risks to the public and those working on the network.
- Reliability – ensuring we meet or exceed the expectation of our customers.
- Economic efficiency – minimising the total cost of ownership while meeting accepted standards of performance.
- Foundation for growth – we provide for expansion without compromising flexibility.

Figure 58: Our asset management lifecycle process



5.7.1 Stage 1 - Identify needs

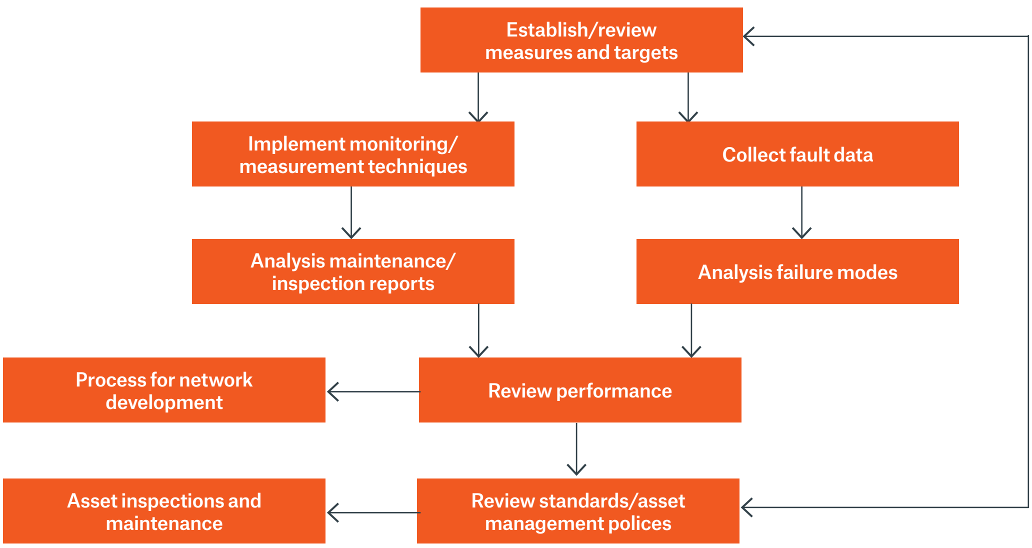
The first step in the asset lifecycle process is identifying need. We base this around two main areas – setting service levels and measuring service levels.

Setting service levels: Our service levels are set based on customer feedback, health and safety considerations and the expectations of our owners. These include SAIDI, SAIFI and faults per 100km, health and safety as well as customer satisfaction. Further details of how our service levels are set and our current performance levels are outlined in Section 4 Customer experience.

Measuring service levels: We collect our network performance data for all interruptions and outages on the network. This is logged through our NOC and performance is reviewed monthly by network management and reported to our board of directors. These results are also independently audited each year.

Significant outages on the network are subject to post-event review to understand the root cause analysis and improvements needed to reduce future occurrences.

Figure 59: Process for performance measurement



We also collect data on our other performance metrics, and these are regularly reviewed and reported to management and at a governance level.

5.7.2 Stage 2 - Planning and option analysis

Our asset replacement decisions are based on balancing several considerations, including our commitment to providing a safe, resilient and affordable electricity supply. We take a balanced approach and consider whether continued maintenance is uneconomic, the criticality of the asset, and the potential health, safety and environmental risk, along with the impact on reliability.

Our asset management approach does differ depending on the asset class and what asset condition information we currently hold. Our current approach is:

- High value, critical substation assets that have a high consequence of failure are replaced based on condition assessments, and prioritised based on criticality. Robust, regular inspections feed into regularly updated condition assessments.
- Distribution overhead assets (e.g. poles, cross-arms, insulators) are inspected regularly and replaced once they pose a risk to reliability, public safety or the environment.
- Our buildings are inspected regularly, maintained and repaired when required.

Asset management approach for each asset class

The following table summarises our asset management approach for each asset class.

Asset class	Condition and criticality analysis	Condition (from asset inspections), performance	Mostly age based	Run to non-operational	Indefinite maintenance and repair
HV switchgear and circuit breakers	✓				
Overhead lines – 11kV		✓			
Distribution transformers		✓			
Power transformers and regulators	✓				
Protection		✓			
Overhead lines – 400V		✓			
Overhead lines - 110kV, 50kV, 33kV	✓				
Underground cables – 400V		✓			
Support structures - concrete and steel		✓			
Communication systems			✓		
Control systems			✓		
Substations (buildings) and 110kV lattice towers					✓
Load management - plant		✓			
Load Management - relays				✓	
Underground cables – 11kV		✓			
Underground cables – 33kV	✓				

✓ - We have assessed the critical assets in these high-value asset classes. We intend to apply the same approach more broadly across different asset classes.

Asset health, criticality and risk grades

One of the tools we use to make asset replacement decisions is considering an asset's health and its criticality.

Asset health

We have adopted the asset health indicators (AHI) for electricity reticulation and equipment provided for by the Electricity Engineers Association (EEA) Asset Health Indicator Guide. This provides condition and non-condition based considerations in construction of an AHI.

We have standardised on the age to condition rating table below, based on observations and analytic assessment.

Age parameter	Age-based AHI	Criteria
Age ≤10% of ODV life	H5	As new condition, no drivers for replacement
10% ≤ Age < 67% ODV life	H4	Asset serviceable, no drivers for replacement, normal in-service replacement
67% ≤ Age < 100% ODV life	H3	End of life drivers for replacement present, increasing asset related risk
100% ≤ Age ≤100% ODV life + 3y (ODV + 5y for subtransmission)	H2	End of life drivers for replacement present, high asset related risk
Age > 100% ODV life + 3y (ODV + 5y for subtransmission)	H1	End of serviceable life, replacement required

Our AHI gradings are initially based on the above age to condition ratings, supplemented with condition-based ratings obtained from regular asset inspections. Over time we will transition to largely asset health based on actual condition-based assessments.

Asset lives

We have adopted standard asset lives from the Commerce Commission's Handbook for Optimised Deprival Valuation (ODV) of System Fixed Assets of Electricity Lines Businesses (ODV Handbook 2004). They are also generally consistent with the Commerce Commission's Electricity Distribution Services Input Methodologies Amendments Determination (2) 2019.

However, there are some variations. We will be able to forecast future deterioration more accurately, including defect rates and replacement intervention triggers/points, as we improve the accuracy of information on serviceable lives for asset types from asset inspections.

Asset class	Standard life (years)	H5 New < 10% ODV	H4 Servicable 10 - 67% ODV	H3 Inc risk 67–100% ODV	H2 High risk ODV–ODV+3 (ST ODV + 5)	H1 Replace > ODV + 3 (ST ODV + 5)
Support structure concrete and steel	60	< 6	6 - 40	40 - 60	60 – 63 (ST 60 - 65)	> 63 (ST > 65)
Support structure wood	45	< 4.5	4.5 - 30	30 - 45	45 – 48 (ST 45 – 50)	> 48 (ST > 50)
Overhead conductors	60	< 6	6 - 40	40 - 60	60 – 63 (ST 60 - 65)	> 63 (ST > 65)
Underground cables HV XLPE & PVC	45	< 4.5	4.5 - 30	30 - 45	45 – 48 (ST 45 – 50)	> 48 (ST > 50)
Underground cables HV PILC	70	< 7	7 - 47	47 - 70	70 – 73 (ST 70 - 75)	> 73 (ST > 75)

Asset class	Standard life (years)	H5 New < 10% ODV	H4 Servicable 10 - 67% ODV	H3 Inc risk 67–100% ODV	H2 High risk ODV–ODV+3 (ST ODV + 5)	H1 Replace > ODV + 3 (ST ODV + 5)
Underground cables LV distribution	60	< 6	6 - 40	40 - 60	60 – 63	> 63
Underground cables LV service and & streetlight	45	< 4.5	4.5 - 30	30 - 45	45 – 48	> 48
Distribution transformers and voltage regulators	55	< 5.5	5.5 - 37	37 - 55	55 – 58	> 58
Reclosers and sectionalisers	40	< 4	4 - 27	27 - 40	40 – 43	> 43
Switchgear HV ground mounted	40	< 4	4 - 27	27 - 40	40 – 43 (ST 40 – 45)	> 43 (ST > 45)
Switchgear and fuses/links HV pole mounted	35	< 3.5	3.5 – 23.5	23.5 - 35	35 – 38 (ST 35 – 40)	> 38 (ST > 40)
Pillars, cabinets and fuses/links LV ground mounted	45	< 4.5	4.5 - 30	30 - 45	45 – 48	> 48
Fuses/links LV pole mounted	35	< 3.5	3.5 – 23.5	23.5 - 35	35 – 38	> 38
Earth grids	45	< 4.5	4.5 - 30	30 - 45	45 – 48	> 48
Substation buildings 110kV	70	< 7	7 - 46	47 - 69	70 – 75	> 75
Substation buildings 33 & 50kV	80	< 8	8 - 53	54 - 79	80 – 85	> 85
Power transformers	60	< 6	6 - 40	40 - 60	60 – 65 (ST)	> 65 (ST)
Substation circuit breakers outdoors	40	< 4	4 - 27	27 - 40	40 – 45 (ST)	> 45 (ST)
Substation circuit breakers indoors	45	< 4.5	4.5 - 30	30 - 45	45 – 50 (ST)	ST > 50 (ST)
Substation bus systems	40	< 4	4 - 27	27 - 40	40 – 45 (ST)	> 45 (ST)
Load control plants	15	< 1.5	1.5 - 10	10 - 15	15 - 18	> 18
Protection relays, static and electromechanical	40	< 4	4 - 27	27 - 40	40 – 43	> 43
Protection relays, numeric	20	< 2	2 - 14	14 - 20	20 - 23	> 23
Battery systems	20	< 2	2 - 14	14 - 20	20 - 23	> 23
Capacitor banks	40	< 4	4 - 27	27 - 40	40 – 43	> 43

Asset criticality

Asset criticality represents the relative seriousness of failure. We use the EEA Asset Criticality Guide to determine Northpower's asset criticality scale detailed below.

Asset critically indicator	Description
C4	Minor: Credible consequence of failure is broadly tolerable and run to failure may be a valid strategy
C3	Typical: Asset failure would cause some disruption and inconvenience, but systems are in place to anticipate and manage outcomes
C2	Elevated: Asset failure would cause significant harm to people, assets, the business or the environment. The consequences are tolerable but should be avoided or mitigated if it is practicable to do so
C1	Extreme: The credible consequences of failure would generally be intolerable

Asset criticality has initially been based only on service levels, however we will include criticality based additionally on public safety, workplace safety, direct cost and environment going forward. We are in the process of developing a system aligned to the EEA Guidelines, establishing a default criticality index value to every asset on the electricity reticulation network based on these variables.

Service levels relate to the electricity supply and customer impact from loss of supply.

Risk grades

Risk reporting matrix

ACI \ AHI	H5 New	H4 Serviceable	H3 Inc risk	H2 High risk	H1 Replace
C4 Minor	Risk grade 5	Risk grade 5	Risk grade 5	Risk grade 5	Risk grade 5
C3 Typical	Risk grade 4	Risk grade 4	Risk grade 4	Risk grade 2	Risk grade 1
C2 Elevated	Risk grade 4	Risk grade 4	Risk grade 2	Risk grade 2	Risk grade 1
C1 Extreme	Risk grade 3	Risk grade 3	Risk grade 1	Risk grade 1	Risk grade 1

Risk reporting includes five risk grade zones, representing a combination of asset health and criticality indicators within which intervention response is likely to be similar.

The definitions and likely interventions of each risk grades are shown in the table below.

Risk grade zones	Definitions and likely interventions
Risk grade 5	Low relative consequences of failure. Interventions would likely be justified on efficiency and/or cost benefit considerations alone. Tolerating increased failure rates and/or running asset to failure may be viable management strategies
Risk grade 4	Typical asset, in useful life phase. Interventions would likely be justified on efficiency and/or cost benefit considerations alone. The predominant strategy is to monitor and maintain
Risk grade 3	Healthy but highly critical assets. Operating context would need to be changed if the consequences of failure are to be reduced (for example redesign to improve redundancy)
Risk grade 2	Combination of criticality and health indicates elevated risk. Appropriate intervention measures should be devised and timetabled, and current risks prudently managed in the interim
Risk grade 1	Combination of high consequences of failure and reduced health indicates high risk, for many organisations justifying immediate intervention

Asset health and investment decision tools

We have developed an interactive tool to model future asset replacement scenarios for many of our assets.

The tool helps us explore questions like: what would our asset-failure-risk profile look like in ten years if our asset replacement scenario is to:

- ramp-up an asset fleet's replacements; or
- reduce an asset fleet's replacements; or
- keep the asset fleet's replacements the same as they are today

Users can then translate these asset replacement insights into different:

- capex investment scenarios; and/or
- corporate risk assessment and risk appetite scenarios; and finally
- the approved ten-year investment forecast for our electricity distribution business.

The tool has filled a need in our asset management toolbox. We will review the other tools available as part of our new asset management system project.

Routine preventative inspection and maintenance practices

Northpower adopts a range of network maintenance strategies for each asset fleet. However, all fleets are generally managed through their lifecycle with the following maintenance regimes.

Preventative maintenance	Periodic inspection and servicing of equipment to identify early signs of deterioration so remedial work can be planned, maximising the operational lifespan of the equipment.
Corrective maintenance	Corrective action for non-urgent defects and deterioration identified from the preventative maintenance inspection.
Reactive maintenance	Urgent or immediate corrective action required to protect people, property or the network from hazards or to restore the electricity supply to normal operating condition.

For preventative maintenance a risk and criticality-based approach gives priority to assets serving either large numbers of customers, specific high electrical demand and critical customers, or where public safety is a concern (for which, condition-based maintenance is the most likely strategy). These assets will be subject to a more comprehensive or frequent inspection regime, or an increased level of monitoring.

This also means that assets serving a small number of non-critical customers are likely to receive a lower priority (with a higher risk of failure and associated reactive repair). High priority is given if safety may be compromised, in which case our response is immediate or more targeted.

Each category of asset is governed by an asset strategy which explains the purpose, the strategy, the technical standards and the identified risks that apply to the particular asset class. Our asset strategies for each asset is covered in Section 7 Managing our assets.

Each asset class is further supported by a network standard that includes data capture requirements to be collected during field inspection and maintenance activities. The existing strategies are currently in the process of being translated from routine condition-based maintenance to risk-based asset condition maintenance.

A more detailed analysis of the routine preventative inspection and maintenance regimes for each of the asset categories is covered in Section 7 Managing our assets.

Process for rectification of defects

During field inspection varying levels of priorities are assigned to different defects and the priorities are identified, which sets the urgency of scheduling of follow-up maintenance.

Individual defects or tasks are collated into a work pack, which is created in our maintenance management system. Upon completion, the contractor returns the work pack along with any as-built information, attributes or data required to be captured.

Through condition assessment we can categorise assets to a grade of condition, which is the basis of a risk profile. We also use asset age, benchmarked against electricity industry accepted useful lives. While many assets (even without some form of mid-life refurbishment) can remain in operation beyond the presumed "end of life", in many cases, it is difficult to predict the risk of future failure, other than acknowledge that it is more likely.

Asset replacement and redeployment

We consider asset lifecycle cost and undertake a risk evaluation in deciding whether to replace or redeploy/upgrade existing assets. We use three primary classes of assets deployed on the network and each class is treated differently regarding redeployment.

Expendable	Assets that are not generally refurbished and/or redeployed on the network. This typically includes equipment with lower value that are difficult to confirm condition or integrity. (e.g. crossarms, line hardware and conductors). Equipment and conductors may be redeployed for temporary use only.
Rotable	Assets that can be recovered, refurbished and redeployed on the network. Assets must be traceable with a serial number and service history recorded. This typically includes equipment with relatively high value and long lifespan such as transformers and HV switchgear.
Re-deployable	High value substation assets with the same characteristics as rotable assets. Due to the high cost of substation equipment, cost benefit analysis is undertaken to compare cost of refurbishing older equipment with purchasing new equipment. Older equipment may also be retained as strategic spares.

Unless a risk assessment identifies unacceptable risk and assets have to be replaced, new assets are acquired only when existing assets cannot be redeployed, or if using recovered assets would be inappropriate. The guiding principle is to achieve the least lifecycle cost, including an implicit recognition that employing used assets carries the risk of higher operating or maintenance costs at a later date.

Asset acquisition

We have a policy governing the acquisition of a third-party constructed distribution network. This policy contains details of capital contributions and transformer capacity charges. It is supported by technical and engineering standards to ensure the guiding principle of least lifecycle cost is preserved.

5.7.3 Step 3 - Design and build our network

We use various service providers to design, maintain and build our network. To support the design and build process we have a range of network standards and specifications that apply, which are set out below.

Safety in design

We are responsible for ensuring the safety of all electricity reticulation and equipment from the Transpower grid exit point (GXP) up to the customer's point of supply. We ensure that network assets are appropriately secured, preventing unauthorised entry or access to exposed live conductors.

We apply safety in design principles to ensure our network is designed so it is safe to build, operate, maintain and decommission. Our safety in design framework is adapted from the EEA guide for safety in design. The main objective of the framework is to ensure that our design process does not introduce new hazards, as well as minimising current hazards during the construction, operation and maintenance phases of an asset's life cycle.

Design and technical standards

To manage the health and safety, cost, efficiency and quality aspects of our network we standardise network design and work practices where practicable. We also engage external consultants to provide designs for our critical assets, including zone sub-station design.

Our technical standards are for authorised service providers working on our network and reference the relevant codes of practice and industry standards as appropriate.

Equipment specifications

We aim to adopt standardised equipment for construction on the network. We have developed specifications detailing accepted performance criteria for significant equipment on our network (e.g. power transformers, switchgear). New equipment must conform to these standards.
We maintain a list of approved equipment for use on the network, which meet our quality requirements. New equipment types are assessed and often tested before being approved on the network.

Equipment operating instructions

To ensure safe operation of our network we have operational instructions covering the different types of equipment on our network. We create new operating instructions for any new equipment introduced onto the network.

Operating standards

To ensure our network is operated safely we have developed standards covering such topics as the release of network equipment, commissioning procedures, system restoration and access permit control.

Documentation control

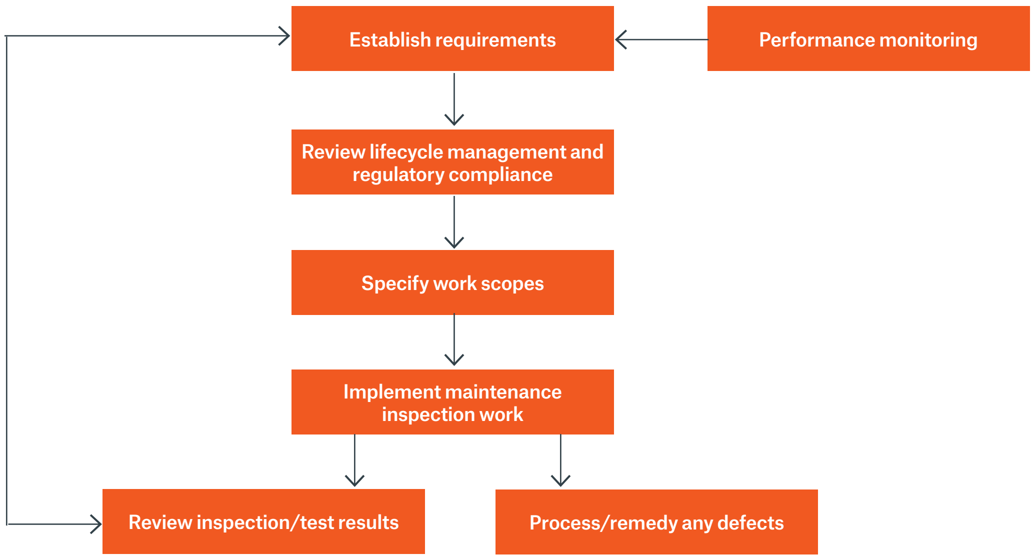
We ensure our documentation and drawings are maintained as accurately as possible by assigning an owner and an approver. Changes are managed through a change control process, through our quality management system. Our network information team is responsible for maintaining and processing changes to these control documents using a process set out in our document control standard. This standard also defines a number convention used to identify our documents based on the type and assets covered.

5.7.4 Step 4 – Operate, maintain and monitor

The operate, maintain and monitor phase of the lifecycle is in accordance with our maintenance plan. Each asset class is subject to a prescribed regime for routine inspection and maintenance, and specified asset replacement programmes. Requirements and scopes of work are developed from these plans, and they are either sourced to our field service provider, other specialist contractors, or for some larger projects we will use a competitive tender process.

Monitoring of our assets is against the service levels in this AMP, and against the specific requirements of that asset class.

Figure 60: Process for routine asset inspection and maintenance



5.7.5 Step 5 – Dispose, replace

Replacement of assets occurs in accordance with our maintenance strategies, and once the criteria for replacement has been met.

We are committed to disposing of our assets safely, in a way that minimises environmental impact, complying with all legislative and local authority requirements. Our service providers are generally responsible for the disposal of redundant assets, equipment, hazardous substances and we ensure that materials such as oil, lead, PCB's and asbestos, which may cause harm, are disposed of consistent with ISO14001. We seek to recycle materials where practical.

5.8 Business case approach

We develop business cases for projects to consider and assess the different options for solving network issues and meeting customer needs. This includes decisions around network development and significant asset lifecycle management capital projects. We consider a range of options, to meet our security of supply standards and network performance measures.

Input for business cases is sought from our asset strategy and planning team, network engineers, as well as our senior management team. Large investments are considered and approved by our board.

5.9 Innovation and new technologies

We actively look to adopt innovations and new technologies where they will improve the services we deliver. We evaluate benefits, costs and risks and undertake trials to confirm the benefits, verify compliance with network standards and performance requirements, and that health and safety requirements are met.

We apply a change management procedure to ensure that the adoption of any new technology or change in existing technology - whether brought about by internal or external influences - is subjected to a robust assessment prior to any implementation. A network standards process is in place to assess any suggested or required change, whether it is new technology or modified work practices. The process is cross functional, engaging with network engineers, contractors, procurement and health and safety expertise, as required.

Northpower

2021 – 2031 Asset Management Plan

Section 6

Planning our network

Table of contents

6.1 Introduction

In this section we set out how we plan our network to prepare for the future. We discuss the changing demands on our infrastructure and responding to changing needs of our region, along with the opportunities and challenges we face with evolving new technologies. Towards the end of this section, we detail our proposed network development projects needed to maintain a safe, reliable and resilient network over the next ten years.

Our capital expenditure is keeping pace with growth on our network, both in terms of connections and electricity demand. Demand for electricity on our network has been increasing steadily, with localised high growth areas and expected changes from industrial loads. High growth areas continue to forecast high growth, such as Mangawhai which is expected to increase in population by 7,200 residents with an additional 3,200 dwellings by 2051. To support this growth and ensure ongoing security of supply during the AMP planning period we have planned significant subtransmission and augmentation projects:

- A programme to improve network security and backfeed capacity on the east coast of our network for Ngunguru, Waipu, Mangawhai and Parua Bay
- New 33kV feeder to Mangawhai to lift security of supply to n-1 and support growth

We are also readying our network for changes in energy consumption and uptake of new energy technologies, such as electric vehicles and home energy systems (battery and solar). Changes in energy flows on our network require a shift to a more active network management. While there is uncertainty on the rate of growth, we are upgrading systems and looking to integrate data from LV sensors and smart meters to help us monitor and manage these emerging technologies.

We have an important role to play in helping our customers realise the benefit from energy options. Our engagement with customers and the Northpower Electric Power Trust has shown they are wanting us to be ready for them to take up new technologies. We are preparing our network as a platform to power the future needs of our communities.

Significant assumptions in planning our network found in Section 8 Expenditure forecasts.

6.2 Preparing for the future

6.2.1 Case for change

The centralised uni-directional power flow model is changing. Drivers to shift to a low carbon economy and advances in energy technologies are heralding a new phase in electricity supply, which is decentralising supply and in time will introduce new services and markets. Over the next ten years we expect increasing:

- Distributed generation – customers self-generating and storing their own electricity from sources such as wind and solar, seeing electricity fed back into the grid.
- Advances in digital technology – enabling control and information flow for customers to manage their energy use and for new markets to emerge.
- New consumption – adoption of EVs and other energy technologies will create new demand for electricity. As batteries become more affordable, this will create greater flexibility to manage energy use and options to improve resiliency.

As these developments emerge and technologies become more accessible, our customers may wish to increasingly participate in their energy choices including:

- Selling surplus energy into the market
- Storing energy to either use when they want or to sell back into the market at a higher price
- Selling to other people (peer-to-peer)
- Developing neighbourhood storage networks
- Charging their electric vehicles or devices at times when the cost of energy is cheaper
- Ramping back their energy consumption at peak times to reduce energy costs

No matter what direction the market and our customers take, we will invest in technologies, systems and partnerships to enable this change.

6.2.2 Starting our journey

Adapting our network to accommodate changes in power flow and customer energy usage demand and patterns requires greater visibility and control of our network. Historically our networks were planned with relatively predictable demand. Household consumption profiles and anticipated growth allowed for long-term investment planning with a fairly high degree of certainty.

It is our LV network which will encounter much of the change with the uptake of new energy technologies. Residential customers are fed off our LV network, and these new technologies give customers greater choice of when and how much electricity they want from the grid without consulting us. We can no longer depend on future energy loads and profiles around the network to be the same as the past. Making sure our LV network has sufficient capacity to enable customers the flexibility of service is part of our focus on future network strategy, which will include integration of LV sensors, metering and devices to gain visibility of our LV network.

At an aggregate level, large volumes of DG and DER could impact our HV network, and our investment in upgrading our SCADA system and foundational elements of our advanced distribution management system is a key step towards moving to a more active distribution management system. In FY21 we completed implementation of the ADMS for our zone substations and subtransmission system. In FY22 we will be implementing our 11kV network. These more advanced systems will give us full visibility across our core backbones, enabling us to better manage capacity constraints at an HV level.

Our journey over the next five years will see us:

- Build greater visibility of our low voltage network
- Develop data and analytics capability to understand our capacity, constraints and opportunities to optimise operations as more distributed generation is connected
- Engage with customers, support their choices to new energy markets, and make it easier for them to access new solutions and technology
- Support and educate consumers to maximise the value they receive from their energy use
- Modernise our pricing ensuring it is fair and equitable for all consumers.
- Partner with providers, other electricity distribution businesses and industry parties to avoid complexity and create a “plug and play system”

6.2.3 LV monitoring

Northpower has completed an initial roll out of LV sensors on selected distribution substations, using the Gridkey solution. This solution utilises portable sensors in the transformers, combined with cellular connections to a cloud-based analytics package. The initial rollout has targeted specific distribution substations, expected to have the most benefits initially. These are in areas where we are seeing increased PV and EV activity – e.g. new subdivisions and areas in the Whangārei CBD.

We are also working with other New Zealand EDB's and metering providers (MEP's) to gain access to smart meter data from homes on our network. Information from smart meters would help us with fault finding in outage scenarios, initially with 'ping' and 'last gasp' capabilities. This data could also help us model real time power flows around our network. We are aiming to deliver an improved customer experience on our network, with accurate real time information and improved fault response.

6.2.4 Improved modelling and forecasting

We will increasingly depend on LV forecasts to plan our subtransmission, HV and LV networks more holistically.

We are currently working on a full GIS CIM interface to our Sincal modelling and forecasting software, enabling a capability to start modelling increasing LV DER scenarios on our network.

Implementation of ESRI and integration with our GIS will enable us to create dynamic maps, providing website visitors with fast access to information about our network. This will include available hosting capacity for connecting large scale DG as well as upcoming major project information and other useful asset location information.

6.2.5 Integration with operational systems and processes

As our ADMS implementation progresses, we are planning to integrate LV monitoring as we collect this information.

Within the next five years we anticipate operators will be able to interrogate near real time information from our distribution transformers and smart meters on our network. The ADMS outage prediction engine will use this information to speed up identification and location of faults on the network, enabling faster fault finding on our network.

This information will support a capability for real time modelling of distribution power flows in the network operations centre, supporting improved decision making. We are aiming to create a capability to support active LV operations management should it be required.

Our customers' will benefit from improved outage information available on the website and to customer service representatives.

6.3 Preparing for growth in our region

Our network development plans are driven by growth in peak demand, not energy. For this reason we concentrate on forecasting peak demand across all levels of our network, rather than how much energy is consumed.

The network development projects in this AMP are to ensure we maintain capacity, quality and security of supply to support the forecast growth rates. Actual growth rates are monitored on an annual basis and any changes are reflected in annual updates.

We forecast growth at the zone substation level and translate this up to Transpower's GXPs and finally to a total network demand forecast.

Our GXP and zone substation forecasts take account of our electric vehicle forecasts, and continued improvements in energy efficiency and growth in households and businesses in our region. Due to uncertainty around uptake, we have not included battery storage in our forecasts at this level.

6.3.1 Peak demand

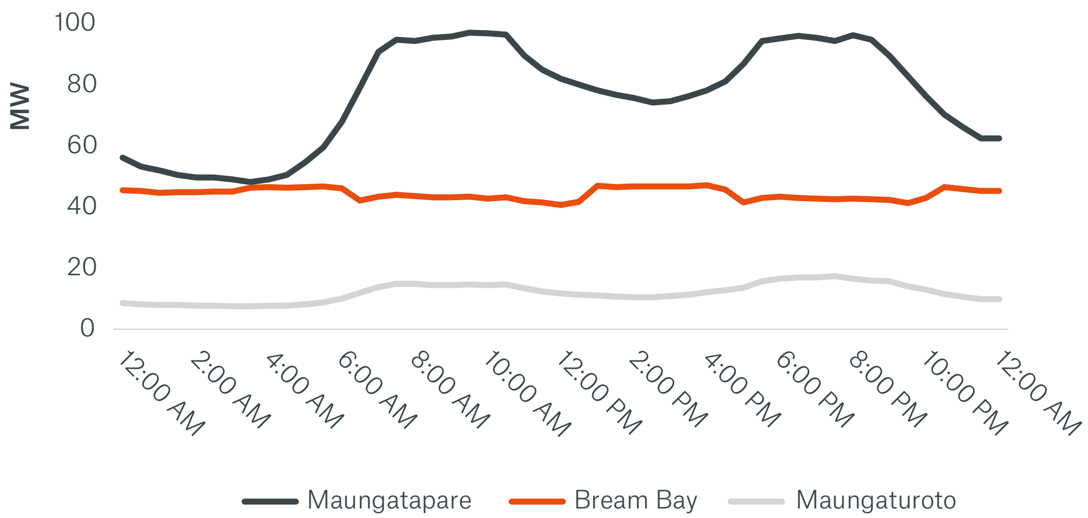
Northpower's electricity network is predominately rural. Apart from the major urban centre of Whangārei, and the smaller regional centres, the balance of the load comprises mainly farming, small townships and coastal settlements.

Hikurangi zone substation is noteworthy as it supplies a significant amount of flood-pumping. Approximately half our customers supplied are in urban areas and the remainder rural. The table below identifies the electricity load characteristics for the five regional bulk supply points.

Major station	Load characteristics
Bream Bay Grid Exit Point (GXP)	• Fairly constant load throughout the year • Predominantly industrial load with some residential and commercial • A slight drop in demand was observed in April 2020 (due to COVID-19 shutdowns) and August 2020
Dargaville zone substation off Maungatapere GXP	• Peak load in winter • Predominantly rural dairy, residential and commercial load with some industrial
Kensington regional substation off Maungatapere GXP	• Peak load in winter • Predominantly residential and commercial load but also significant industrial and some rural
Maungatapere regional substation off Maungatapere GXP	• Fairly constant load throughout the year • Mixture of all load types with significant large industrial
Maungaturoto GXP	• Peak load in winter • Predominantly dairy and industrial load • Increasing coastal settlement load

Typically the load on the network peaks in winter, usually late July or early August.

Figure 61: Typical GXP load profile, 3 July 2020

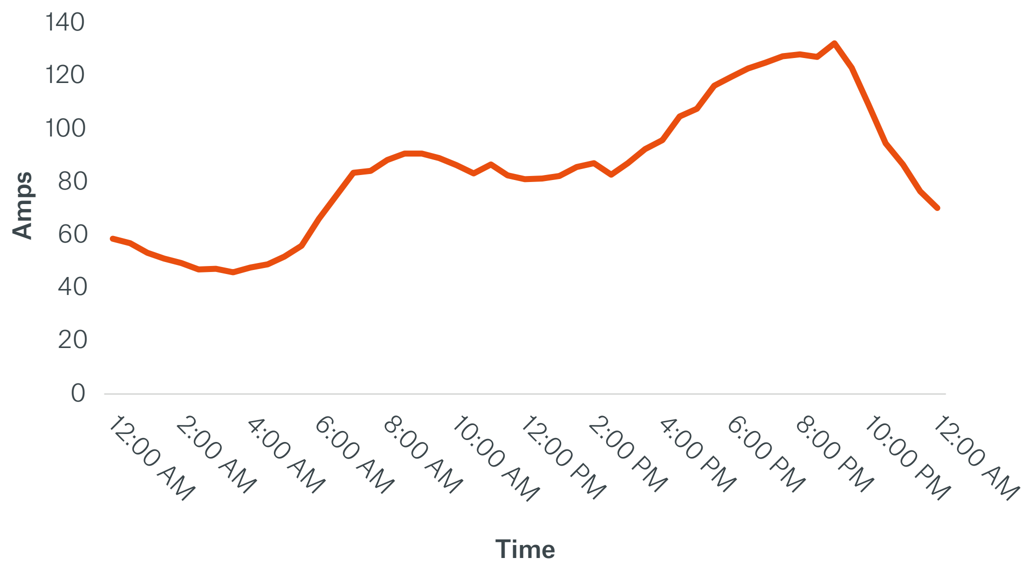


A typical daily profile of the three grid exit points during July 2020 is shown above over a 24-hour period. The combined evening peak demand across all three Transpower supply points on this day is approximately 167 MW.

While peak demand currently occurs in winter, we are seeing peak demand in summer increasing with the emergence of increasing climate control and refrigeration load.

A typical 24-hour residential feeder load profile is shown below. The 'spiky' nature of the load peaks is due to the operation of hot water load control which has suppressed the natural peak.

Figure 62: Typical 24-hour load profile (Tikipunga circuit breaker #1)



Northpower's ripple injection load control equipment (controlling largely hot water) is currently used to manage peak demand at Transpower GXP level. We are unable to manage peak loadings at specific zone substations or feeder level, and for most parts of the network peak load is approximately coincidental across the network.

6.3.2 Forecasting peak demand

Peak demand on the network is caused by consumer activity. Demand increases in residential areas in the mornings and evenings at the end of the business day. Residential demand is also highest during winter months.

Peak demand is an important consideration when managing electricity assets as the network must have capacity to meet the peak demand, to ensure uninterrupted delivery of electricity.

Many things influence changes in behaviours affecting how our customers consumer energy. This includes advances in technology and available energy options. Other factors we need to consider include major new loads on the network (such as processing plants) as well as reductions in existing large loads.

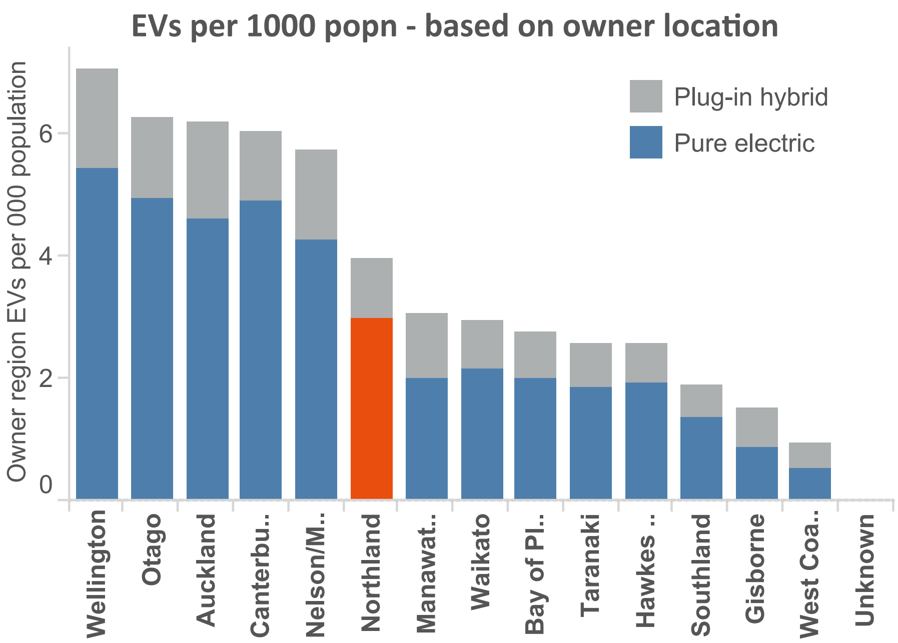
Many things influence changes in customer energy behaviour, which are hard to predict. These include:

- **Electric vehicles:** EV uptake rates are uncertain - the proportion of EVs that will charge from home and when, the diversity of home charging, and what size charge will be used are all current unknowns.
- **PVs:** the future uptake rate and size of installations is uncertain.
- **Home batteries:** battery uptake rates remain uncertain, as does knowledge of how customers will use batteries and the impact on peak demand. Customers may discharge batteries at peak, and recharge when electricity is cheaper or from their PV panels during the middle of the day.
- **Flexibility services and home energy management systems:** technology is developing which will manage and optimise home or business energy consumption, through the use of smart devices and control mechanisms. This could be in response to peak demand price signals. This could flatten or reduce network peaks, but customer appetite to adopt this technology and the rate of adoption is currently unknown.

Battery electric vehicles (BEV)

EV numbers in Northland are the highest of provincial centres in NZ; after more populated provinces of Otago, Canterbury and Nelson.

Figure 63: EVs per 1,000 population based on owner location. (Ministry of Transport, January 2021)



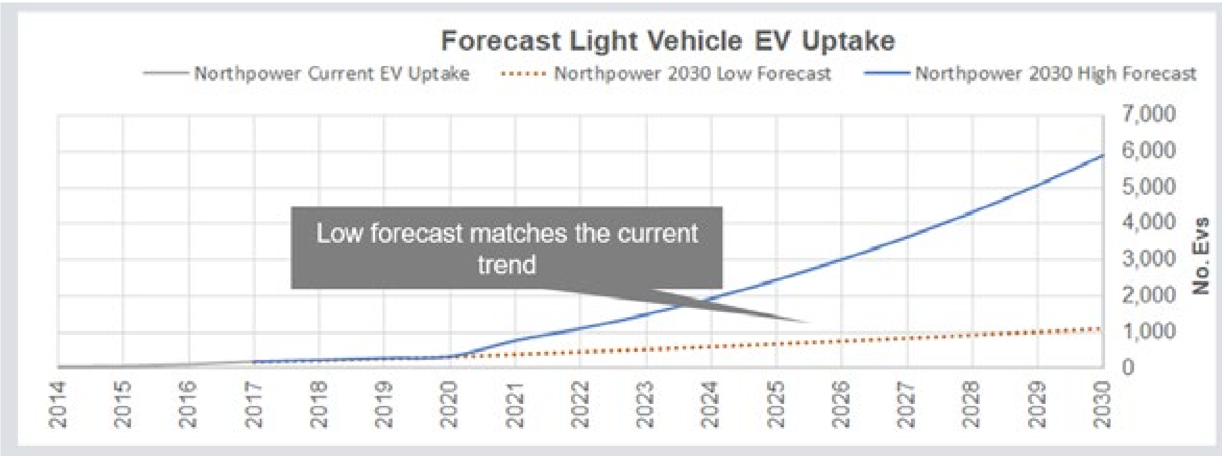
Source: https://www.transport.govt.nz/statistics-and-insights/fleet-statistics/sheet/monthly-ev-statistics

Based on current trends, we are forecasting an increase in BEV in our supply area of around 150 new vehicles per annum. This currently represents less than 1% of the light vehicle petrol fleet, increasing to around 2% by 2030 (our low case in Figure 64).

The high forecast below, takes the projected growth rate of accelerated electrification of light vehicles in Transpower's Whakamana i Te Mauri Hiko. Based on Transpower's growth rates, it would take until 2050 for light EVs to make up 30% of light passenger vehicles (reaching only 5% by 2030).

More recently, the Climate Change Commission's recommendation to Government is for EVs to reach 40% of all light vehicles by 2035 to meet NZ's climate change targets. We will monitor government policy and industry developments closely and incorporate these into our future annual planning studies, as there may be an upside risk in our current high case forecast based on the latest Climate Change Commission's recommendations.

Figure 64: Forecast light vehicle EV uptake on Northpower's network

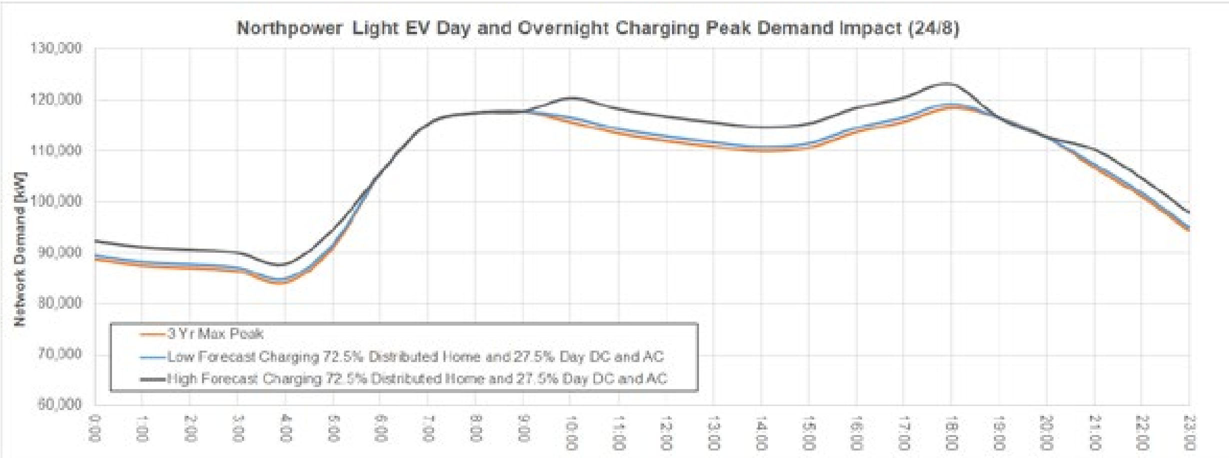


The impact on the network is harder to predict than for PVs, as BEV are mobile and can charge at many potential locations and at any time of the day or night. Future rapid charging stations will most likely be of a capacity requiring their own connection to the network. Rapid charging stations are more likely to be spread at different locations and generally at town centres close to other amenities. HV network capacity is not seen as a major constraint in the short to medium term.

Opportunity charging is currently limited on the Northpower network as only a small number of business and facilities frequented by the public have charging stations. Generally, AC charging stations with capacity up to 22kW per charger are often supplied from the associated business or facility. If associated with high-capacity business e.g. large shopping complexes, the increase in demand may be relatively small in the short to medium term.

A key unknown is the behaviour of EV home charging. We expect, based on studies in New Zealand that around 70-75% of EV charging will occur at home. Based on the Low Forecast and assuming 72.5% of charging is at home in the late evening or early morning (between 9pm and 6am) and the remaining 27.5% is charged during the day, the impact on peak demand by 2030 is not significant. However, uncontrolled charging has the potential to impact demand peaks.

Figure 65: EV plus overnight charging impact on peak demand



Source: Update of solar, battery and EV peak demand analysis, Jacobs, October 2020

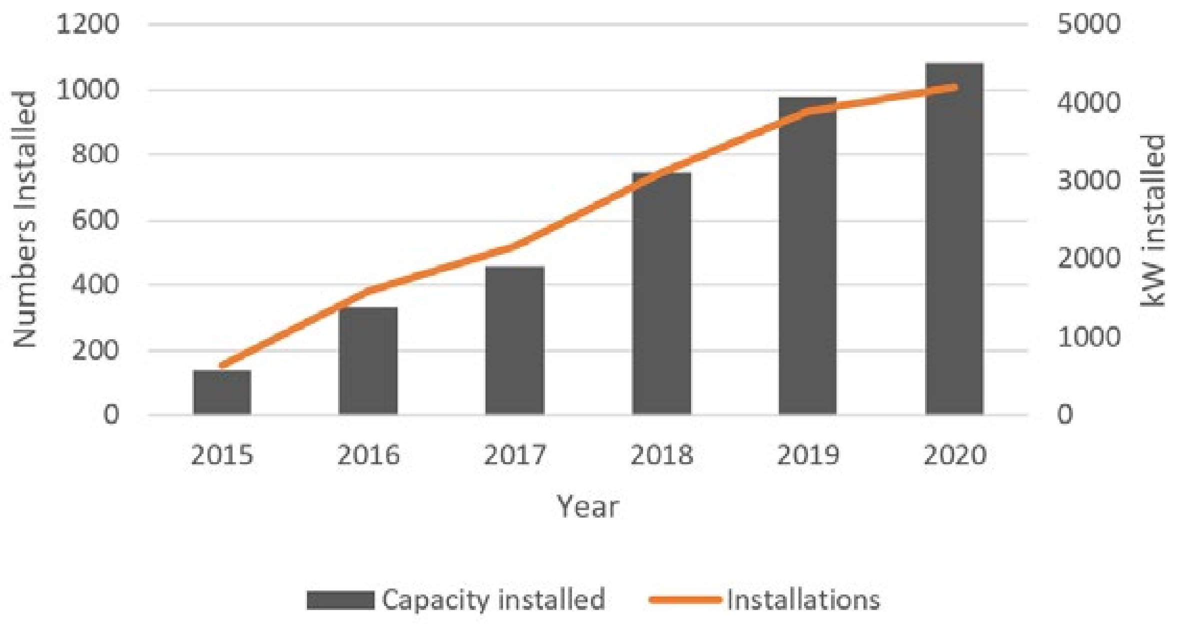
We anticipate there will be considerable diversity in EV charging behaviours (based on prior industry studies). To avoid significant increases in peak demand we expect pricing signals will be important to signal to consumers that they should charge at off-peak, when there is plenty of network capacity available. We have recently introduced time of use pricing for all mass market consumers, which has different pricing depending on when electricity is used.

Charging times could also be controlled by the smarts in the vehicle or by a smart home charger. If vehicle to grid (V2G) technology becomes more common, it may be possible for EVs to support weaker parts of the grid or during grid emergencies as well as operating as a smart charger.

Distributed generation/PVs

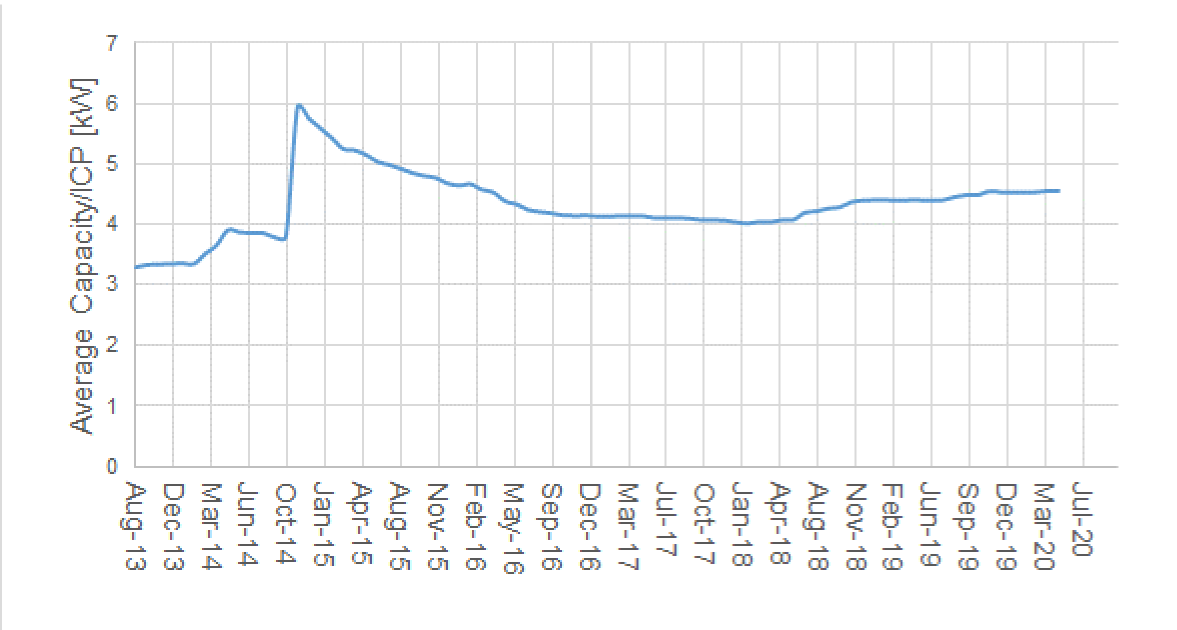
There has been a steady uptake of PV installs in recent years across our network. As at October 2020, there is around 5.4 MW of PV installed on the Northpower network – across 1.9% of ICPs, slightly higher than the national average of 1.5%.

Figure 66: Number and kW of PV installed on Northpower's network, April 2020



In line with New Zealand trends, the installed capacity per ICP has also slowly increased to about 4.5 kW / ICP from 3.9kW / ICP in 2018. The large increase in 2015 is associated with the 240 kW installation on Tarewa Shopping Centre. The average residential is 3.9kW and commercial 17.8kW.

Figure 67: Average installed solar capacity/ICP 2013-2020

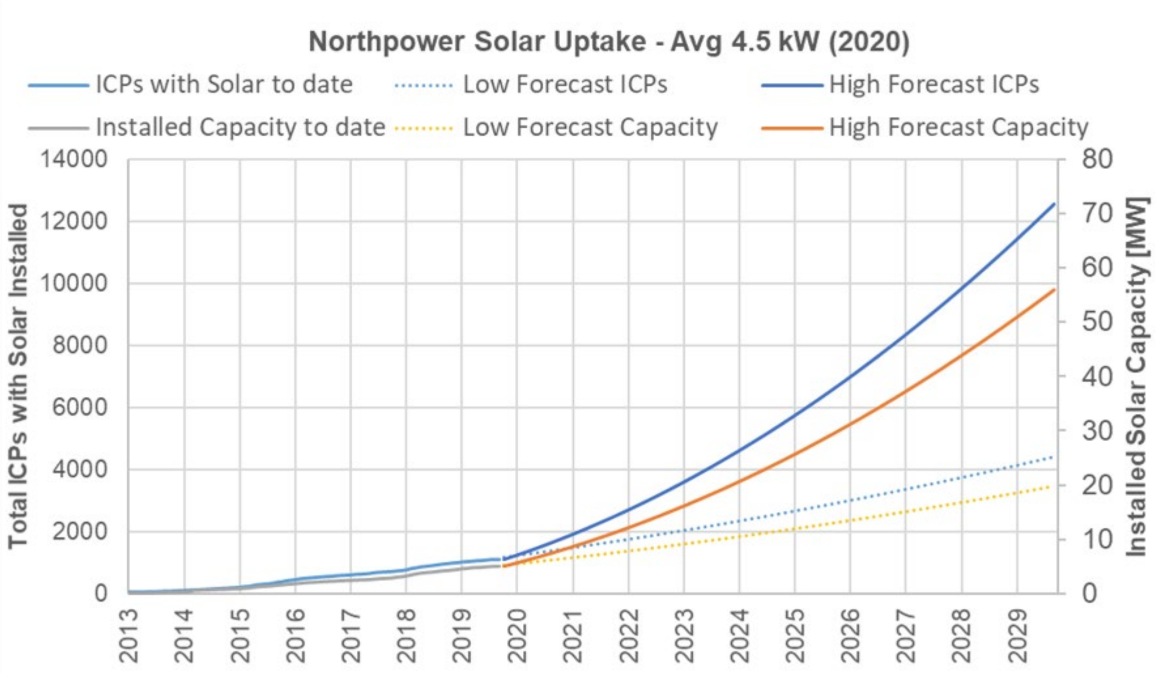


In forecasting future customer activity around PV, the uptake rate and size of installations is unclear. Modelling high and low scenarios gives an indication of the likely range of uptake:

- Low growth – assumes continuation of historical installed solar PV and forecasting this trend out to 2030
- High growth – curve fit to an assumed 25% of ICPs having an average of 3.9kW of solar PV installed by 2030

The high growth curve utilises the solar growth scenario included in Whakamana i Te Mauri Hiko (Figure 11 on page 35 of the report). The implied growth rate in this figure was applied to Northpower's current installed solar capacity of 5 MW in 2020 and projected out to 2030. This gave a projected total installed capacity of 56 MW of solar PV on our network in 2030. Based on an average of 4.5kW of solar installed per ICP, this would indicate that about 19% of Northpower's ICPs could have solar installed at this date (2030).[1]

Figure 67: Northpower solar uptake forecasts



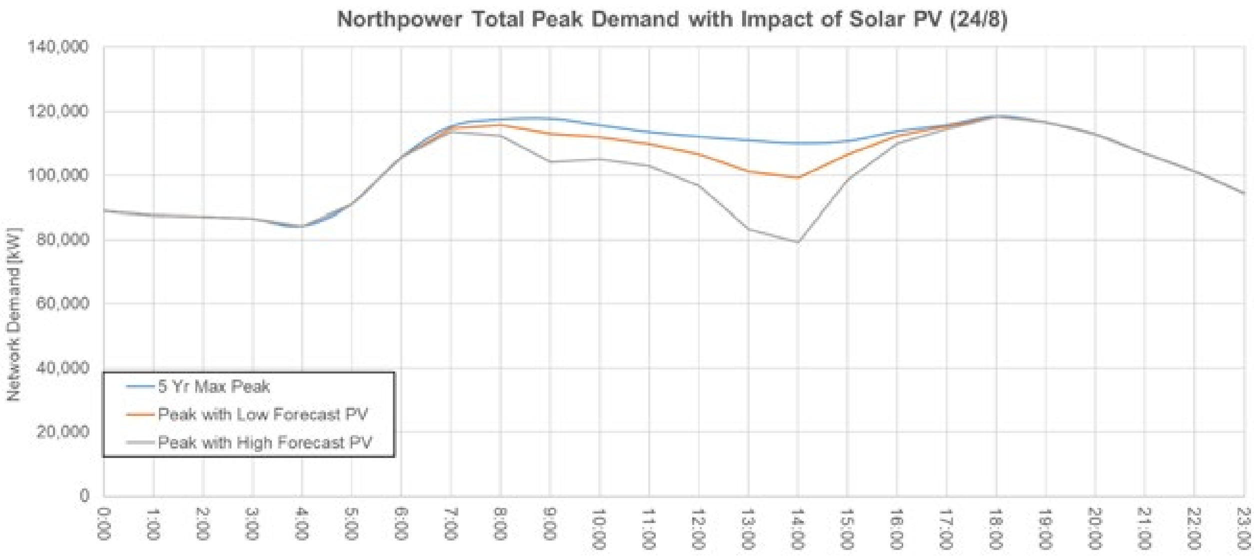
Source: Update of solar, battery and EV peak demand analysis, Jacobs, October 2020

The total demand profiles for the three GXPs on the Northpower network (Bream Bay, Maungaturoto, and Maungatapere), have been modelled based on the maximum demand profile of the last five years, against both the high and low PV forecasts, as shown below.

The demand profile was taken as a typical winter's day (24 August) with high network peaks and low solar generation. Figure 69 shows that under both solar growth scenarios, the embedded solar generation reduces the combined GXP demand during the middle of the day and has some impact on the morning peak, but has no impact on the evening peak.

[1] *Assuming the same ratio of residential to commercial solar PV installations as at 2020*

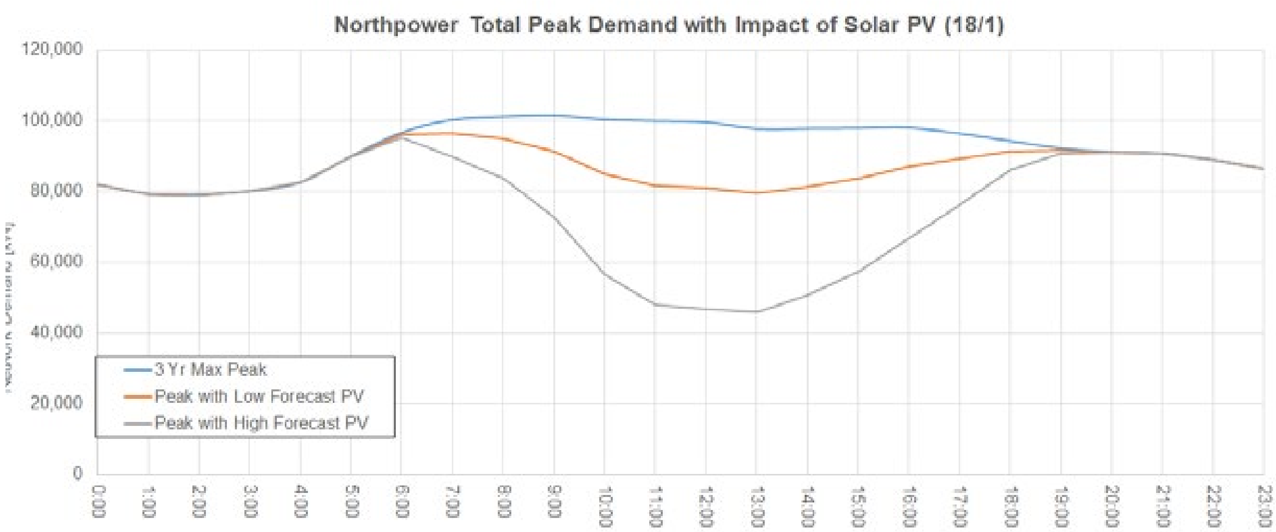
Figure 69: Northpower total peak demand with impact of solar PV (winter)



Source: Update of solar, battery and EV peak demand analysis, Jacobs, October 2020

Repeating this analysis on a typical summer's day (low network loads and high solar generation), the embedded solar profile in summer has a more substantial negative impact on the demand profile. Under the high forecast scenario, the combined GXP loading has dropped to less than half the evening peak during the middle of the day.

Figure 70: Northpower total peak demand with impact of solar PV (summer)



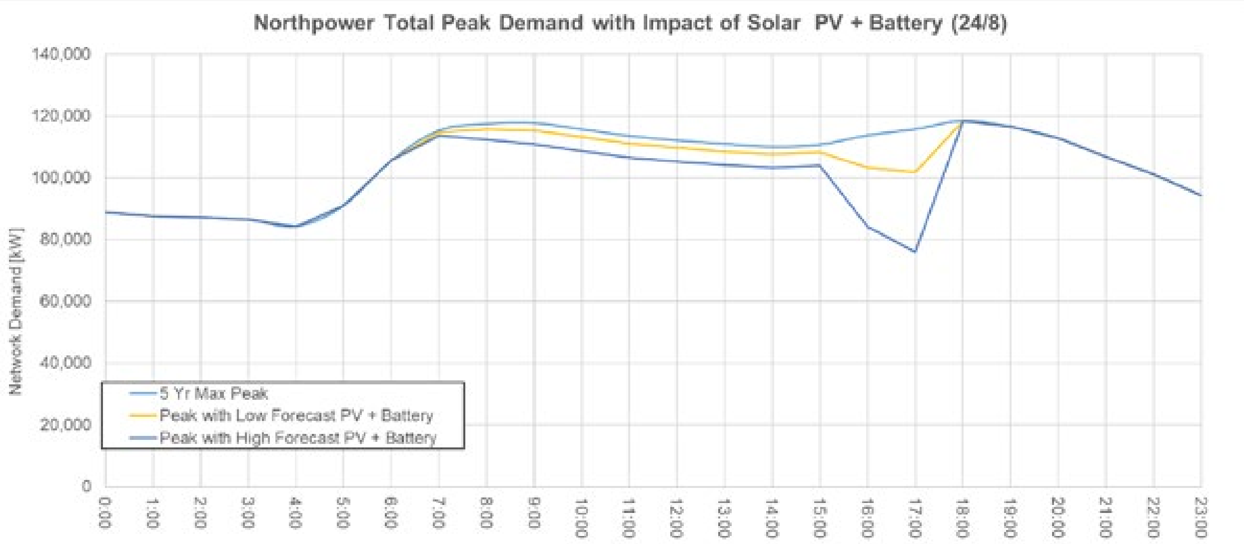
Source: Update of solar, battery and EV peak demand analysis, Jacobs, October 2020

Impact of solar with standard batteries on peak demand (winter)

Solar and battery combinations have the potential to reduce network peaks, as illustrated by the modelling below. The models below assume the average solar customer has a 5kW/13kWh battery) and the battery control logic is based on the default setting of batteries that are being supplied for solar systems – which is to maximise the use of solar in the home.

Figure 71 shows this behaviour scaled up on a cold winter's day with a lot of cloud cover. The average customer load starts to exceed solar generation by 3pm in the afternoon and the battery starts discharging. As there has not been a lot of solar generation on this day, the battery has not been filled to capacity and is completely discharged by 6pm. As a result, the stored energy in the batteries do not reduce the network peak after this point.

Figure 71: Northpower total peak demand with impact of solar PV and battery (winter)

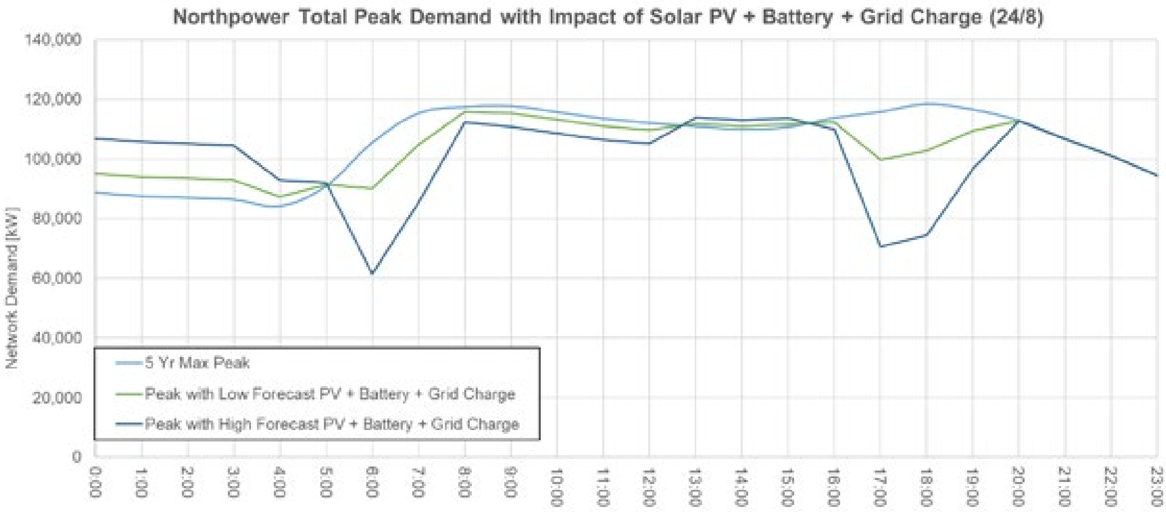


Impact of solar with smart batteries on peak demand (winter)

This modelling was then applied to batteries with a more intelligent battery control logic (enabling charging of the batteries from the grid in the early morning hours ahead of the morning peak, as well as during the afternoon on cloudy winter days).

Figure 72 shows this behaviour scaled up on the same winter day as above. The impact of battery charging in the hours after midnight can be seen as an increased load on the network, after which the batteries are discharged to reduce the morning peak. Likewise, in the early afternoon the batteries draw down from the grid to top up the battery before the evening peak. This enables them to discharge until 8pm helping to keep the network peak down during this period.

Figure 72: Northpower total peak demand with impact of solar PV, battery, and grid charging (winter)



This modelling does not reflect the diversity in the solar production profiles across multiple systems and battery types and the different responses of individual home load profiles on Northpower's network. However, relevant for our forecasting for network development:

- Solar systems with batteries installed, may or may not help to reduce network peaks but are least likely to contribute significantly when needed most (i.e. on cold cloudy winter days) in their default setting.
- Battery systems could provide network benefits if installed with control modes that include response to network pricing signals.

Population growth

The Whangārei and Kaipara District Councils have published their long-term plans and forecasted population increases out to 30 years. The population increases are driving significant re-zoning to support future large-scale residential and commercial growth, particularly in areas with closer proximity to Auckland. There are also some forecasts that coastal beach towns may turn into "zoom towns" with people moving to more idyllic areas as remote working remotely becomes the norm.

Population forecasts for Whangārei district estimates a higher growth trend over the next 30 years compared to the previous census period (2013-2018) where population grew by 18% increase compared to the NZ average of 10.8%. Whangārei district is forecasting population to reach 138,161 residents by 2048.

Population for Kaipara is showing some softening compared to 2013-2018 growth rate which reached 20% over this period. Population predications for Kaipara are forecasted to reach a total of 32,600 residents by 2051.

Figure 73: Whangārei District Council Growth strategy, Oct 2020

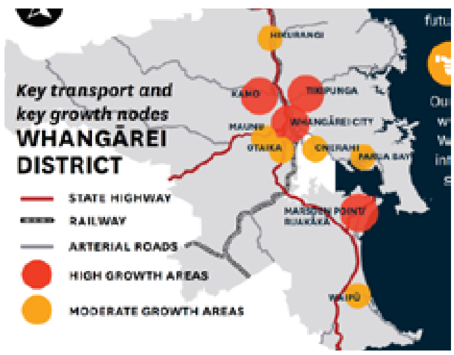


Figure 74: Whangārei district population projections, Whangārei District Council, Draft Sustainable Future Growth Strategy, 2020

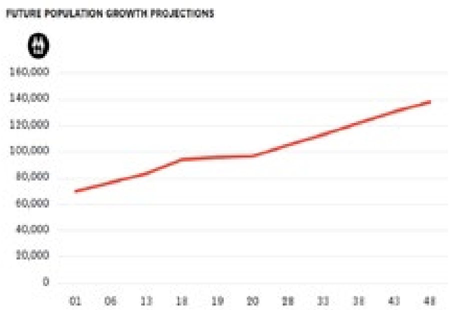
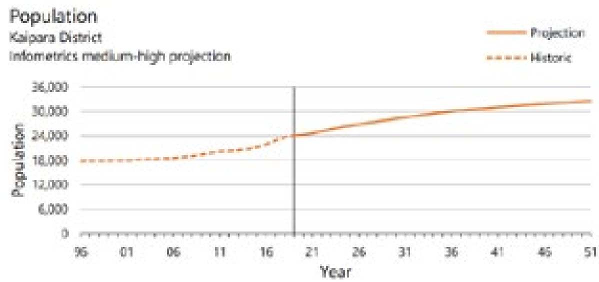


Figure 75: Kaipara district population projections, Infometrics for Kaipara District Council, Oct 2020



Electrification of process heat

To meet New Zealand's obligations under the Climate Change Response Amendment Act 2019 the country must reduce emissions of greenhouse gases, other than biogenic methane, to net-zero by 2050. This is likely to see movement towards the sun-setting of fossil fuel industries (particularly gas and coal) and maximising the use of electricity for process heat.

The potential impacts for the network would be process industries switching from gas to electric for heating such as electric boilers.

It is difficult to predict to what extent the home use of gas will decrease. Gas becoming more expensive may encourage a switch to heat pumps for space heating and summer cooling, and a standard electric cylinder for hot water, although heat pump technology may also become more common for hot water.

We have not included any specific load forecast for the electrification of process heat.

Hydrogen fuel cell electric vehicle HFCEV

Hydrogen is an emerging technology, and could be become a long-term transport fuel of the future (superseding BEV) or it could be more targeted towards heavy vehicles. Given the need to have a "greener" transport fuel, it is unlikely that hydrogen will be produced from fossil fuel (presently at 95%). Hydrolysing hydrogen from water is currently the most likely option for New Zealand and given the efficiencies of the process, it will require much more electrical energy than BEVs.

The potential impact to our network will depend on the uptake of hydrogen as a transport fuel, and the location of the hydrolysing plants. It is generally considered that hydrogen is a better fuel for heavy long haul vehicles, indicating the need for hydrogen filling stations at or near main distribution centres for goods.

Hydrogen Filling Station

However, it is not clear if hydrogen will be produced at the main filling stations or produced near the generation or major substations and distributed to the filling station. Hydrogen distribution can be either via pipes or tanker vehicles. A local hydrolysing plant is likely to require 2–4 MW of capacity. We have not included any specific load forecasts in relation to hydrogen production.

6.3.3 Overall load growth

Over the last five years we have seen a steady increase of around 1.7% growth in peak demand per year. However, in the last year, peak demand during the winter months decreased by 6 MW. We expect this was due to a reduction in consumption of major manufacturers and retail operators over the COVID-19 lockdowns, as well as a scaling down of some industrial operations during 2020.

Comparison of peak loads and energy consumption

Year ending	Peak load MW	Annual consumption MWh
31 March 2020	173	1,091,195
31 March 2019	176	1,056,828
31 March 2018	172	1,094,708
31 March 2017	170	1,056,000
31 March 2016	163	1,028,849

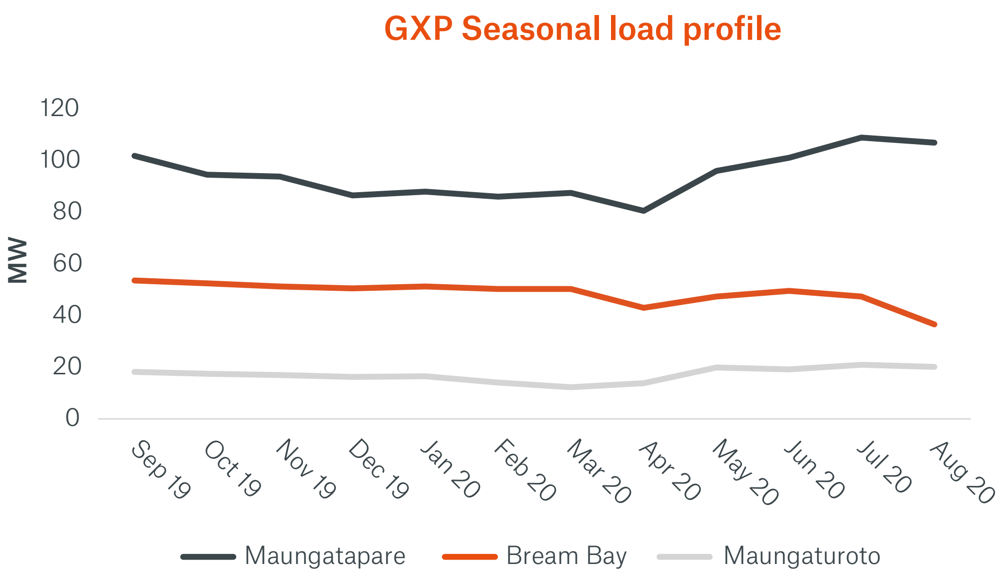
This current demand growth comprises reasonably steady growth in domestic connections, static growth in commercial connections, overlaid by some new industrial projects, as well as upgrade projects initiated by existing large commercial and industrial customers.

Transpower grid exit point	Supply voltage kV	Peak load MW	Annual consumption MWh	% of total
Bream Bay	33	53.37	339,409	33.1
Maungatapere	110	107.02	580,812	56.7
Maungaturoto	33	21.20	104,021	10.2
Total		167	1,024,242	100.0%

Data: 1 September 2019 – 31 August 2020 (peak loads at individual GXP's occurred at different times)

The GXP load profile is reasonably consistent across GXPs, although the sharper uplift at Maungatapere reflects greater customer numbers and a large residential population, driving peak demand in winter.

Figure 76: Peak loads and energy consumption by GXP



Very large industrial customers

Customers with high consumption (either maximum demand (MW) or annual energy consumption) are defined as very large industrial (VLI) loads.

These customers generally have special requirements regarding security of supply (typically duplicate transformers and lines or cables) as their loads are too large to supply with emergency standby or backup generation. These loads are normally supplied directly from the sub-transmission system at 33kV or by one or more dedicated 11kV distribution feeders from a nearby zone substation.

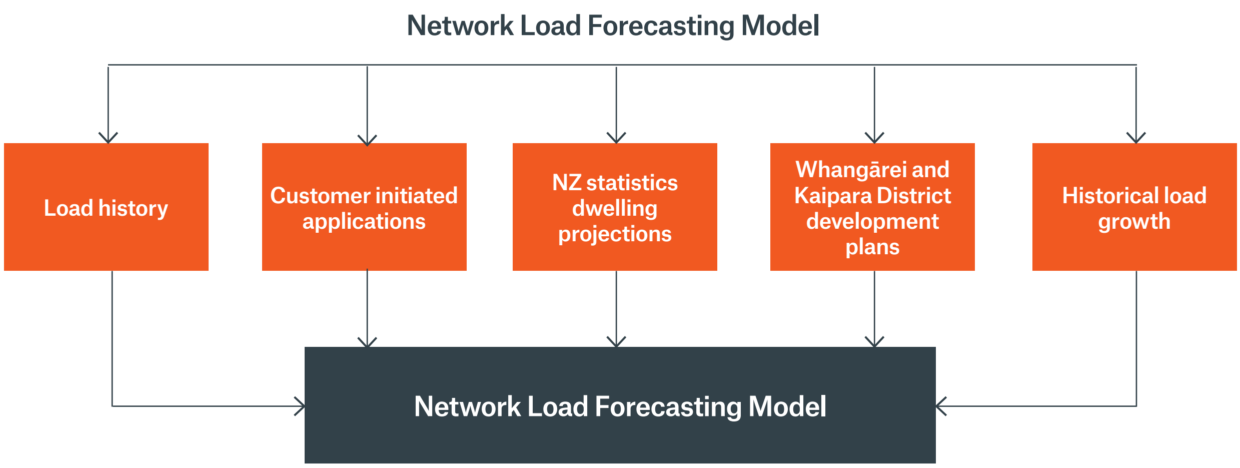
Five VLI customers currently consume around 43% of the electricity supplied by our network (down from 50% in previous years).

VLI customers	Peak load MW	Annual consumption MWh	% of total
Total (1/9/2019-31/8/2020)	73.34	442,032	43%

6.3.4 Load forecasting methodology

Our load forecasting process looks at a range of data inputs.

Figure 77: Network load forecast process and data requirements



We rely on several variables to generate the final load forecast:

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

We are continually looking to improve our load forecasting methodology to more accurately reflect emerging technology and potential changes in energy usage.

Recording and analysing network loading

We record network loading via the SCADA system for current and power at the following levels:

- GXP
- Subtransmission feeder
- Regional substation
- Zone substation
- 11kV distribution feeder

This information is recorded in OSI Pi historian.

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

Several factors can distort data when analysing current or historical network demand information for establishing trends, such as:

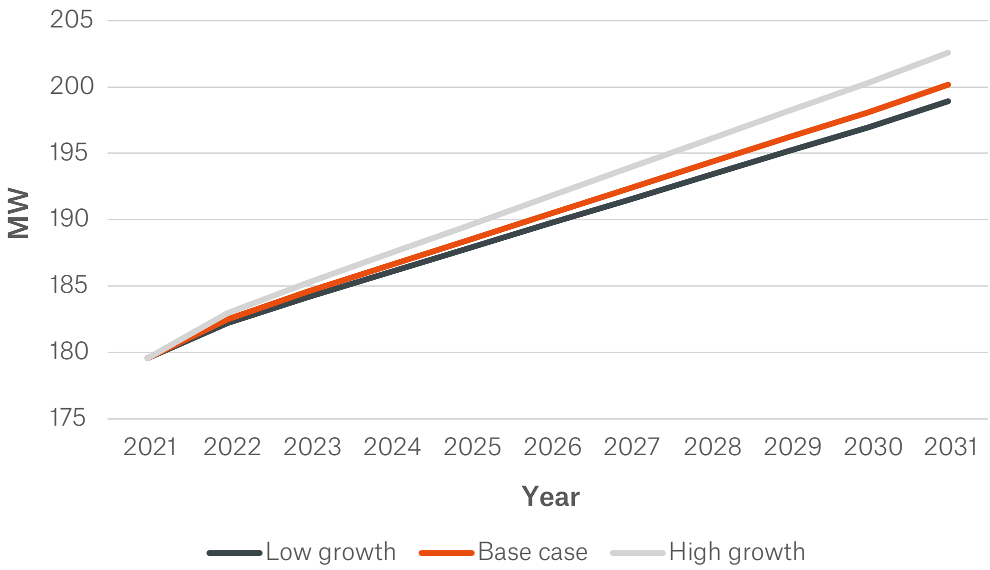
- Seasonal effects e.g. wet/dry summer, cold/warm winter
- The system may have been configured differently for a shutdown, fault event or permanent change to the normal supply configuration
- Use of load control on switching off and restoration of controlled load
- Economic cycles slowing or accelerating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

6.3.5 Projected load growth

The demand growth averaged across the entire network is expected to be approximately 1.1% per annum for the ten-year forecast period. Output from the embedded generators at Wairua and Bream Bay, and domestic solar PV will offset some of this growth.

The peak load (without embedded generation) on the network is expected to increase from the present 180 MW to around 203 MW during the next ten years using the above forecasting techniques and data.

Figure 78: Network peak load forecast (without generation) 2021-2031



The load forecasts above disguise the extremes of growth expected at local levels which can range from nil (or even negative) up to about 5% per annum in high growth areas. The estimated annual growth rates are based both on historical trends and an examination of present and expected future activity at feeder and zone substation level. The forecast includes anticipated step-load increases.

The trend assumes continued use of load control. Without load control the magnitude of the load would be approximately 10 MW to 15 MW higher.

Actual load growth could increase higher than predicted, or may drop in the short to medium term with possible downsizing of large industrial and manufacturing businesses. Possible large scale embedded solar and wind generation may also play a part in changing the forecasted load growth over the next ten years.

6.3.6 Load growth considerations

In their 30 year+ population forecasts, Whangārei and Kaipara District Councils are projecting significant residential growth in Ruakaka, Waipu, Mangawhai and Maungaturoto. Some coastal towns are also projected to have an increase in population, with growth in people working remotely.

Area	Growth forecasts and uncertainties
Bream Bay	The Whangārei District Council has designated large areas of land for development, with the possibility of a deep-water port being established at Marsden Point. In the medium to long-term the load at Bream Bay could increase substantially.
Waipu	Waipu is a fast growing area we have noticed a sizeable increase in load demand in the area. With large areas being designated for development we suspect the load to increase over the planning period. 11kV upgrades are planned for FY22 to cater for the growing demand.
Dargaville	Potential for large scale forestry development with wood processing that could lead to significant load growth in the longer term.
Hikurangi	Moderate growth is expected off the substation associated with the development of holiday homes and lifestyle blocks.
Kamo	Medium growth in the development of residential areas and lifestyle blocks that is expected to continue for the next five to ten years.
Whangārei City	The urban area is expected to grow out towards the west and substantial residential load growth is expected on the Maungatapere substation in the medium term. A new substation at Maunu will take some load off Maungatapere when commissioned.
Mangawhai	With its proximity to Auckland, the Mangawhai area has seen a steady increase in residential and commercial development as more permanent residents make this area their home and increased amenities and services are established. Mangawhai substation experiences higher temporary load peaks as people come to the area during long weekends and holiday periods. For about 270 hours (or 11 days) per year, a higher peak of about 7.5 MW is experienced, which is an increase of 2.5 MW from the normal winter average peak - generally around 5 MW. Future load forecasts however are uncertain, as it is not clear whether growth will accelerate or continue at current trends. We are reviewing development plans in the area, and will regularly reforecast expected load growth in order to determine whether additional capacity is required earlier than forecast. The AMP has a project to reinforce 33kV subtransmission supply to the area by duplicating the existing 33kV subtransmission line from Maungaturoto, in line with our security of supply and reliability criteria. We also have provisions in FY22 to increase the backfeeding capacity to Mangawhai to enable greater restoration in the event of an outage.

Details of customer numbers, transformer capacities, peak loads and feeder maps for each zone substation are provided in Appendix B.

6.3.7 Substation load growth projections

The following table compares the firm capacity of our zone substations with present and forecast load. The electrical vehicle uptake scenario (low uptake) have been incorporated into the forecast. The uptake of solar PV connections is recorded but not incorporated into the forecast because the impact on peak demand (given our winter peak) is negligible. At this stage we have not incorporated the impact of battery storage into our zone substation forecasts, as we do not anticipate the impact of batteries to be significant within the next ten years.

Northpower ten-year peak load forecast

Substation	0	1	2	3	4	5	6	7	8	9	10	Notes
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	
Kensington Regional Substation	**63.5**	**64.0**	**64.8**	**65.6**	**66.4**	**67.2**	**68.0**	**68.8**	**69.6**	**70.4**	**71.2**	
Alexander Street	13.0	12.8	12.8	12.9	13.0	13.1	13.2	13.3	13.4	13.5	13.6	Portion of load to be transferred to new Maunu Substation in FY22
Hikurangi	5.6	5.7	5.7	5.8	5.9	5.9	6.0	6.0	6.1	6.2	6.2	
Kamo	11.6	11.7	11.9	12.0	12.2	12.3	12.4	12.6	12.7	12.8	13.0	
Ngunguru	3.4	3.4	3.5	3.6	3.7	3.8	3.8	3.9	4.0	4.1	4.2	
Onerahi	7.5	7.6	7.7	7.8	7.9	8.0	8.1	8.2	8.4	8.5	8.6	
Parua Bay	3.3	3.4	3.5	3.6	3.7	3.8	3.9	3.9	4.0	4.1	4.2	
Tikipunga	14.5	14.8	15.1	15.3	15.5	15.7	15.9	16.1	16.3	16.5	16.8	
Bream Bay Transpower (without generation)	**56.3**	**56.7**	**57.0**	**57.3**	**57.6**	**58.0**	**58.3**	**58.6**	**58.9**	**59.2**	**61.4**	Demand may drop if reductions in operations in manufacturing and processing businesses
Bream Bay	4.9	5.0	5.1	5.2	5.3	5.5	5.6	5.7	5.8	5.9	6.0	
Ruakaka	7.1	7.4	7.6	7.8	8.0	8.2	8.4	8.6	8.8	9.1	7.5	Portion of load to be transferred to new Waipu Substation in FY31
Waipu	-	-	-	-	-	-	-	-	-	-	3.6	
Maungatapere Transpower (without generation)	**111.4**	**113.0**	**114.2**	**115.5**	**116.7**	**117.9**	**119.1**	**120.4**	**121.6**	**122.8**	**124.0**	
Maungatapere Regional (without generation)	**40.7**	**41.3**	**41.6**	**42.0**	**42.3**	**42.7**	**43.0**	**43.4**	**43.7**	**44.1**	**44.5**	
Maungatapere	6.7	6.0	6.1	6.3	6.4	6.5	6.7	6.8	6.9	7.1	7.2	Portion of load to be transferred to new Maunu Substation in FY22
Maunu	-	2.0	2.1	2.1	2.2	2.2	2.2	2.2	2.3	2.4	2.4	
Kioreroa	9.2	9.2	9.2	9.2	9.2	9.3	9.3	9.3	9.3	9.4	9.4	
Poroti	3.1	3.1	3.2	3.2	3.3	3.3	3.4	3.4	3.5	3.5	3.6	

Northpower ten-year peak load forecast												
Substation	0	1	2	3	4	5	6	7	8	9	10	
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Notes
Whangārei South	10.4	9.5	9.6	9.7	9.8	9.9	10.0	10.2	10.3	10.4	10.5	Portion of load to be transferred to new Maunu Substation in FY22
Dargaville	10.8	10.9	11.0	11.1	11.1	11.2	11.3	11.4	11.4	11.5	11.6	
Maungaturoto Transpower	**21.2**	**22.3**	**22.8**	**23.2**	**23.6**	**24.0**	**24.4**	**24.8**	**25.1**	**25.5**	**24.3**	
Maungaturoto	6.2	6.2	6.3	6.3	6.4	6.4	6.4	6.5	6.5	6.6	6.6	
Ruawai	3.1	3.1	3.2	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.4	
Kaiwaka	2.3	3.0	3.1	3.1	3.1	3.2	3.2	3.2	3.2	3.3	3.3	
Mangawhai	7.4	7.7	8.0	8.2	8.5	8.7	9.0	9.2	9.5	9.7	8.2	Portion of load to be transferred to new Waipu Substation in FY31
Mareretu	2.6	2.7	2.7	2.7	2.8	2.8	2.8	2.9	2.9	2.9	3.0	
Total GXP load (with generation)	167.1	170.0	172.0	174.0	175.9	177.9	179.8	181.7	183.7	185.6	187.7	
Total GXP load (without generation)	**179.6**	**182.5**	**184.6**	**186.5**	**188.4**	**190.4**	**192.3**	**194.3**	**196.2**	**198.1**	**200.2**	

Substation ten-year load forecast (MW peak) - data 2020 April to August

Notes to the load forecast table

1. Kensington and Maungatapere 110/33kV transformer loading is managed by transferring load (Kioreroa, Whangārei South and Alexander Street substations) between these two stations as required.
2. Northpower's 5MW Wairua hydro power station output (run of river) is dependent on rainfall and a 9MW diesel generator plant at Bream Bay is operated by its owner as a peaking plant. The output of these plants is unpredictable and may or may not reduce network peak loading.

6.4 Network planning

6.4.1 Planning criteria and assumptions

In planning our network we:

- Take into account customer feedback to determine the value they put on reducing interruption times. This is a key input into how much reliability investment is justified.
- Preserving our security of supply standard, which is the ability of our network to meet the demand for electricity when electrical equipment fails.
- Monitoring network utilisation thresholds to understand what reinforcement needs to be undertaken.
- Comparing our current network capacity with load forecast scenarios. The resulting projects are based on our design standards.
- Consider, especially where the network becomes constrained, non-network solutions to relieve those constraints, as an alternative to or to delay network investment.

Our investment drivers for planning and developing our network are categorised as follows:

- **Growth** (new customer connection and growth of existing load). The zone substation load forecast is used to identify future capacity constraints and possible solutions are identified. Technical and financial analyses are carried out in order to identify the most suitable long-term solution. Projects are then defined and planned.
- **Replacement and renewal** (asset deterioration or obsolescence). Assets requiring upgrading or replacement due to end of life or condition (safety, performance, maintenance costs) are identified and their replacement planned.
- **Improvement** (safety, reliability, environmental). Projects required to improve public and employee safety, network reliability and performance as well as reducing environmental impact where possible are identified, defined and planned.
- **Relocation** (relocation of existing assets). Assets required to be relocated for road works, property owner requests, network reconfiguration or safety reasons.

6.4.2 Security of supply standard

Security of supply is the ability of a network to meet the demand for electricity in certain circumstances when electrical equipment fails. The more secure an electricity network, the greater its ability to continue to perform or the quicker it can recover for a fault or series of faults.

Security of supply underpins our HV network resilience. We often build flexibility into our network so if there is a fault or we need to de-energise equipment to maintain or replace it, the network can often be reconfigured to provide power from alternative sources.

This additional capacity is termed N-1, which expresses the ability of the network to lose a component without causing an overload failure elsewhere. This is usually in the form of duplicate power lines and transformers, or ability to redirect power flows using spare capacity in other circuits. Our network only has full N-1 capacity in certain strategic areas such as high-density urban areas, supplies to critical loads, or where a customer has requested and paid for it.

Our security of supply criteria has planning rules for different categories of fixed assets as outlined in the table below.

Category of asset	Capacity criteria	Reliability criteria (worst case)	Security of supply criteria
400V distribution network	Statutory voltage level	Supply restoration within repair time or within switching time where 400 V link pillars present	(N) security of supply for standard residential or commercial connection (N-1) where link pillars present and backstop capacity available
11kV/400V distribution substation	Transformer continuous rating	Supply restoration within fuse or transformer replacement time or within switching time where 400V link pillars present	(N) security to most urban distribution networks (N-1) where link pillars present and backstop capacity available
11kV distribution network	Maximum operating load 80% of lowest segment rating	Supply restoration of 80% within switching time	(N-1) security except for spurs
11kV distribution equipment	Regulator rating RMU rating Cable rating	Supply restoration within switching time	(N-1) security except for spurs
33/11kV zone substation	80% of firm maximum load relative to firm capacity	Load restored 100% within 30 min for >5MVA 80% within 1 hr for <5MVA	(N-1) >5 MVA (N) <5 MVA
33kV sub-transmission network	110% of overhead line rating 80% of cable thermal rating	Load restored 100% within 30 min for >5 MVA 80% within 1 hr for <5 MVA	(N-1) for dual circuits (N) for single circuits
33kV assets within Transpower GXP	CB load and fault level rating	Supply restoration within switching time	(N-1) >5 MVA (N) <5 MVA

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

6.4.3 Network capacity constraints

As part of the planning process we identify network constraints that arise under normal system conditions and fault conditions, or when major plant is temporarily out of service for maintenance. This includes network components such as circuit breakers, isolators, transformers, cables and lines, which need to have sufficient capacity to ensure overloading does not occur during peak load periods.

Resolution of constraints usually involves upgrading of existing equipment, but in some cases network reconfiguration of new assets is also required. In the case of N-1 capacity constraints (where there is one level of redundancy), decisions on actions to take are based on risk and required levels of security. Temporary load shedding may be considered an acceptable solution in some cases, particularly where costs of resolving the constraint are excessive.

Thermal constraints can sometimes be resolved more cost effectively using cooling (e.g. fans for power transformers), improving ground thermal resistivity for underground cables, or re-tensioning or raising overhead line conductors, achieving a higher thermal rating (i.e. increased load transfer capacity). Voltage constraints can be resolved by increasing conductor size, installing voltage regulators, improving the power factor using capacitor banks, operating at a higher voltage level or constructing new assets.

We utilise power system modelling and thermal rating software, in conjunction with load forecast data to identify future capacity constraints on the network. Load flow studies are carried out for system normal power flows and contingency situations. The results of these studies are used to optimise asset capacity utilisation and delay investment in new assets until they are necessary. As future capacity constraints are identified, modelling software is used to model and evaluate alternative options to resolve the constraint(s).

6.4.4 Capacity determination for new projects

Capacity and subsequent rating of new equipment is generally determined by the size of the forecast load to be supplied and the prevailing fault level.

Reliability and security of supply aspects are based on the number of customers, nature of the load, susceptibility of the network to faults in the area and affordability of contingent capacity margins or duplication of assets.

Technical specifications for the range of equipment used on our network are detailed in the electricity network design standards and the network approved materials standard, which are part of Northpower's electricity network standards.

6.4.5 Standardised assets and designs

Northpower has a suite of standards across voltage levels. These include for overhead and underground networks, things like earthing, and selection standards for transformers, poles, switchgear, cable, conductor and fuse standards to name a few.

The network architecture standard is the starting point for design of new assets, providing direction on the overall architecture (use of HV, LV, connecting industrial loads, use of 3-phase vs. single etc.).

Standardisation ensures equipment is fit for purpose, suitable for local conditions (e.g. coastal corrosion is a significant local issue), faults are minimised, supply chain efficiencies (spares, procurement), and helps the network achieve lowest total cost of ownership.

6.4.6 Project prioritisation

The methodology employed to prioritise or rank projects across the network is based on risk and cost benefit analysis, and considers our obligations to:

- Ensure public safety and minimise environmental impact
- Meet network capacity, reliability and security of supply objectives
- Meet regulatory requirements

The prioritisation of projects also considers the following constraints:

- Budget allocations, and the smoothing of projects to align with capacity to deliver in any one year
- Timeframes for acquisition of resource consents and permissions
- Equipment lead-times
- Risk associated with project deferral

6.4.7 Non-network solutions

Where increases in demand for key service level parameters (capacity, reliability and security of supply) are identified, we consider both non-network and traditional network methods of meeting that increase in demand.

Traditional solutions include investment in new zone sub-stations, 11kV feeders and 400V reinforcement. However, there may be other solutions that will address this constraint including:

- Customer demand management
- Distributed generation
- Customer contributions

Other technical solutions considered include:

- Power factor recording or installation of half-hour metering to ensure customer compliance with power factor requirements
- Technological solutions e.g. motor starting methods, switched capacitors, voltage regulators, line drop compensation (transformer tap changers)
- Load shifting or rearranging existing assets to optimise plant usage
- Installation of distributed generation
- Customer education such as promoting energy conservation practices
- Minimisation of electrical losses in lines, cables and transformers.

We also consider alternative supply options for areas where it could be more economic to disconnect from the network, rather than upgrading the network. To date we have not yet identified any areas that would be considered suitable. Most remote loads are farms and lodges and if extraordinary maintenance requirements occur to these sites, we will consider alternative supplies in collaboration with the customers. There are no current proposals to provide alternative supplies at this time.

There are some areas of the network, particularly during holiday times, where mobile standby generators could reinforce the supply. The technical and commercial viability of this option will be investigated as required.

All significant investment decisions are subject to an assessment of alternative options during project initiation including, where applicable, any new technology options. Options are ranked depending on lifecycle costs/benefits as well as taking into account local factors and stakeholder considerations.

6.4.8 Customer demand management and ripple control

Customer demand management (and flexibility services) provides an alternative to distribution network development. Where customer demand can be influenced to reduce peak demand there is a benefit to the network, driving a more efficient outcome. The benefits of customer demand management include:

- Increased utilisation of the network
- Customer benefits through becoming more efficient in the utilisation of energy and network capacity
- Ultimately lower prices for customers

We recognise that incentives are important for customers to shift their demand through such means as interruptible or off-peak tariffs and other new demand flexibility services (and shared platforms).

We currently use the following customer demand management strategies:

- Ripple control – controlled hot water load
- Ripple system – other controlled load

We have also introduced time of use pricing, which has a higher variable price for consumption in the peak period. While the differential pricing between peak and off peak is currently small, this is expected to increase over time, providing an incentive for customers to move consumption to times where there is greater capacity in the network.

For some major projects we would consider paying for customer demand management to avoid or defer network development. These options are considered as part of investment case approvals.

6.4.9 Battery storage

In addition to batteries being used to buffer PVs or for vehicles, batteries also have an application for grid or local electricity network support. Batteries are likely to be an option for grid support when the peak loads are infrequent and/or short duration, due to the churn losses of the battery. The addition of more batteries with PV installations will help mitigate some of the potential problems that PV saturation would lead to.

The provision of batteries for support during peak load periods may in some cases be more economic than upgrading the network.

Use applications for grid sized battery storage include:

- Distribution network voltage support for locations with supply constraints.
- Participation in Transpower's demand response programmes including participation in the electricity reserves market.
- Energy arbitrage with respect to spot prices.
- Remote area power supplies that involve PV and/or wind generation for storage of excess energy produced and for the stabilisation of the microgrid.

We have no firm plans to adopt large scale battery technology, but we will consider these as options to help manage infrequent and seasonal peak load spikes on our distribution network.

6.4.10 Distributed generation policy

Our policy on the connection of distributed generation follows the requirements set out in Part 6 of the Electricity Industry Participation Code 2010, and our website includes guidelines on connection requirements, consultation and approval.

We recognise that distributed generation can provide a range of benefits:

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

Distributed generation can however have undesirable impacts needing management:

- Increased fault levels, requiring protection and switchgear upgrades
- More complex network management resulting from multiple points of supply
- Uncontrolled voltage rise beyond statutory ceiling limits
- The introduction of harmonic currents
- Increased line losses where surplus energy is being exported through a network constraint
- Potential for back-feeding into the network with inherent safety implications
- Reticulation capacity requires upgrading where generation exceeds existing capacity
- Stranding of assets or at least part of an asset's capacity
- Imbalances on the low voltage network

We will work with those wanting to connect distributed generation to our network to deliver the benefits, while also ensuring that all parties manage and mitigate any adverse impacts.

Where customers want to connect distributed generation, they are required to pay any costs associated with upgrading the network to accommodate the connection and to deliver the required export capacity. We do not anticipate that distributed generation will materially impact development plans by requiring network expenditure to be brought forward.

The key requirements for those wishing to connect distributed generation to the network are covered in the following sections.

Connecting distributed generation

A party connecting distributed generation must comply with our safety requirements, as well as all electrical industry codes and regulations. Our requirements for small scale generation are based on AS/NZS 4777 Grid Connection of Energy Systems via Inverters. To protect the network and other energy consumers, we may physically disconnect any distributed generation that does not comply with these requirements.

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

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

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

Distributed generation and development planning

As at October 2020, there are 1,184 distributed generation systems with a total capacity of 19.5 MW connected to Northpower's network:

Owner	Generation type	Number	Capacity MW
Trustpower	Diesel	1	9
Northpower (Wairua)	Hydro	1	5
Private	Solar Photo Voltaic	1,181	5.485
Private	Hydro	1	0.015
Total		1,184	19.5

Data from Oct 2020

Additionally, there is increasing interest in large-scale solar and wind generation sites across our network, requiring HV connections if they proceed.

Solar PV generation without battery storage has the potential to increase voltage levels to beyond acceptable limits on 400/230V networks, as maximum output occurs during sunlight hours when loading on these networks is generally low. To achieve over 50% penetration of PVs in residential homes it is likely that the capacity in the LV network will need increasing to maintain voltage within legal limits due to the bi-directional power flows.

For this reason, the number of connections off a distribution transformer will need to be limited, customer's generation output curtailed at certain times or upgrades required before further connections are made.

The installed capacity on the network may be able to be increased with the following:

- Reducing the voltage of the LV network allowing more resilience to voltage rise
- Increasing conductor size or reducing conductor lengths reducing voltage drop and rise
- Increasing the number of transformers in the network
- Installation of voltage regulators with distribution transformers

Battery storage is now becoming more common with solar PV installations allowing off-peak generation to be utilised during peak periods, reducing adverse effects on the network.

Distributed generation is considered in the long-term planning process, and operating connections are monitored. As trends develop, data will be used to understand the impact on changing network demand and we will continue to model the potential impact of increased PV uptake, and develop plans to manage this.

6.5 Network development

6.5.1 Network development principles

Our guiding principles ensure that target service levels are met at the lowest lifecycle cost. Accordingly, we evaluate the following approaches to meet service levels:

- Do nothing
- Construct additional asset(s)
- Modify or improve the capacity of an existing asset
- Retrofit advanced technology enabling greater operating ranges
- Reconfigure assets
- Install or procure distributed generation
- Influence customers' demand for levels of service

During the design process for network upgrades and/or new assets, we seek to minimise network losses by determining the optimal voltages and current carrying capacity of assets. This is done by performing loss calculations and load flow simulations for various options.

The table below is a summary of network development options that we may use to resolve constraints:

Network development options		
Constraint	**Network solutions**	**Non-network options**
Voltage	Upgrade conductor	Install generator (peak load)
	Upgrade voltage	Promote demand side management
	Install voltage regulator	Distributed generation or grid storage battery support
	Install capacitor	Install grid storage battery
	Reconfigure feeder(s)	None
	Construct new feeder	None
Capacity	Upgrade conductor	Install generator (peak load)
	Install forced oil cooling for zone power transformers	Promote demand side management
	Improve power factor	Promote distributed generation
	Improve thermal resistivity	None
	Increase line clearance (thermal upgrades)	Embedded generation during peak load times
	Upgrade voltage	None
	Duplicate asset	None
Reliability	Install additional devices such as reclosers and sectionalisers and with more remote operational capability	None

We use a range of investment assessment techniques such as NPV analysis, payback period and risk assessment to determine which option will give the lowest lifecycle cost and deliver the desired outcome.

The degree to which decision tools are applied depends on the investment level and significance of it, and desired outcome. For example, recurring decisions made at the operational level of our business typically use a pre-defined decision tool that considers several parameters and identifies one as being optimal. In contrast, non-recurring decisions made at executive or governance level may consider wide-ranging and complex data and may use several decision tools to identify an optimal option from among many possible options.

6.5.2 Capacity constraints

Our security of supply standards provides a useful benchmark to identify areas on our network that may not currently receive the same high level of security as the majority of our network.

Once we identify these areas, we consider options with a lower cost than what customers would be prepared to pay through increased line charges. One of the ways we do this is through our annual customer survey feedback on lines charges and reliability trade-offs. We also use national third-party value of lost load studies as a general indication of what customers would be prepared to pay to accept or avoid electricity outages. In some cases, no economic option is available, or may only be economic in the future. The best option with the highest expected cost-benefit is included in our AMP network development plan.

The following sections outline our security gap analysis and capacity constraints on our network and our current solutions to address these gaps.

Resolving security of supply

Some areas of the network do not currently meet our target security of supply criteria, and our network development plans include targeted investments to improve this over the next five years. The following maps:

- Highlight the current restoration across all N security substations and the main projects planned to meet the reliability requirements
- Show the improvements delivered by 2026 through projects aimed at increasing restoration times

Figure 79: All N security substations and their restorability 2021

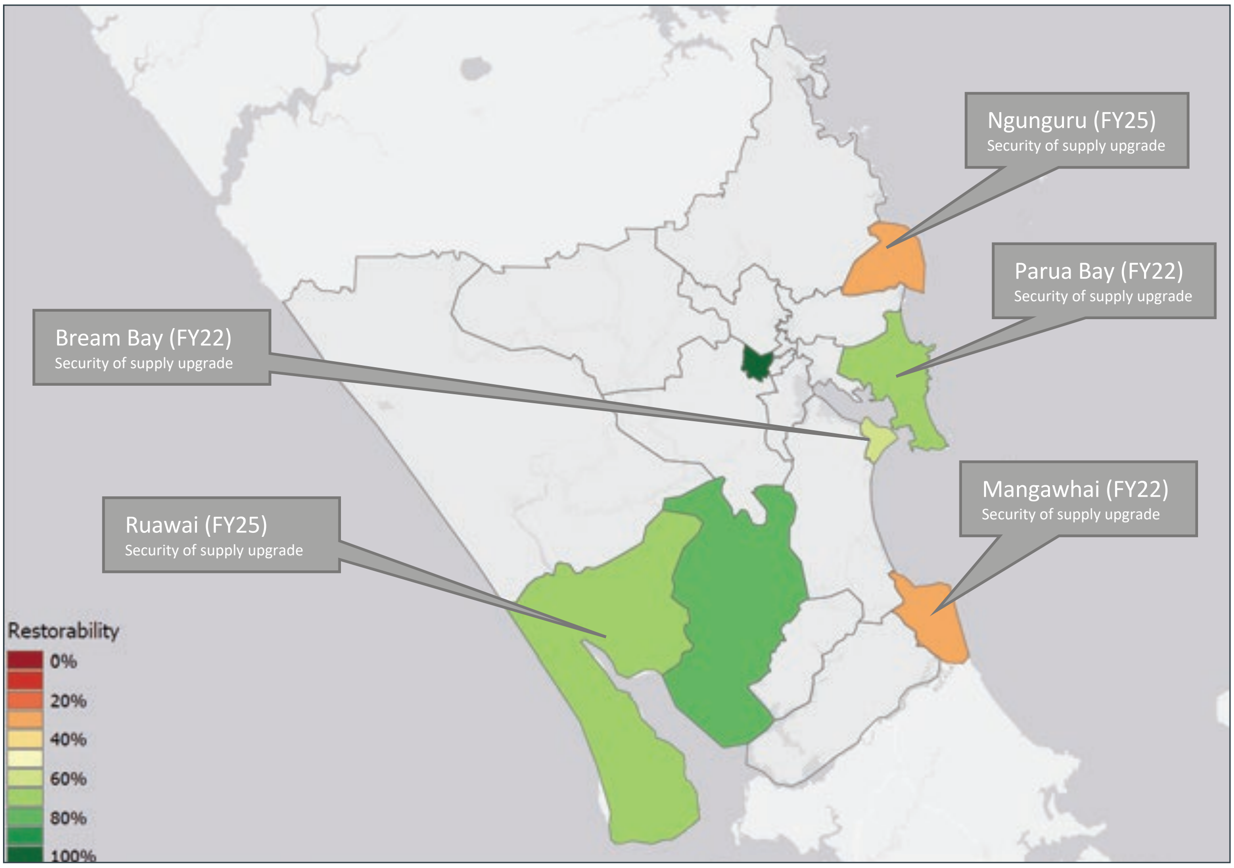
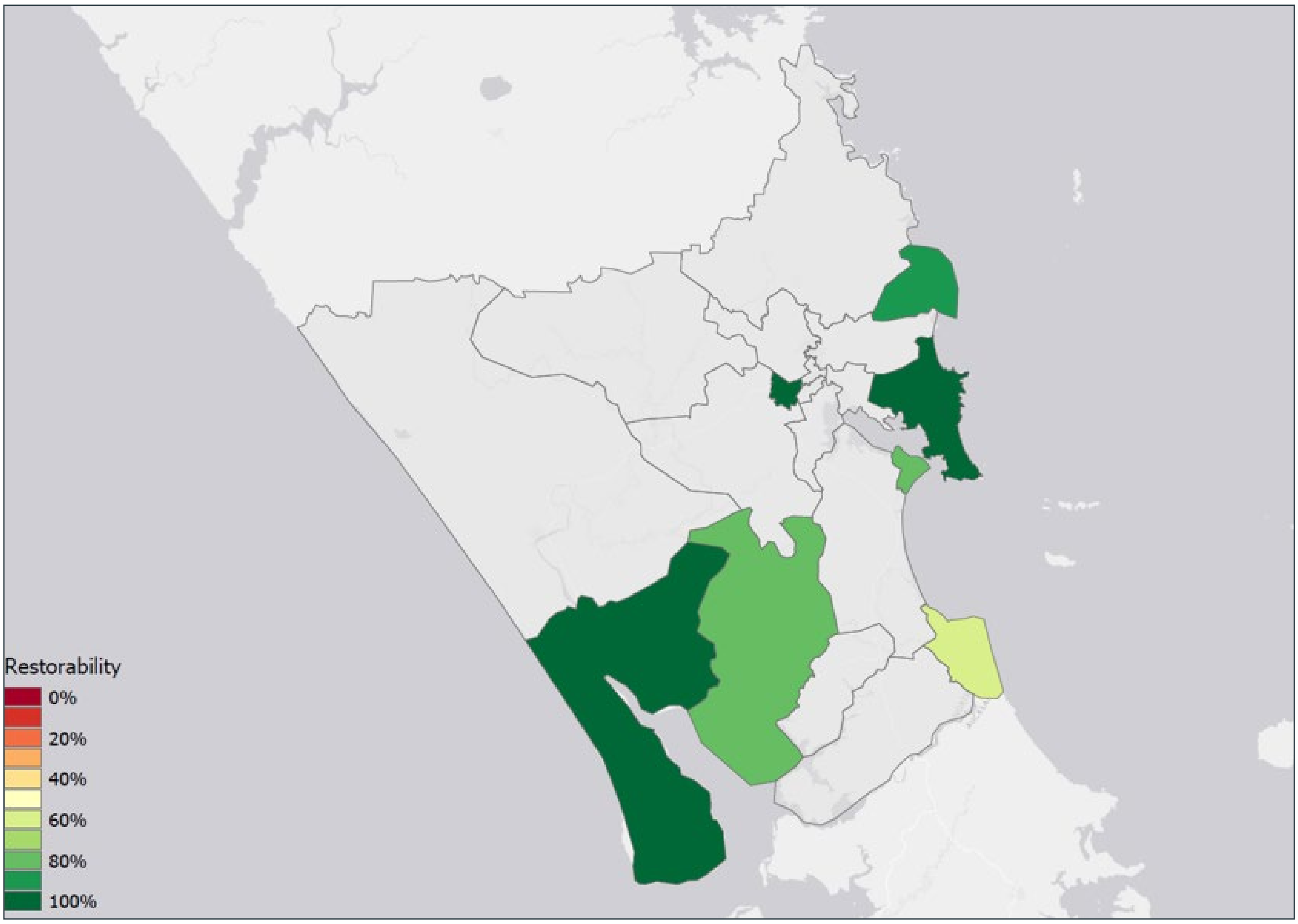


Figure 80: All N security substations and their restorability 2026.

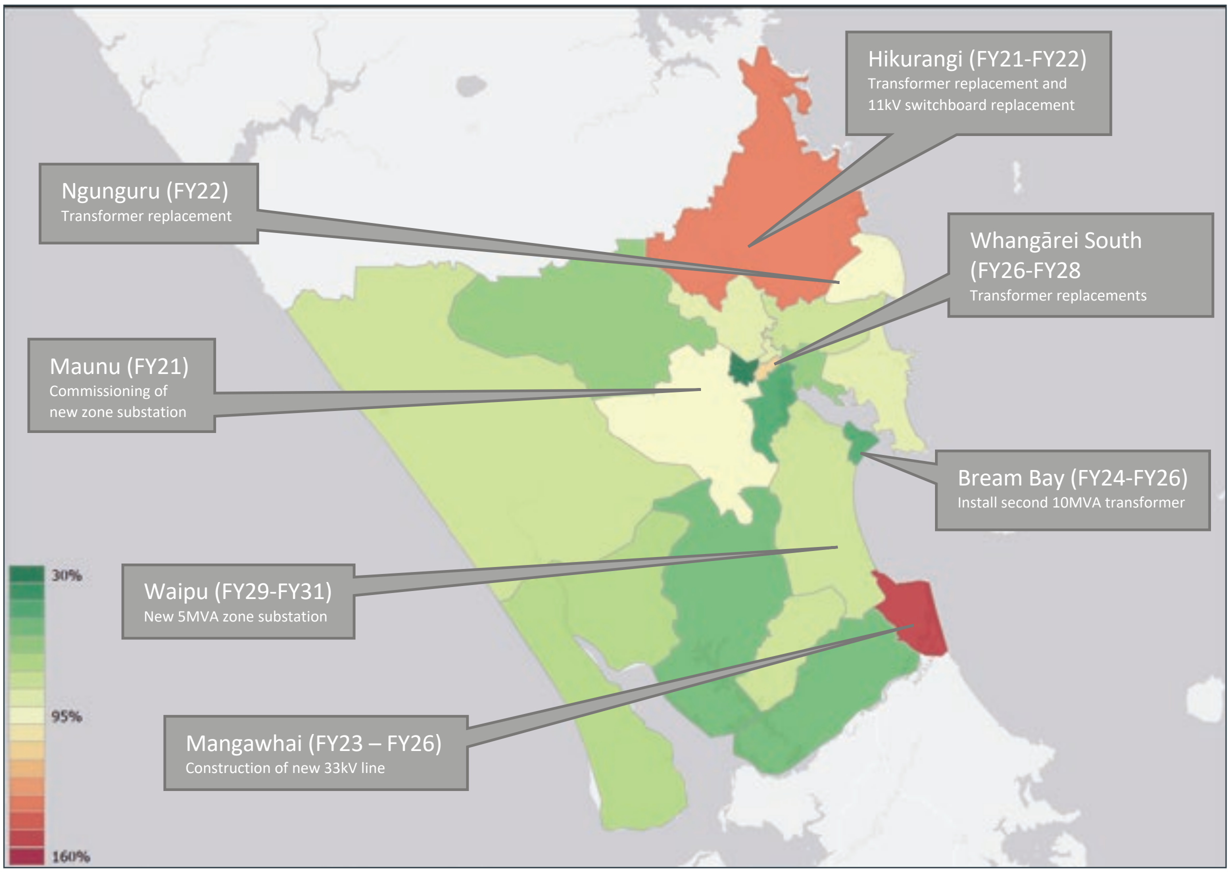


Zone substation loading and load growth expectations

Several large industrial loads are supplied at 33kV at Bream Bay (two customers), Maungatapere (one customers), Hikurangi (one customer) and at 11kV at Maungaturoto (one customer). For the purposes of this AMP we have assumed a reasonably static load growth.

Figure 81 shows a map highlighting the firm capacity utilisation across all substations and the main projects planned to meet the projected load requirements.

Figure 81: Firm capacity utilisation



Subtransmission constraints

The subtransmission circuits and zone substations form the backbone of our network. The most significant constraints to supply (both in terms of the number of customers potentially affected and the cost of overcoming the constraint) arise at zone substations and on the subtransmission network supplying them. Constraints at this level are normally a result of equipment current ratings limitations (load as well as fault) rather than voltage.

Significant components are:

- Power transformers
- Circuit breakers and isolators
- Bus bars and jumpers
- Cables and conductors

Constraints on the subtransmission network over the next ten years relate to underground subtransmission cable or overhead conductor condition, along with thermal limits and power transformers remaining reliable during their serviceable life.

Subtransmission cable/line circuit constraints anticipated over the next ten years are referenced to the continued provision of N-1 capacity to key substations. Some of the issues identified will be addressed in the next ten years as follows:

Substation	Proposed project	Reason
Kensington regional substation	110kV bus re-configuration	To improve security of supply and resilience
Mangawhai zone substation	Maungaturoto to Mangawhai 34km 33kV line easements	In preparation for the additional 33kV line to address security of supply and to accommodate a possible additional zone substation in the area beyond the ten-year planning horizon.
Maungatapere regional substation	33kV bus outdoor-to-indoor conversion	Condition, age and operational constraints when maintaining equipment. Replace with new switchgear equipment to a modern standard. Also lifts resilience of this critical asset.
Proposed Waipu zone substation	Installation of new zone substation	To address growing demand and offload nearby zone substations such as Ruakaka and Mangawhai
	Waipu to Ruakaka 10km 33kV line & easements	In preparation for the additional 33kV line to supply proposed Waipu zone substation

The next table shows anticipated zone substation transformer capacity constraints (for both N and N-1 requirements) and planned resolutions during the next ten-years (refer to the ten-year capex programme):

Substation	Voltage kV	Transformer MVA	Maximum demand MW		N constraint	N-1 constraint	11kV Backstop	Planned resolution
			2021	2031				
Alexander St zone	33/11	2x 7.5/15	13.1	14.1	None	Transformer rating	Whangārei South, Tikipunga, Kioreroa, Onerahi, Maunu	Load transfer
Bream Bay zone	33/11	1x 7.5/10	4.5	6.1	None	No supply	Ruakaka, Trustpower peaking plant	N/A
Bream Bay Transpower GXP	220/33	2x50/100	50.0	64.0	None	None	None	N/A
Dargaville zone	50/11	2x15	10.8	12.5	None	None	Maungatapere, Ruawai, Poroti	N/A
Hikurangi zone	33/11	2x5	6.8	8.2	None	Transformer rating	Kamo, Ngunguru	Transformer upgrade.
Kaiwaka zone	33/11	1x5	2.3	2.8	None	No supply	Maungaturoto, Mangawhai	N/A
Kamo zone	33/11	2x 7.5/15	12	15.3	None	Transformer rating	Hikurangi, Tikipunga, Poroti	N/A Load transfer
Kensington regional	110/33	2x50	64.9	76.9	None	Transformer rating	Maungatapere	Transformer upgrade.
Kioreroa zone	33/11	2x15/20	8.6	10.4	None	None	Whangārei South, Alexander Street, Maungatapere, Ruakaka	N/A
Mangawhai zone	33/11	2x5	7.4 5	9.9	None	Transformer rating	Kaiwaka, Ruakaka	11kV reinforcement
Marеretu zone	33/11	1x5	2.6	3.0	None	No supply	Maungaturoto, Ruawai, Maungatapere	N/A
Maungatapere regional (1)	110/50	2x25/35	10.8	12.5	None	None	None	N/A

[1] This represents the peak load that is recorded for 270 hours per year (3%)
[2] This represents the normal average winter peak load

Substation	Voltage kV	Transformer MVA	Maximum demand MW 2021	2031	N constraint	N-1 constraint	11kV Backstop	Planned resolution
Maungatapere regional (2)	110/33	2x30	37.5	41.4	None	Transformer rating	Kensington	Transformer upgrade.
Maungatapere zone	33/11	2x7.5	6.9	6.7	None	None	Poroti, Dargaville, Mareretu, Kamo, Kioreroa, Maunu	N/A
Maungaturoto Transpower GXP	110/33	2x30	19.4	23.0	None	Switchgear rating	None	Transpower assets
Maungaturoto zone	33/11	2x7.5	5.7	6.3	None	None	Kaiwaka, Mareretu	N/A
Maunu zone	33/11	1x10	0	2.2	None	None	Whangārei South, Maungatapere, Alexander St	
Ngunguru zone	33/11	1x3.75	3.4	4.1	Transformer rating	No supply	Tikipunga, Hikurangi	Transformer upgrade
Onerahi zone	33/11	2x15	8.3	9.2	None	None	Parua Bay, Alexander St, Tikipunga	N/A
Parua Bay zone	33/11	1x3.75	3.2	3.9	Transformer rating	No supply	Onerahi, Tikipunga	Transformer upgrade
Poroti zone	33/11	1x5	3.1	3.4	None	No supply	Maungatapere, Kamo, Dargaville	Strategic spare transformer
Portland Chip Mill	33/11	1x3.75	2.2	2.2	None	No supply	None	Strategic spare transformer
Ruakaka zone	33/11	2x10	7.1	8.6	None	None	Bream Bay, Mangawhai, Kioreroa	N/A
Ruawai zone	33/11	1x5	3.3	3.6	None	No supply	Dargaville, Mareretu	N/A
Tikipunga zone	33/11	2x20	14.5	16.8	None	None	Alexander Street, Kamo, Onerahi, Ngunguru,	N/A
Whangārei South zone	33/11	2x10	11.2	11.4	None	Transformer rating	Alexander Street, Kioreroa, Maunu,	Load transfer

Distribution constraints

Several 11kV rural distribution feeders are expected to become voltage constrained within the next ten years. Some feeders will become constrained due to load and/or the total number of connected premises impacted by an 11kV feeder fault.

Each constrained feeder is unique in length, conductor size, connected customers, load distribution and load characteristics. Several solutions are deployed to rectify these constraints including:

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

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

Substation	Feeder	Constraint	Possible solution	Stage
Alexander Street	Western Hills Drive	Voltage, customer numbers	Maunu substation	Completing
Dargaville	North	Voltage regulator capacity	200 Amp regulator	Monitoring
Dargaville	Te Kopuru	Voltage	Switched capacitors	Monitoring
Dargaville	Tangowahine	Voltage	Switched capacitors	Monitoring
Hikurangi	Jordan Valley	Voltage	Switched capacitors	Monitoring
Hikurangi	Whakapara	Voltage and customer numbers	Helena Bay substation or feeder upgrade	Monitoring
Hikurangi	Swamp North	Voltage	Switched capacitors	Monitoring
Maungatapere	Maunu	Voltage and customer numbers	Maunu substation	Completing
Poroti	Titoki	Voltage	Conductor upgrade	In Progress
Ruakaka	Marsden Point	Customer numbers	Reconfiguration	In Progress
Ruawai	Tangaihi	Voltage	Switched capacitors	Monitoring
Tikipunga	Tikipunga Hill	Customer numbers	Switched capacitors	Monitoring
Tikipunga	Kiripaka Road	Customer numbers	Reconfiguration	In Progress
Whangārei South	Otaika	Customer numbers	Maunu substation	Completing
Ruakaka	Waipu	Customer numbers	Reconfiguration/ Waipu substation	Monitoring
Poroti	Titoki	Voltage	Distribution tap settings re-adjusted	Monitoring

6.5.3 Network development proposals

This section outlines the significant network development and asset replacement projects over the ten-year planning period, and what alternatives have been considered. Where replacement is based on end-of-life drivers, particularly with sub-transmission elements of the network, there are often no practical alternatives. All major investment is subject to further options analysis before any capital is committed.

Significant projects currently underway or planned to start within the next year (FY22)

Mangawhai to Maungaturoto easements for additional 33kV line	Obtain electricity easements	**$2,800,000**
Required to secure route for additional line to improve security of supply.		
Alternatives considered: Battery/diesel hybrid system, diesel only standby system. Further options will be considered as part of the investment approval process.		
Kensington 110kV bus re-configuration and transformer circuit breakers	Re-configure transformer-feeder arrangement	**$2,700,000**
Re-configure transformer-feeder arrangement to support upcoming transformer replacement outages and make the subtransmission circuits supplying the greater Whangārei area (39,000 customers - 2021).		
Alternatives considered: Construction of 110kV bus, this reduces risk by allowing us to take an 110kV line out of service and still have operation of both transformers. However, this does not address growth requirements for additional capacity.		

Significant projects planned to start within the next four years (FY23 - FY25)

Bream Bay second transformer	Install second 10MVA transformer	**$1,800,000**
Required to increase substation capacity to meet load growth and provide N-1 capacity to improve security of supply and facilitate outages for plant maintenance.		
Alternatives considered: Battery storage.		
Bream Bay 11kV switchboard upgrade	Upgrade indoor switchgear	**$1,900,000**
Required to increase substation capacity to meet load growth.		
Alternatives considered: there are no other practical options if the load growth eventuates.		

Significant projects planned to start within the next ten years (FY26 - FY31)

Mangawhai to Maungaturoto additional 33kV line	Install second subtransmission line	**$6,500,000**
Required to provide N-1 capacity to improve security of supply, facilitate outages for line maintenance and to increase capacity to meet future load growth.		
Alternatives considered: Battery/diesel hybrid system, diesel only standby system. We will continue to review load growth in this area and consider all feasible options to defer investment.		
Whakapara 11kV feeder express line extension	Extend 33kV express line (11kV operation) back to Hikurangi substation	**$700,000**
Required to extend the existing section of express line (no distribution transformers) which is insulated to 33kV but operated at 11kV from its present starting point back to Hikurangi substation, to enable operation as a true express line from the substation to the 11kV voltage regulator at Helena Bay. This extension is required to improve feeder performance.		
Alternatives considered: Interim measures to improve performance were implemented in 2012 comprising of the installation of additional 11kV automatic sectionalisers and auto reclose function on the feeder circuit breaker.		
Waipu to Ruakaka 33kV line and easements	Install new subtransmission line	**$7,200,000**
Required to supply proposed Waipu substation and capacity for anticipated load growth.		
Alternatives considered: We will continue to review load growth in this area and consider all feasible options to defer investment.		
Waipu 33/11kV substation	New zone substation	**$6,700,000**
Construction of new 5MVA zone substation and feeder to strengthen the 11kV network in the Waipu area and provide capacity for anticipated load growth.		
Alternatives considered: We will continue to review load growth in this area and consider all feasible options to defer investment.		
Bream Bay 33kV switchboard upgrade	Upgrade indoor switchgear	**$3,100,000**
Required to increase substation capacity to meet load growth		
Alternatives considered: None. If load grows and isand is to be supported from this substation, this upgrade is required.		
Maungatapere 33kV bus outdoor to indoor conversion	Upgrade bus	**$6,000,000**
Required reliability improvements and compliance with safety clearances.		
Alternatives considered: Maintain existing configuration and accept reliability impacts.		

Northpower

2021 – 2031
Asset Management Plan

Section 7
Managing our assets

Table of contents

7.1 Introduction

Our asset replacement programmes dominate our ten-year capex programme, with over 57% of our spend on asset replacements and renewals. While reliability continues to be a critical factor for customers, they are generally happy with our network reliability, and therefore only 9% of our capital spend is targeted at reliability improvement projects.

Preventative maintenance inspections highlight areas where renewal and refurbishment is required. Historical information also provides some indication of likely expenditure for any category on the assumption that the preventative maintenance inspections or remedial maintenance responses do not identify any potential systemic issues.

The history of performance for each asset fleet sets the baseline reliability profile. Northpower has commenced a transition towards condition-based asset management, which will lead to more optimal renewal timelines for assets. To date, much of our renewal work has either been driven by rectification of defects, addressing risks associated with deteriorating condition (e.g. copper and ACSR conductor replacements) or age-based replacement based on accepted industry standard asset lives.

The renewal and refurbishment expenditure on the distribution network mostly include poles, crossarms, insulators, fuses and conductors. Expenditure on vegetation control is also included in the broad category of ‘asset refurbishment’ (separate to the reactive vegetation management).

We have commenced a risk-based approach to proactively lessen the impact that vegetation has on our electricity network. We operate under the framework of the Electricity (Hazards from Trees) Regulations and work with landowners to secure effective vegetation clearance.

In the first part of this section we discuss our approach to maintaining and renewing assets, improving asset reliability and safety of private service lines. The second part of this section we discuss our approach to managing asset lifecycles by asset category.

7.2 Maintenance, renewal and improvement plans

7.2.1 Preventative maintenance

Northpower manages 48 preventative maintenance regimes across 26 asset classes. Inspections on high volume assets - poles, pillars, distribution earths and ground-mounted transformers - account for most preventative maintenance tasks. Inspection cycles range from monthly to eight years.

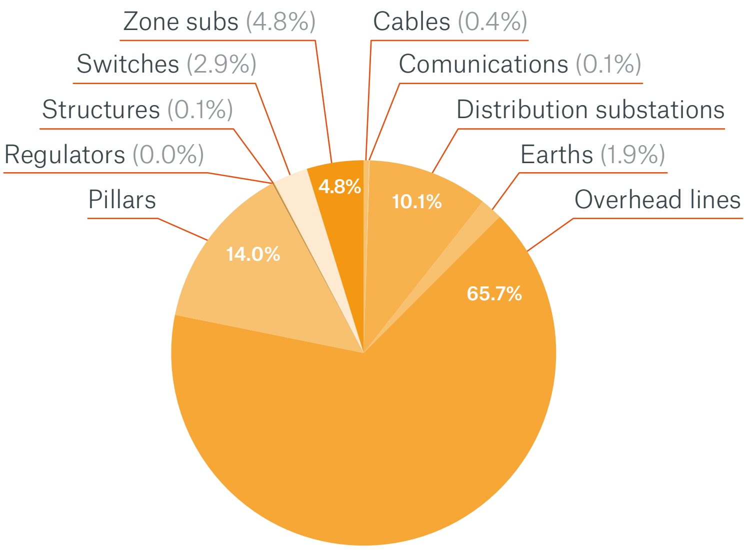
In 2020 we introduced our new overhead inspection standard to improve accuracy of defect capture and focus on capturing asset condition of our overhead network. The standard has been rolled out with enhanced training to our inspections team to ensure consistency.

These changes also have been associated with the introduction of five prioritisation levels and a corresponding time to remediate.

These are listed in the table below:

Priority level	Criteria	Days to remediate
Priority 1	Fix immediately	1
Priority 2	Replace within 3 months	90
Priority 3	Replace within 12 months	365
Priority 4	Opportunistic replacement	1,100
Priority 5	Scoping task	1,200

Figure 82: Reported defects FY21 year to date as at 1 January 2021



Our preventative maintenance regime mix will be refactored in 2022 to level inspection cycles and expand the scope of some inspections, including those for pillar and ground mounted distribution substations. This will allow a greater focus on safety and security to be placed on these assets.

As part of an ongoing review of asset condition capture, Northpower is transitioning from a traditional age-based proxy for a growing number of assets to condition capture, consistent with the EEA Asset Health (AHI) Indicator Guide (Revision 2019). These options are being evaluated during FY21 and it is expected the transition will take place over the next two years.

7.2.2 Refurbishment and renewal maintenance (follow-up maintenance)

Increased resourcing in the maintenance area and review processes has ensured the work issued to the service provider accurately reflects defect priorities, along with monitoring to ensure remediation works are completed within the timeframe specified.

The bulk of poles are concrete and the number of wood poles on the network continues to reduce with about 1,220 remaining in service as at February 2021. Priority for these replacements has focussed on the subtransmission network, critical 11kV lines and poles associated with the conductor replacement program.

An ongoing conductor replacement programme is focused on 7/.064 copper and some older gopher with priority based on age and condition. An average of 35 to 45 km is removed per year leaving 1,330 km remaining as at February 2021.

7.2.3 Vegetation maintenance

Faults caused by vegetation continue to be a significant contributor to outage statistics, although performance has been reasonably consistent year on year. Current strategies include:

- feeder by feeder clearance program
- rolling surveys and identification of vegetation hotspots
- regular aerial inspections of subtransmission and critical HV lines.

We are also introducing a risk and criticality based approach this year, which will see prioritisation of vegetation clearance on feeder sections upstream of a recloser to minimise the numbers of customers affected by vegetation faults.

7.2.4 Fault and emergency maintenance (reactive maintenance)

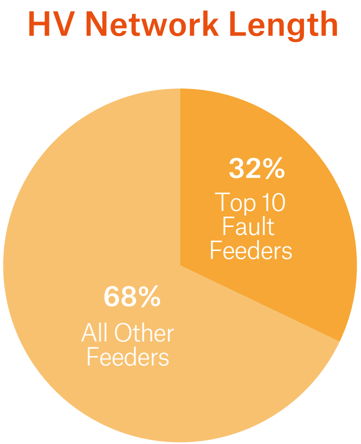
Faults associated with overhead lines make up approximately 70% of reactive maintenance expenditure. Weather-related events are unpredictable however, and ongoing initiatives to build resilience into the network are expected to impact on the expenditure in this area over time, as network resilience improves.

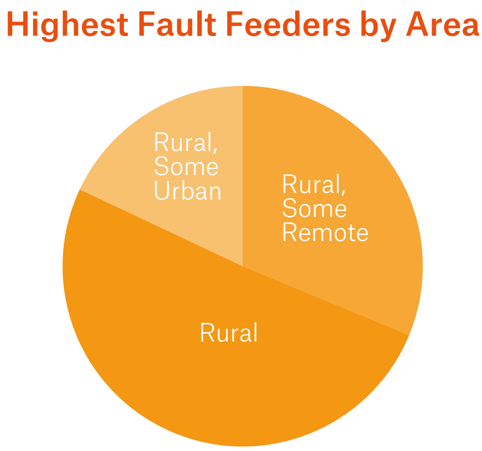
7.2.5 11 kV feeder improvement initiatives

We are monitoring feeder reliability to identify the feeders that are less reliable, aiming to increase the reliability performance of these feeders though root cause analysis, assessing contributing factors and identifying ways to prevent future faults.

The ten feeders with the highest number of faults are also some of the longest feeders on our network and represent 32% of the total network length and 11% of our total customers. They are predominately rural feeders as highlighted below. The 11kV feeder with the highest number of faults is our longest radial feeder with many spurs.

Figure 83: HV network length of top ten feeders with the highest number of faults and the highest fault feeders by area (rural and urban)





Vegetation	From 2018 we increased spend on our annual vegetation management program, to increase the focus on removing vegetation related risks from the network. We are currently reviewing our vegetation strategy to prioritise works based on asset criticality and tree risk, and reviewing the scope of works (trimming vegetation as opposed to full removals) to achieve the best overall improvement in network performance from the allocated budget.
Defect remediation	We are also increasing our overhead line replacement programs, with focus on ensuring robust inspection and defect prioritisation for the poor performing feeders.
Sectionalising and automation	We are looking for opportunities to establish additional 11kV feeder ties to improve restoration options to enable more customers to be restored faster. Our HV automation strategy is introducing additional remote-control switches on the 11kV overhead network, with priority on worst performing feeders, followed by greatest customer benefit and improved fault response.

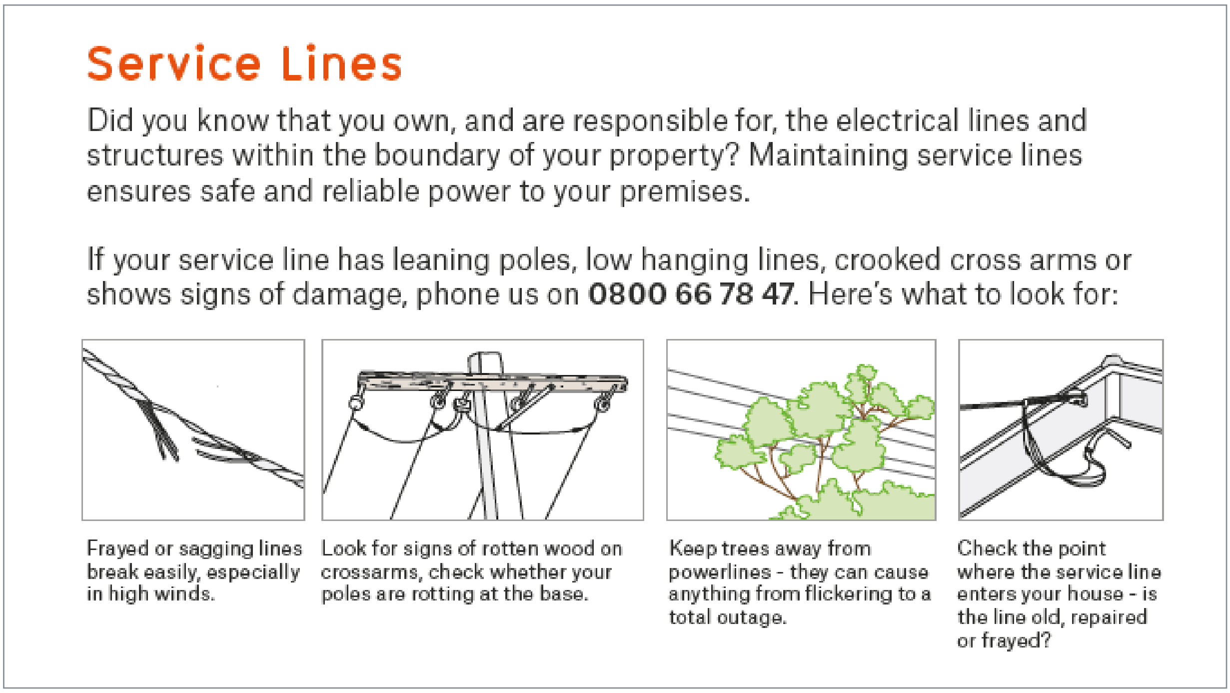
7.2.6 Private service line safety

We recognise the issues surrounding potentially unsafe private low voltage service lines and understand that landowners may be unaware of the risks of non-maintained private service lines. We are helping landowners become more aware of maintenance needs and what they need to do to address this risk.

Our annual preventative maintenance line inspections will often identify unsafe private service lines which are not maintained by us. Where an unsafe customer owned service line is identified, we attempt to work with the owner to remedy this. Occasionally we take over the responsibility to ensure line safety due to a private service line location (for example, road crossings) or where there are multiple customers supplied.

There appears to be a lack of understanding among landowners (particularly in rural areas) that the low voltage line within their property is generally under their ownership and responsibility. We promote public awareness of this customer responsibility and how to spot unsafe service lines on our website, social media, at community events, newspapers and other media avenues. We also provide advice about engaging suitably qualified service providers to undertake remedial work.

Figure 84: An example of our customer information – raising awareness and helping customers know what to look for.



7.3 Overhead support structures for conductors

7.3.1 Overview

Northpower's overhead network is supported predominately by concrete poles. The wooden poles in use on the network are largely hardwood. The condition of these assets is fair but there are wooden poles which are reaching end of life. Concrete poles tend to spall with age.

Our preventative maintenance inspections identify poles for replacement. We have a targeted programme to replace wood poles with concrete poles as they reach the end of their serviceable lives. We also focus on identifying and replacing spalling concrete poles.

Crossarm and insulator replacements generally result from preventative maintenance inspections and are often replaced in conjunction with pole replacements due to economic efficiency. Asset renewals for these items are also conducted in conjunction with other maintenance tasks on poles or conductors.

7.3.2 Asset description

We have the following support structures on the network.

Structure type	Details of utilisation
Concrete	Approved pre-stressed poles are Northpower's standard pole to be utilised in most situations. We have mass reinforced poles (not pre-stressed) in service on the network however they are no longer installed.
Wood	No longer installed on the network as they generally have a shorter lifespan than concrete poles. Hardwood poles have been widely utilised on the sub-transmission and distribution networks. Softwood poles have generally only been utilised for service lines.
Steel monopoles	Occasionally utilised where a pole with a lower weight than a standard concrete pole is required in an access-challenged location.
Steel lattice towers or pylons	Only utilised for the 110kV subtransmission line and the combined sections of the 50kV subtransmission lines.

Pole Types	Total	110kV Subtrans	50kV Subtrans	33kV Subtrans	11kV Distribution	400 V Distribution	400 V Service
Concrete	53,000	0	417	2504	41028	7016	2035
Wood	1,256	0	22	70	124	802	238
Steel	99	38	11	0	42	5	3
Unknown	81	0	0	0	0	29	52
Total	54,436	38	450	2574	41194	7852	2328

The crossarms used to support and separate the insulators/conductors are typically 100 x 75mm hardwood on the HV network, and 75 x 75mm hardwood on the LV network. They do vary in length however, depending on pole spacing to provide sufficient conductor spacing.

We now use galvanised steel crossarms, which have a longer life, for the most common sized cross arms on our HV network. All support structures are inspected every five years except for steel lattice towers, which are inspected every two years.

7.3.3 Performance requirements

We have newly established performance criteria for this fleet. Reporting against performance levels is being developed.

Safety	All support structures	Zero injuries due to failure (including crossarms, insulators, steel bracing, stay poles and guy wires) within design loads and while working on an asset. Excludes third-party interference such as car versus pole
	All support structures	As low as reasonably practicable risk of step and touch potential
Reliability	Steel lattice towers	Zero unassisted failure within designed loads including wind speeds. Excludes third-party interference and earthquake
	All other support structures	Zero unassisted failures within designed loads and wind speeds. Excludes third-party interference
	Crossarms, insulators, steel braces and other associated components	Annual reduction in the number of unassisted failures within designed loads and wind speeds. Excludes third-party interference and vegetation making contact from outside the clearing zone
Cost	All support structures	Design, construct and maintain asset to minimise lifecycle costs without compromising other requirements
Environment	All support structures	No significant environmental breach

Note: An unassisted failure is where an asset or an associated component of an asset fails due to deterioration, fatigue, incorrect design and installation at the time established, including if the asset is operated beyond its safe design capacity.

7.3.4 Asset condition

Subtransmission support structures

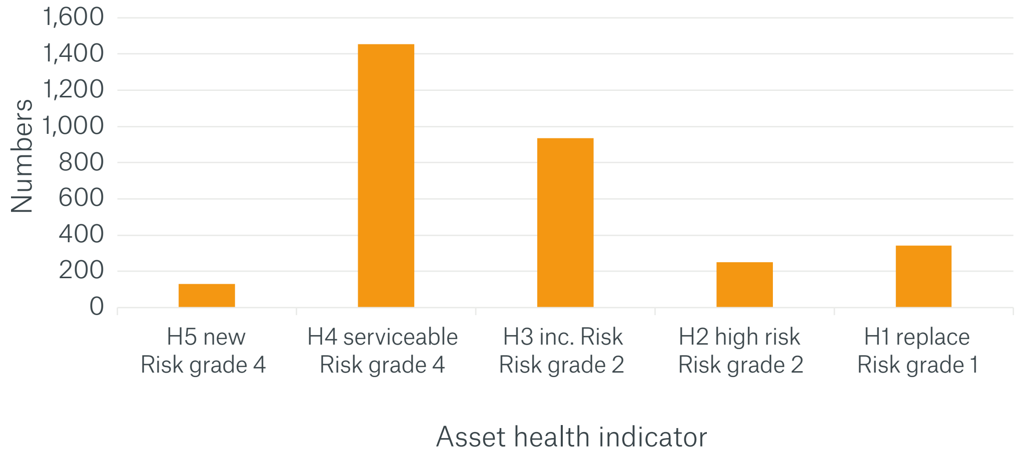
There are 110kV, 50kV and 33kV overhead subtransmission lines in operation on Northpower's network.

The sub-transmission support structures on our network are generally in a satisfactory and serviceable condition.

110kV support structures with defects identified during inspection are programmed for remediation within 12 months.

The 33kV poles rated H1 or H2 have been assessed based on age. These will be inspected during our inspection programme to determine condition in the field, and from there replacements programmed for those assessed as end of life.

Figure 85: Subtransmission support structures age based asset health and risk grade

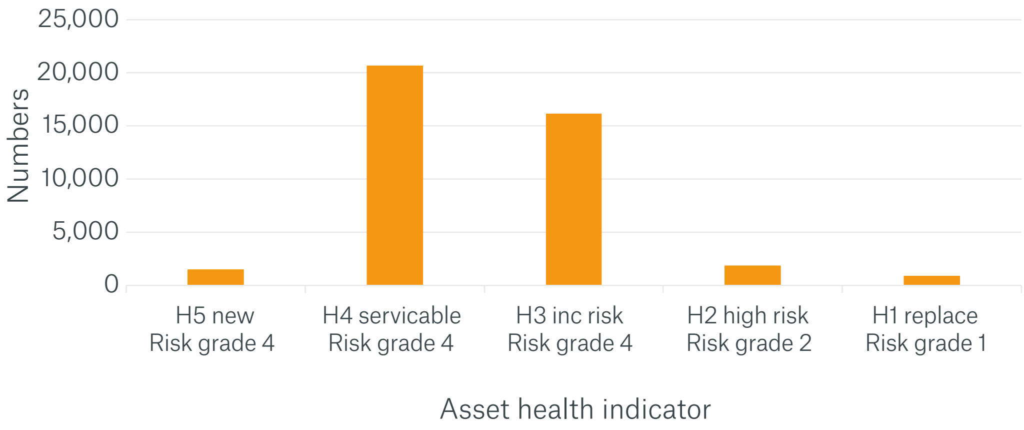


High voltage distribution support structures

There are 11kV overhead express and distribution feeders in operation on our network.

The 11kV support structures are generally in satisfactory condition. Poles rated H1 or H2 have been assessed based on age. These will be inspected during our inspection programme to determine condition in the field, and from there replacements programmed for those assessed as end of life.

Figure 86: HV distribution support structures age based asset health and risk grade



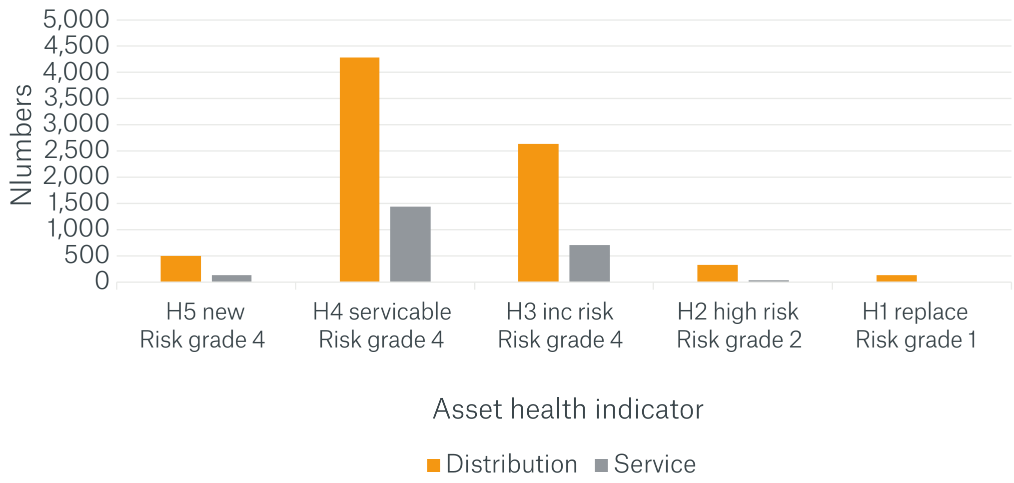
Low voltage support structures

There are 400 Volt overhead distribution lines extending from transformers on our network.

There are also Northpower owned sections of service lines extending from the 400 Volt distribution networks.

The 400 Volt support structures on our network are generally in satisfactory condition. Poles rated H1 or H2 have been assessed based on age. These will be inspected during our inspection programme to determine condition in the field, and from there replacements programmed for those assessed as end of life.

Figure 87: Low voltage support structures age based asset health and risk grade



7.3.5 Maintenance plan

Our maintenance activities for overhead support structures are listed below. Where issues are identified, we may undertake further investigation before we decide to take further corrective action or replace the asset.

Overhead structures preventative maintenance	Timing	Scope of work
Towers	Two yearly	Visual check of OH lines, towers (steel and bolt), foundations and all tower hardware
Overhead structures and overhead conductors	Five yearly	Visual check of OH lines, poles, and all pole hardware including switches
Aerial inspection of subtransmission and express lines	Yearly	Survey overhead subtransmission and express lines from a helicopter. Capture any defects and vegetation issues.
Wood pole testing	Five yearly or condition based	Wood pole testing with micro-drill and a visual hardware inspection.

7.3.6 Capital (renewal) strategy

Structure type	Renewal strategy
Concrete	Replace when unserviceable or damage/deterioration could lead to failure
Wood	Progressively being replaced with concrete poles as they reach the end of useful life
Steel monopoles	Replace as become unserviceable or damage/deterioration that could lead to failure. Maintenance is generally limited to corrosion protection
Steel lattice towers	Provided a steel lattice tower is regularly maintained, deteriorated metal components replaced and corrosion protection, these assets have the potential for an extended life

7.4 Overhead electricity conductors

7.4.1 Overview

Northpower distributes electricity from zone substations to local distribution transformers at 11kV (HV). Over 90% of this distribution network is overhead HV lines. Overhead conductors over 60 years are progressively being visually inspected and tested to assess remaining serviceable life and are programmed for replacement as required.

7.4.2 Asset description

All aluminium alloy conductor (AAAC) is the current standard conductor type utilised on our subtransmission and HV distribution networks. Aluminium core steel reinforced (ACSR) is also utilised for spans longer than are possible with AAAC. Aluminium aerial bundled conductor (ABC) is the current standard conductor type utilised on our LV distribution networks.

AAAC is also utilised in LV distribution for spans longer than is possible with ABC.

Copper neutral screened cable is the current standard conductor type utilised for LV service reticulation.

The following conductor types are no longer installed, however are still common in the network:

- Aluminium alloy conductor (AA or AAC)
- Aluminium alloy conductor PVC covered (AA PVC)
- Hard drawn bare copper (HDBC)
- Hard drawn copper PVC covered (HDC PVC)

Summary of overhead conductor types and amount in route length on the network[2]

Total km	110kV subtransmission	50kV subtransmission	33kV subtransmission	11kV HV distribution	LV 400 V distribution	LV 400/230 V service	LV 230 V streetlight
5,201	28	77	217	3502	1068	133	174

7.4.3 Performance requirements

We have a newly established performance criteria for overhead conductors fleet. Reporting against performance levels is being developed.

Safety	All conductors	Zero electrocution or (human) fatality due to unassisted failure of conductor or associated equipment, includes causes due to contact of conductors of same or differing voltage
Reliability	Subtransmission conductors	Zero unassisted lines down[3] (excluding third party interference and direct lightning strikes)
	HV distribution conductors	Zero unassisted lines down (excluding third party interference and direct lightning strikes)
	LV distribution and service conductors	Annual real reduction in the number of unassisted lines down (excluding third-party interference and service lines owned and managed by private parties)
Cost	All conductors	Design, construct and maintain asset to minimise lifecycle costs without compromising other requirements
Environment	All conductors	No significant environmental breach

[2] *The lengths are for circuit length (km) and include the phases, neutral and pilot that are present on the particular circuit.*

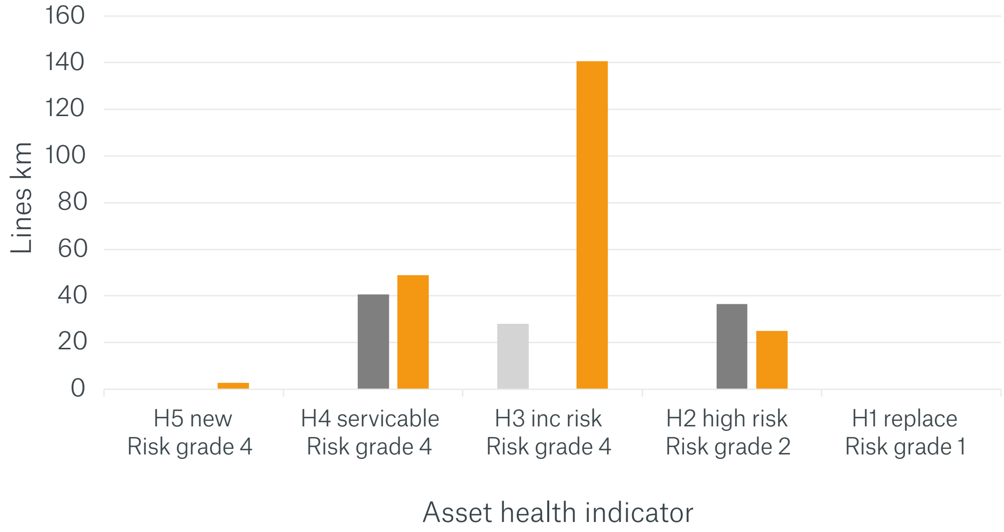
[3] *An unassisted failure is where an asset or an associated component of the asset fails due to deterioration, fatigue, incorrect design or installation method, including operating beyond its safe design capacity or tension.*

7.4.4 Asset condition

Subtransmission conductors

There are 110kV, 50kV and 33kV subtransmission circuits with overhead lines in operation on Northpower's Network.

Figure 88: Subtransmission conductors age based asset health and risk grade



Northpower's subtransmission overhead assets are well maintained. Our conductor sampling schedule is used to identify sections of overhead subtransmission lines that are reaching end of life which are then programmed for replacement. In particular, overhead conductors over 60 years old are being tested and testing is proposed for conductors over 50 years old. Results so far indicate:

- The 110 kV conductors have been assessed to be in acceptable condition.
- The 50 kV conductors have been sampled and tested and are in satisfactory condition.

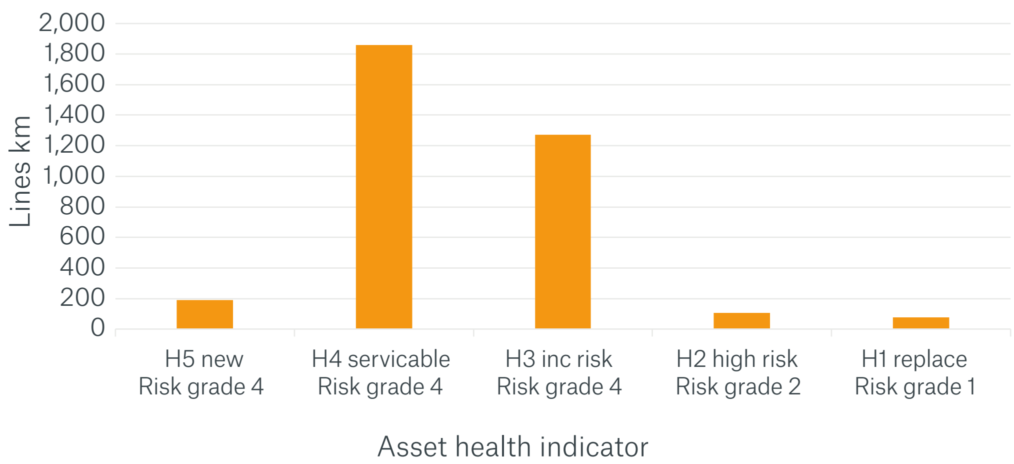
The 33kV conductors over 60 years old are undergoing a sampling and testing program. The conductors tested so far have shown satisfactory serviceable condition.

High voltage distribution conductors

There are 11kV express and distribution feeders with overhead lines originating from zone substations in operation on our network.

The 11kV conductors have been assessed as being in generally good condition. All conductors aged over 60 years are to be visually inspected and tested for condition and replaced if they are a failure risk.

Figure 89: High voltage distribution conductors age based asset health and risk grade



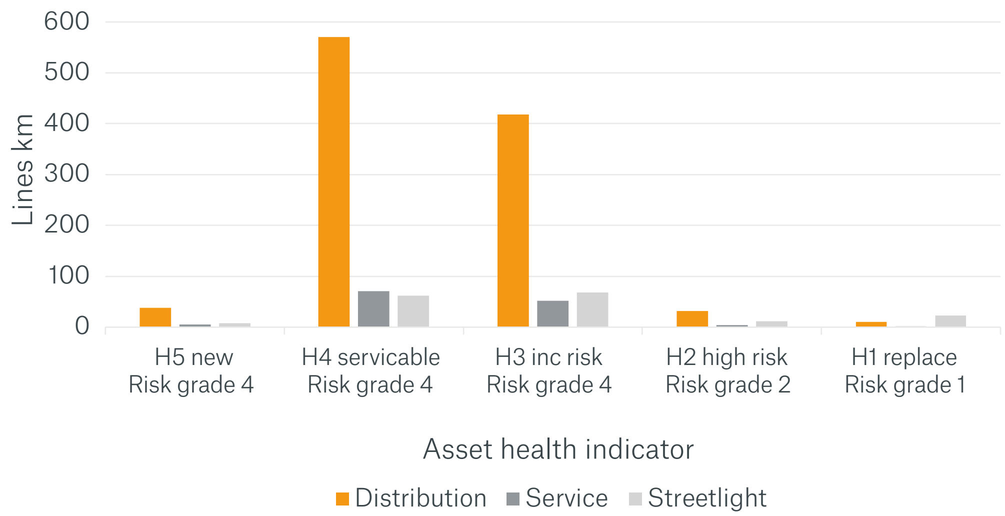
Low voltage conductors

Our 400 Volt distribution networks with overhead lines extend from transformers on our network and are often installed in conjunction with the HV distribution. Overhead streetlight conductors are included with the 400 Volt distribution networks.

There are also Northpower owned sections of overhead service lines extending from the 400 Volt distribution networks.

The low voltage conductors have been assessed as being in generally good condition.

Figure 90: Low voltage conductors age based asset health and risk grade



7.4.5 Maintenance plan

Overhead conductors Preventative maintenance	Timing	Scope of work
Overhead conductors	Five yearly	Visual check of OH lines, poles, and all pole hardware including switches
Aerial inspection of sub-transmission and express lines	Yearly	Survey overhead subtransmission and express lines from a helicopter. Capture any defects and vegetation issues
Conductor testing	As required	We test our conductors to the manufactured standard when they were constructed. We test multiple samples, which then gives us a better picture of the line's strength and its future performance under loads

7.4.6 Capital (renewal) strategy

Conductor type	Renewal strategy
Subtransmission	A subtransmission conductor replacement strategy to sample and test conductors aged over 50 years to determine condition and replacement if required
HV distribution	A multi-year project to replace old deteriorating copper conductors (HDBC) and aluminium (ASCR) conductors with corroding steel reinforcing. All conductors over 60 years are to be visually inspected and tested for condition
LV distribution, service, and streetlight	A multi-year project to replace old deteriorating copper conductors (HDBC) and aluminium (ASCR) conductors with corroding steel reinforcing. All conductors aged over 60 years are to be visually inspected and sample tested to assess condition.

7.5 Underground cables

7.5.1 Overview

The overall condition of cables is satisfactory. Replacement of distribution cables is mostly driven by condition, performance and defects (deterioration, damage or reduced dielectric strength) identified through preventative maintenance inspections of above ground sections and equipment cable terminations. Oil filled 33kV cable are approaching end of life and replacement programme in the AMP period will address the oldest oil filed cables in our network.

7.5.2 Asset description

Aluminium cross-linked polyethylene (XLPE) is the standard cable type utilised on our underground subtransmission and distribution networks, along with copper neutral screened cables for service cables.

Paper insulated lead covered (PILC) cables are no longer installed but are still in service.

Oil filled or insulated PILC cables are also no longer installed but are still in service on the subtransmission network.

Summary of route length of types of underground cable:

Total km	33kV Subtransmission	11kV Distribution	400 V Distribution	400 V Service	400 V Streetlight
1,334.9	19.0	288.2	7,47.3	43.9	236.5

7.5.3 Performance requirements

We have newly established performance criteria for this fleet. Reporting against performance levels is being developed.

Safety	All cables	Zero injuries through failure of cables, joint or termination due to premature failure, degradation or from operating beyond safe design limits. Installation achieves minimum mandatory depth of cover
Reliability	33kV cables	Zero failures per annum including damage by third parties
	11kV & 400 V cables	Annual reduction in number of failures of cables, joints or terminations, excluding damage by a third party
Cost	All cables	Design, construct and maintain asset to minimise lifecycle costs without compromising other requirements
Environment	All cables	No significant environmental breach

7.5.4 Asset condition

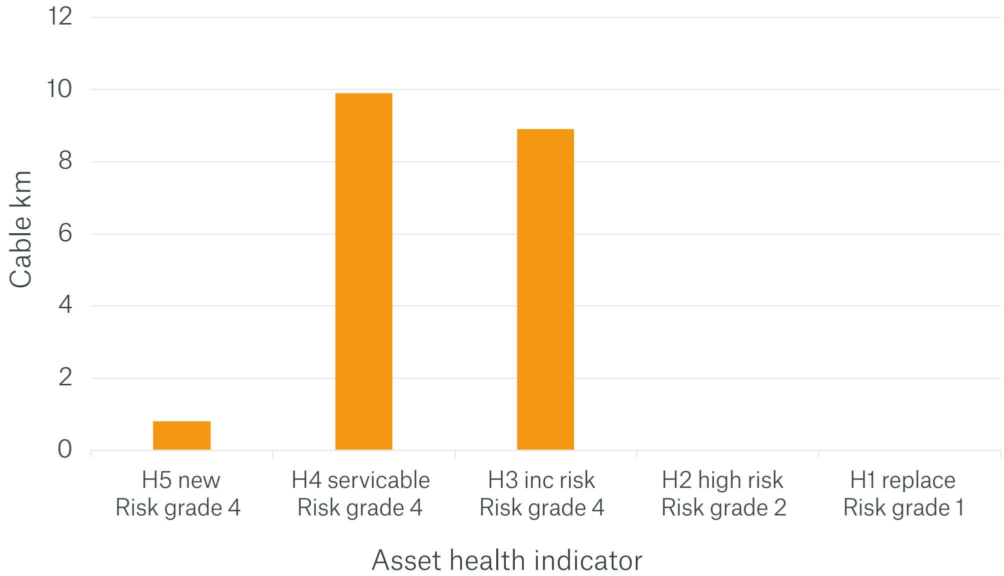
Underground subtransmission cables

There are three 33kV underground subtransmission cable circuits in operation on our network. There are also some short sections of underground and submarine cables on other circuits that are predominately overhead.

The 33kV cable testing completed so far indicates that cable condition is acceptable but some sections will reach end of life within the next five to ten years. Further testing is required to provide accurate condition assessment.

This AMP will see the start of replacing our ageing 33kV oil filled underground cables with modern XLPE 33kV cables, where the circuit needs to be retained. This includes four 33kV PILC oil filled underground cable circuits with a total length of 6.5km that form part of the Whangārei City subtransmission network and are approaching end of life. The oldest of these cable circuits was commissioned in 1965. Over the next ten years, we will commence progressive replacement with modern underground 33kV cables where the circuit needs to be retained for network security.

Figure 91: Subtransmission cables age based asset health and risk grade



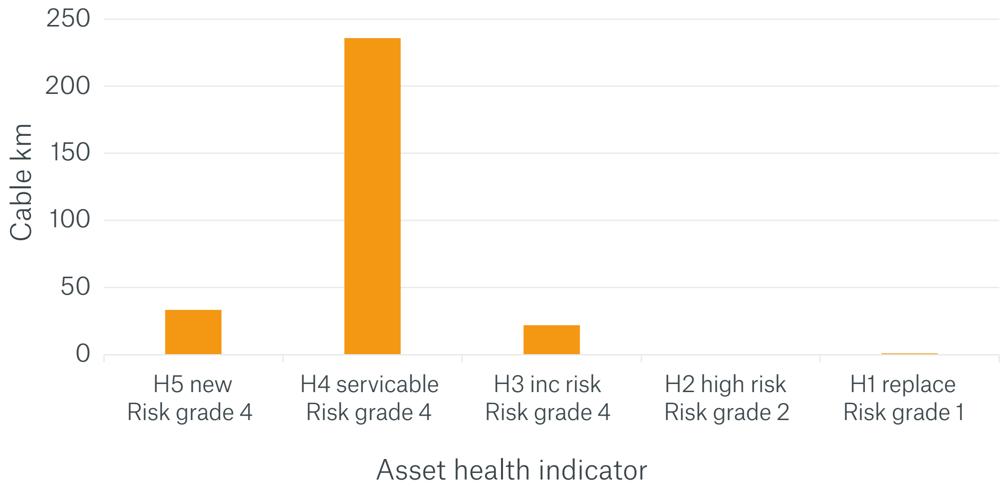
High voltage distribution cables

Distribution feeders with underground cables, originating from zone substations that are operating on our network.

The average overall condition of our HV cables is reasonably good. A large percentage was installed using second generation XLPE cable, which does not prematurely fail due to insulation degradation typically associated with first generation cables.

There is a quantity of aging paper lead (PILC) cable mainly in Whangārei CBD areas and zone substations, which needs to be evaluated. Condition assessment and targeted replacement for cables with higher criticality is under development.

Figure 92: HV distribution cables age based asset health and risk grade



Low voltage cables

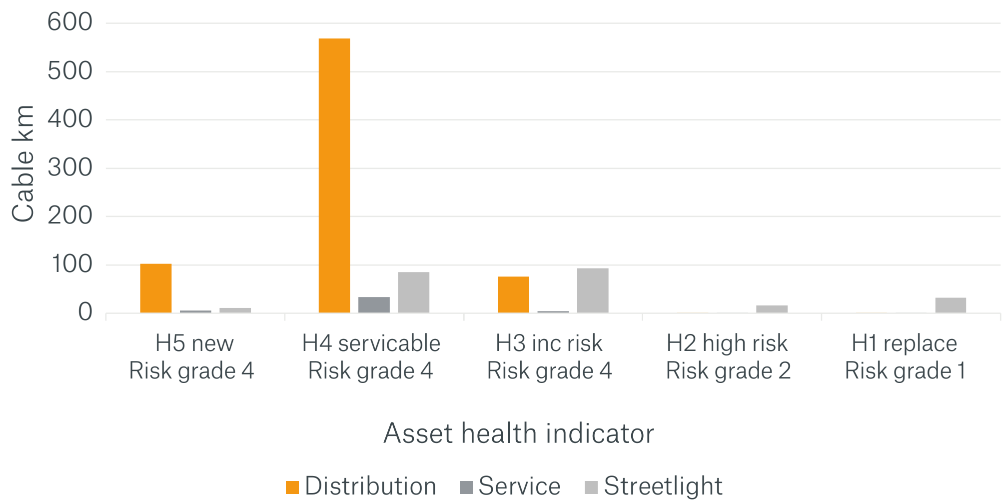
There are 400 Volt distribution networks with underground cables extending from transformers on our network, and underground streetlight cables included with the 400 Volt distribution networks.

There are also Northpower owned sections of underground service cables extending from the 400 Volt distribution networks.

Low voltage cables have proven to be very reliable, with only small amounts of failures at terminations or joints. However, older underground "breech" or "tee" joints are showing increasing failure rates due to ingress of moisture through the epoxy joint. We are monitoring the volume of faults.

This issue is not widespread, and replacement occurs because of failure, or in conjunction with other work on the asset. We are monitoring failure rates and a replacement programme will be developed in future if necessary.

Figure 93: LV cables age based asset health and risk grade



7.5.5 Maintenance plan

Underground cables preventative maintenance	Timing	Scope of work
Subtransmission cable patrol of key circuits	Monthly	Drive through inspection to check for any excavation or encroachment activity.
Check and record oil pressure readings and maintenance	Monthly	Read and record pressure readings (including spare cables). Clean out pressurisation pits, test gauge calibration and transducer alarms.
Pillar visual inspection	Five yearly	Visually identify any hazards or defects (e.g. damage, screws missing, damaged hinges, pillar not straight, burial depth too great or too little). Includes opening pillars that have key locks and doing a thermographic (hand-held) survey.
Cable cover protection unit (SVLs), cross bonding link boxes and serving tests on key circuits	Three yearly	Undertake all SVL, cross bonding and serving tests on cables.

7.5.6 Capital (renewal) strategy

Cable type	Renewal strategy
Subtransmission	All cables reaching an asset health index of H2, are subject to a replacement programme or have cable insulation tests or other comprehensive health assessment. Oil filled: replaced with XLPE cables. PILC and XLPE: routine inspection of cable terminations. Replace upon premature failure or when cables exhibit visible deterioration that may lead to failure.
11kV feeder exit	Routine inspection of cable terminations. Replace upon failure or when cables exhibit visible deterioration that may lead to failure.
HV distribution	Cables on main feeders or that supply critical customers reaching an asset health indication of H2, are subject to a replacement programme or have cable insulation tests or other comprehensive health assessment. Cables should be replaced on failure, damage or when safety or reliability is compromised. Progressively replace old cast iron pot heads as the opportunity arises with other work.
LV distribution, service and streetlight	Replace as becomes unserviceable unless systemic issues identified or damage/deterioration that could lead to failure.

7.6 Electricity distribution equipment

7.6.1 Overview

Overall our distribution equipment performance is satisfactory. However, certain types of distribution switchgear have been identified as having a heightened safety risk, which will be addressed as part of our programme of works.

7.6.2 Asset description

Electricity distribution equipment includes the following:

- Voltage regulators
    - HV switchgear including:
    - Reclosers (including subtransmission line reclosers)
    - Sectionalisers
    - Ring main units (including subtransmission ring main units)
    - Ground mount and pole mount switches (including subtransmission line switches)
    - HV fuses and links (including pole mounted subtransmission links)
    - Distribution substations / transformers
- Pillars, pits and cabinets
- LV fuses, disconnectors and links
- Equipment earthing and equipotential bonding

These asset categories are examined in more detail below under each asset heading.

7.6.3 Performance requirements for all distribution equipment

We have newly established performance criteria for this fleet. Reporting against performance levels is being developed.

Safety	Zero electrocution or fatality through failure or deterioration of distribution equipment.
	Zero injury while working on or near distribution equipment because of incorrect operation or failure of equipment.
Reliability	Annual reduction of the total number of faults through failure of distribution equipment.
Cost	Design, construct and maintain asset to minimise lifecycle costs without compromising other requirements.
Environment	No significant environmental breach.

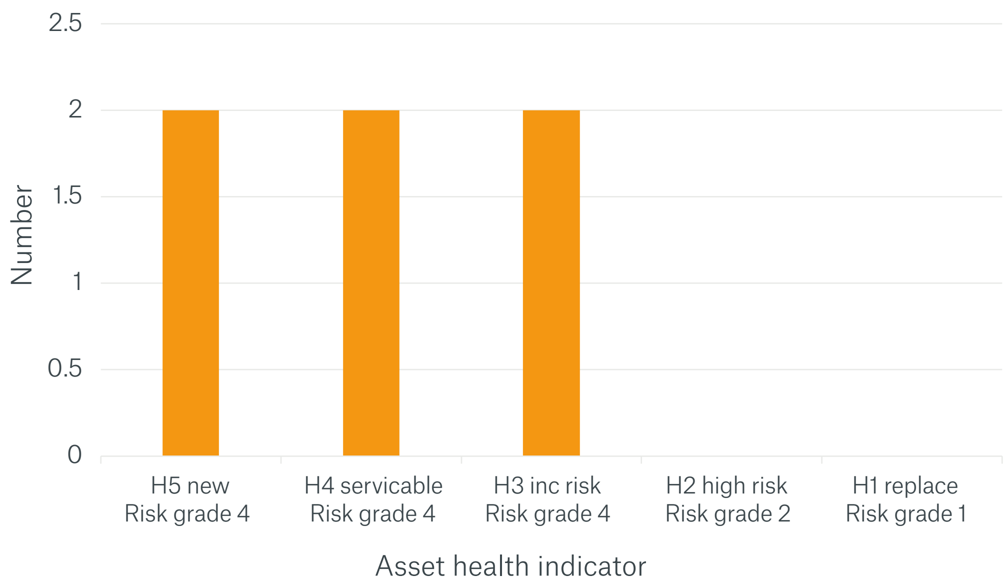
7.6.4 Maintenance plan

Distribution network preventative maintenance	Timing	Scope of work
Overhead pole mounted substations/transformers		
Overhead pole mounted substations/transformers	Five yearly	Visual inspection.
Overhead switchgear		
Remote switchgear operation	Six monthly	Operational check of remote-controlled switchgear overhead.
Overhead remote switch battery change	Four yearly	Change the battery on all remote switch control units. Check alarms. Visual inspection.
Oil recloser oil change	Eight yearly	Recloser refurbishment at workshop.
Ground mounted switchgear and transformers		
Key ground mount asset security inspection	Every year	Visual security and vegetation check.
Inspect ground-mounted distribution substation and switchgear	Two yearly	Visual inspection. Paint touch-up. Remove litter & cobwebs. Thermal imaging and partial discharge diagnostic tests. Check signs/labels, lightbulbs.
Ground mounted oil filled HV switchgear service	Five yearly	Service oil switches and check operation.
Distribution earthing		
Distribution earthing systems	Five yearly	Inspect and test earthing of overhead switches (sectionalisers & reclosers), distribution substations, regulators, out of service overhead lines and associated lightning arrestors plus any standalone lightning arrestor installations (e.g. cable terminations).
Voltage regulators		
Regulator inspection	Annual	Visual inspection. Paint over graffiti as well as treat and paint surface rust. Remove rubbish, cobwebs and vegetation. Check signs/labels and silica gel condition. Record tap changer operations. Check regulating voltage as per standard.
Regulator thermal image survey	Annual	Thermal image survey of regulator and all associated equipment and connections.
Regulator ultrasonic survey	Annual	Ultrasonic survey of regulator and all associated equipment and connections.
Regulator controller test	Two yearly	Operation and alarm test.
Regulator oil change	Four yearly	Change the oil in all regulators/refurbishment.

7.6.5 Voltage regulators

There are six 11,000 Volt voltage regulators currently installed on our HV distribution network. These regulators are used on long rural feeders to maintain the voltage between the required limits.

Figure 94: Voltage regulators age based asset health and risk grade



Maintenance issues

Preventative maintenance inspections on regulators highlight deterioration issues requiring remedial action or refurbishment. Regulators are generally replaced when additional capacity is required. The level of expenditure on regulators is consistent with maintaining regulators in good condition.

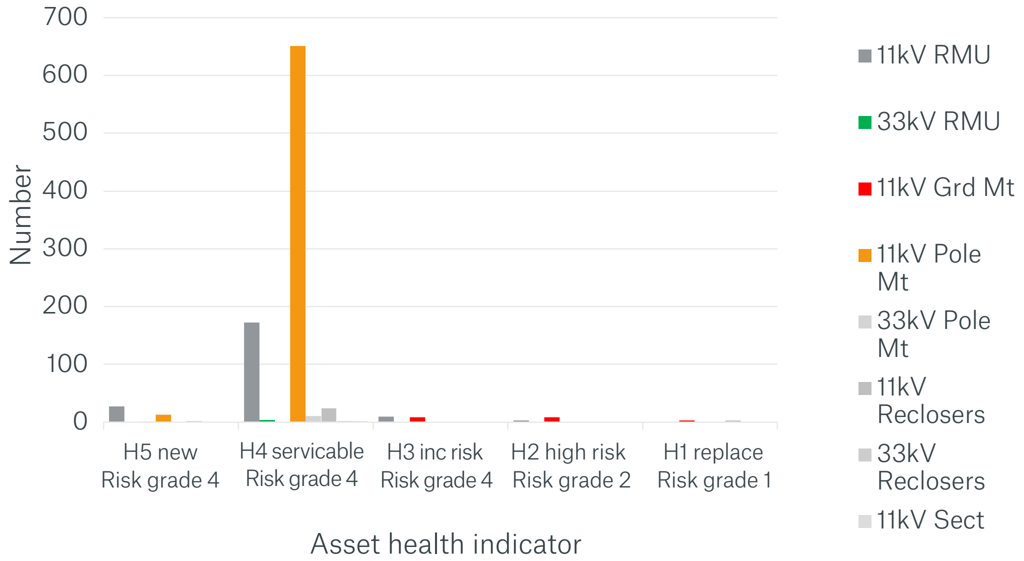
7.6.6 High voltage switchgear

High voltage switchgear is installed on our subtransmission and distribution networks. Switches are installed for the isolation and connection of transformers and sections of the network.

The switchgear includes the following equipment:

Switchgear type	Total	11kV	33kV
Recloser (pole mounted)	31	29	2
Sectionaliser (pole mounted)	2	2	0
Ring main unit (ground mounted)	216	212	4
Ground mount switch	21	21	0
Pole mount switch	675	664	11
Total	945	928	17

Figure 95: HV switchgear age based asset health and risk grade



Maintenance issues

Preventative maintenance inspections on switchgear highlight deterioration issues requiring remedial action, refurbishment or replacement. This includes:

- Long and Crawford oil insulated switches are subject to a replacement programme for safety.
- ABB Safelink ring main units have had failures and operating issues. We have a program to upgrade the operating mechanisms and are investigating further actions and replacement options.
- Sectos switches are showing issues with corrosion and mechanical failures. We are progressively removing these switches from service and replacing with other types.

The remaining switchgear is in satisfactory condition.

7.6.7 High voltage fuses and links

High voltage fuses and links are installed in the overhead distribution network to isolate 11kV transformers and spur lines. Fuses also provide short circuit protection for the equipment or reticulation beyond. Links are also installed in the overhead subtransmission network to isolate 33kV circuit sections.

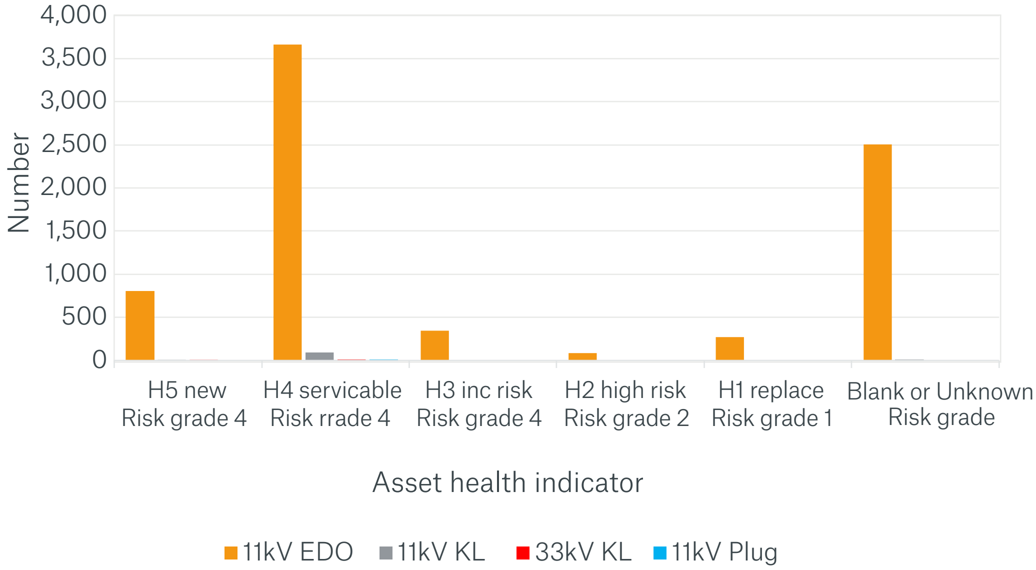
This includes the following equipment:

Fuse/link type	Total	11kV	33kV
Expulsion drop out (pole mount)	7,674	7,674	0
Knife links (pole mount)	115	104	11
Pluggable links (cabinet)	6	6	0
Total	7,795	7,784	11

Each expulsion drop out (EDO) fuse/link and knife links (KL) listed above includes three separate fuse/link holders in 3-phase systems and two separate holders in 2-phase systems.

The pluggable links are installed in ground mounted cabinets and each unit includes three sets of links.

Figure 96: HV fuses and links age based asset health and risk grade



Maintenance issues

A significant number of expulsion dropout fuses have unknown age. However, we complete a condition assessment of every installation during routine pole inspections.

Some types of expulsion dropout fuses or link holders are prone to corrosion and reliability issues. These types are generally replaced in conjunction with other associated works.

7.6.8 Distribution transformers

Distribution transformers are installed on our network to provide a low voltage supply to customers from the high voltage distribution network.

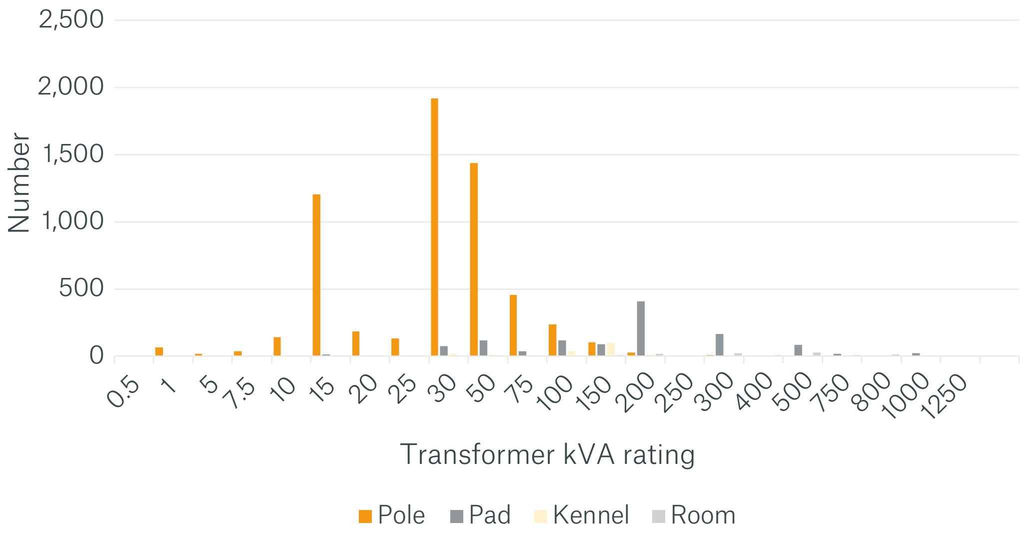
11,000/415 Volt transformers, with off load tap changers, are provided for domestic, commercial and industrial customers on the 11,000 volt distribution feeders that are supplied from the zone substations.

Transformer types	Total	11kV/415 V	11kV/3.3kV	33kV/415 V
Pole mounted	5,956	5,955	0	0
Pad mounted or berm	1,148	1,148	0	1
Kennel	191	191	0	0
Room or kiosk	120	112	2	9
Total	7,415	7,406	2	10

We have dedicated assets for some single customers:

- Eight 33,000/415 Volt transformers provided for an industrial customer from the subtransmission network and one spare.
- One 11,000/3,300 Volt transformer in service for an industrial customer and one spare.

Figure 97: Number and type of transformers by kVA rating



The high proportion of rural overhead network means there are many pole mounted 15, 30 and 50kVA transformers in service.

Maintenance plans

Preventative maintenance inspections on transformers highlight deterioration issues requiring remedial action, refurbishment or replacement.

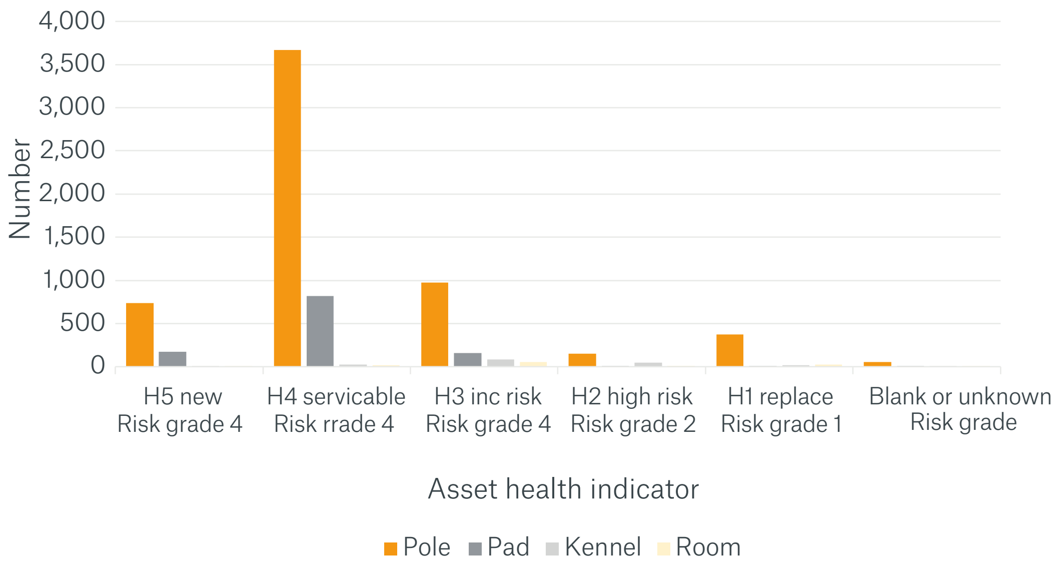
We have a significant number of older transformers installed (falling into the H1 category based on age in the table above), however they are still providing reliable service. Pole mounted transformers are generally replaced when they show high levels of corrosion. Ground mounted transformers also have significant maintenance due to graffiti and vandalism.

Maintenance issues under management include:

- Transformers on two pole structures are subject to a replacement program, being replaced with pad mounted transformers for improved public safety.
- Transformers installed within kennels are also considered for replacement with pad mount transformers, for improved public safety. For further information on our risk evaluation and management processes - see Section 3 Managing risk

Transformers are also replaced when capacity increases are required due to load growth.

Figure 98: 11kV and 415V transformers age based asset health and risk grade



7.6.9 Low voltage distribution pillars and cabinets

Distribution pillars and cabinets are installed on the LV distribution network to enclose disconnects, links, fuses and joints as:

- A link between two distribution circuits
- Disconnection point for a distribution circuit
- Service fuses for customer connection
- Revenue metering installed in cabinet with service fuses
- Solid joints or studs

Individual pillars and cabinets may include multiple functions.

The pillars and cabinets include fuses, links, holders, bases, disconnects, earth bars and mounting frames.

Pillar types	Numbers in service
Plastic pillar	12,627
Plastic pit or underground pillar (TUDS)	140
Cabinets (polycarbonate, fibreglass, aluminium & steel)	332
Concrete pillar	85
Total	13,184

Figure 99: Pillars and cabinets age based asset health and risk grade

Maintenance issues

Preventative maintenance inspections on pillars highlight deterioration issues requiring remedial action or replacement. The main driver for inspections is safety, as pillars are generally located in road or property access frontages, are readily accessible to the public, and vulnerable to damage. We are considering adopting more detailed internal inspections for pillars to improve our data on the condition of pillar internal components.

The following types are prone to corrosion, reliability or safety issues:

- Concrete pillars
- Older steel cabinets (common in Dargaville CBD)
- Plastic pillars with stud connections (mostly pre-2005)

These types are generally replaced along with any new connections or associated works.

Many distribution pillars on the network have no recorded age or year of manufacture. All pillars are visually inspected ensuring they are in good condition and safe and are replaced when their condition has deteriorated.

7.6.10 Capital (renewal) strategy

Equipment type	Renewal strategy
Voltage regulators	Replace as become unserviceable unless systemic issues identified or damage/ deterioration that could lead to failure
HV switchgear	Long and Crawford oil insulated switches are now part of a replacement program. ABB Safelink Ring Main Units are part of a program to upgrade the operating mechanisms. Replace as becomes unserviceable unless systemic issues identified or damage/ deterioration that could lead to failure
HV fuses and links	Replace as becomes unserviceable unless systemic issues identified or damage/ deterioration that could lead to failure
Transformers	Transformers on two pole structures and in kennels are being replaced with pad mount transformers. Replace as becomes unserviceable unless systemic issues identified or damage/ deterioration that could lead to failure
LV pillars and cabinets	Replace as becomes unserviceable unless systemic issues identified or damage/ deterioration that could lead to failure

7.7 Regional and zone substations

7.7.1 Overview

The first half of this ten-year AMP will see many of our older power transformer and switchboards replaced with new units. Our previous strategy of rotating transformers between zone substations means that our power transformers fleet has a high proportion of 1950's and 60's transformers in service compared with our peers. While power transformers are subject to a rigorous inspection and servicing regime, the risk of component or winding failure is becoming unacceptable, which is driving our current replacement strategy.

7.7.2 Asset description

We have the following electricity substations:

- Two regional substations (Maungatapere and Kensington)
- Twenty zone substations
- One industrial substation (Portland Chipmill)

Our substations are typically a building housing switchgear, protection panels and auxiliary DC equipment. Newer substations also locate power transformers, switchgear and buses within the building.

Older substations have power transformers, switchgear and buses located in securely fenced outdoor yards.

Substations and equipment includes:

- Buildings and grounds
- Power transformers and tap changers
- Circuit breakers
- Indoor switchboards and outdoor buses
- Auxiliary systems (refer to Section 7.8)

7.7.3 Performance requirements

We have newly established performance criteria for this fleet. Reporting against performance levels is being developed.

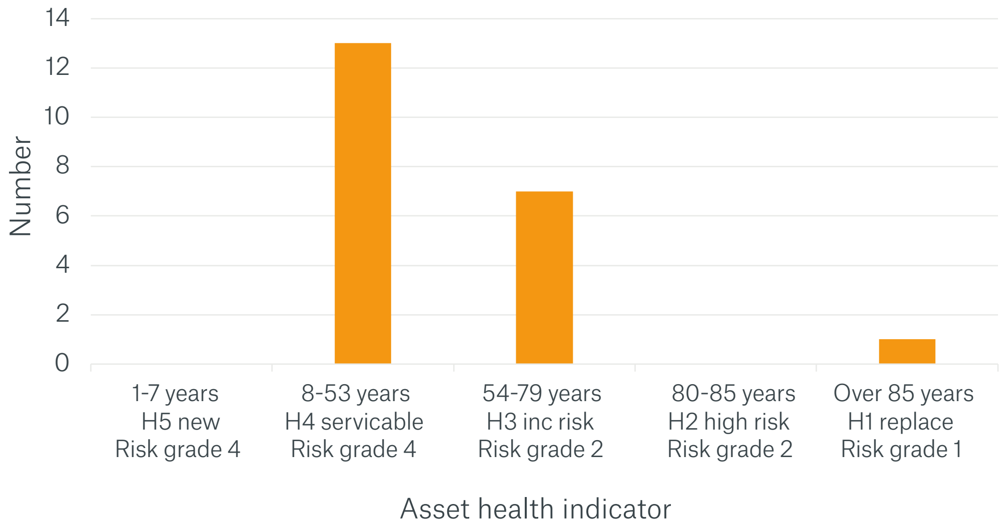
Safety	All indoor and outdoor equipment	Zero injury while working on or near or operating equipment
		Clearances between equipment, equipment to ground and egress points comply with all relevant standards
Reliability	Indoor equipment	Total unplanned outages less than 5 SAIDI minutes per annum
	Outdoor equipment	Total unplanned outages less than 10 SAIDI minutes per annum
	110 & 50kV transformers	No more than one failure every 25 years where unit is uneconomic to repair
	33kV transformers	No more than one failure every 10 years where unit is uneconomic to repair
Cost	All indoor and outdoor equipment	Design, construct and maintain asset to minimise lifecycle costs without compromising other requirements
Environment	All indoor and outdoor equipment	No significant environmental breach

7.7.4 Substation buildings

We have 20 regional and zone substation sites, with 21 buildings housing electricity distribution and subtransmission equipment.

Preventative maintenance inspections on substation buildings and grounds highlight deterioration issues requiring remedial action. The main driver for inspections is safety and specific attention is given to site security and safety signage.

Figure 100: Substation buildings age based asset health and risk grade



The buildings are in satisfactory, functional, and safe condition. Buildings are either retained indefinitely or until no longer required. Our oldest building is 81-year-old Mareretu zone substation, which is intended to be retained for the foreseeable future.

Maintenance

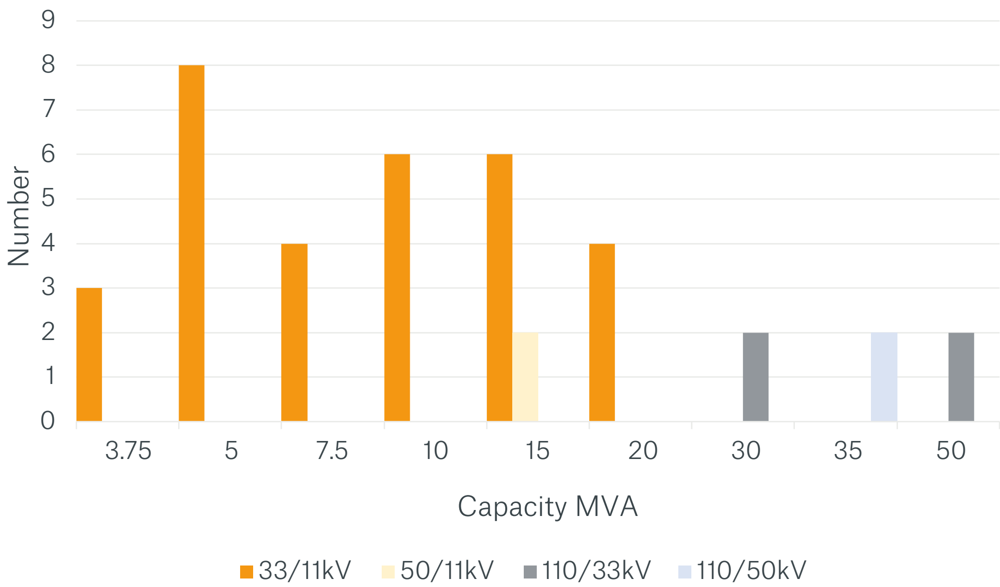
Buildings and grounds preventative maintenance	Timing	Scope
Zone substation	Two monthly	Inspect buildings, fittings, fencing. Check for damage, leaks and security. Check internal fittings and trench covers. Clean floors, toilet etc as required. Restock toiletries, replace blown light bulbs. Log defects.
Zone substation grounds maintenance	Monthly	Mow lawns, trim edges, unblock drains, trim trees, remove rubbish, weed control, and maintain gardens (if any).
Security system test	Six monthly	Check operation and service as necessary.
Smoke detector testing	Six monthly	Check operation and service as necessary.
Air conditioning unit service	Annual	Check operation, clean filters and service.

7.7.5 Power transformers

Power transformers are installed at substations, providing voltages suitable for subtransmission circuits or high voltage distribution feeders. We have 39 operational and three spare 3-phase power transformers.

All power transformers except the 110/33kV transformers at the two regional substations, are equipped with on load tap changers (OLTC).

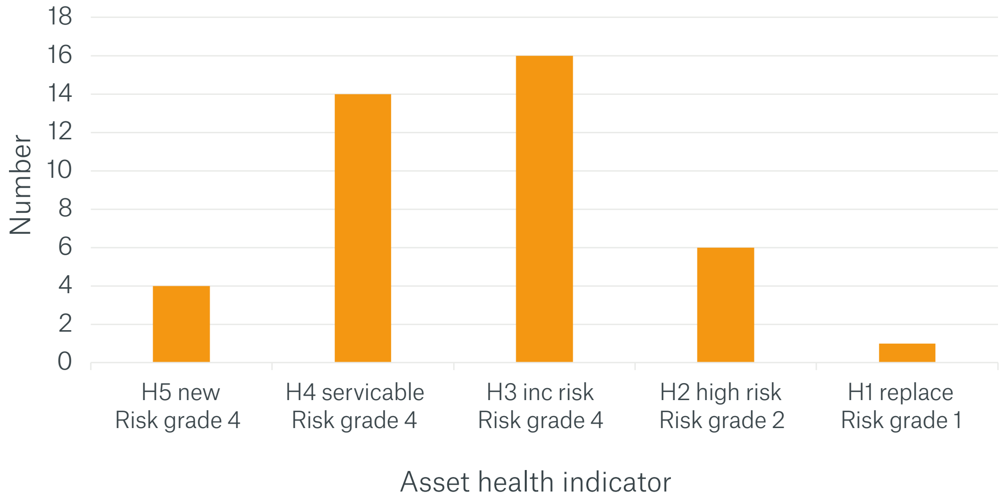
Figure 101: Capacity ratings of power transformers in service



Assessing asset health of power transformers

We use the EEA Asset Health Indicator (AHI) Guide 2019 for assessing power transformer health by determining scores for end-of-life drivers such as, paper degree of polymerisation, bushing condition, tank external condition, and insulation system condition. We apply weightings to establish an overall health assessment.

Figure 102: Power transformers age and condition based asset health and risk grade



Approximately half (mainly older) power transformers have been conditionally assessed and the remainder have an age-based asset health. Condition assessments are being arranged for the remainder.

All transformers with risk grade one or two are programmed for replacement over the next ten years.

Maintenance

Power transformer preventative maintenance	Timing	Scope of work
Routine equipment inspections and checks	Two monthly	Routine visual equipment inspections and checks.
Thermal image survey acoustic inspection	Annual	Acoustic emission and thermal imaging on cable box.
Partial discharge survey	Two yearly	Partial discharge testing.
Transformer oil test	Annual	Test oil for acidity, power factor, breakdown voltage, moisture content, interfacial tension, colour and DGA.
Tap changer service	Four yearly	Clean out tap changer to ensure free of arc products and deposits. Replace insulating oil. Check contact alignment and correct operation of tap changer. Check operation of tap changer control relay and secondary protection devices.
Transformer maintenance	Four yearly	Close visual inspection, insulation resistance, impedance and winding capacitance and power factor test. Buchholz and pressure relief operational test, temperature gauge check, neutral earth resistor test.

Replacement plan

A major focus with these assets continues to be with rust treatment, painting, and panel repairs. Transformer oil is tested annually and oil found to be out of specification is routinely replaced. Dissolved gas levels in oil are regularly assessed and used as a further indicator of transformer oil and internal condition.

Our previous policy of rotating transformers between zone substations means that our in service power transformers fleet has a high number of older units. While power transformers are subject to a rigorous inspection and servicing regime, the risk of component or winding failure increases with age. The first half of this ten-year AMP will see many of our older power transformer fleet replaced with new units.

The table below lists substations with ageing power transformers and proposed replacement dates. Where the transformer life expectancy has been extended due to mid-life refurbishment, this has been considered.

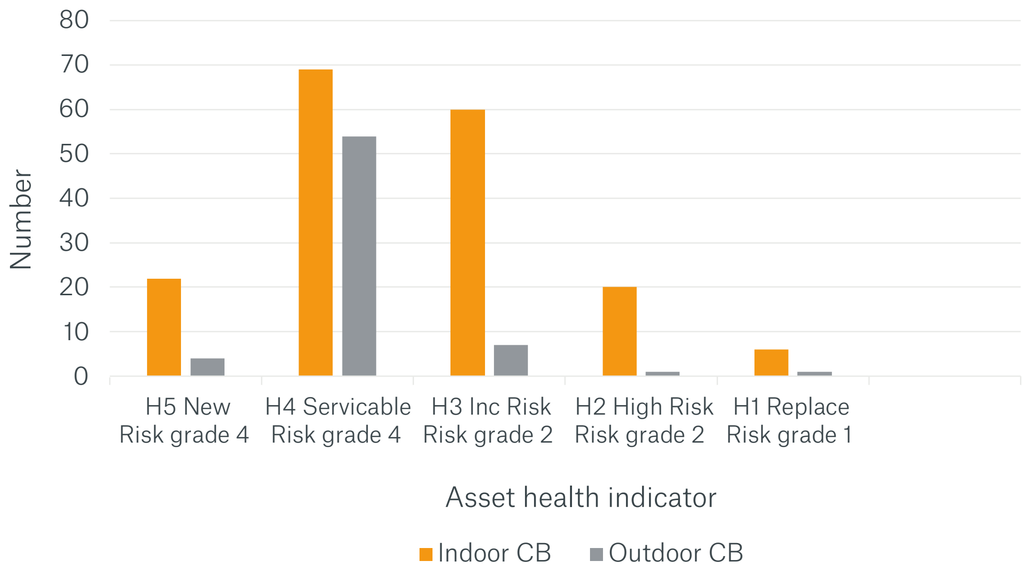
Substation	Type	Original manufacture date(s)	Replacement transformers	Proposed replacement year
Parua Bay	Zone	1956	1 x 33/11kV 5 MVA	FY 21-23
Ngunguru	Zone	1956	1 x 33/11kV 5 MVA	FY 21-22
Ruawai	Zone	1963	2 x 33/11kV 5MVA	FY 21-23
Maungatapere	Regional	1964	2 x 110/33kV 70-100 MVA	FY 24-26
Kensington	Regional	1965 & 1967	2 x 110/33kV 70-100 MVA	FY 22-24
Portland Chipmill	Industrial	1956	1 x 33/11kV 5 MVA	FY 23-24
Hikurangi	Zone	1961	2 x 33/11kV 10 MVA	FY 21-22
Poroti	Zone	1961	1 x 33/11kV 5 MVA	FY 22-24
Maungaturoto	Zone	1964	2 x 33/11kV 10 MVA	FY 23-25
Ruakaka (T2)	Zone	1969	1 x 33/11kV 10 MVA	FY 25-26
Whangārei South	Zone	1969	2 x 33/11kV 15 MVA	FY 26-29

Other items, such as renewal of cable terminations and end boxes, refurbishment of cooling fans and the replacement of silica gel, typically fall into the renewal and refurbishment category.

7.7.6 Substation circuit breakers

Circuit breakers are used to open and close electrical high voltage circuits on our network. To quench electrical arcs during circuit breaker operation, the circuit breaker employs vacuum, SF6 or oil.

Figure 103: Substation circuit breakers age and condition based asset health and risk grade



Replacement plan

Northpower has a program to replace old indoor switchboards that are equipped with oil insulated 11kV indoor circuit breakers with modern gas insulated vacuum circuit breakers. Seven 11kV switchboards are scheduled to be replaced over the next ten years.

In addition, there are two 33kV indoor switchboards which are planned for replacement.

Substation	Type	Voltage	Proposed replacement
Kaiwaka	Zone	11kV	FY 22-24
Ngunguru	Zone	11kV	FY 21-22
Bream Bay	Zone	33kV	FY 30-32
Kensington	Regional	33kV	FY 24-26
Hikurangi	Zone	11kV	FY 20-22
Poroti	Zone	11kV	FY 22-24
Maungaturoto	Zone	11kV	FY 23-25
Whangārei South	Zone	11kV	FY 20-21
Ruawai	Zone	11kV	FY 21-23

Northpower is also progressively replacing outdoor 33kV circuit breakers that have reached the end of their serviceable life with modern gas insulated vacuum circuit breakers.

Maintenance

Switchgear preventative maintenance	Timing	Scope of work
Indoor switchgear		
Routine equipment inspections and checks	Two monthly	Routine visual equipment inspections and checks.
Thermal image survey	Annual	Thermal imaging.
Partial discharge survey	Two yearly	Partial discharge testing.
Indoor 11kV oil circuit breaker major servicing	Four yearly or condition	Circuit breaker timing and operational test. Visual inspection of switchgear condition. Breaker service oil change, inspect contact.
Indoor 11kV vacuum and SF6 circuit breaker servicing	Four yearly	Circuit breaker timing and operational test. Visual inspection of switchgear condition, check SF6 gas pressure.
Indoor 33kV SF6 circuit breaker servicing	Four yearly	Circuit breaker timing and operational test. Visual inspection of switchgear condition, check SF6 gas pressure.
Outdoor switchgear		
Routine equipment inspections and checks	Four monthly	Routine visual equipment inspections and checks.
Thermal image survey, Acoustic inspection	Annual	Acoustic emission and thermal imaging.
Outdoor 33kV SF6 circuit breaker servicing	Four yearly	Circuit breaker timing and operational test. Visual inspection of switchgear condition, check SF6 gas pressure.
Outdoor oil circuit breaker major servicing	Four yearly	Circuit breaker timing and operational test. Visual inspection of switchgear condition. Breaker service oil change, inspect contact.
Outdoor current transformer and voltage transformer		
Routine equipment inspections and checks	Two monthly	Routine visual equipment inspections and checks.
Thermal image survey, Acoustic inspection	Annual	Acoustic emission and thermal imaging.

7.7.7 Outdoor buses

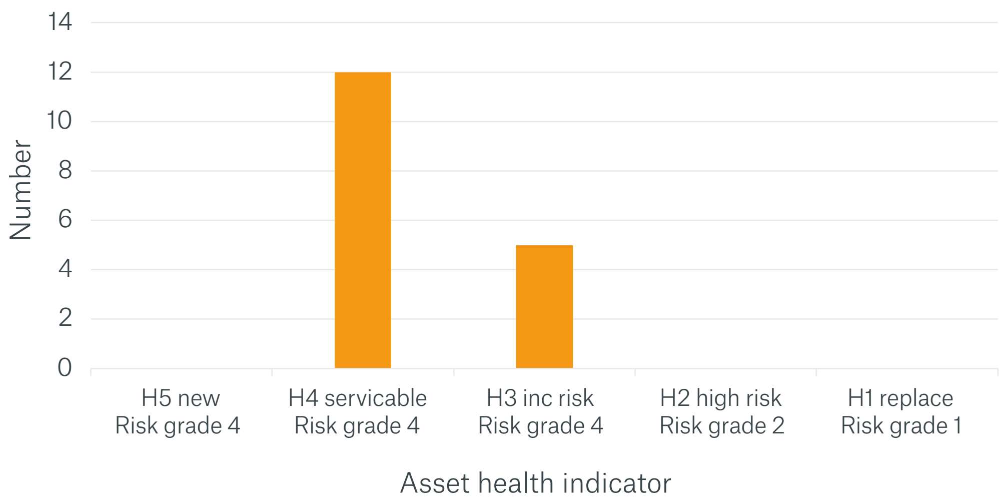
Outdoor buses or busbars are bare conductors utilised within a substation to link high voltage equipment.

All 50kV and 110kV buses are located outdoors. Most 33kV buses are located outdoors except for six substations with indoor buses as part of the 33kV indoor switchboard. All 11kV buses are located indoors as part of the 11kV indoor switchboard.

Outdoor buses are usually installed during construction of the substation. They are also upgraded, extended or modified when upgrading or adding high voltage substation equipment. Asset health is based on original construction, as ages of specific bus components are not generally recorded.

Bus systems are generally in a satisfactory condition however the 33kV buses at Maungatapere and Maungaturoto present some challenges when operating and/or carrying out maintenance. We plan to examine problematic outdoor arrangements and consider converting these to an indoor arrangement.

Figure 104: Outdoor buses condition based asset health and risk grade



7.7.8 Maintenance plan

Preventative maintenance inspections on substation bus systems and structures highlight deterioration and issues requiring remedial action. Visual examination, thermal imaging, acoustic and partial discharge testing are used to identify components that need to be replaced.

Outdoor structures preventative maintenance	Timing	Scope of work
Routine equipment inspections and checks	Two monthly	Routine visual equipment inspections and checks.
Thermal image survey, Acoustic inspection	Annual	Acoustic emission and thermal imaging.
Close inspection of outdoor structure	Four yearly	Shut down and close inspection of structure and hardware.
33kV outdoor oil filled VT's & CT's	Four yearly	Insulation resistance test, oil change.

7.7.9 Capital (renewal) strategy

Equipment type	Renewal strategy
Buildings	Buildings are regularly maintained and retained indefinitely.
Power transformers	All transformers with risk grade two are programmed for replacement over the next ten years.
Circuit breakers	Ongoing programme replacing aged oil filled circuit breakers with modern vacuum breakers over the next ten years.
Buses	Upgraded or extended in conjunction with equipment installation and consider outdoor to indoor conversions where feasible.

7.8 Auxiliary systems

7.8.1 General

Overall our auxiliary systems performance is satisfactory, however certain types of numeric protection relays are known to be less reliable than others and are being addressed in FY22. We intended to replace most of our electromechanical protection relays during our switchboard replacements programme which will enable enhanced reporting during faults as well as operational data to our SCADA system.

7.8.2 Asset description

Auxiliary substation systems are essential systems required for operation of a substation and include the following:

- Load control plants
- Protection systems
- Battery systems
- Capacitor banks
- Earthing systems

7.8.3 Performance requirements

We have newly established performance criteria for this fleet. Reporting against performance levels is being developed.

Safety	All indoor and outdoor equipment	Zero injury while work on or near or operating equipment
		Clearances between equipment, equipment to ground and egress points comply with all relevant standards
Reliability	Protection relays	Total unplanned outages less than five SAIDI minutes per annum
	All other equipment	Annual reduction of the total number of faults due to failure of equipment
Cost	All indoor and outdoor equipment	Design, construct and maintain asset minimising lifecycle costs without compromising other requirements
Environment	All indoor and outdoor equipment	No significant environmental breach

7.8.4 Load control central plants

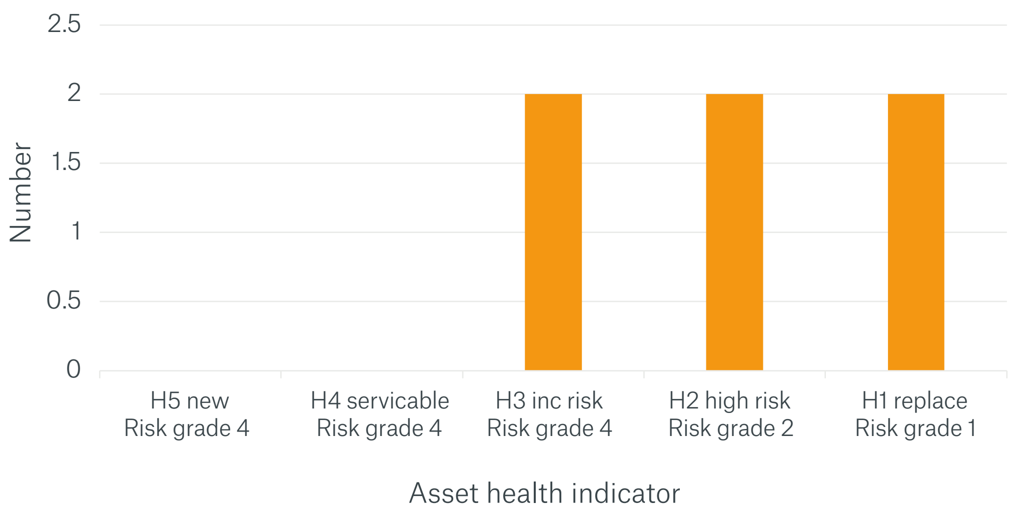
Our ripple control signalling is utilised to activate controlled loads on distribution network for:

- Controlled load
- Streetlights
- Day/night metering
- Tsunami warning siren activation.

There are six static type load control or ripple injection plants, comprising a control system, coupling cell and transmitter utilising a 283 Hz injection frequency, at these zone substations.

Ripple plant location	Injection voltage	Transmitter ratings
Maungatapere	33kV	200kVA
Tikipunga	33kV	200kVA
Maungaturoto	33kV	80kVA
Bream Bay	11kV	40kVA
Dargaville	11kV	40kVA
Ruakaka	11kV	40kVA

Figure 105: Load control plants age based asset health and risk grade



Load control plants are inspected and maintained by specialist contractors who repair or replace components as required. The load control plants rated H1 or H2 have been assessed based on age. These will be inspected during our inspection programme to determine condition in the field, and from there replacements programmed for those assessed as end of life.

Maintenance regime

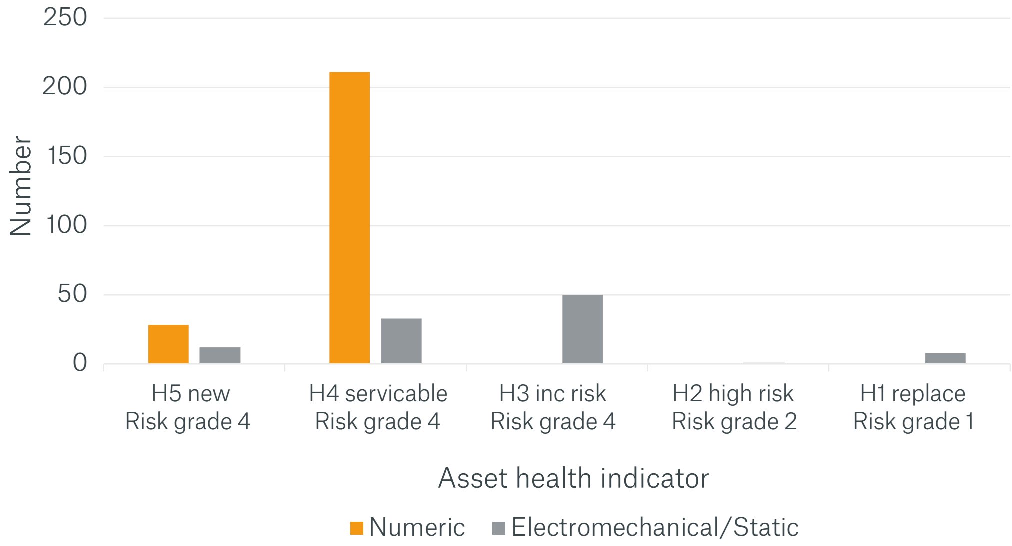
Load control plant	Timing	Scope of work
Routine equipment inspections and checks	Two monthly	Routine visual equipment inspections and checks.
Equipment test	Annual	Check operation and signal strength.

7.8.5 Protection systems

Protection systems are installed in substations to detect faults, and include relays to operate circuit breakers which isolate the faults.

Relay types September 2020	Number installed
Numeric relays (computer controlled)	239
Electromechanical and static relays	104
Total	343

Figure 106: Protection relays age based asset health and risk grade



Regular inspections, maintenance and refurbishment ensures that the equipment remains within operating tolerances and specification for network requirements.

The average condition of our protection relays is satisfactory, with older electromechanical relays gradually replaced with modern numeric relays alongside substation switchboard upgrades.

Maintenance regime

Protection relays	Timing	Scope of work
Routine equipment inspections and checks	Two monthly	Routine visual equipment inspections and checks.
Equipment test	Numeric – four years Electro-mechanical – two years	Check operation

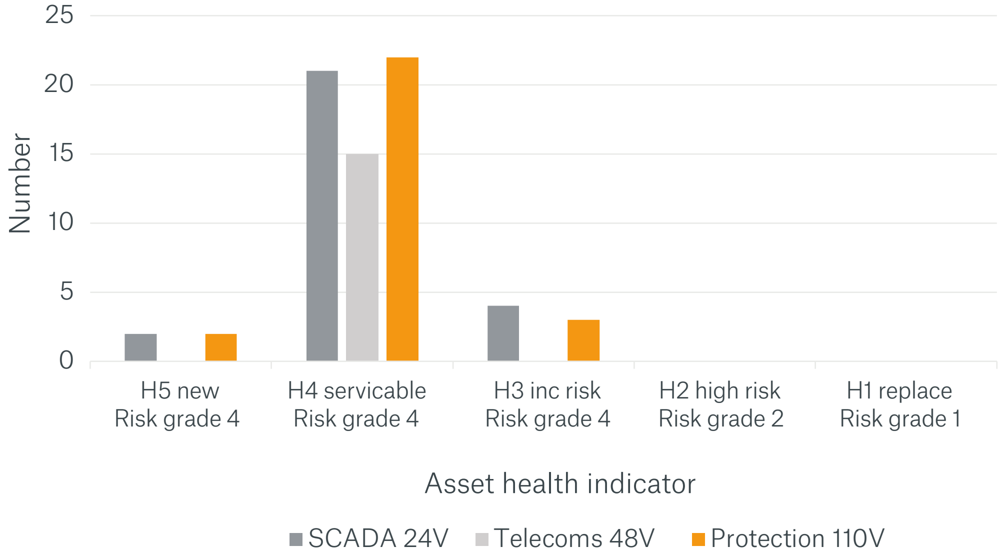
7.8.6 Battery systems

Substations have standby DC power systems providing power for essential equipment including protection systems during a power outage.

Standby power systems comprise a battery bank, charger, and monitoring equipment supplying a direct current (DC) supply. We operate these at three different voltages.

System purpose	Battery voltage	Number installed
Protection systems	110V	27
Telecommunications	48V	15
SCADA	24V	27
Total		69

Figure 107: Battery systems condition based asset health and risk grade



Battery systems are regularly inspected and tested and replaced as recommended by the manufacturer or when showing signs of deterioration.

There is a replacement program for battery banks and renewal and refurbishment is generally based on age, however maintenance is also driven from condition assessment identified through the routine preventative maintenance inspections.

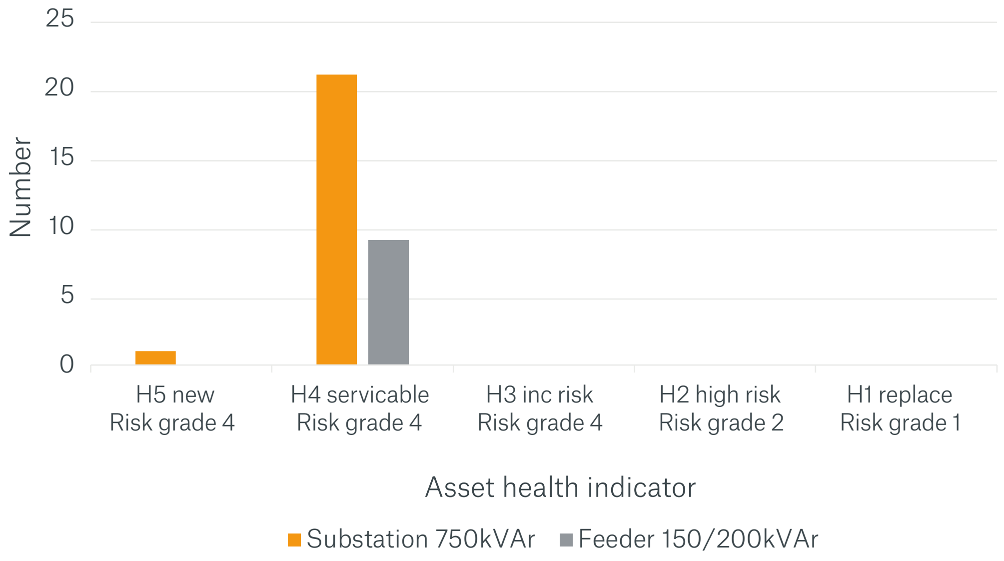
Condition assessments indicate batteries are all in satisfactory condition.

7.8.7 Capacitor banks

Capacitor banks are installed in substations or at specific locations on the 11kV distribution network for power factor correction and to improve voltage levels.

One or two sets of 750kVAr capacitors are installed at most substations. One, two or three sets of 150 or 200kVAr capacitors are installed on several 11kV feeders with significant reactive loads.

Figure 108: Capacitor banks age based asset health and risk grade



Substation and feeder capacitor banks are in good condition.

Capacitor banks preventative maintenance	Timing	Scope of work
Overhead pole mounted/substation capacitor banks	Five yearly	Visual inspection.

7.8.8 Earthing systems

Every substation includes an earth grid. There is little specific data on each earth grid as these were installed when the substation was established.

Preventative maintenance inspections including testing of substation earthing systems highlight deterioration and compliance issues requiring remedial action. The main driver for inspections is electrical safety and that systems prevent or minimise potential induced voltage on structures and equipment during fault conditions.

Earthing systems preventative maintenance	Timing	Scope of work
Test zone substation earthing system	Four yearly	Test zone substation earth grids. Test bonding of equipment and structure.

7.8.9 Capital (renewal) strategy

Equipment type	Renewal strategy
Protection systems	Replace in conjunction with substation switchboard upgrades
Ripple plants	Replace when there is a need to resize or when units exhibit unreliable service
Battery systems	Replace when recommended by manufacturer Replace as becomes unserviceable or systemic issues identified or damage/deterioration that could lead to failure
Capacitor banks	Replace as becomes unserviceable unless systemic issues identified or damage/deterioration that could lead to failure
Earthing systems	Replace as becomes unserviceable unless systemic issues identified or damage/deterioration that could lead to failure

7.9 Secondary systems

7.9.1 Overview

Secondary systems are separate systems that provide support for our electricity network and include:

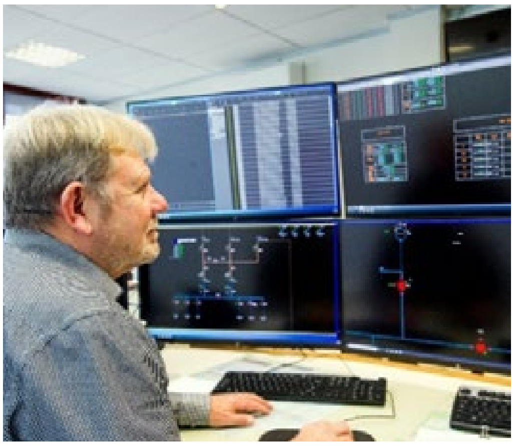
- Network operations centres
- Advanced distribution management system
- Telecommunications
- Mobile substation and generator
- Power monitoring and metering
- Load control relays

7.9.2 Performance requirements

We have newly established performance criteria for this fleet. Reporting against performance levels is being developed.

Safety	Operations centres	Continuous safe operation of our electricity network
	All equipment	Zero injury while working on or near, or operating equipment
		Clearances between equipment, equipment to ground and egress points comply with all relevant standards
Reliability	Operations centres	Maintain continuous monitoring and control of our electricity network
	All equipment	Annual reduction of total number of faults due to equipment failure
Cost	All equipment	Design, construct and maintain asset minimising lifecycle costs without compromising other requirements
Environment	All equipment	No significant environmental breach

7.9.3 Network operations centres



Northpower's main 24-hour network operations centre (NOC) is located at our headquarters in Raumanga. A backup NOC or disaster recovery site with identical functionality is located at Tikipunga zone substation, five kilometres from the main operations centre.

The electricity network can be fully monitored, managed, and controlled from both the main and backup operations centres.

The ADMS system continuously monitors loads, alarms, and operation of equipment in all the substations including the Wairua power station, along with regulators and remote-controlled switches on the network.

The operations centre also monitors security access systems and cameras at substations and other critical sites.

7.9.4 Advanced distribution management system (ADMS)

We recently implemented the first modules of a new GE PowerOn advanced distribution management system (ADMS), starting with replacement of the aging Power TG SCADA system. This has mitigated the risk of failures with our aging SCADA systems, and reduced cyber security risks. Operations will use ADMS applications to manage, monitor and control the network.

The following modules/subsystems have been recently implemented or upgraded or are planned:

Implemented	
Supervisory control and data acquisition (SCADA)	At the heart of our ADMS is a SCADA system providing a real-time view of tele controlled parts of the network, including switch position and energisation, loading and voltage levels, alarm status and event logs. This is dynamically generated using graphical displays of network schematics combined with active tables and charts. The core SCADA system comprises: Remote terminal units (RTUs) – field devices concentrating sensor/actuator information Communications network – provides the link between the field and central server (comprising fibre, radio links and associated switching facilities) Servers – the system runs four real time application nodes across our head office and disaster recovery sites, providing a very high level of redundancy. The server stack consists of 12 physical severs hosting 30+ virtual servers. SCADA Workstations – provides the human machine interface (HMI). The system is a bespoke design and implementation with cyber-security in mind, minimising the likelihood of any potential security breach. Redundancy is another core design principle, with all parts of the system implemented allowing for failures to occur without impacting operations.
Load management system (LMS)	The Catapult OnDemand load control sub-systems automatically control interruptible load on the network. This system interfaces with Transpower's energy markets, curtailing load when transmission is becoming a constraint – ensuring minimum disruptions for our consumers.

To be implemented FY22 – FY23	
Distribution management system (DMS)	The SCADA system will be integrated with GIS, extended to include non-remote controlled parts of the network. This enables us to digitise the supporting processes, including our 11kV wall mimic and access permits. We will be able to simulate outage impacts, and the system will help prevent unsafe operation of the network, reducing the possibility of switching relating incidents.
Network access request system	New fully electronic network access permit systems will improve operations permit planning processes, helping minimise disruptions.
Outage management system (OMS) and advanced applications	A new OMS will help automatically identify fault causes, and improve communications between our systems, staff, and customers. Sub-systems are also deployed that support our operations alongside ADMS.

Maintenance

Our new ADMS system is kept patched and cyber-secure, with regular updates provided by General Electric (GE). The ADMS comes with higher ongoing overheads than the legacy SCADA system, reflecting the improved operations capability, with anticipated increased costs of operational management of distributed energy resources, and the need to keep the system well maintained and cyber-secure. Other older sub-systems are monitored, risks mitigated or systems flagged for replacement when necessary.

With regular patching and maintenance the recently installed GE PowerOn ADMS system will serve as a platform for Northpower for many years. The second and third phases of the ADMS implementation (outlined in this AMP) will replace many manual operations systems and processes, as well as enable retirement of some of our older bespoke operational sub-systems currently in place for network access permits, fault identification and reporting, and shutdowns planning, as well as enabling new capabilities in the future.

7.9.5 Ancillary systems

Several other sub-systems also support our operations. These are monitored and regularly maintained, including:

- Data historian
- Interactive voice response system (IVR)
- Cardax and CCTV

Security and access control has been implemented at the main office and at several substations. It is planned for the system to be rolled out across the balance of the zone substations over the next few years.

7.9.6 Telecommunications

We have both data and voice telecommunication systems. The telecommunication network is integral to the remote monitoring and control of network equipment. A separate land mobile radio network provides contact with operating staff and contractors in the field.

Core telecommunications systems	
Land mobile radio	We own and operates our own private land mobile radio network. This provides a radio telephone (RT) service for the exclusive use of our network staff and contractors. This consists of six VHF repeaters linked via a radio dispatch system in the Whangārei control centre. These repeaters provide coverage across 90% of our distribution area. Three of the repeaters have recently been upgraded to Digital Mobile Radio (DMR) tier II standard. The remaining analogue repeaters will be upgraded shortly. There are approximately 120 mobile radios installed in Northpower vehicles and another 21 located at substations. There are also approximately 120 remote controlled switches, reclosers and regulators in operation on our network. We are replacing all analogue radios with digital mobile radios following completion of the repeater upgrades.

Core telecommunications systems	
Point to multi point radio	We have a point to multi point data network operating with the land mobile radio equipment utilised for controlling remote controlled HV switchgear, reclosers and regulators.
Point to point radio	We own and operate a point to point radio network for SCADA and network control for substations. This is also utilised for linking some land mobile radio repeaters. There are eight UHF radio links and one microwave radio linking four radio repeater and link sites and six zone substations, including five that are not connected to the fibre network. The system utilises ethernet for data transfer. The principal hub is located at Maunu Mountain. Six new digital UHF radio links are planned for installation, replacing the remaining analogue radios and to link additional repeaters.
Fibre	We own fibre assets that connect our substations. The Northpower Group also owns and operates a fibre network principally for provision of broadband telecommunications services to residential and commercial customers and we purchase services from Northpower Fibre Limited. We use fibre for SCADA, network control for substations and the land mobile radio repeater hub. It provides links from the NOCs to 17 substations. We expect to procure additional links with diverse routes to our critical substations.

Maintenance

We undertake periodic visits to each radio site for proactive maintenance. In these visits, visual inspections are performed, alarm logs checked and performance histories reviewed. In most cases remote monitoring of radio equipment is limited.

Our technicians also respond to faults on the radio networks, which includes the supervisory control, SCADA and land mobile radio networks, from their base in Whangārei. To support this capability we maintain a small holding of essential radio spares.

All fibre assets are maintained by Northpower's fibre division.

Telecommunications assets that are faulty are generally repaired where economic and returned to service. Equipment is generally replaced due to technical obsolescence rather than age.

Northpower will replace RTU's as part of other network projects where the requirements of the network equipment being installed cannot be met by existing RTU's. Alternatively, older RTU's will be progressively replaced at end of life.

7.9.7 Mobile substation and generators

We hold 500kVA and 150kVA mobile generators on site, which can provide supply through a direct connection into the LV distribution network in the event of a planned or unplanned shutdown. We also have priority access to mobile generators through a services agreement with a hire firm. To provide greater flexibility, the AMP programme also includes acquisition of a mobile 33/11kV substation, supporting fault response and maintenance for zone substations with single power transformers.

7.9.8 Power monitoring and metering

GXP energy metering and power quality monitoring

Energy metering is installed at Transpower GXP supply points (Maungatapere, Maungaturoto and Bream Bay) to record energy delivered to our network from the national grid.

The energy metering equipment is relatively new, monitoring power quality including voltage disturbances (sags, swells and transients).

Distribution transformer monitoring

We have installed transformer monitoring equipment in selected distribution transformers to monitor and log load. Monitoring includes power, voltage, current and power factor. Currently there are 22 systems installed and it is intended to install this equipment in transformers 200kVA and over, supplying multiple commercial or industrial customers.

Existing maximum demand indicators (MDI) currently installed in transformers within the CBD are obsolete and are gradually being replaced with alternative transformer monitoring equipment.

7.9.9 Load control relays

Relays controlled by ripple injection plants are used for the activation of controlled loads.

Controlled loads include controlled load, day/night rate metering, streetlighting and tsunami warning sirens.

Load control relays are generally installed in the following locations:

- Customers' meter station (domestic and commercial controlled supplies)
- Transformer LV panels and LV distribution cabinets (streetlight and hot water pilot control)
- On poles (streetlight and hot water pilot control)
- With equipment being controlled (individual streetlights and tsunami warning sirens)

Northpower load control relays	Total recorded	Customers' meter station	Ground mounted transformer	Pole mounted transformer
September 2020	35,175	34,213	664	298

The preventative maintenance checks by specialist contractors are used to highlight any potential issues that may negatively impact reliability. Issues are addressed as identified and consist of repairs and replacement of equipment.

7.9.10 Maintenance plan

Secondary system assets preventative maintenance	Timing	Scope of work
SCADA and communications		
Radio site checks	Four monthly	Visual inspection and tidy. Battery charger and battery impedance tests.
Radio tests	Annual	Visual inspection and tidy. UHF signal strength, frequency tests and compliance.
Auxiliary Supplies		
Battery maintenance	Two monthly	Battery impedance test and charger test. Visual inspection.
UPS battery change	Four yearly	Visual inspection. Change rack mounted battery packs in rack mounted UPSs.
Protection Relays		
Routine equipment inspections and checks	Two monthly	Routine visual equipment inspections and checks.
Protection testing for electromechanical/static relays	Two yearly	Secondary injection tests and check operation.
Protection testing for numerical relays	Four yearly	Secondary injection tests and check operation.
Protection review	Two yearly	Relay attributes check including settings, standards, discrimination and records checks. Check for the impact of any changes in the network.

7.9.11 Capital (renewal) strategy

Equipment type	Renewal strategy
Operations centres	Replace or upgrade systems so equipment meets requirements for network control.
Distribution management system	Replace or upgrade systems so equipment meets requirements for network management.
Telecommunications	Replace or upgrade systems so equipment is compatible or meets requirements for SCADA, network control and mobile radio. Replace individual equipment as it becomes unserviceable unless systemic issues identified or damage/deterioration that could lead to failure.
Mobile substation and generator	Replace as it becomes unserviceable unless systemic issues identified or damage/deterioration that could lead to failure.
Power monitoring and metering	Replace as it becomes unserviceable unless systemic issues identified or damage/deterioration that could lead to failure.
Load control relays	Replace as it becomes unserviceable unless systemic issues identified or damage/deterioration that could lead to failure.

7.10 Non-network assets

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

Short to medium term capital expenditure on network related systems include:

CRM - Development of Salesforce customer relationship management systems and interfaces.	Core system implemented, enhancements FY21
Billing system: Replacement of the Gentrack customer billing system with Axos.	Completed FY21
Data analytics: Implementation of the ESRI GIS toolset.	Commencing FY22
Asset management: Replacement of legacy WASP asset management system.	Requirements gathering commencing in FY22

Digital systems are actively developed, maintained and renewed;

- Systems regularly patched and tested for security and reliability (disaster recovery capability where applicable).
- Digital hardware and operating systems upgraded/replaced as they become unsupported, typically five to seven years.

The policies guiding the approach, maintenance and replacement of these non-network assets are all based on generally accepted accounting procedures. From a maintenance perspective, the likely expenditure over the AMP period is consistent with that undertaken currently. Except for the expenditure mentioned above, no material capital expenditure is planned for these classes of assets other than which could normally be expected following disposal of aged assets, in accordance with company policy.

A company motor vehicle policy aims to meet our operational and financial objectives and to achieve consistency in the way vehicles are purchased, leased, assigned and used at Northpower. We have a policy of ANCAP 4 or better safety standard for vehicles.

7.11 Addressing systemic asset issues

Our maintenance guidelines identify systemic issues with assets on the network and provides a series of actions to address these. The guidelines are integrated in the asset specific inspection and maintenance network standards. The following table summarises our approach to managing those known defects.

Asset type	Equipment type	Equipment sub-type	Issue/replacement criteria	Replacement type
Overhead structure and conductors	General		Assets that are not likely to last to the next maintenance cycle (typically five years) and assets with known defect issues are replaced	As required for the situation
	Dropout fuses	All types	Fuses with common fault problems, e.g. bolted steel bands at top and bottom of the fuse, with corrosion issues. Replace with the current type, as opportunist replacements.	Current approved model
			Note: spur lines should be isolated with solid links if all transformers are individually fused and there are no vegetation issues.	
	Lightning arrestors	All types	Replace any 9kV rated lightning arrestors except lightning arrestors specific to overhead switchgear.	Current approved model
			Or replace if older than ten years and the opportunity arises.	
	Insulators	33kV brand D	The brown two piece insulators have issues of cracking where the two pieces join. These are progressively being replaced.	Current approved model
		33kV clamp top	An older type of Clamp top has been known to fail where the clamp top is cemented to the insulator. These are replaced when other work is being done on the structure.	Current approved model
		Kidney type	There are issues of tracking across the surface and corrosion of the connection points. They are replaced when other work is being done on the structure.	Current approved model
		Pin types	Replace with approved post insulator when the crossarm is replaced.	Current approved model
	Crossarms		Crossarms are replaced when their condition has deteriorated to a state where they no longer support the design loading of the conductor and when the pole is replaced.	Current approved model
	Connections	PG clamps	Replace PG clamps with approved Ampac connector when other work is done onsite.	Current approved model
		Transition (copper to aluminium)	Replace uncovered Ampacs connectors where used for transition (copper to aluminium) and fit Gelpack cover	Current approved model
		Live line type	Replace ‘live line’ type connectors, when the opportunity arises.	Current approved model
	Possum guards		Replace where missing on HV poles only and on stub poles.	Current approved model

Asset type	Equipment type	Equipment sub-type	Issue/replacement criteria	Replacement type
	Pole	Wood	Wooden pole failure generally due to decay. Replace pole when a crack in the head extends to the cross-arm bolt or if rot exists at or below ground level.	Current approved model (concrete preferred)
			General notes: For all situations pole design/calculation will be carried out as per the network standards.	
		Concrete	Spalling causes a structural strength risk and potentially a risk from falling debris.	Current approved model (concrete preferred)
			Replace the pole if there is excessive spalling.	
			Poles in marine environments, particularly estuaries, can absorb salt water below the high water table and cause rust of the reinforcing steel. Replace the pole if there is evidence of rust leaching and/or cracking below the high water level.	
		Concrete slab	Recent testing shows that concrete slab poles still exhibit good strength characteristics. They are replaced when spalling is evident.	Current approved model (concrete preferred)
		2-pole transformer structure	This type of structure was installed near kerbsides, where there is a greater risk of being hit by large trucks. This type of structure is progressively being replaced with ground mount transformers.	Current approved model
		Telecom (especially larch type)	Poles that are supporting Northpower conductors and are identified as showing signs of exceeding design loads, are being replaced	Current approved model
		All types	Shoulder of pole is exposed by stock rutting around the base of the pole. In extreme cases the stability of the pole could be compromised. Backfill with compacted limestone hard fill.	Current approved model (concrete preferred)
	HV Knife link	-	Knife links fail when operated. Manufacturer defect. Replace in conjunction with other work.	Current approved model
	Overhead LV jumper leads to service connection	-	Potential safety hazard to line mechanics as bare LV jumpers to the service connection may have been fitted in the past. Upgrade jumper leads to insulated conductor wherever upgrade work is taking place or other work is carried out, and it is practical to upgrade the jumper.	Current approved model of Cu PVC conductor
	400 V fuses	Rewireable	Corrosion may exist at conductor termination on the fuse causing a burn off of the conductor. Replace fuse when other work is happening at the same site.	Current approved model
		Brand G	Corrosion may exist at conductor termination on the fuse causing a burn off of the conductor. Replace fuse when other work is happening at the same site.	Current approved model

Asset type	Equipment type	Equipment sub-type	Issue/replacement criteria	Replacement type
	Conductor	11kV jumpers	Corrosion may exist at the aluminium connection to the dropout fuse due to the presence of dissimilar metals. Replace with a copper jumper using correct bimetallic connectors at the main line connection.	Current approved model of Cu PVC conductor and connector
		11kV 7/.064 HDBC	There is an increased risk of failure due to corrosion or work hardening. A long-term replacement strategy with a priority based on risk.	Current approved model of AAAC conductor
		11kV ACSR	There is an increased risk of failure due to corrosion of the steel due to insufficient grease during manufacture, particularly in coastal environments. A long-term replacement strategy with a priority based on risk.	Current approved model of AAAC conductor
	Conductor Binding	Wraplock tie	Failure of the binding to the insulator due to corrosion of the wraplock tie. Replace wraplock ties with approved preform ties when other work is undertaken at the same site or a site immediately adjacent.	Current approved model
		Binder wire	Binder wire is to be replaced with approved preform distribution ties when the insulators or crossarm is replaced.	Current approved model
	Cable conduits on pole riser		Broken cable conduits up poles due to third party vandalism is a potential safety hazard. Provide additional mechanical protection if replacing the cable or the conduit, or as identified	Current approved model
	HV cable termination	Cast iron pot head	Pot heads are susceptible to rust and the pitch cracking. When pot heads are replaced, section of cable up the pole will also be replaced.	Current approved model
		Termination without crucifix	Mechanical stress on termination hardware may cause premature failure. There is no program for a retrospective replacement but a crucifix should be fitted in conjunction with other work if it is cost effective.	Current approved model
		Heat shrink or cold shrink cable termination	In high pollution areas a premature breakdown of the insulation may result in a flashover. Replace the termination if it is in poor condition, e.g. signs of tracking or physical damage. Replace with an approved cable termination.	Current approved model
		Existing termination onto OH lines that do not have surge arrestors	Add surge arrestors if doing other maintenance, e.g. pole cross arm replacement etc, only if practical to do so.	Current approved model
	Guy	Stiles	Stock may damage the guy if timber stile is damaged or missing. Replace with new timber stile to network standard where required.	Current approved construction standard
			Guy termination may rust off or be removed by third party from guy rod causing pole to lean. Re-terminate guy when identidied.	Current approved model

Asset type	Equipment type	Equipment sub-type	Issue/replacement criteria	Replacement type
Pillars	Pillars	General	Pillars that have had gardens created around them are not considered a high maintenance priority unless this poses a safety risk or it is likely to cause damage to the components within the pillar.	Current approved model
		Damaged pillars lids	Minor lid repairs can be fixed on site without replacement of the complete pillar.	Current approved model
		Concrete pillar with steel face plate	Potentially unearthed metalwork is accessible to third parties. Replace the complete pillar in conjunction with other substantial repairs or if an upgrade is required at the same site.	Current approved model
		Concrete with aluminium cap	Potentially unearthed metalwork is accessible to third parties. Replace the complete pillar in conjunction with other substantial repairs or if an upgrade is required at the same site.	Current approved model
		Stud pillar	Studs may fail, disconnecting the supply and causing an outage. Replace the complete pillar in conjunction with other substantial repairs or if an upgrade is required at the same site.	Current approved model
		Neutral bars	Some pillars have only been fitted with a small single neutral stud which does not provide sufficient room for multiple neutral connections. A separate multi stud neutral bar should be fitted.	Current approved model
		Service fuses	Tails (supply or load) are corroded causing potential burn off issues. Re-terminate at existing fuse or replace complete fuse when identified.	Current approved model
		Meter pillars	The retailer's meter reading contractor is unable to read the meter due to the window in the pillar becoming opaque. Pillar window replaced as required	Current approved model
			Cases where the meters would be shifted to the house are:	
			When the old house is removed and a new house built.	
			Where there is a major alteration to the electrical mains to the installation.	

Asset type	Equipment type	Equipment sub-type	Issue/replacement criteria	Replacement type
Ground mounted distribution transformers and switchgear	Transformer	Pad mounted	Rusting of the transformer may result in an oil leak or safety risk. If repairs cannot be completed on site, the transformer will be replaced.	Current approved model
		11kV bushings	A risk of contact with live parts exists from exposed and uncovered transformer bushings for electrical workers accessing the transformer enclosure. Fit a shroud or replace the transformer while undertaking other substantial repairs or if an upgrade is required at the same site.	Current approved model
		Neutral bars	The potential exists for high resistance neutral connections where neutral lugs have been "stack" connected on stainless steel studs. Lugs are to be fitted directly back-to-back when carrying out other work within the transformer enclosure.	
		Old kennel type	Access issues may exist due to tight tolerances between the transformer and the kennel cover. If the transformer and/or LV distribution panel needs replacing, then upgrade to a standard mini sub and LV panel.	Current approved model of mini sub and LV panel.
			Minor maintenance, including kennel repairs and earthing work, can still be carried out without requiring the replacement of the kennel.	
		Room type	Non-standard LV panels compromise the ability to cost effectively add additional outgoing circuits. If the transformer needs to be replaced or the existing LV panel needing significant maintenance, then upgrade the complete unit.	Current approved model of room type transformer.
			Note: Transformers and LV panels are separate items. The upgrading of one does not necessarily mean that the other should be upgraded.	Current approved model of standard LV panel.
		All	Graffiti is to be removed or painted over when identified.	
	11kV Switchgear	All	Excessive partial discharge may indicate failure of switch unit is imminent. Replace equipment.	Current approved model
		Wilde unit	Excessive partial discharge may indicate failure of unit is imminent. Replace equipment. The current capital project underway will see all of this type removed from system.	Current approved model
Distribution earthing	Earthing and bonding	Distribution earth grids	High resistance earth grid may cause electric shock hazard. Upgrade to the current Network standard if not compliant or in conjunction with other work, e.g. a replacement or upgrade of the transformer, pole or earth grid.	Current approved practice
		Equi-potential bonding	The potential exists for a third party to sustain an electric shock due to all metalwork not being bonded together. Bond ground mounted equipment to metal covers, if found to be not bonded. Directly bolted on covers are deemed to be electrically bonded.	Current approved practice
			Doors of mini/micro sub (transformer) to be bonded if found to be not bonded.	

7.12 Asset replacement programme

The table below shows asset groups that have assets with asset health indicators of H1 and H2 which are an input into our ten-year asset replacement programme. Replacement timing will be changed if favourable condition assessments become available which suggests better asset health. The adoption of greater levels of condition monitoring and reporting will, over time, lead to a refinement of renewal volumes.

Asset category	Units	Total	H5 New	H4 Service	H3 Inc. risk	H2 High risk	H1 Replace	Unknown
Support structures	No	54,669	2,325	27,915	20,509	2,517	1,403	0
Overhead conductors	Km	52,00.6	241.4	26,52.4	1,979.4	216.5	110.9	0
Underground cables	Km	1,335	152.2	932.1	199.3	17.8	33.6	0
Voltage regulators	No	6	2	2	2	0	0	0
HV switchgear	No	945	43	866	19	11	6	0
HV fuses & links	No	7,795	816	3,767	348	82	269	2,513
Distribution transformers	No	7,415	920	4,536	1,269	210	419	62
LV pillars & cabinets	No	13,184	2,359	3,230	9	0	0	7,586
Substation buildings	No	21	0	13	7	0	1	0
Power transformers	No	39	3	15	7	15	0	0
Substation circuit breakers	No	265	19	147	67	16	16	0
Bus systems	No	17	0	12	5	0	0	0
Load control central plant	No	6	0	0	2	2	2	0
Protection systems	No	343	40	244	50	1	8	0
Battery systems	No	69	4	58	7	0	0	0
Capacitor banks	No	31	1	30	0	0	0	0

Note that for assets with unknown AHI's, the original installation date is generally not recorded, and the true age is unknown. These assets are subject to regular safety inspections and are repaired or replaced if condition makes the asset unserviceable or unreliable.

Significant projects currently underway or planned to start within the next year (FY22)

Distribution overhead line conductor replacement	Replacement of EOL HDBC and corroding ACSR conductor	**$15,200,000**
Multi-year project to replace old 7/.064 copper conductor and corroding ACSR conductor (including associated cross arms and insulators) based on sample conductor test results		
Timely replacement of at risk conductor to maintain and improve current levels of network reliability		
Kaiwaka 11kV switchboard upgrade	Replacement of EOL switchgear	**$2,500,000**
Required to ensure personnel safety and plant reliability.		
Hikurangi 33/11kV transformer replacements	Replace EOL transformers	**$2,400,000**
Replace 2 x 5MVA transformers with 2 x 10MVA units		
Hikurangi 11kV switchboard upgrade	Replacement of EOL indoor switchgear	**$2,100,000**
Required to ensure personnel safety and plant reliability.		
Whangārei South 11kV switchboard upgrade	Replace EOL indoor switchgear	**$2,400,000**
Required to ensure personnel safety and plant reliability.		
Ruawai 33/11kV transformer replacement	Replace EOL transformer	**$1,200,000**
Required to ensure continuity of supply		
Ruawai 11kV switchboard upgrade	Replacement of EOL indoor switchgear	**$2,600,000**
Required to ensure personnel safety and plant reliability.		
Poroti 33/11kV transformer replacement	Replace EOL transformer	**$1,600,000**
Required to ensure continuity of supply.		
Poroti 11kV switchboard upgrade	Replace EOL indoor switchgear	**$2,500,000**
Required to ensure personnel safety and plant reliability.		
Ngunguru 11kV switchboard upgrade	Replace EOL indoor switchgear	**$2,900,000**
Required to ensure personnel safety and plant reliability.		
Ngunguru transformer upgrade	Replace EOL transformer	**$640,000**
Required to ensure continuity of supply.		
Parua Bay transformer upgrade	Replace EOL transformer	**$1,400,000**
Required to ensure continuity of supply.		
Kensington 110/33kV transformer upgrade	Replace 2 x 50MVA EOL transformers with larger units	**$6,700,000**
Replace end of life 50MVA transformers with larger units to provide increased capacity and continued N-1 security of supply to the greater Whangārei City area.		

Significant projects planned to start within the next four years (FY23 - FY25)

Maungaturoto 33/11kV transformer replacements	Replace EOL transformer	**$2,600,000**
Required to ensure continuity of supply.		
Maungaturoto 11kV switchboard upgrade	Replace EOL indoor switchgear	**$2,400,000**
Required to ensure personnel safety and plant reliability.		
Maungatapere 110/33kV transformer upgrade	Replace 2 x 30 MVA EOL transformers	**$6,700,000**
Replace EOL transformers with larger units to maintain N-1 capacity.		
Kensington 33kV switchboard replacement	Replace EOL indoor switchgear	**$3,450,000**
Required to ensure personnel safety and plant reliability.		
Portland Chipmill 33/11kV transformer	Replace EOL transformer	**$800,000**
Required to ensure continuity of supply		
Ruakaka 33/11kV transformer T2	Replace EOL transformer	**$1,850,000**
Required to ensure continuity of supply		

Significant projects planned to start within the next ten years (FY26 - FY31)

Whangārei South 33/11kV transformer	Replace EOL transformer	**$4,700,000**
Required to ensure continuity of supply.		
Mobile 33/11kV substation	Install second subtransmission line	**$2,500,000**
Required to facilitate outages for maintenance on substations with single transformers or N security.		

Northpower

2021 – 2031 Asset Management Plan

Section 8

Expenditure forecasts

Table of contents

8.1 Overview

This section outlines Northpower's forecast operational and capital expenditure for the ten-year period FY22 to FY31.

Our total expenditure forecast is $0.53 billion over the next ten years, an increase of 1.3% on our FY21 total expenditure forecast of $0.52 billion. This comprises of:

- Forecast operational expenditure, which averages $27.9 million per annum over the ten-year period
- Forecast capital expenditure, which averages $25.1 million per annum over the ten-year period

Expenditures presented in this section are in 2020 dollars.

8.2 Key assumptions

Based on the information available, our ten-year forecast remains a solid 'base case' for future network investment and expenditure. There are however a number of areas which could alter expenditure profiles (particularly in years five to ten of the programme) and are being kept under close review.

Accelerated growth	Localised growth in areas such as Mangawhai and Waipu could bring growth investments forward. We are currently working with stakeholders to understand development plans in Mangawhai, which are subject to considerable uncertainties. This growth, if it eventuates, may require a new substation (which is not in the ten-year plan). We would expect this would be largely funded by the parties requiring the capacity upgrades. Growth forecasts will be kept under review with close monitoring of feeder and substation demand, engagement with local councils and developers to understand the timing of upcoming developments.
Impact of distributed energy resources (DER)	We acknowledge the uncertainty associated with how New Zealand will approach its decarbonisation targets. Policy settings could increase EV uptake, causing capacity constraints at the low voltage (LV) level to emerge earlier than forecast. No significant upgrades of LV networks have been allowed for in the capex forecasts.
Control and visibility system costs	Our working assumption is that we do not need extensive LV monitoring across the network for at least ten years, with modest provision for targeted monitoring in hot spot areas. This assumption could change if policy settings change, driving greater uptake of DER at the LV level.
Contractor costs	Civil costs are reasonably volatile but are likely to be a small overall component over the next ten years, so low upside risk to the overall expenditure profile. Negotiated service provider costs continue to be a market risk, particularly with increase in demand side.
Uplift in end of life asset replacements	Replacement rates for overhead assets (poles, conductors and distribution transformers) still need to be determined through condition assessments to determine expected asset lives. Current analysis of concrete poles suggests a longer life than the current assumed life of 60 years. We expect another three years of inspection data is required to validate asset condition across key fleets.
Project costs	Project costs are built up based on high level scopes, and will be refined following detailed design. Mangawhai line build will depend on route, and extent of easements required (could be +50% over current estimate, i.e. $5M variable). Costs will be refined following detailed design.

8.3 Price inflation

In this AMP our cost forecasts are stated in real dollars in FY21 terms. For some of our regulatory disclosures in Appendix C, the report on forecast capital expenditure (schedule 11a) and the report on forecast operational expenditure (schedule 11b), we allow for price inflation and forecast in nominal dollars in certain components of the schedules.

We have based our inflation assumptions on the ten-year inflation forecast in the Reserve Bank of New Zealand Monetary Policy Statement, November 2020.

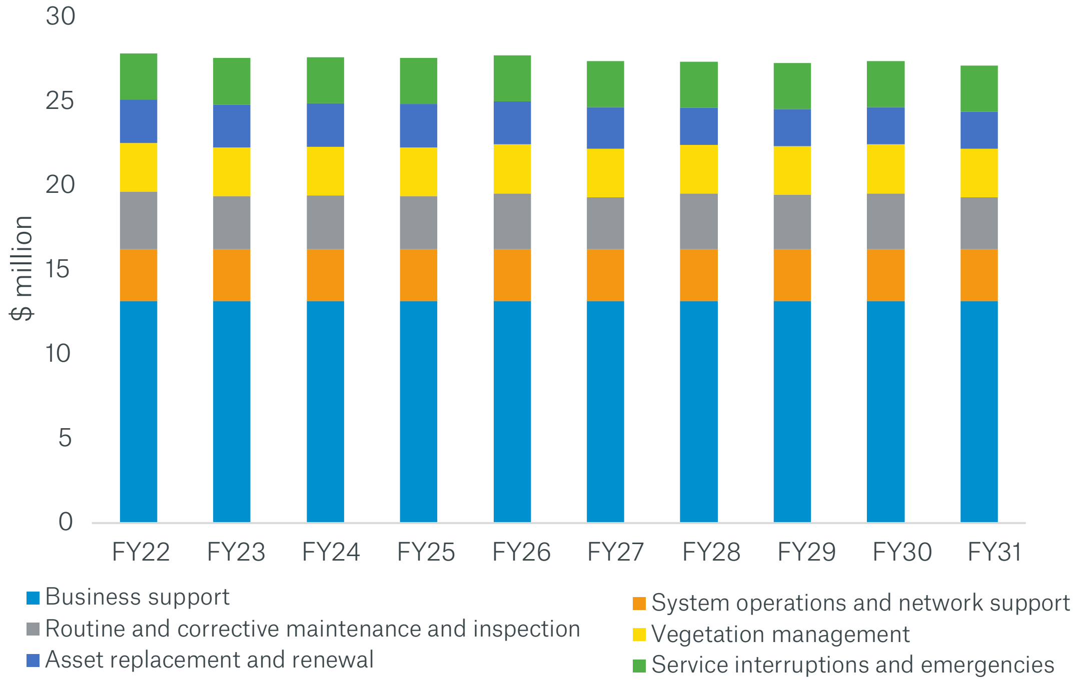
8.4 Operational expenditure

Operational expenditure has as its basis the network operational activities outlined in Section 2 (About our business) and is comprised of the following components:

- Routine and corrective maintenance and inspections (preventative maintenance)
- Asset replacement and renewal (follow up work on defects identified from routine maintenance)
- Vegetation management (preventative and follow-up work relating to vegetation control)
- Service interruptions and emergencies (fault related work)
- System operations and network support (network operating overheads)
- Business support (corporate allocations and other overheads)

The forecast operational expenditure allocations are presented in graphical and tabular form below.

Figure 109: Northpower ten-year opex plan (FY20 dollars)



The operational expenditure forecast assumes current resourcing levels are held, and any increase in capability, systems or sourcing of services is funded by substituting existing spend.

Northpower ten-year opex plan (FY20 $000)	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Category	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**
Service interruptions and emergencies	2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742
Vegetation management	2,889	2,889	2,889	2,889	2,889	2,889	2,889	2,889	2,889	2,889
Routine and corrective maintenance and inspection	3,438	3,142	3,187	3,161	3,326	3,087	3,295	3,225	3,327	3,077
Asset replacement and renewal	2,569	2,569	2,569	2,569	2,569	2,467	2,212	2,212	2,212	2,212
Total network opex	**11,638**	**11,341**	**11,386**	**11,360**	**11,526**	**11,185**	**11,138**	**11,067**	**11,170**	**10,920**
System operations and network support	3,050	3,050	3,050	3,050	3,050	3,050	3,050	3,050	3,050	3,050
Business support	13,194	13,194	13,194	13,194	13,194	13,194	13,194	13,194	13,194	13,194
Total non-network opex	**16,244**	**16,244**	**16,244**	**16,244**	**16,244**	**16,244**	**16,244**	**16,244**	**16,244**	**16,244**
Total opex	**27,881**	**27,585**	**27,630**	**27,604**	**27,769**	**27,428**	**27,382**	**27,311**	**27,413**	**27,164**

8.5 Maintenance expenditure

Network operating expenditure is broken down in more detail below.

Type/asset	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total (FY22-FY31)
Preventative maintenance											
Others / multiple asset groups	2,927	2,927	2,927	2,927	2,927	2,927	2,927	2,927	2,927	2,927	29,272
Circuit breakers	198,588	110,534	89,818	156,501	198,588	110,534	89,818	156,501	198,588	110,534	1,420,004
Communications	20,363	20,363	20,363	20,363	20,363	20,363	20,363	20,363	20,363	20,363	203,627
Distribution earthing	303,936	375,450	473,782	268,178	268,178	325,390	325,390	325,390	325,390	325,390	3,316,473
Zone sub earthing	-	21,140	-	-	-	21,140	-	-	-	21,140	63,419
Ground mounted substations	264,420	278,591	221,907	224,742	289,927	264,420	278,591	221,907	224,742	289,927	2,559,173
Oil containment	4,832	4,832	4,832	4,832	4,832	4,832	4,832	4,832	4,832	4,832	48,316
Overhead lines	698,921	571,495	566,191	525,672	558,151	545,771	768,862	501,553	542,072	545,771	5,824,459
Outdoor structures	74,517	44,703	74,517	29,797	74,517	44,703	74,517	29,797	74,517	44,703	566,287
Overhead switches	-	-	-	55,222	-	-	22,450	88,897	-	-	166,568
Pillars	68,643	68,643	68,643	68,643	68,643	68,643	68,643	68,643	68,643	68,643	686,433
Protection relays	142,440	48,265	38,951	134,161	142,440	48,265	38,951	134,161	142,440	48,265	918,337
Regulators	38,281	14,907	9,090	57,512	37,493	14,907	9,090	57,512	37,493	14,907	291,193
Ripple plants	22,800	23,279	23,279	23,279	23,279	23,279	23,279	23,279	23,279	23,279	232,309
Subtrans cables	25,729	25,729	50,692	25,729	25,729	50,692	25,729	25,729	50,692	25,729	332,182
Zone sub buildings and grounds	134,227	123,608	123,608	123,608	123,608	134,227	123,608	123,608	123,608	123,608	1,257,320
Zone sub transformers	168,829	88,530	99,698	120,869	168,829	88,530	99,698	120,869	168,829	88,530	1,213,212
Unplanned inspections	100,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	1,450,000
Total for preventative maintenance	**2,269,451**	**1,972,996**	**2,018,298**	**1,992,034**	**2,157,505**	**1,918,623**	**2,126,747**	**2,055,967**	**2,158,414**	**1,908,549**	**20,578,584**

Type/asset	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total (FY22-FY31)
Corrective maintenance											
Battery banks	25,525	25,525	25,525	25,525	25,525	25,525	25,525	25,525	25,525	25,525	255,250
Circuit breakers	64,323	64,323	64,323	64,323	64,323	64,323	64,323	64,323	64,323	64,323	643,230
Communications	15,315	15,315	15,315	15,315	15,315	15,315	15,315	15,315	15,315	15,315	153,150
Distribution earthing	15,315	15,315	15,315	15,315	15,315	15,315	15,315	15,315	15,315	15,315	153,150
Ground mounted substations	204,200	204,200	204,200	204,200	204,200	204,200	204,200	204,200	204,200	204,200	2,042,000
Multiple asset groups	102,100	102,100	102,100	102,100	102,100	102,100	102,100	102,100	102,100	102,100	1,021,000
Outdoor CT's and VT's	10,210	10,210	10,210	10,210	10,210	10,210	10,210	10,210	10,210	10,210	102,100
Overhead lines	1,225,200	1,225,200	1,225,200	1,225,200	1,225,200	1,225,200	1,225,200	1,225,200	1,225,200	1,225,200	12,252,000
Outdoor structures	104,755	104,755	104,755	104,755	104,755	104,755	104,755	104,755	104,755	104,755	1,047,546
Overhead switches	153,150	153,150	153,150	153,150	153,150	51,050	51,050	51,050	51,050	51,050	1,021,000
Pillars	153,150	153,150	153,150	153,150	153,150	153,150	153,150	153,150	153,150	153,150	1,531,500
Protection relays	30,630	30,630	30,630	30,630	30,630	30,630	30,630	30,630	30,630	30,630	306,300
Regulators	10,210	10,210	10,210	10,210	10,210	10,210	10,210	10,210	10,210	10,210	102,100
Ripple pPlants	18,378	18,378	18,378	18,378	18,378	18,378	18,378	18,378	18,378	18,378	183,780
Subtrans cables	45,945	45,945	45,945	45,945	45,945	45,945	45,945	45,945	45,945	45,945	459,450
Vegetation	2,654,600	2,654,600	2,654,600	2,654,600	2,654,600	2,654,600	2,400,000	2,400,000	2,400,000	2,400,000	25,527,600
Zone sub buildings and grounds	81,680	81,680	81,680	81,680	81,680	81,680	81,680	81,680	81,680	81,680	816,800
Zone sub earthing	15,315	15,315	15,315	15,315	15,315	15,315	15,315	15,315	15,315	15,315	153,150
Zone sub transformers	97,449	97,449	97,449	97,449	97,449	97,449	97,449	97,449	97,449	97,449	974,493
Total for corrective maintenance	**5,027,450**	**5,027,450**	**5,027,450**	**5,027,450**	**5,027,450**	**4,925,350**	**4,670,750**	**4,670,750**	**4,670,750**	**4,670,750**	**48,745,599**

Type/asset	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total (FY22-FY31)
Remedial maintenance											
Battery banks	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	100,000
Capacitor banks	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	50,000
Circuit breakers	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	250,000
Communications	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	300,000
Distribution earthing	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	25,000
Ground mounted substations	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	150,000
Multiple asset groups	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	50,000
Outdoor CT's and VT's	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	50,000
Overhead lines	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	15,000,000
Overhead switches	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	150,000
Oil containment	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	25,000
Structures	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	100,000
Pillars	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	1,000,000
Protection relays	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	100,000
Regulators	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	100,000
Ripple plants	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000	800,000
Subtrans cables	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	100,000
Underground cables	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	3,000,000
Vegetation	220,000	220,000	220,000	220,000	220,000	220,000	220,000	220,000	220,000	220,000	2,200,000
Zone sub buildings and grounds	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	300,000
Zone sub earthing	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	50,000
Zone sub transformers	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	350,000
Voltage complaints	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	300,000
Total for remedial maintenance	**2,455,000**	**2,455,000**	**2,455,000**	**2,455,000**	**2,455,000**	**2,455,000**	**2,455,000**	**2,455,000**	**2,455,000**	**2,455,000**	**24,550,000**

Type/asset	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	Total (FY22-FY31)
Value added maintenance											
Cable location	255,250	255,250	255,250	255,250	255,250	255,250	255,250	255,250	255,250	255,250	2,552,500
Customer equipment	459,450	459,450	459,450	459,450	459,450	459,450	459,450	459,450	459,450	459,450	4,594,500
Data capture	20,420	20,420	20,420	20,420	20,420	20,420	20,420	20,420	20,420	20,420	204,200
High loads	20,420	20,420	20,420	20,420	20,420	20,420	20,420	20,420	20,420	20,420	204,200
Load checks	25,525	25,525	25,525	25,525	25,525	25,525	25,525	25,525	25,525	25,525	255,250
Network initiated field switching	3,063	3,063	3,063	3,063	3,063	3,063	3,063	3,063	3,063	3,063	30,630
Safety disconnects and permits	285,880	285,880	285,880	285,880	285,880	285,880	285,880	285,880	285,880	285,880	2,858,800
Vegetation	35,225	35,225	35,225	35,225	35,225	35,225	35,225	35,225	35,225	35,225	352,245
Value added	1,105,233	1,105,233	1,105,233	1,105,233	1,105,233	1,105,233	1,105,233	1,105,233	1,105,233	1,105,233	11,052,325
6221 - Value added on-charged to customer	- 483,300	- 483,300	- 483,300	- 483,300	- 483,300	- 483,300	- 483,300	- 483,300	- 483,300	- 483,300	-4,833,000
6222 - Third party damage on-charged	- 200,000	- 150,000	- 200,000	- 150,000	- 200,000	- 150,000	- 200,000	- 150,000	- 200,000	- 150,000	- 1,750,000
Total for value added maintenance	**421,933**	**471,933**	**421,933**	**471,933**	**421,933**	**471,933**	**421,933**	**471,933**	**421,933**	**471,933**	**4,469,325**
Total maintenance forecast	**10,173,834**	**9,927,378**	**9,922,681**	**9,946,417**	**10,061,887**	**9,770,905**	**9,674,430**	**9,653,650**	**9,706,097**	**9,506,231**	**98,343,509**

**excludes contractor's management fee.*

8.6 Capital expenditure

Capital expenditure has at its basis, the activities outlined in Section 2 (About our business) and Section 6 (Planning our network) comprising of the following components:

- Customer connection (new connections and supply upgrades)
- System growth (substation and line capacity)
- Asset relocation (line re-routes or overhead to underground conversion)
- Reliability, safety and environment (network performance and compliance)
- Asset replacement and renewal (defective, end of life or obsolete)
- Non-network (operational, systems, engineering, research and development)

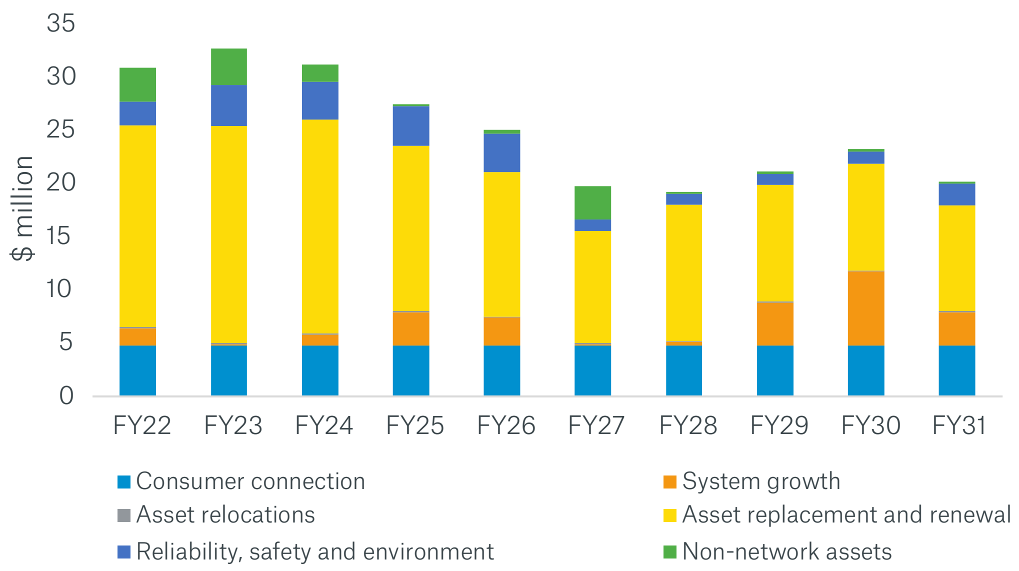
Projects (and associated high-level cost estimates) listed in the development plan below are requirements as foreseen at this point in time. The further out a project appears on the planning horizon, the more likely it is that it could change with time as better or new information becomes available, or unforeseen developments arise necessitating changes to the plan in the annual review.

The forecast percentage of total expenditure per category for the ten-year period FY22 to FY31 is given in the following table. As can be seen, the majority of planned expenditure is on asset replacement due to the large number of aging assets on the network.

Capex category	Ten-year capex %
Customer connection	19%
System growth	9%
Asset relocations	<1%
Asset replacement and renewal	57%
Reliability, safety, environment	9%
Non-network assets	5%

The forecast ten-year capital expenditure plan and expenditure allocations are presented in graphical and tabular form below.

Figure 110: Northpower ten-year capex plan (FY20 dollars)



Key aspects of the ten-year forecast include:

- The first five years are heavily loaded with substation transformer and switchgear upgrades, as these critical assets reach end of life and the likelihood of failure increases. Our proactive approach ensures that the reliability performance of these assets is maintained, and thus our network reliability performance targets outlined in Section 4 will be met.
- Over the next three years we see several core systems upgraded (including subsequent phases of ADMS and a new asset management system), which contribute to the higher expenditure in non-network asset expenditure.
- System growth investments support several high growth areas in the south of our network, but the timing of these may alter if growth slows or conversely accelerates.

Northpower EDB ten-year capex plan (FY20 $000)			1	2	3	4	5	6	7	8	9	10	Total
Project number	**Project title**	**Expenditure category**	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY22-FY31**
6106	Capital contributions (network)	Consumer connection	505	510	515	520	526	531	536	541	547	552	5,283
6107	Capital contributions (customer)	Consumer connection	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	35,000
6108	Transformer acquisition costs	Consumer connection	800	800	800	800	800	800	800	800	800	800	8,000
6109	Transformer credits from upgrades	Consumer connection	-130	-130	-130	-130	-130	-130	-130	-130	-130	-130	-1,300
6463	Ripple relay purchases	Consumer connection	85	85	85	85	85	85	85	85	85	85	850
	Total	**Consumer connection**	**4,760**	**4,765**	**4,770**	**4,775**	**4,781**	**4,786**	**4,791**	**4,796**	**4,802**	**4,807**	**47,833**
6401	Minor capital expenditure (system growth)	System growth	75	75	75	75	75	75	75	75	75	75	750
6430	Distribution transformer and LV feeder constraint mitigations (reactive)	System growth	50	50	50	50	50	50	50	50	50	50	500
6479	Waipu zone substation (new) (5MVAx1)	System growth	0	0	0	0	0	0	0	400	3,300	3,000	6,700
6480	Bream Bay T2 (10MVAx1) (Project 2)	System growth	0	0	200	1,000	600	0	0	0	0	0	1,800

Northpower EDB ten-year capex plan (FY20 $000)			1	2	3	4	5	6	7	8	9	10	Total
Project number	**Project title**	**Expenditure category**	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY22-FY31**
6481	Bream Bay 11kV switchgear extension or replacement (project 3)	System growth	0	0	200	1,000	700	0	0	0	0	0	1,900
6497	Whakapara feeder express line to Hikurangi	System growth	0	0	0	0	700	0	0	0	0	0	700
6551	Land purchases (future zone substations)	System growth	500	0	500	0	500	0	0	0	0	0	1,500
	Waipu to Ruakaka 10km 33kV line and easements	System growth	0	0	0	0	0	0	200	3,500	3,500	0	7,200
	Parua Bay back-feed constraint mitigation	System growth	500	0	0	0	0	0	0	0	0	0	500
	Mangawai back-feed constraint mitigation	System growth	500	0	0	0	0	0	0	0	0	0	500
	Ngunguru back-feed constraint mitigation	System growth	0	0	0	500	0	0	0	0	0	0	500
	Ruawai back-feed constraint mitigation	System growth	0	0	0	500	0	0	0	0	0	0	500
	Waipu feeder capacity constraint mitigation	System growth	45	0	0	0	0	0	0	0	0	0	45
	Total	**System growth**	**1,670**	**125**	**1,025**	**3,125**	**2,625**	**125**	**325**	**4,025**	**6,925**	**3,125**	**23,095**

Northpower EDB ten-year capex plan (FY20 $000)			1	2	3	4	5	6	7	8	9	10	Total
Project number	**Project title**	**Expenditure category**	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY22-FY31**
6402	Minor capital expenditure (relocation)	Asset relocations	55	55	55	55	55	55	55	55	55	55	550
6540	Roading works asset relocations	Asset relocations	50	50	50	50	50	50	50	50	50	50	500
	Total	**Asset relocations**	**105**	**105**	**105**	**105**	**105**	**105**	**105**	**105**	**105**	**105**	**1,050**
6274	Targeted capex - RTU replacements (zone substations)	Asset replacement and renewal	0	0	0	0	0	0	0	0	150	150	300
6393	Spare transformer replacement (5MVAx1)	Asset replacement and renewal	0	0	0	0	0	400	0	0	0	0	400
6396	Targeted capex - protection relay replacements	Asset replacement and renewal	350	100	100	100	100	100	100	100	100	100	1,250
6397	Targeted capex - 33kV CT and VT replacements	Asset replacement and renewal	0	0	0	0	90	0	0	90	0	0	180
6483	Parua Bay transformer replacement (5MVAx1)	Asset replacement and renewal	1,000	200	0	0	0	0	0	0	0	0	1,200
6494	Ngunguru transformer replacement (5MVAx1)	Asset replacement and renewal	600	0	0	0	0	0	0	0	0	0	600

Northpower EDB ten-year capex plan (FY20 $000)			1	2	3	4	5	6	7	8	9	10	Total
Project number	**Project title**	**Expenditure category**	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY22-FY31**
6501	Kaiwaka 11kV switchboard replacement	Asset replacement and renewal	400	1,700	400	0	0	0	0	0	0	0	2,500
6502	Ruawai 11kV switchboard replacement	Asset replacement and renewal	1,500	1,000	0	0	0	0	0	0	0	0	2,500
6503	Hikurangi 11kV switchboard replacement	Asset replacement and renewal	1,000	0	0	0	0	0	0	0	0	0	1,000
6505	Ngunguru 11kV switchboard replacement	Asset replacement and renewal	2,100	0	0	0	0	0	0	0	0	0	2,100
6506	Poroti 11kV switchboard eplacement	Asset replacement and renewal	200	1,800	500	0	0	0	0	0	0	0	2,500
6507	Targeted capex - tap changer controller upgrades	Asset replacement and renewal	90	90	0	0	60	0	0	60	0	0	300
6510	Maungatapere 110/33kV transformer replacements (50-70MVAx2)	Asset replacement and renewal	0	0	1,000	3,000	2,700	0	0	0	0	0	6,700
6512	Kensington 110/33kV transformer replacements (70-100MVAx2)	Asset replacement and renewal	1,000	3,000	2,700	0	0	0	0	0	0	0	6,700
6529	Maungaturoto 11kV switchboard replacement	Asset replacement and renewal	0	400	1,400	600	0	0	0	0	0	0	2,400

Northpower EDB ten-year capex plan (FY20 $000)			1	2	3	4	5	6	7	8	9	10	Total
Project number	**Project title**	**Expenditure category**	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY22-FY31**
6532	Chip mill transformer replacement (5MVAx1)	Asset replacement and renewal	0	200	600	0	0	0	0	0	0	0	800
6533	Hikurangi transformer replacements (10MVAx2)	Asset replacement and renewal	1,000	0	0	0	0	0	0	0	0	0	1,000
6534	Poroti transformer replacement (5MVAx1)	Asset replacement and renewal	200	1,000	400	0	0	0	0	0	0	0	1,600
6536	Maungaturoto transformer replacements (10MVAx2)	Asset replacement and renewal	0	400	1,600	600	0	0	0	0	0	0	2,600
6583	Communications system replacements and minor upgrades	Asset replacement and renewal	255	100	0	0	0	0	0	0	0	0	355
6586	Targeted capex - recloser replacements	Asset replacement and renewal	0	65	0	65	0	65	0	65	0	0	260
6587	Targeted capex - replacement of oil filled RMUs (incl. L&C units)	Asset replacement and renewal	400	300	300	300	300	300	300	300	300	300	3,100
6588	Targeted capex - recloser controller replacements	Asset replacement and renewal	65	0	65	0	65	0	65	0	65	0	325

Northpower EDB ten-year capex plan (FY20 $000)			1	2	3	4	5	6	7	8	9	10	Total
Project number	Project title	Expenditure category	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY22-FY31
6596	Targeted capex - remote switch RTU and comms replacements	Asset replacement and renewal	0	0	0	0	128	128	128	128	120	120	752
6598	Targeted capex - ripple injection plant replacements	Asset replacement and renewal	0	100	100	0	0	0	0	0	0	0	200
6599	Targeted capex - battery bank and battery charger replacement and minor upgrades	Asset replacement and renewal	0	50	0	50	0	50	0	50	0	0	200
6605	Ruakaka T2 replacement (10MVAx1)	Asset replacement and renewal	0	0	0	450	1,400	0	0	0	0	0	1,850
6606	Whangārei South transformer replacements (15MVAx2)	Asset replacement and renewal	0	0	0	0	400	2,000	2,300	0	0	0	4,700
6616	RT network DMR tier II replacements (Tait T800)	Asset replacement and renewal	280	0	0	0	0	0	0	0	0	0	280
6618	Kensington 33kV switchboard replacement	Asset replacement and renewal	0	0	600	2,450	400	0	0	0	0	0	3,450
6621	Network strategic spares	Asset replacement and renewal	55	50	0	60	0	0	65	0	65	0	295

Northpower EDB ten-year capex plan (FY20 $000)			1	2	3	4	5	6	7	8	9	10	Total
Project number	**Project title**	**Expenditure category**	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY22-FY31**
6622	Targeted capex - pole replacements	Asset replacement and renewal	300	300	500	500	500	500	500	500	500	500	4,600
6623	Targeted capex - sub-transmission line conductor replacements	Asset replacement and renewal	0	300	350	0	500	0	700	0	700	0	2,550
6624	Targeted capex - distribution line conductor replacements	Asset replacement and renewal	1,200	1,400	1,400	1,600	1,300	1,700	1,800	1,800	1,800	1,800	15,800
6625	Targeted capex - low-voltage ine conductor replacements	Asset replacement and renewal	200	200	200	200	250	250	250	250	250	250	2,300
6626	Targeted capex - overhead switch replacements	Asset replacement and renewal	60	60	60	70	70	70	80	80	80	80	710
6627	Targeted capex - low-voltage service connection replacements	Asset replacement and renewal	100	100	100	100	100	100	100	100	100	100	1,000
6628	Targeted capex - distribution transformer replacements	Asset replacement and renewal	100	130	130	150	150	150	200	200	200	200	1,610
6629	Targeted capex - subtransmission oil cable replacements	Asset replacement and renewal	200	2,000	2,000	0	0	0	1,000	2,500	0	0	7,700
6630	Targeted capex - distribution cable replacements	Asset replacement and renewal	100	100	100	100	100	100	100	100	100	100	1,000

Northpower EDB ten-year capex plan (FY20 $000)			1	2	3	4	5	6	7	8	9	10	Total
Project number	**Project title**	**Expenditure category**	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY22-FY31**
6633	Targeted capex - 33kV circuit breaker replacements	Asset replacement and renewal	0	0	100	0	0	0	110	0	110	0	320
6635	Targeted capex - zone substation outdoor switch replacements	Asset replacement and renewal	0	0	0	0	0	0	0	0	250	50	300
6637	Targeted capex - capacitor bank replacements	Asset replacement and enewal	0	0	0	25	0	0	25	0	0	0	50
6638	Minor capital expenditure (asset replacement and renewal)	Asset replacement and renewal	75	75	75	75	75	75	75	75	75	75	750
6640	Ruawai transformer replacement (5MVAx1)	Asset replacement and renewal	800	200	0	0	0	0	0	0	0	0	1,000
6658	Placeholder for installing new Sectos switches	Asset replacement and renewal	500	500	500	500	0	0	0	0	0	0	2,000
	Bream Bay 33kV switchboard replacement (project 1)	Asset replacement and renewal	0	0	0	0	0	0	0	0	100	1,500	1,600
	Subtotal (projects)		**14,130**	**15,920**	**15,280**	**10,995**	**8,688**	**5,988**	**7,898**	**6,398**	**5,065**	**5,325**	**95,687**
9500	Corrective capex - BATT battery systems	Asset replacement and renewal	26	26	26	26	26	26	26	26	26	26	263

Northpower EDB ten-year capex plan (FY20 $000)			1	2	3	4	5	6	7	8	9	10	Total
Project number	Project title	Expenditure category	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY22-FY31
9501	Corrective capex - COND distribution conductors	Asset replacement and renewal	368	368	368	368	368	368	368	368	368	368	3,675
9502	Corrective capex - DEAR distribution earthing	Asset replacement and enewal	210	210	210	210	210	210	210	210	210	210	2,100
9503	Corrective Capex - GMSU ground mounted distribution substations	Asset replacement and renewal	263	210	263	210	263	210	263	210	263	263	2,415
9506	Corrective capex - OHLN distribution overhead lines	Asset replacement and renewal	1,649	1,649	1,649	1,649	1,649	1,649	1,649	1,649	1,649	1,649	16,485
9507	Corrective capex - OHSW distribution overhead switches	Asset replacement and renewal	53	53	53	53	53	53	53	53	53	53	525
9508	Corrective capex - PILL distribution pillars	Asset replacement and renewal	158	158	158	158	158	158	158	158	158	158	1,575
9509	Corrective capex - POLE poles	Asset replacement and renewal	368	368	368	368	368	368	368	368	368	368	3,675
9510	Corrective capex - PROT protection relays	Asset replacement and renewal	5	5	5	5	5	5	5	5	5	5	53

Northpower EDB ten-year capex plan (FY20 $000)			1	2	3	4	5	6	7	8	9	10	Total
Project number	**Project title**	**Expenditure category**	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY22-FY31**
9511	Corrective capex - RIPP ripple lants	Asset replacement and renewal	5	5	5	5	5	5	5	5	5	5	53
9512	Corrective capex - UCAB distribution cables	Asset replacement and renewal	83	83	83	93	93	103	103	103	103	103	945
9513	Corrective capex - XARM distribution crossarms	Asset replacement and renewal	1,365	1,365	1,365	1,365	1,365	1,365	1,365	1,365	1,365	1,365	13,650
9517	Corrective capex - COMM communication network	Asset replacement and renewal	1	1	1	1	1	1	1	1	1	1	11
9519	Corrective capex - AREG voltage regulators	Asset replacement and renewal	21	21	21	21	21	21	21	21	21	21	210
	Corrective capex - TOWER 110kV towers and equipment	Asset replacement and renewal	231	0	252	0	316	0	316	0	366	0	1,481
	Subtotal (corrective capex)		4,803	4,520	4,824	4,530	4,898	4,540	4,908	4,540	4,958	4,592	47,114
	Total	**Asset replacement and renewal**	**18,933**	**20,440**	**20,104**	**15,525**	**13,586**	**10,528**	**12,806**	**10,938**	**10,023**	**9,917**	**142,801**
6348	New reclosers	Reliability, safety and environment	0	0	55	0	0	55	0	0	55	0	165

Northpower EDB ten-year capex plan (FY20 $000)			1	2	3	4	5	6	7	8	9	10	Total
Project number	**Project title**	**Expenditure category**	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY22-FY31**
6374	Zone substation security improvements	Reliability, safety and environment	90	90	75	0	0	0	0	0	0	0	255
6400	Additional 11kV RMU's	Reliability, safety and environment	100	0	0	0	56	0	0	0	60	0	216
6404	11KV Feeder mid- and tie-point remote controlled switching	Reliability, safety and environment	180	180	180	180	0	0	0	0	0	0	720
6435	Minor capital expenditure (reliability, safety, environment)	Reliability, safety and environment	100	100	100	100	100	100	100	100	100	100	1,000
6581	Provision for fibre	Reliability, safety and environment	50	50	50	50	50	50	50	50	50	50	500
6591	Communication backbone extra resilience	Reliability, safety and environment	0	100	100	0	0	0	0	0	0	0	200
6613	Overhead-to-underground conversions	Reliability, safety and environment	100	100	100	100	550	550	550	550	550	550	3,700
6614	Ground mounting of 2- and 4- pole distribution transformers	Reliability, safety and environment	290	290	290	290	290	290	290	290	290	290	2,900

Northpower EDB ten-year capex plan (FY20 $000)			1	2	3	4	5	6	7	8	9	10	Total
Project number	**Project title**	**Expenditure category**	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY22-FY31**
6639	SMART distribution system (load monitoring)	Reliability, safety and environment	100	100	100	0	0	0	0	0	0	0	300
6660	LV automation	Reliability, safety and environment	30	30	30	30	30	30	30	30	30	30	300
	Maungatapere 33kV bus outdoor-to-indoor conversion	Reliability, safety and environment	0	0	0	0	0	0	0	0	0	1,000	1,000
	Maungaturoto to Mangawhai 34km 33kV line	Reliability, safety and environment	200	800	0	3,000	2,500	0	0	0	0	0	6,500
	Maungaturoto to Mangawhai 34km 33kV line easements	Reliability, safety and environment	800	1,000	1,000	0	0	0	0	0	0	0	2,800
	Kensington 110kV bus e-configuration and Tx CBs	Reliability, safety and environment	200	1,000	1,500	0	0	0	0	0	0	0	2,700
	Total	**Reliability, safety and environment**	**2,240**	**3,840**	**3,580**	**3,750**	**3,576**	**1,075**	**1,020**	**1,020**	**1,135**	**2,020**	**23,256**
6525	ADMS (advanced distribution management system)	Non-network assets	1,565	945	0	0	0	0	0	0	0	0	2,510

Northpower EDB ten-year capex plan (FY20 $000)			1	2	3	4	5	6	7	8	9	10	Total
Project number	Project title	Expenditure category	FY22	FY23	FY24	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY22-FY31
6546	Research and development (component testing)	Non-network assets	30	30	30	50	50	50	80	50	50	50	470
6569	Aerial imagery (GIS)	Non-network assets	0	40	0	0	50	0	0	0	50	0	140
6571	AMS (WASP replacement)	Non-network assets	200	2,300	1,500	0	0	0	0	0	0	0	4,000
6572	Engineering hardware/ software	Non-network assets	0	0	0	55	0	0	0	55	0	0	110
6590	Research and development (new technology)	Non-network assets	50	50	60	70	80	85	90	100	100	100	785
6644	Minor capital expenditure (non-network assets)	Non-network assets	25	25	25	25	25	25	25	25	25	25	250
6662	Faults management system	Non-network assets	300	0	0	0	0	0	0	0	0	0	300
6663	Asset management "digital-twin" model (w/ lines and service-lines LiDAR data)	Non-network assets	700	0	0	0	0	700	0	0	0	0	1,400
6664	ESRI Geospatial tool sets	Non-network assets	80	0	0	0	0	0	0	0	0	0	80

Northpower EDB ten-year capex plan (FY20 $000)			1	2	3	4	5	6	7	8	9	10	Total
Project number	**Project title**	**Expenditure category**	**FY22**	**FY23**	**FY24**	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**FY30**	**FY31**	**FY22-FY31**
	Mobile substation / step-up / STATCOM	Non-network assets	0	0	0	0	200	2,300	0	0	0	0	2,500
	Development of customer systems and interfaces	Non-network assets	225	0	0	0	0	0	0	0	0	0	225
	Total	**Non-network assets**	**3,175**	**3,390**	**1,615**	**200**	**405**	**3,160**	**195**	**230**	**225**	**175**	**12,770**
	Total EDB capex		**30,883**	**32,665**	**31,199**	**27,480**	**25,078**	**19,779**	**19,242**	**21,114**	**23,215**	**20,150**	**250,805**

Northpower

2021 – 2031 Asset Management Plan

Section 9

Ability to deliver

Table of contents

9.1 Funding the AMP

9.1.1 Investment scenarios / authorisations

Northpower's electricity network is funded primarily through network distribution charges, recovered from electricity retailers and some large customers. Peaks in capital expenditure may result in the lines charges received in any one year being insufficient to fund both operating and capital expenditure for that year.

In these instances, the additional funding is sourced via cash flows from Northpower's non-network operating businesses or external bank borrowings. Regular forecasts throughout the financial year ensures appropriate funding remains available.

We complete an annual budgeting and planning process, which focusses on the forthcoming year and prepare a ten-year financial forecast reflecting the expenditure profiles in the AMP. The budgets and forecasts are used by management and the board to assess the required funding levels.

9.1.2 AMP finance processes

The Group treasury policy is a key governing document that is approved by the board. This policy outlines key target financial ratios and requirements to ensure liquidity is appropriately managed, including requirements such as gearing ratios, bank borrowing facilities that will be maintained and authorised counterparties. The Group treasury policy parameters are set with a view to ensuring Northpower can fund planned activities and provides sufficient headroom to fund any unexpected events.

Actual expenditure is approved according to the Group's delegated authority policy. This policy is approved by the board of directors and includes specific authorities held by the Chief Executive. The Chief Executive has the ability to sub-delegate these authorities. Capital projects are supported by a proposal which clearly justifies the reason for the expenditure and provides appropriate financial analysis. This includes a comparison to the relevant financial information included in the most recent approved AMP. The board approves any projects over $2 million.

The planning, budgeting and forecasting processes, along with the Group treasury and delegated authorities policies provide assurance that we are making prudent investment decisions in the long-term interests of our consumers. These processes and polices also ensure that appropriate funding is available to meet investment needs.

9.2 Resourcing the AMP

The following high-level objectives inform our strategy and decisions around the procurement of goods and services for the electricity network:

- Ensuring that the services delivered meet the requirements and expectations of the consumers of Whangārei and Kaipara.
- A cost-effective delivery model that delivers efficiencies for the long-term benefit of consumers.
- Achieves a high performing safety culture across all areas of our business, including staff and contractors.
- Ensuring that works programmes are delivered in accordance with our asset management strategies, including the ability to access resources to meet peak workloads.
- Achieving innovation and continuous improvement in the areas identified above.

The choice around suppliers and procurement models, will depend on the existing market for specific goods or services, the strategic importance of the services, and the long-term needs of the network and its consumers.

Goods or services with characteristics that support a transactional relationship are likely to be subject to market contestability. In contrast, strategic supplier relationships are more likely to be based on a collaborative approach, underpinned by long-term relationships. Where goods or services are not acquired through market contestability, we ensure that transactions are valued as if they were an arm's length transaction by utilising independent and objective measures.

9.2.1 AMP resourcing model and processes

Resourcing

Our ability to deliver to our AMP relies on having an appropriate level of competent, experienced and skilled resources – both across our Northpower team and our service providers. Sufficient competent staff are essential to delivering planned capital and operational programmes, supporting customer-initiated works, and our ability to effectively respond to network faults, emergencies and natural disasters.

We continually reassess the level of resourcing required and adjust our resourcing as required to meet our objectives.

Northpower resourcing

Over the last three years we have significantly increased staffing within the network business to support a lift in our asset delivery programme. This includes investment in engineering and operations resources, as well as customer experience.

We actively encourage ongoing professional development of our staff, with allocated training budgets and personal development plans. We are members of the Electricity Engineers Association, with engineering and operations staff frequently attending professional development courses and seminars. We acknowledge the importance of learning from our peers, and we encourage staff to engage with other distribution businesses to identify leading practice and to adopt those within our business.

Works delivered by field services contractor

Work negotiated directly with our main field service provider (Northpower Contracting) is based on negotiated labour, plant and unit rates. The majority of work completed by the service provider is governed by a field services agreement, referred to as the service level agreement (SLA). The SLA outlines how network and Northpower Contracting will work together, specifies the scope of services provided by the service provider and rates, including a set of key performance indicators (KPIs). The agreement is negotiated between representatives of the two Northpower divisions and approved by the respective General Managers.

While field services are contracted, Northpower network retains responsibility for our AMS and GIS systems, ensuring core asset knowledge is kept in house.

Ensuring quality of works delivery

The SLA has a structured governance model where quality of delivery is jointly overseen. Each forum has a nominated chair with an agenda sent prior to the meeting. Minutes are captured and distributed in a timely manner. A relationship survey is used annually to assess relationship health and improvement opportunities.

Figure 111: Relationship Management Structure

Additional works not funded directly by Northpower

In addition to the works we undertake to build and maintain our network, external stakeholders require work to be completed on or near the network. Examples of such works include:

- connecting assets to the network – for example streetlighting and LV service connections
- constructing electricity assets where Northpower will be taking over ownership and maintenance of these assets. These are referred to as customer initiated works (CIW); or
- undertaking (unsupervised) routine works requiring permission from Northpower to work within four metres of our electricity network – for example streetlight maintenance, vegetation trimming.

To enable customer choice in this area, and ensure quality of work and safe work practices are adhered to, we have developed a network approved contractor framework. Network approved contractor status is required for all contractors undertaking works on the network via an engagement with a third party (for example a local Council or customers).

9.2.2 AMP resourcing assessment

Capacity planning

Part of the AMP resource planning process gives the field service provider an indication of the amount of work available on the network. There is an annual process to align resourcing with work available. This process is detailed below:

Due date	Action
1 November	Network gives to the service provider the annual works programme, which includes the preventative maintenance plan, reactive maintenance budget, a schedule of proposed capital works projects (including scope, planned milestone timeframes and designations as directly allocated, yours to lose and contestable), and highlights any significant changes to individual areas of the corrective opex and capex budget for the next contract year.
30 November	Service provider gives feedback on the annual works programme and provides a written response to network, including confirmation that the service provider has the resources to meet the annual programme.
15 December	Network finalises the annual works programme (subject to board approval).
On-going	Network provides a rolling three monthly view of directly allocated and yours to lose work to the service provider, who in turn provides a rolling three month report on progress and resource availability.

Application in practice

Large capital projects (typically a defined set of works with a value of over $1 million) conducted by network are generally based on fixed price contracts. Our electricity management team determine whether these projects are subject to a comptitive tender process or negotiated directly with our field services partner, Northpower Contracting. In assessing whether these projects should be subject to tender, we consider:

- The urgency of the project in terms of network function and safety, and delivery timeframe requirements
- Contractor availability and capability
- Whether the project will be seen as attractive to external contractors. This review involves factors such as the size of the project, the number of crews required, the type of work being undertaken, travel and mobilisation costs

Competitive tender processes follow established tender processes that are based on industry recognised tendering and contracting frameworks (generally standard NZS3910).

The specialised nature of construction and maintenance services, including management of safety risks, dynamic workflow requirements and short response times, along with the value of the work offered and efficiency benefits, lends itself to Northpower establishing a preferred supplier relationship for the procurement of these services.

This long-term delivery relationship has been established with Northpower Contracting, meaning they complete the majority of network's capital (other than tendered) and maintenance work. Northpower Contracting is an established provider of construction and maintenance services for electrical networks for many electricity distribution companies in New Zealand. This provides the capability and scale to ensure the division is well placed to provide high quality and efficient services.

The following guide explains our current procurement approach:

Category	Supplier options	Procurement process	Contract agreement used
Large capital projects	Established electrical industry contractors	Sole source or closed tender process	NZS3910
Major network assets	Reputable hardware suppliers	Sole source or closed tender process	Northpower equipment and services supply agreement (SA)
Small to medium capital projects	Internal contractor	Sole source Formalised, transparent quoting process	Northpower service level agreement and project templates
Maintenance programmes	Internal contractor	Sole source.	Network and contracting service level agreement with specific key performance indicators
Minor network assets, subcontractors and network consumables	Internal contractor	Sole source. Supplied with agreed margin as per SLA	Network and contracting service level agreement with specific approved materials and competency requirements
Network design	Reputable network design agencies	Programme or job related quoting	Northpower professional services agreement (PSA)
Vegetation control	Internal contractor – 85% of programme Suitably qualified vegetation maintenance service providers – 15%	Sole source. Programme or job related quoting	Internal contractor - network and contracting service level agreement External contractors - Northpower standing services agreement (SSA) plus job sheet

9.3 Digital technology supporting AMP delivery

The digital landscape at Northpower is broad, covering all aspect of digital, technology and data across each business unit. While we operate within a centrally managed group, we have structured our resources to support a business partnership model to ensure we are aligned in understanding the unique and specific needs for our business.

The landscape itself has been undergoing a transformation to align with our diverse business functions and capabilities. As part of this transformation, the digital group have adopted a change program built around key initiatives to enable, modernise, transform or embed technology platforms.

Some example initiatives that support this transformation:

- Embedding: continuing to support the delivery of the ADMS platform and embed the processes and data into the overall electricity platform architecture roadmaps
- Enabling: facilitating the changes to network billing and improved customer experience platforms, through enabling technologies, interfaces and customer journeys
- Modernising: uplifting our capabilities and platforms in key areas to drive improvements in our geospatial data and visualisations, billing platforms and ICP management
- Transforming: re-imagining our faults and outage management processes and platforms to deliver a robust service, modernising our asset management system and processes, and leveraging data and analytics to drive business improvement and transformation

9.3.1 Digital technology support

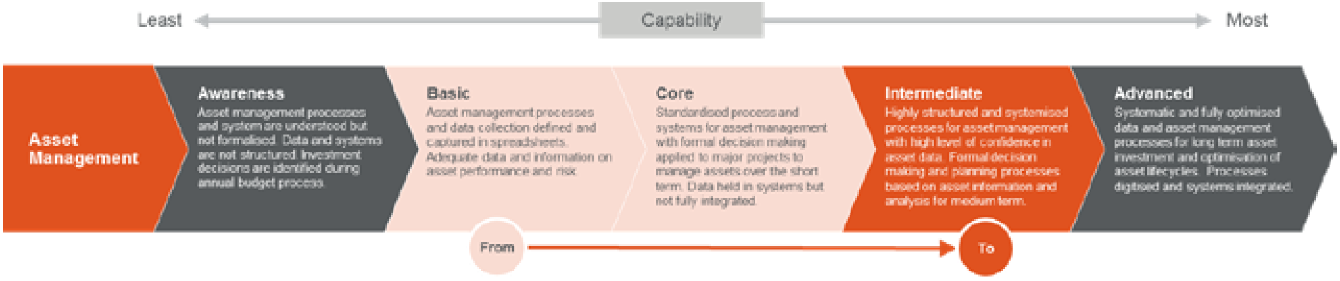
The relationship between digital group and the business is evolving from a customer/supplier oriented model to one of business partnership, fundamentally changing the way digital engages and enables the business. Within digital, a network systems team supports the Northpower network business unit and provides an interface into other digital teams and capability.

This model supports key business functions through a business partner and service/product owner approach, with the following outcomes:

- Ensuring digital investments are strategically aligned and delivering business value
- Ensuring the services delivered are fit for purpose, and features are delivered according to network's priority and roadmaps
- Enhancing vendor management practices to align costs to organisational and business unit appetite for investment
- Looking outside of our business for digital innovation and partnering with network to test and apply innovations.

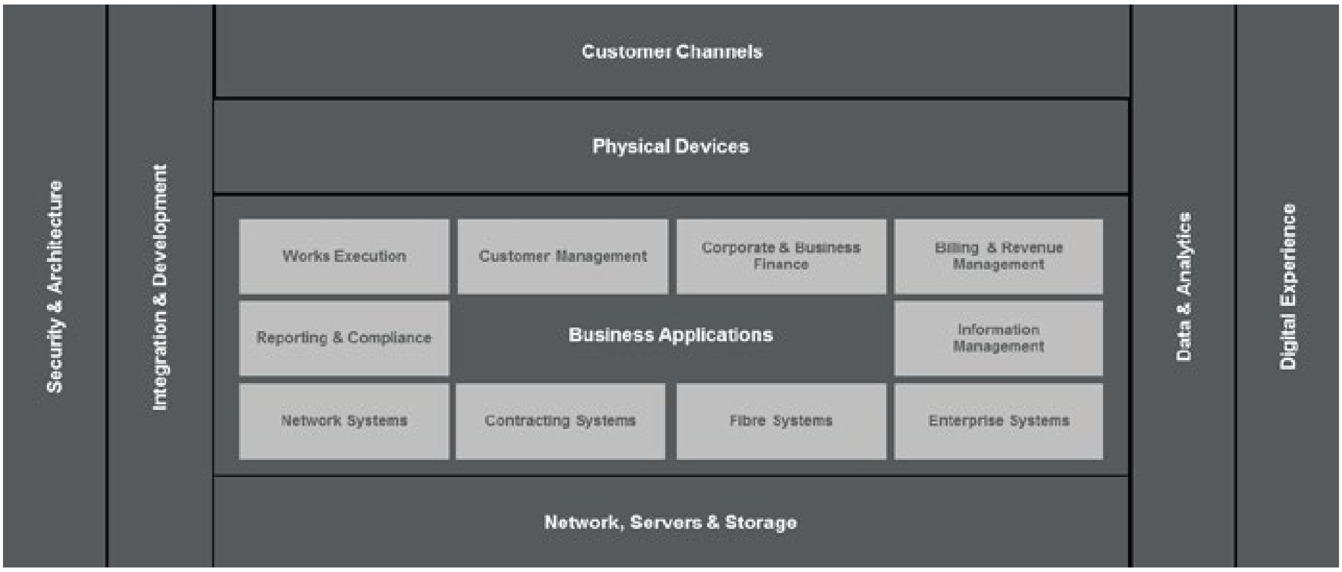
Our digital resourcing and capability strategy ensures we meet specific outcomes for asset management, with the transformation program supporting a lift in capability from "basic" to intermediate within the next two to five years.

Figure 112: Asset management systems maturity



We have also recently formalised shared functions to support our continued capability development in digital experience, cloud platforms, integration development and cyber security.

Figure 113: High level digital architecture



Northpower

2021 – 2031 Asset Management Plan

Appendix A

Glossary of terms

Appendix A - Glossary of Terms

A	Ampere
AAAC	All aluminium alloy conductor
AAC	All aluminium conductor
ABB	Asea Brown Boveri (Company)
ABC	Aerial bundled conductor
AC	Alternating current
ACSR	Aluminium conductor steel reinforced
ADMS	Advanced distribution management system
AHI	Asset health indicator
AMMAT	Asset management maturity
AMP	Asset management plan
AMS	Asset management system
ANCAP	Australian New Car Assessment Programme
AS/NZS	Australian and New Zealand Standard
AXOS	Network billing system
BCP	Business continuity planning
BEV	Battery electric vehicle
BIL	Basic insulation level
BU	Business unit
CAIDI	Customer average interruption duration index
Capex	Capital expenditure
CB	Circuit breaker
CBD	Central business district
CCTV	Closed circuit television
CEO	Chief Executive Officer
CIMP	Coordinated incident management plan
CMP	Crisis management plan
COVID	Coronavirus disease
CT	Current transformer
Cu	Copper
DC	Direct current
DER	Distributed energy resources
DFA	Delegated financial authority
DG	Distributed generation
DGA	Dissolved gas analysis
DMR	Digital mobile radio
DMS	Distribution management system
EAM	Enterprise asset management
EDB	Electricity distribution business
EDO	Expulsion dropout (HV fuse or link)
EEA	Electricity Engineer's Association of New Zealand

ELT	Executive leadership team
EMF	Electromagnetic field
EMS	Environmental management system
EOL	End of life
EPR	Earth potential rise
EV	Electric vehicle
FaMECA	Failure mode, effects and criticality analysis
FY	Financial year
GE	General Electric (Company)
Gentrack	Network billing system
GIS	Geographical information system
GM	Ground mounted
GM	General Manager
GPS	Global positioning system
GWh	Gigawatt hour
GXP	Grid exit point
HDBC	Hard drawn bare copper (Conductor type)
HDC	Hard drawn copper (Conductor type)
HFCEV	Hydrogen fuel cell electric vehicle
HILP	High impact low probability event
H&S	Health and safety
HMI	Human machine interface
HR	Human resources
HSQE	Health, safety, quality and environment
HV	High Voltage, greater than 1kV
ICP	Installation control point (meter station)
IMT	Information management technology
IMT	Incident management team
IP	Internet protocol
ISO	International Standards Organisation
IVR	Interactive voice response system
KL	Knife links
km	Kilometre
KPI	Key performance indicator
kV	Kilovolt
kVA	Kilovolt Ampere
kVAr	Kilovolt Ampere (reactive)
kW	Kilowatt
kWh	Kilowatt hour
LED	Light emitting diode
LiDAR	Light Detection and Ranging

LINZ	Land Information New Zealand
LMS	Load management system
LV	Low Voltage, less than 1kV
MD	Maximum demand
MDI	Maximum demand indicator
mm	Millimetre
MS	Microsoft
MVA	Megavolt Ampere
MW	Megawatt
MWh	Megawatt hour
N	Power system security – unable to take full load with loss of a single element
N-1	Power system security – able to take full load with loss of a single element
N/A	Not applicable
NCI	Not a critical indicator
NEPT	Northpower Electric Power Trust
NOC	Network operations centre
NPV	Net present value
NZTA	Waka Kotahi, New Zealand Transport Authority
ODV	Optimised deprival value
OH	Overhead
OHUG	Overhead to underground (conversion)
OLTC	On load tap changer
Opex	Operational expenditure
OMS	Outage management system
OSI PI	Electrical data historian software
PCB	Polychlorinated biphenyl
PCBU	Person conducting a business or undertaking
PDC	Polarisation depolarisation current
PESTLE	Political, economic, social, technological, legal, environmental
PHEV	Plug-in hybrid electric vehicle
PILC	Paper insulated lead covered (cable type)
PM	Project Manager
PSA	Professions services agreement
PV	Photovoltaic
PVC	Poly vinyl chloride
RACI	Responsible, accountable, consulted and informed
RAS	Risk appetite statement
RMA	Resource Management Act
RMU	Ring main unit
RT	Radio telephone
RTU	Remote terminal unit

SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCADA	Supervisory control and data acquisition system
SCI	Statement of Corporate Intent
SF6	Sulphur hexafluoride
SINCAL	Power system simulation software
SLA	Service level agreement
SOA	Service orientated architecture
SSA	Standing services agreement
ST	Subtransmission
SVL	Sheath voltage limiter
TUDS	Total underground distribution system (underground pillar or pit)
UAV	Unmanned aerial veuicle
UFB	Ultra-fast broadband
UG	Underground
UHF	Ultra high frequency
UPS	Uninterrupted power supply
V	Volt
VAR	Volt Ampere (reactive)
VHF	Very high frequency
VLI	Very large industrial customer
VOIP	Voice over internet protocol
VoLL	Value of lost load
VT	Voltage transformer
V2G	Vehicle to grid
WASP	Works, assets, solutions and people (maintenance management system)
XLPE	Cross linked polyethylene (cable type)
Y	Year

Northpower

2021 – 2031
Asset Management Plan

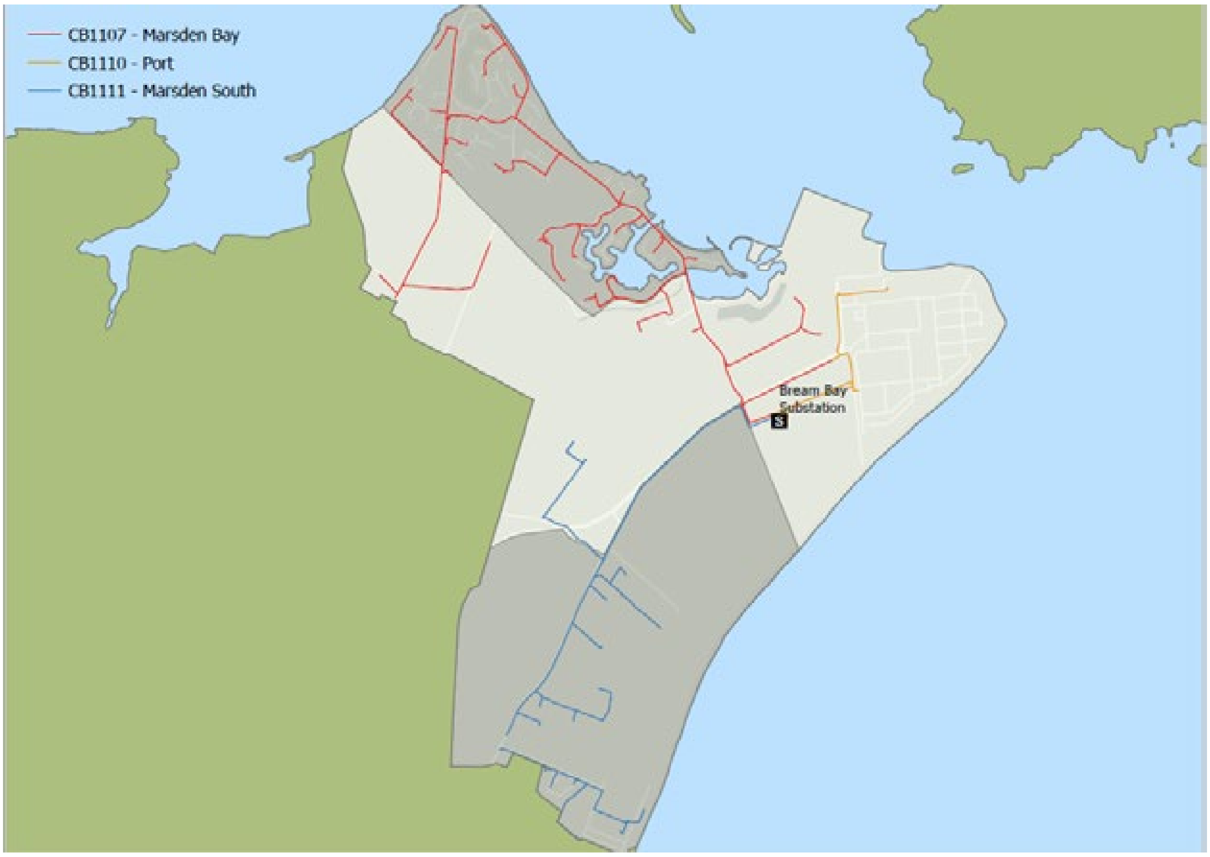
Appendix B
Substation data and feeder maps

Table of contents

1. Bream Bay zone substation

Bream Bay zone substation profile				
Transformer capacity			1 unit 7.5MVA ONAN/10MVA OFAF	
Peak load			4.5MW	
Total Number of customers supplied			1,423	
11kV feeder name	Circuit breaker id	Number of customers	Predominant construction of lines	Predominant customer type
Marsden south	1,107	1,325	Overhead	Residential
Port feeder	1110	8	Underground	Industrial
Marsden south	1,111	90	Overhead	Residential/commercial mix

Bream Bay geographic feeder layout



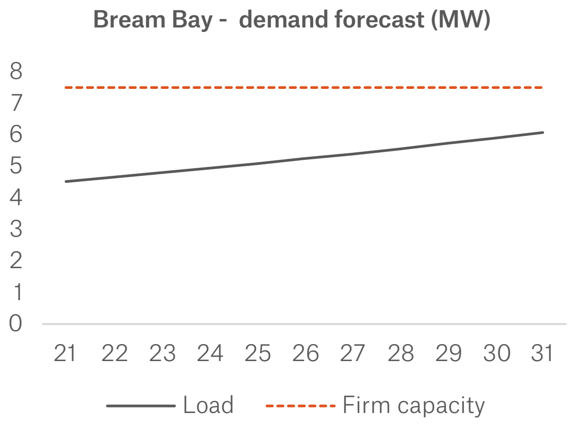
2. Bream Bay substation description

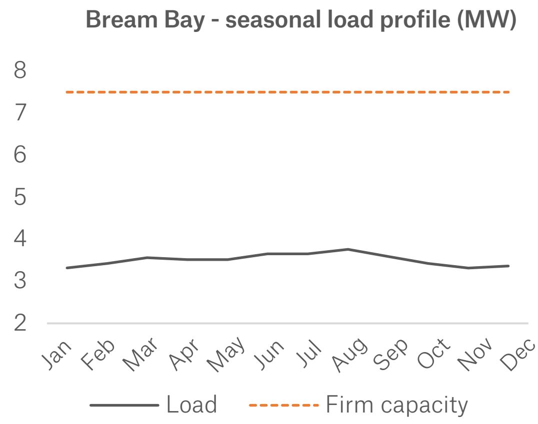
This substation supplies a mixture of industrial, commercial and residential load. The potential for growth in the surrounding area is very high, with the district council designating large areas of land for heavy industry, service industry and residential development. The present 11kV load is relatively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

Installation of a second transformer is planned for the future (FY24 - FY26) to increase security of supply as the load grows. The need for and timing of a second transformer will be taken into consideration with the existing 10MW peak lopping generation plant (connected to the station's 11kV bus) by an energy company as this plant could be used for backstopping purposes.

An 11kV conductor upgrade project is currently underway to relieve a distribution constraint. Once completed, this will also allow for future load growth and improve 11 kV feeder backstopping capability. The existing 11kV switchgear is planned for upgrade from FY24 - FY26.

3. Substation load graphs





4. Forecasted capital investments

Driver	Description	Year
Security of Supply	Installation of second transformer	FY24-26
Aging equipment and reaching capacity	Bream Bay 11kV switchboard replacement	FY24-26

5. Ruakaka zone substation

Bream Bay zone substation profile				
Transformer capacity			2 units 10MVA	
Peak load			7.1MW	
Total Number of customers supplied			3,949	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
Marsden Pt	1	1,274	Overhead	Residential
Waipu	2	1,077	Overhead	Residential
Mata	3	424	Overhead	Residential
One Tree Point	6	331	Overhead	Residential
North River	7	843	Overhead	Residential

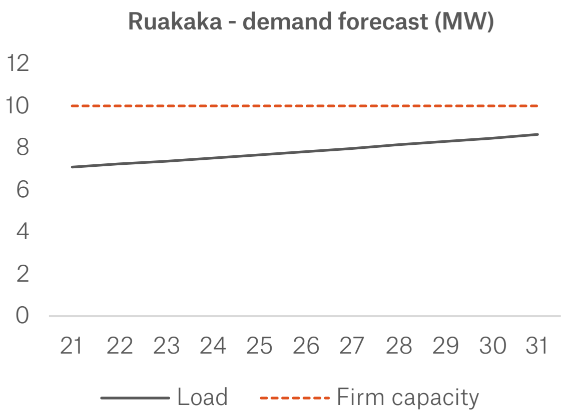
Ruakaka geographic feeder layout

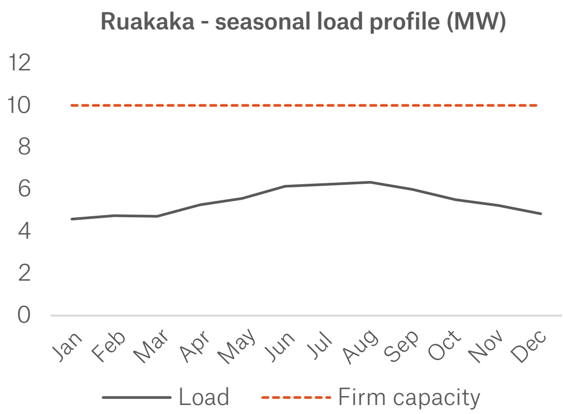
6. Ruakaka substation description

This substation is centred around the Ruakaka township and also supplies the surrounding rural dairying area, Waipu township and the south-east coast holiday resort area. The rural area is becoming more lifestyle in nature and significant subdivision activity and growth is expected in the future. The switchboard incorporates a spare feeder for the anticipated future growth.

A voltage regulator was installed on the Waipu feeder in 2016 to support the growing load in the area. We have recently identified an approaching capacity constraint for this regulator, and a feeder reconfiguration has been proposed in the near future that will relieve this constraint. Another benefit from the feeder reconfiguration will be providing additional back feed capacity to the Mangawhai substation. A future zone substation in the Waipu area is planned for FY29 - FY31 as a long-term solution, which will allow for future anticipated load growth and development. This will also improve supply resilience in the area and provide greater backstopping capability to Mangawhai and Ruakaka substations. In FY25 – FY26 we plan on replacing transformer No. 2 due to age.

7. Substation load graphs





8. Forecasted capital investments

Driver	Description	Year
Aging asset	Ruakaka transformer replacement (T2)	FY25 - FY26
Load growth	Waipu feeder capacity constraint mitigation	FY22

9. Dargaville zone substation

Dargaville zone substation profile				
Transformer capacity			2 units 7.5MVA ONAN/15MVA OFAF	
Peak load			10.8MW	
Total Number of customers supplied			5,683	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
North Dargaville	1	619	Overhead	Residential/commercial mix
Te Kopuru	2	909	Overhead	Residential
Town Dargaville	3	752	Overhead	Residential/commercial mix

Dargaville zone substation profile				
Transformer capacity			2 units 7.5MVA ONAN/15MVA OFAF	
Peak load			10.8MW	
Total Number of customers supplied			5,683	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
Awakino Point	4	367	Overhead	Residential
Coast	6	984	Overhead	Residential
Hokianga Rd	7	952	Overhead	Residential
Tangowahine	8	588	Overhead	Residential/Commercial mix
Turiwiri	9	512	Overhead	Residential/Commercial mix

Dargaville geographic feeder layout

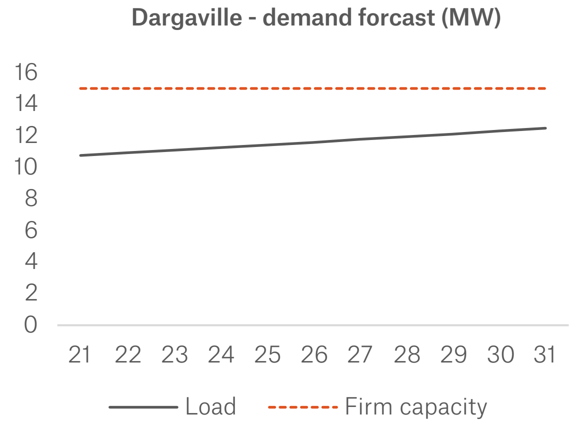
10. Dargaville substation description

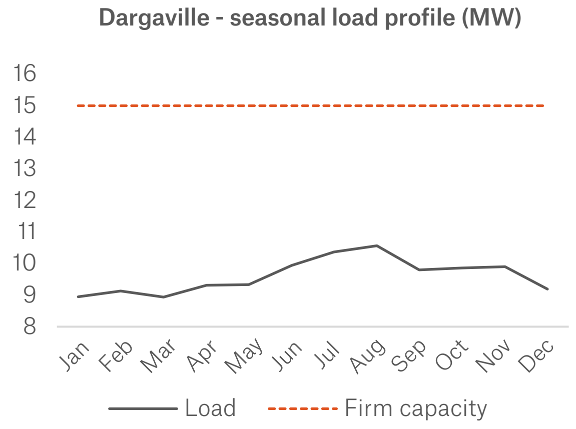
A major reconfiguration of the 11kV feeders at this station was completed in 2015 in order to remove a double circuit line running through the Dargaville town and which optimised the 11 kV feeder loading.

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

The mostly likely sector for significant future load growth is forestry as the large plantations to the north of Dargaville mature. The growth in the medium to longer term is expected to be low. The area has attracted some interest for large distributed energy resources connected to the network.

11. Substation load graphs





12. Forecasted capital investments

Driver	Description	Year
	None identified	-

13. Alexander Street zone substation

Alexander Street zone substation profile				
Transformer capacity			2 units 7.5MVA ONAN/15MVA OFAF	
Peak load			13.1MW	
Total Number of customers supplied			4,679	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
Norfolk St	1	851	Underground	Residential
Forum North	2	411	Underground	Residential/commercial mix
Second Ave	3	996	Underground	Residential
Bank of NZ	6	463	Underground	Residential/commercial mix
Western Hills Dr	7	885	Overhead	Residential
Kensington	8	758	Overhead	Residential

Alexander Street geographic feeder layout

14. Alexander Street substation description

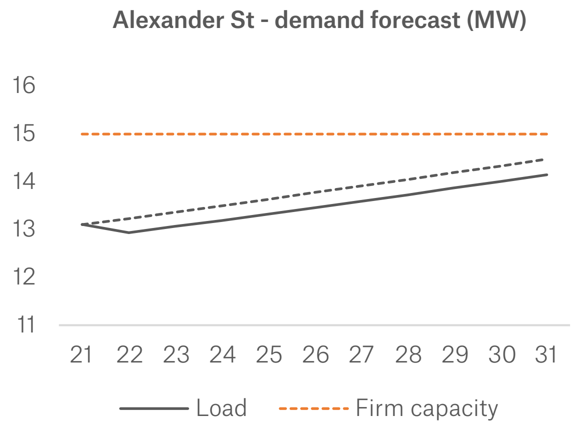
This substation supplies the Whangārei City CBD and the central residential areas. The substation is supplied directly from Kensington 110/33kV Regional Substation.

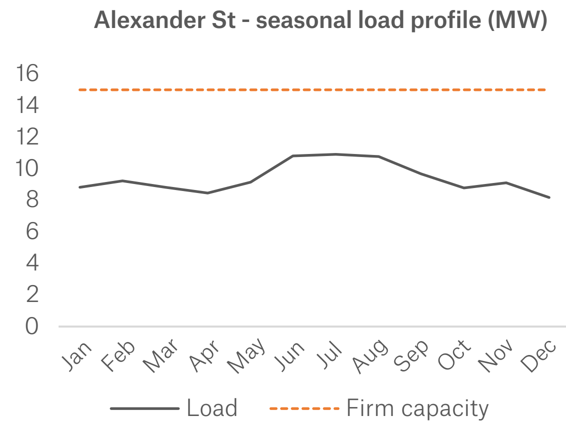
The long-term load growth in the area is expected to be moderate as the CBD area is almost fully developed. Business expansion taking place in Whangārei tends to be outside the current CBD area and a number of businesses have also relocated away from the central commercial area.

Some residential load will be transferred from this station to the new Maunu substation in FY22, thus delaying the need to upgrade the transformers in the current ten year planning horizon. The Maunu substation is expected to be operational in FY22 and was constructed to address the growing needs in Maunu and provide contingency supply to Alexander Street, Whangārei South and Maungatapere zone substations.

Alexander Street substation is an important backstop for any contingency at Whangārei South or Tikipunga substations. Alexander Street substation is fully restorable through the 11kV network.

15. Substation load graphs





In 2021, load will be transferred to the new Maunu substation, the grey dotted line is a forecast of the likely load without Maunu substation.

16. Forecasted capital investments

Driver	Description	Year
	None identified	-

17. Hikurangi zone substation

Hikurangi zone substation profile				
Transformer capacity			2 units 5MVA	
Peak load			6.8MW	
Total Number of customers supplied			3,359	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
Whakapara	1	1,068	Overhead	Residential
Town Hikurangi	2	535	Overhead	Residential
Jordan Valley	3	471	Overhead	Industrial
Swamp South	4	22	Overhead	Residential/commercial mix
Otonga	5	562	Overhead	Residential
Marua	6	306	Overhead	Residential
Swamp North	7	395	Overhead	Residential/commercial mix

Hikurangi geographic feeder layout

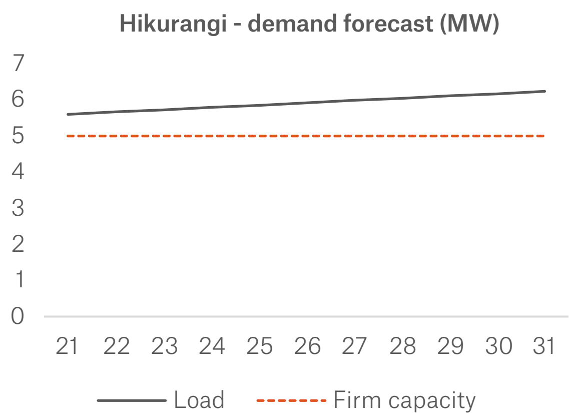
18. Hikurangi substation description

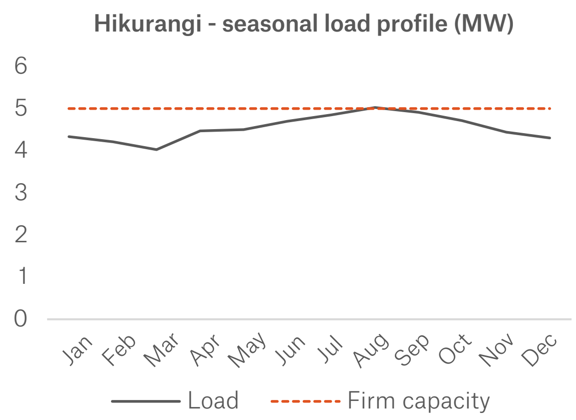
The mainly dairy farming rural load surrounding the Hikurangi township dominates the area supplied by this substation, although there is also some industrial load in the town. The substation also supplies a large flood-pumping scheme in the Hikurangi swamp area (occasional operation) as well as the coastal resort areas along the east coast as far north as Bland Bay.

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

Load growth in the short to medium term is likely to be moderate but could increase in the longer term in association with growth in Whangārei. Northpower has plans in place to upgrade and strengthen the 11kV network feeding the Helena Bay, Oakura and Bland Bay areas and will proceed when the capacity of the existing network needs to be increased (currently planned for FY22). The 2 x 5MVA 33/11kV transformers are planned to be replaced with 2 x 10MVA units in FY21-FY22 and the 11kV switchboard is planned for replacement at the same time. This will provide capacity for the area for the foreseeable future.

19. Substation load graphs



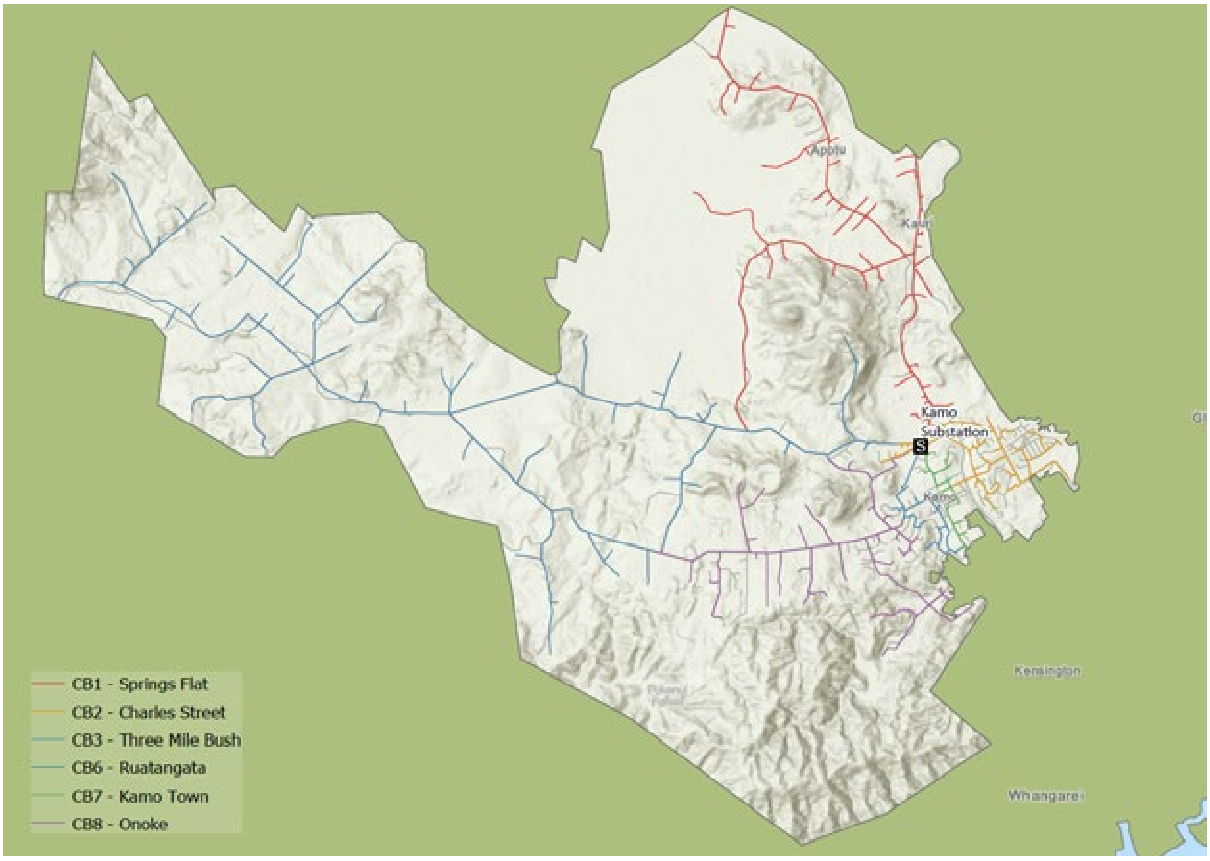


20. Forecasted capital investments

Driver	Description	Year
Load growth and age	Hikurangi switchboard replacement	FY21 – FY22
Load growth	Hikurangi transformer replacement	FY21 – FY22

21. Kamo zone substation

Kamo zone substation profile				
Transformer capacity			2 units 7.5MVA ONAN/15MVA OFAF	
Peak load			12MW	
Total Number of customers supplied			5,606	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
Springs Flat	1	645	Overhead	Residential
Charles St	2	1541	Overhead	Residential
Three Mile Bush	3	835	Overhead	Residential
Ruatangata	6	721	Overhead	Residential
Kamo Town	7	670	Overhead	Residential
Onoke	8	1194	Overhead	Residential



Kamo geographic feeder layout

22. Kamo substation description

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

The industrial and commercial load is minimal, with the main growth occurring in the residential segment through a high number of lifestyle blocks and new residential developments. This trend is likely to continue with planned development to the west, and a relatively high growth rate can be expected over the next 5-10 years. Associated moderate commercial and light industrial load growth is also expected.

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

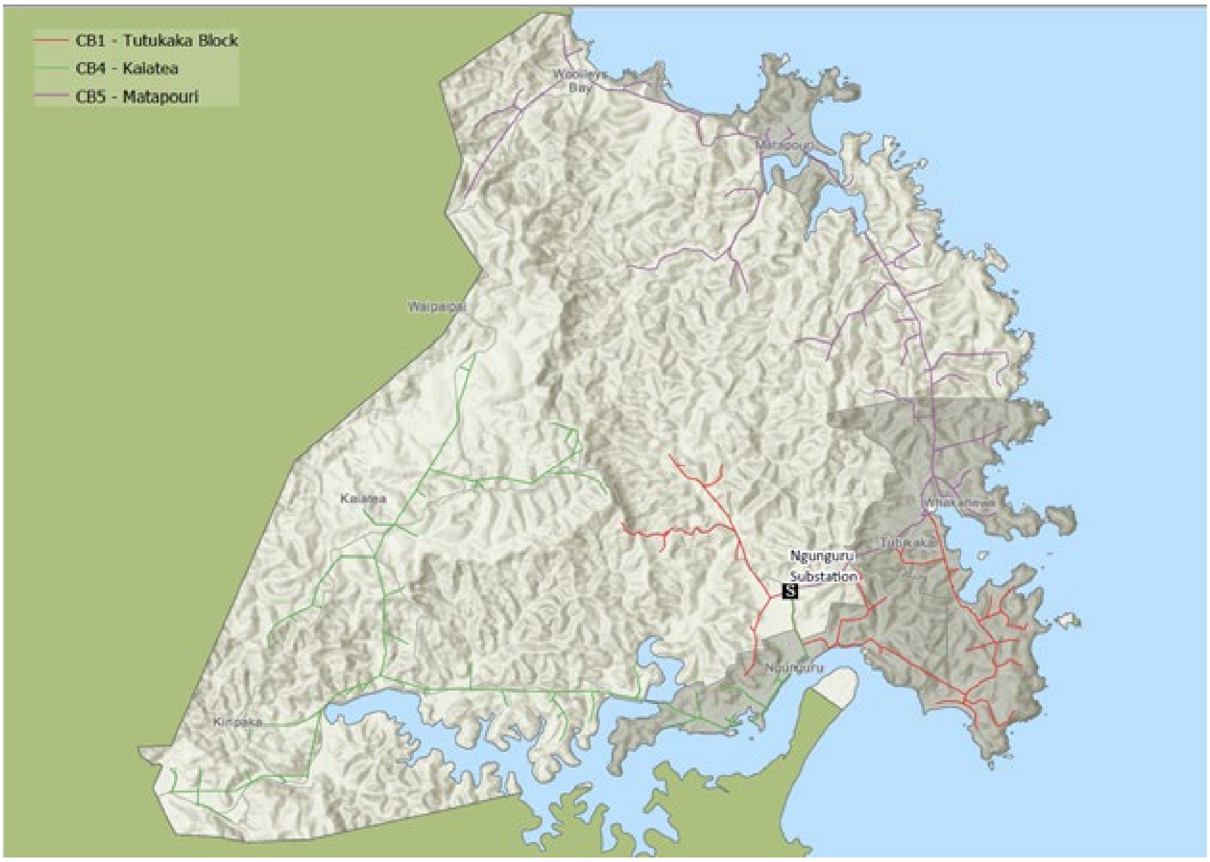
23. Substation load graphs

24. Forecasted capital investments

Driver	Description	Year
	None identified	-

25. Ngunguru zone substation

Ngunguru zone substation profile				
Transformer capacity			1 unit 3.75MVA	
Peak load			3.4MW	
Total Number of customers supplied			2,050	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
Tutukaka Block	1	637	Overhead	Residential
Kaiatea	4	676	Overhead	Residential
Matapouri	5	737	Overhead	Residential



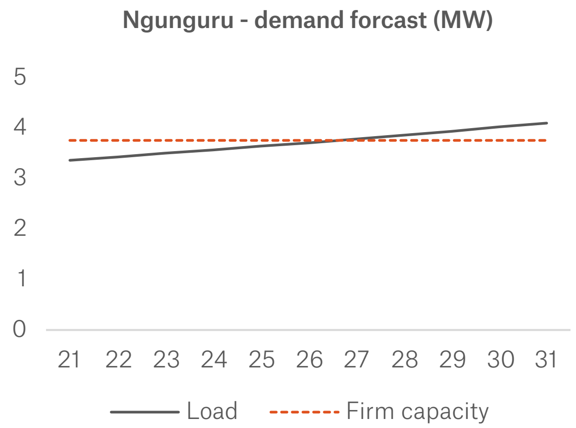
Ngunguru geographic feeder layout

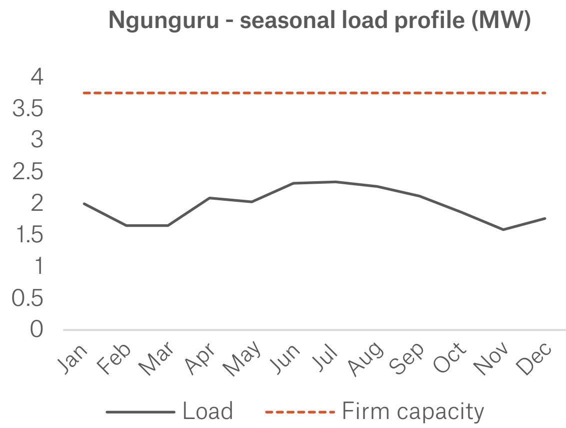
26. Ngunguru substation description

This substation supplies the Ngunguru township, Tutukaka, and Matapouri areas comprising mainly of residential type load. Load growth has been fairly low, however, there is potential for significant development. The 3.75MVA transformer is planned to be replaced with a 5MVA unit in FY21 and FY22 as it reaches end of life. At the same time the 11kV switchboard will be replaced. The new transformer will have enough capacity to meet growth for the foreseeable future. Ngunguru has relatively low restorability due to the remote location and being a coastal substation.

We have identified a potential 11kV reinforcement upgrade that would allow for stronger backstopping to the area. This project had been included in the Asset Management Plan and for completion in FY25.

27. Substation load graphs





Ngunguru load is forecasted to exceed the 3.75MVA transformer's rating in 2027 during the winter period. The new 5MVA transformer to be installed will ensure adequate capacity for future residential load growth for the foreseeable future.

28. Forecasted capital investments

Driver	Description	Year
Aging asset	11kV switchboard replacement	FY21 – FY22
Aging asset	Transformer upgrade	FY21 – FY22
Security of supply	Ngunguru back-feed constraint mitigation	FY25

29. Onerahi zone substation

Onerahi zone substation profile				
Transformer capacity			2 units 15MVA	
Peak load			7.5MW	
Total Number of customers supplied			4,003	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
Beach Road	2	636	Overhead	Residential
Alamein Ave	3	994	Overhead	Residential
Cartwright Rd	6	795	Overhead	Residential
Tamaterau	7	552	Overhead	Residential
Montgomery Ave	8	1,026	Overhead	Residential

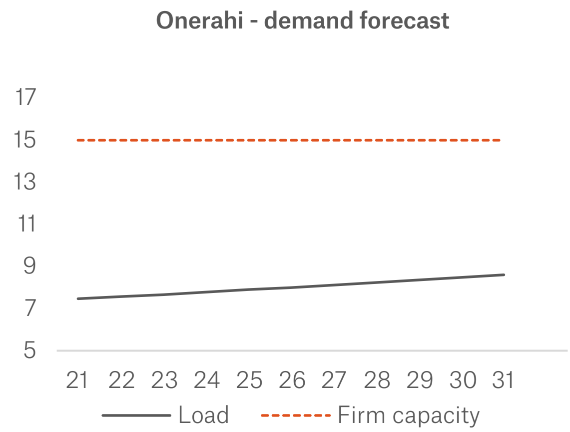
Onerahi geographic feeder layout

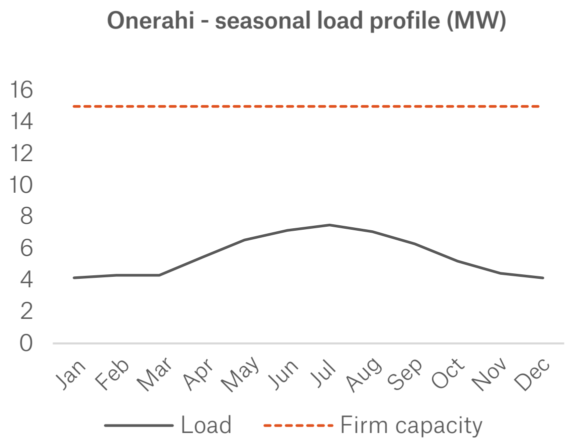
30. Onerahi substation description

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

The 11kV switchboard at Onerahi substation was upgraded in 2010 and 2 x 11kV feeders were reconfigured in 2015 to offload the Montgomery Road feeder. The 2 x 7.5MVA 33/11kV transformers have been replaced with 2 X 15MVA transformers in 2019 to provide additional long-term capacity. The removed transformers have been refurbished and used in other parts of the network.

31. Substation load graphs





32. Forecasted capital investments

Driver	Description	Year
	None identified	-

33. Parua Bay zone substation

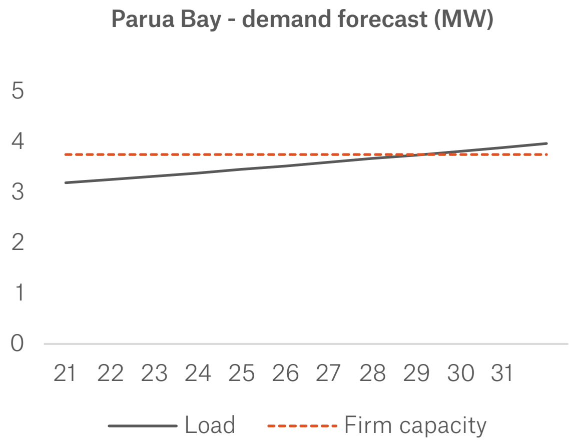
Parua Bay zone substation profile				
Transformer capacity			1 unit 3.75MVA	
Peak load			3.2MW	
Total Number of customers supplied			2,218	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
Pataua	1	905	Overhead	Residential
Parua Bay	2	554	Overhead	Residential
Whangārei Heads	3	759	Overhead	Residential

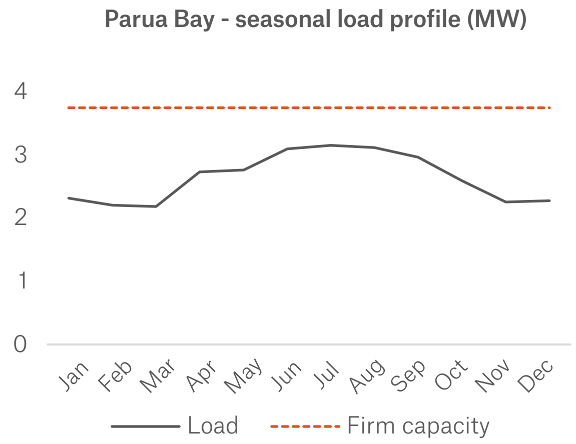
Parua Bay geographic feeder layout

34. Parua Bay substation description

This substation supplies the Parua Bay, McLeod's Bay, Whangārei Heads and Pataua areas comprising of mainly residential type load. Load growth has been fairly low during the past 5 years, however, there is potential for significant development. This substation was commissioned early in 2007 utilising one of the refurbished 3.75MVA transformers relocated from the Hikurangi zone substation. This transformer is planned to be replaced with a 5MVA unit in FY21 to FY22 as it reaches end of life. The new transformer will have enough capacity to meet forecasted incremental growth. A strategic spare transformer held in the second transformer bay will remain until it is no longer needed. An 11kV back feeding upgrade is planned for FY22. This project will increase the restorability of the single transformer zone substation significantly in preparation for the transformer upgrade.

35. Substation load graphs





Parua Bay load is forecasted to exceed the 3.75MVA transformer's rating in 2030 during the winter period. The new 5MVA transformer to be installed in FY22 will ensure adequate capacity for future residential load growth for the foreseeable future.

36. Forecasted capital investments

Driver	Description	Year
Aging asset	Parua Bay transformer upgrade	FY21 – FY22
Security of supply	Parua Bay back-feed constraint mitigation	FY22
Commentary		

37. Tikipunga zone substation

Tikipunga zone substation profile				
Transformer capacity			2 units 20MVA	
Peak load			14.5MW	
Total Number of customers supplied			7,138	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
Whau Valley	1	1,134	Overhead	Residential
Mains Ave	2	843	Overhead	Residential

Tikipunga zone substation profile				
Transformer capacity			2 units 20MVA	
Peak load			14.5MW	
Total Number of customers supplied			7,138	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
Tikipunga Hill	4	998	Overhead	Residential
Cairnfield Rd	5	1,186	Overhead	Residential
Paranui	6	626	Overhead	Residential
Otangarei	7	943	Overhead	Residential
Kiripaka Rd	8	1,408	Overhead	Residential

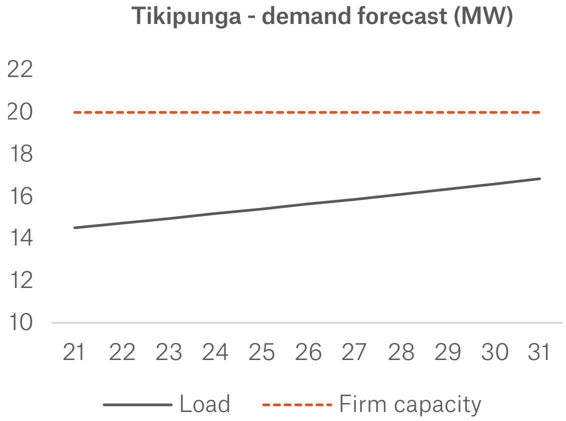
Tikipunga geographic feeder layout

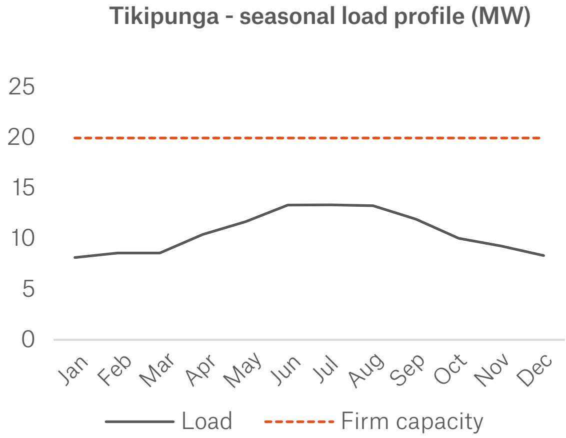
38. Tikipunga substation description

This is Northpower's largest zone substation based on number of premises connected. Feeders supply the residential areas to the north of the CBD as well as the rural area to the north-east of Whangārei, which includes a large sawmill load. The substation load peaks in winter due to heating load. Load growth is moderate, driven primarily by residential growth in the Kensington and Tikipunga suburbs due to urban 'in-fill'. Development is expected to continue in the area to the north and east of the substation.

The old 11kV oil switchgear at this station was replaced with modern gas insulated switchgear in 2008 and the transformers were upgraded to 2 x 20MVA units in 2009. Some changes were recently made to feeder configurations resulting in the transfer of some load from Kamo substation to Tikipunga substation. There is a feeder reconfiguration in progress which will offload portion of CB8 feeder to provide future load growth.

39. Substation load graphs



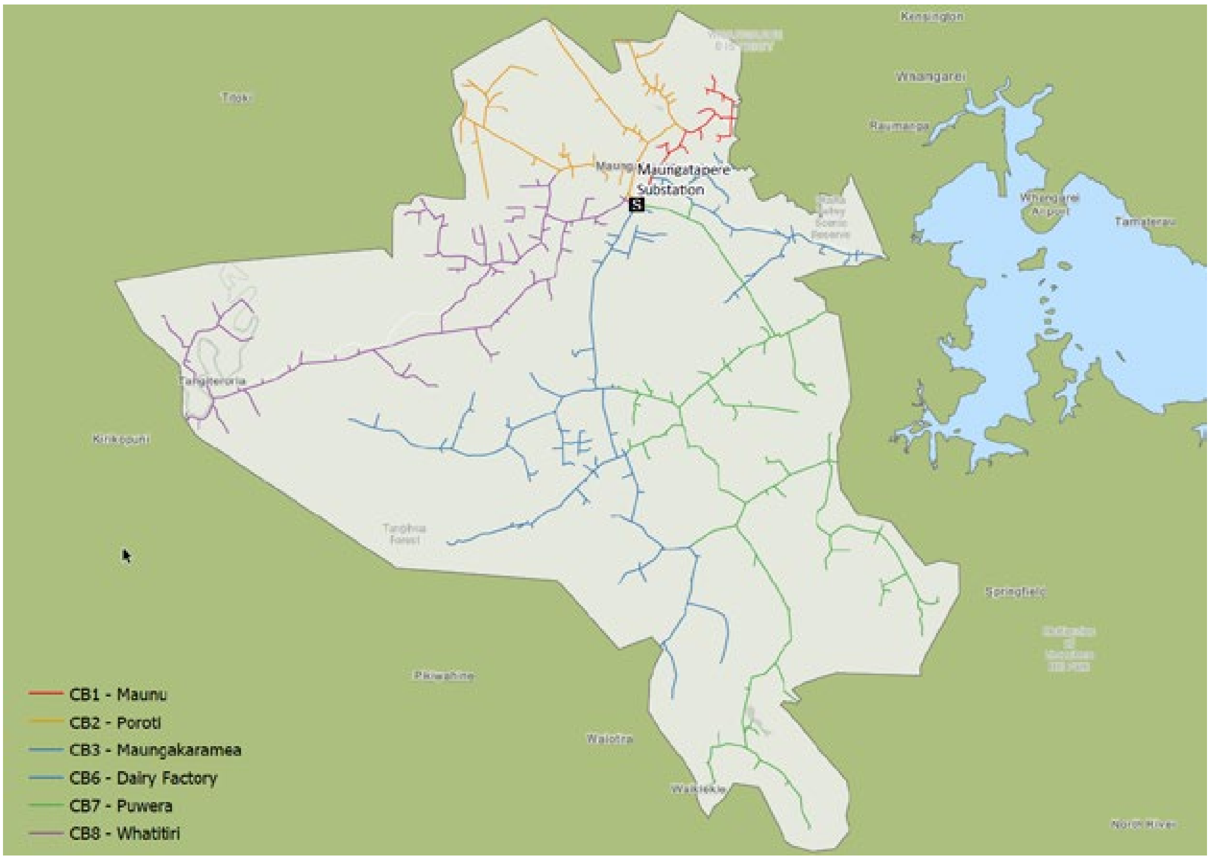


40. Forecasted capital investments

Driver	Description	Year
	None identified	-

41. Maungatapere zone substation

Maungatapere zone substation profile				
Transformer capacity			2 units 7.5MVA	
Peak load			6.9MW	
Total Number of customers supplied			3,526	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
Maunu	1	231	Overhead	Residential
Poroti	2	596	Overhead	Residential
Maungakaramea	3	602	Overhead	Residential
Maungatapere - Dairy Factory	6	287	Overhead	Residential
Puwera	7	437	Overhead	Residential/commercial mix
Whatatiri	8	608	Overhead	Residential



Maungatapere geographic feeder layout

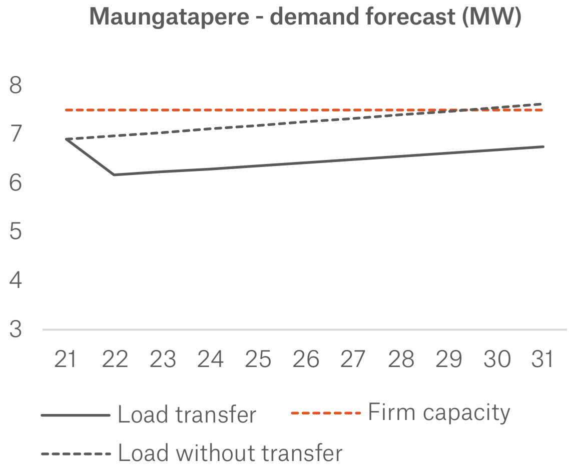
42. Maungatapere substation description

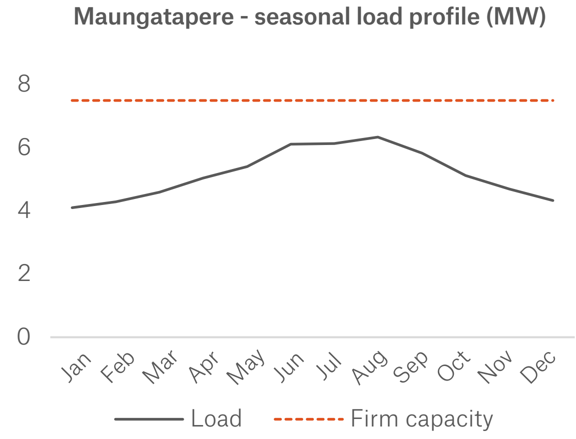
The substation supplies a predominantly rural area (dairy and fruit farming) around Maungatapere village which includes Maungakaramea, Poroti, Tangiteroria, Puwera and Mangapai.

Some load was transferred to Kioreroa substation in 2010 in order to maintain N-1 security. It is also possible to backfeed some of the Maungatapere load via the 11kV network from Poroti substation in the event of a contingency.

Some changes were recently made to feeder configurations in order to provide additional capacity in the Maunu area as an interim measure before the new Maunu substation is completed. Maungatapere substation transformers have been recently replaced by the 2 x 7.5MVA 33/11kV transformers removed from Onerahi, providing the substation the capacity required for the foreseeable future.

43. Substation load graphs





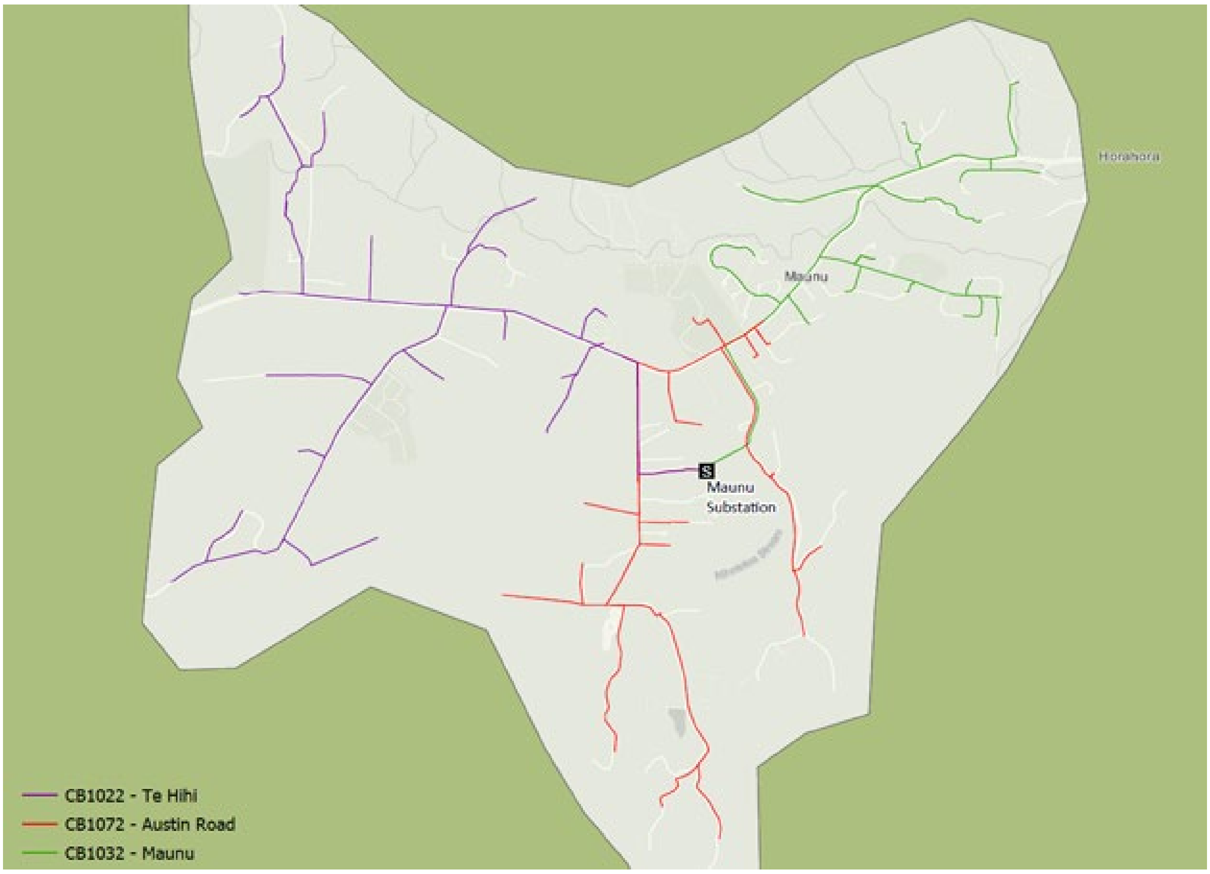
In FY22, a portion of the Maungatapere load of around 1MVA will be transferred to the new Maunu substation, the grey dotted line is a forecast of the likely load without Maunu substation.

44. Forecasted capital investments

Driver	Description	Year
	None identified	-

45. Maunu substation

Maunu Substation profile				
Transformer capacity			1 unit 10MVA	
Peak load			3.3MW	
Total Number of customers supplied			1,563	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
Te Hihi	1022	319	Overhead	Residential
Maunu	1032	798	Overhead	Residential
Austin Road	1072	446	Overhead	Residential



Maunu geographic feeder layout

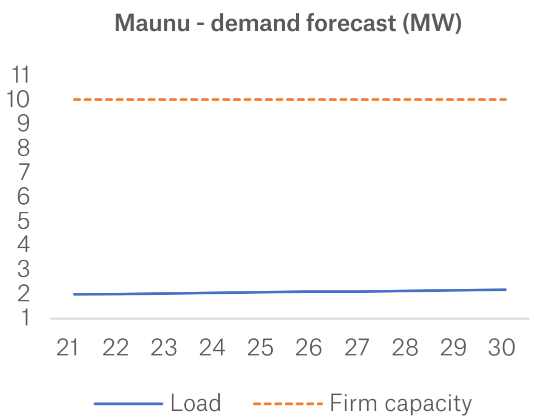
46. Maunu substation description

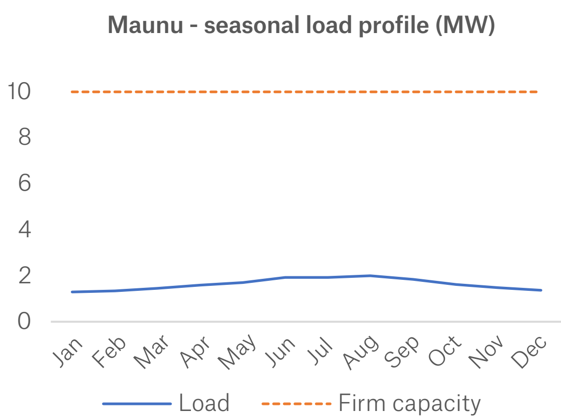
Maunu supplies a predominant residential area to the west of Whangārei City. There is a significant amount of lifestyle development in the rural areas and this trend is expected to continue in the future.

With the commissioning of Maunu substation in April 2021 Maungatapere zone substation load constraint will be relieved. Maunu substation also offloaded parts of Whangārei south and Alexander Street substations. Maunu substation gives Whangārei hospital an extra level of security as it can be used as an additional supply in the case of contingency.

A large amount of upmarket subdivision activity is expected in the Maunu area as Whangārei City spreads westward. This is expected to result in substantial residential load growth in the medium to long-term.

47. Substation load graphs





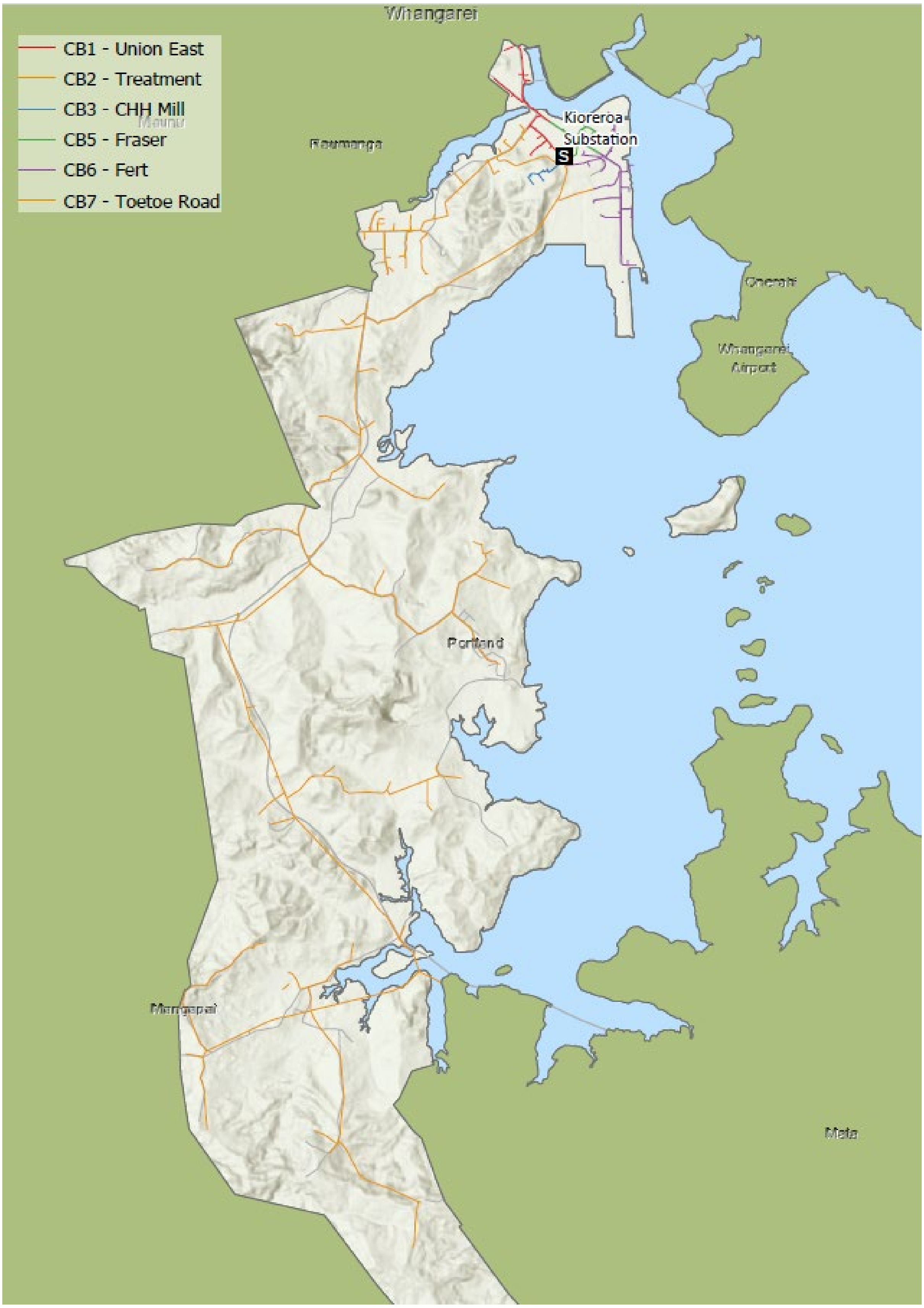
Substation seasonal profile is a forecast

48. Forecasted capital investments

Driver	Description	Year
	None identified	-

49. Kioreroa zone substation

Kioreroa zone substation profile				
Transformer capacity			2 units 15MVA ONAN/20MVA OFAF	
Peak load			8.6MW	
Total Number of customers supplied			1,107	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
Union East	1	109	Overhead	Residential/commercial mix
Treatment	2	215	Overhead	Residential/commercial mix
CHH Supermill	3	1	Underground	Industrial
Fraser	5	79	Overhead	Industrial
Fert. Works	6	86	Overhead	Industrial
ToeToe Rd	7	617	Overhead	Residential



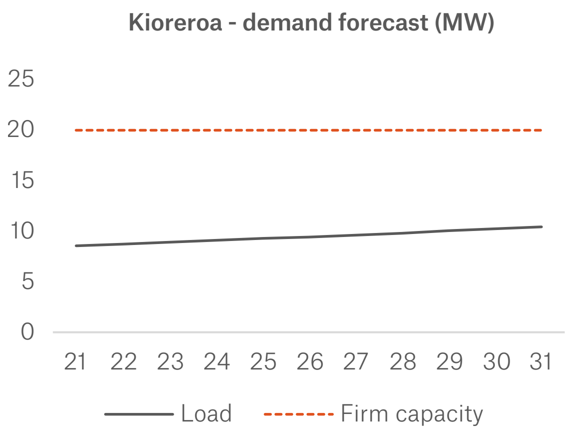
Kioreroa geographic feeder layout

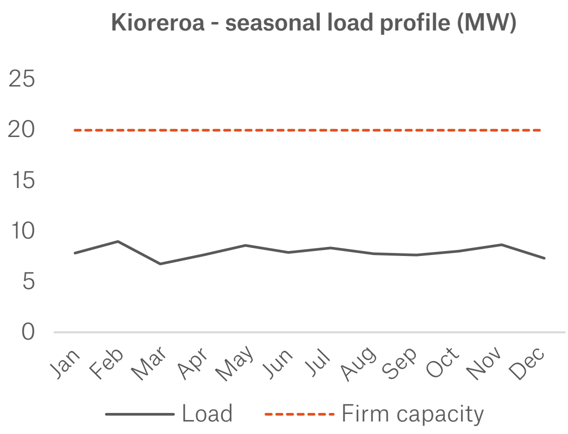
50. Kioreroa substation description

The area supplied by this substation is dominated by heavy industry with associated light industry and commercial loads. The Portland area to the south of Whangārei is also supplied from this substation and includes some rural load. Load growth has been high in the past due to the expansion of some industries but has been marginal in recent years. The development of the deep-water port at Marsden Point will see a continuation of the downsizing of the existing port activities resulting in a substantial amount of land being available for the establishment of new industries to the south-west of the substation. Significant load growth can be expected if development of this area proceeds. A large industrial load has recently been decommissioned on CB1 allowing capacity for new connections in the area.

The 2 x 10MVA transformers at this station were upgraded to 2 x 15/20MVA in early 2006 in anticipation of the expected future load growth as well as to facilitate the upgrading of the transformers at three other zone substations. Some rural load south of Whangārei was transferred to this station from Maungatapere substation in 2010 in order to offload the transformers at the latter station. An additional 11kV feeder was commissioned in 2014 to offload Whangārei South substation and optimise feeder loadings.

51. Substation load graphs





52. Forecasted capital investments

Driver	Description	Year
	None identified	-

53. Poroti zone substation

Poroti zone substation profile				
Transformer capacity			1 unit 5MVA	
Peak load			3.1MW	
Total Number of customers supplied			1,347	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
Titoki	1	765	Overhead	Residential/commercial mix
Hotel	4	117	Overhead	Commercial

Poroti zone substation profile				
Transformer capacity			1 unit 5MVA	
Peak load			3.1MW	
Total Number of customers supplied			1,347	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
Wharekohe	5	75	Overhead	Residential/commercial mix
Kokopu	6	390	Overhead	Residential

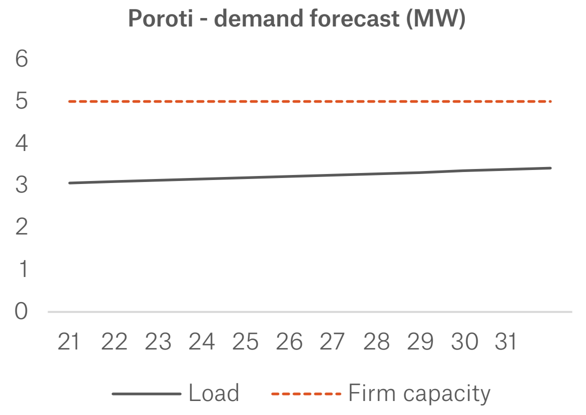
Poroti geographic feeder layout

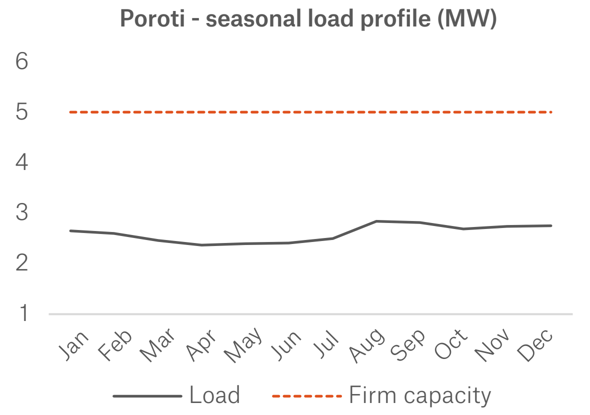
54. Poroti substation description

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

The load is seasonal and weather dependent. Residential and lifestyle growth is relatively low and any significant growth is more likely to come from additional irrigation schemes. The 5MVA transformer capacity at the substation is considered adequate for the medium term. The transformer and 11kV switchboard are planned to be replaced between FY22 – FY24 due to their age.

55. Substation load graphs



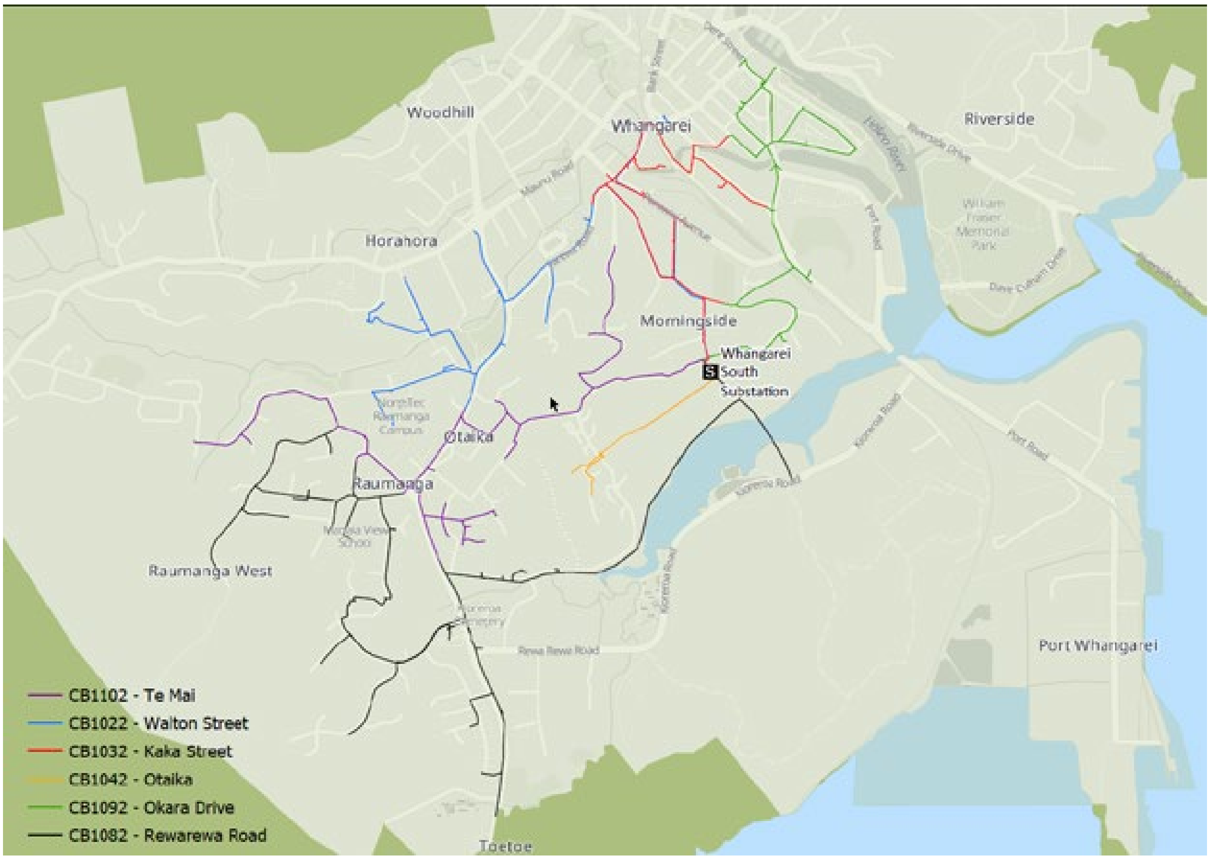


56. Forecasted capital investments

Driver	Description	Year
Aging asset	Poroti 11kV switchboard replacement	FY22 – FY24
Aging asset	Poroti transformer replacement	FY22 – FY24

57. Whangārei South zone substation

Whangārei South zone substation profile				
Transformer capacity			2 units 10MVA	
Peak load			11.2MW	
Total Number of customers supplied			3,749	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
Otaika	1042	988	Overhead	Residential
Kaka St	1032	447	Overhead	Residential/commercial mix
Te Mai	1102	932	Overhead	Residential
Rewa Rewa Rd	1082	904	Overhead	Residential
Okara Drive	1092	478	Overhead	Residential



Whangārei South geographic feeder layout

58. Whangārei South substation description

This substation is situated to the south of Whangārei CBD and supplies a mixture of residential, commercial and light industrial load. Two major customers are supplied from Whangārei South: Whangārei Hospital and Northland Polytechnic. The transformers at this station were upgraded to 2 x 10MVA in 2006. The removed transformers have been refurbished and used in other parts of the network.

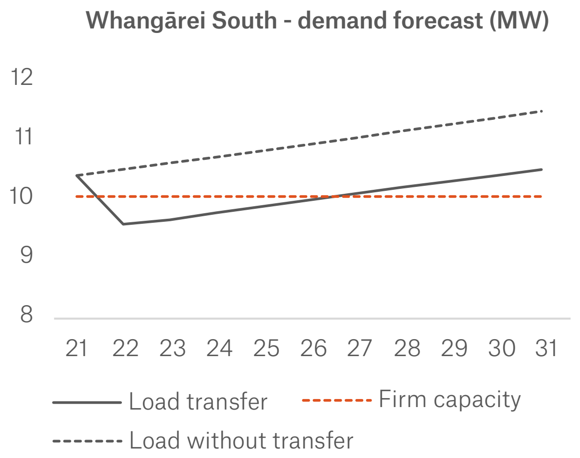
The peak load exceeds the transformer n-1 capacity however, due to the close proximity of Alexander Street and Kioreroa substations, it is possible to transfer load in the event of a contingency. These transformers are planned to be replaced in FY26 - FY28 due to age.

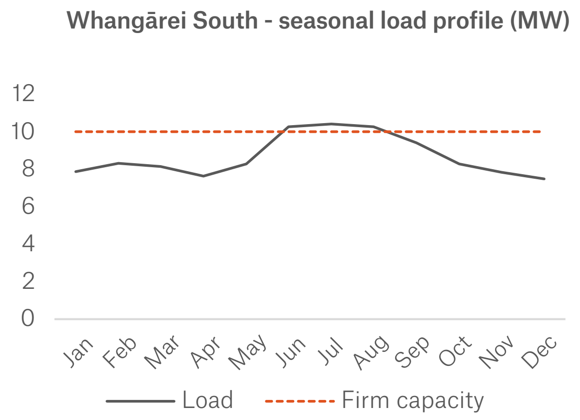
The new Maunu zone substation, once completed in FY22, will result in the transfer of some residential load lying to the west of Whangārei South. This will free up capacity to accommodate anticipated new load to the south as well as some marginal growth of existing load.

The commissioning of a new feeder at Kioreroa substation in 2014 allowed a portion of load from Whangārei Sub to be transferred to Kioreroa substation.

The 11kV switchgear is currently being replaced due to age.

59. Substation load graphs





In FY22 a portion of load will be transferred to the new Maunu substation, the grey dotted line is a forecast of the likely load without Maunu substation.

Whangārei Zone substation load constraint will be temporarily relieved by transferring load to new Maunu substation in FY22.

The two transformers are planned for replacement in FY26 - FY28. The new 15MVA transformers to be installed will ensure adequate capacity for future residential load growth for the next 10 years.

60. Forecasted capital investments

Driver	Description	Year
Aging asset and growth	11kV switchboard replacement	FY21
Security of supply	Whangārei zone substation transformer replacements	FY26 – FY28

61. Maungaturoto zone substation

Maungaturoto zone substation profile				
Transformer capacity			2 units 7.5MVA	
Peak load			5.7MW	
Total Number of customers supplied			932	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
Brynderwyn	1	189	Underground	Residential/commercial mix
Bickerstaff	2	741	Overhead	Residential
Maungaturoto - Dairy Factory	4	2	Overhead	Industrial

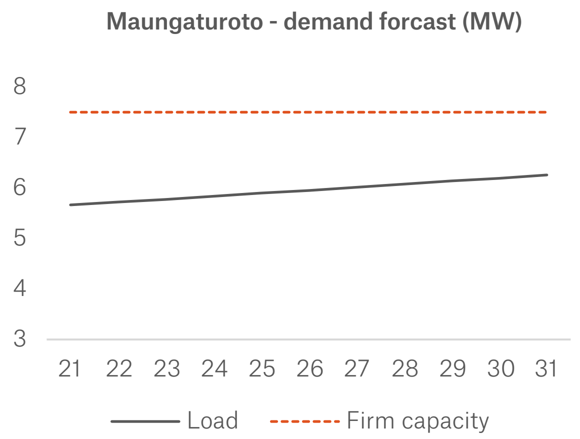
Maungaturoto geographic feeder layout

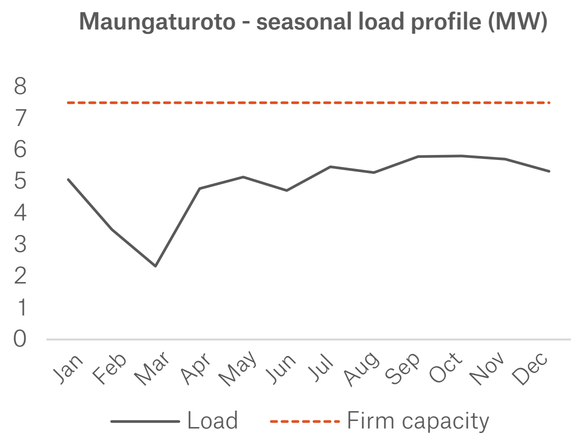
62. Maungaturoto substation description

The load on this substation is dominated by the local dairy factory, which accounts for approximately 75% of the substation's maximum demand. The dairy factory load is expected to increase in the short to medium term. The remainder of the load comprises of the Maungaturoto township and large surrounding rural area in which the load is predominantly dairy farming. Maungaturoto substation is an important backstop for Kaiwaka and Mareretu single transformer substations.

The growth in the township and surrounding area is low and the future load growth potential is mainly driven by the possible expansion of the dairy factory in the longer term. The 2 x 5MVA transformers at this station were replaced with 7.5MVA units in 2006. The ten year plan makes provision for upgrading the 11kV switchboard and replacing the transformers in FY23 to FY25 for age reasons.

63. Substation load graphs





Large dip in March due to factory shutdown (COVID lockdown)

64. Forecasted capital investments

Driver	Description	Year
Aging assets	Maungaturoto 11kV switchboard replacement	FY23 – FY25
Aging assets	Maungaturoto transformer replacements	FY23 – FY25

65. Kaiwaka zone substation

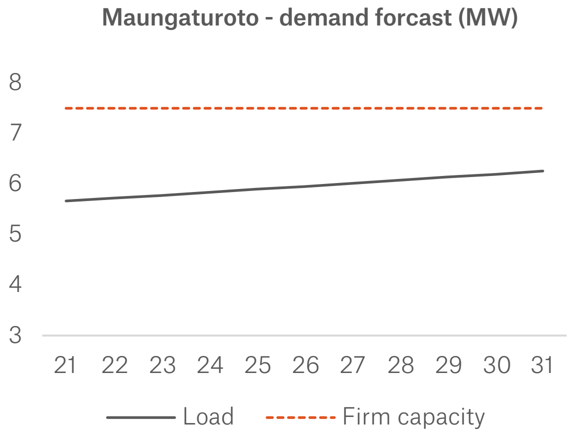
Kaiwaka zone substation profile				
Transformer capacity			1 unit 5MVA	
Peak load			2.3MW	
Total Number of customers supplied			1,852	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
North Kaiwaka	1	206	Overhead	Residential
Kaiwaka Town	4	459	Overhead	Residential
Hakaru	5	696	Overhead	Residential
Topuni	6	491	Overhead	Residential

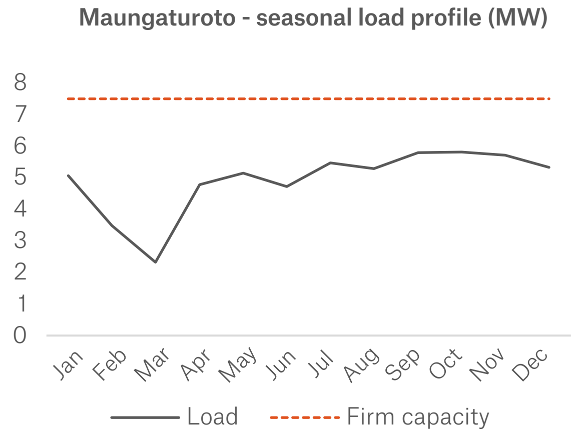
Kaiwaka geographic feeder layout

66. Kaiwaka substation description

This substation supplies Kaiwaka Town and surrounding rural area, which is predominantly dairy farming. There is however an increasing amount of lifestyle block development and the expectation is that the demand for lifestyle properties will continue or even increase due to the proximity to Auckland and the development in the Oneriri and Topuni (Kaipara harbour) area. The 11kV switchboard is planned to be replaced in FY22 to FY24.

67. Substation load graphs



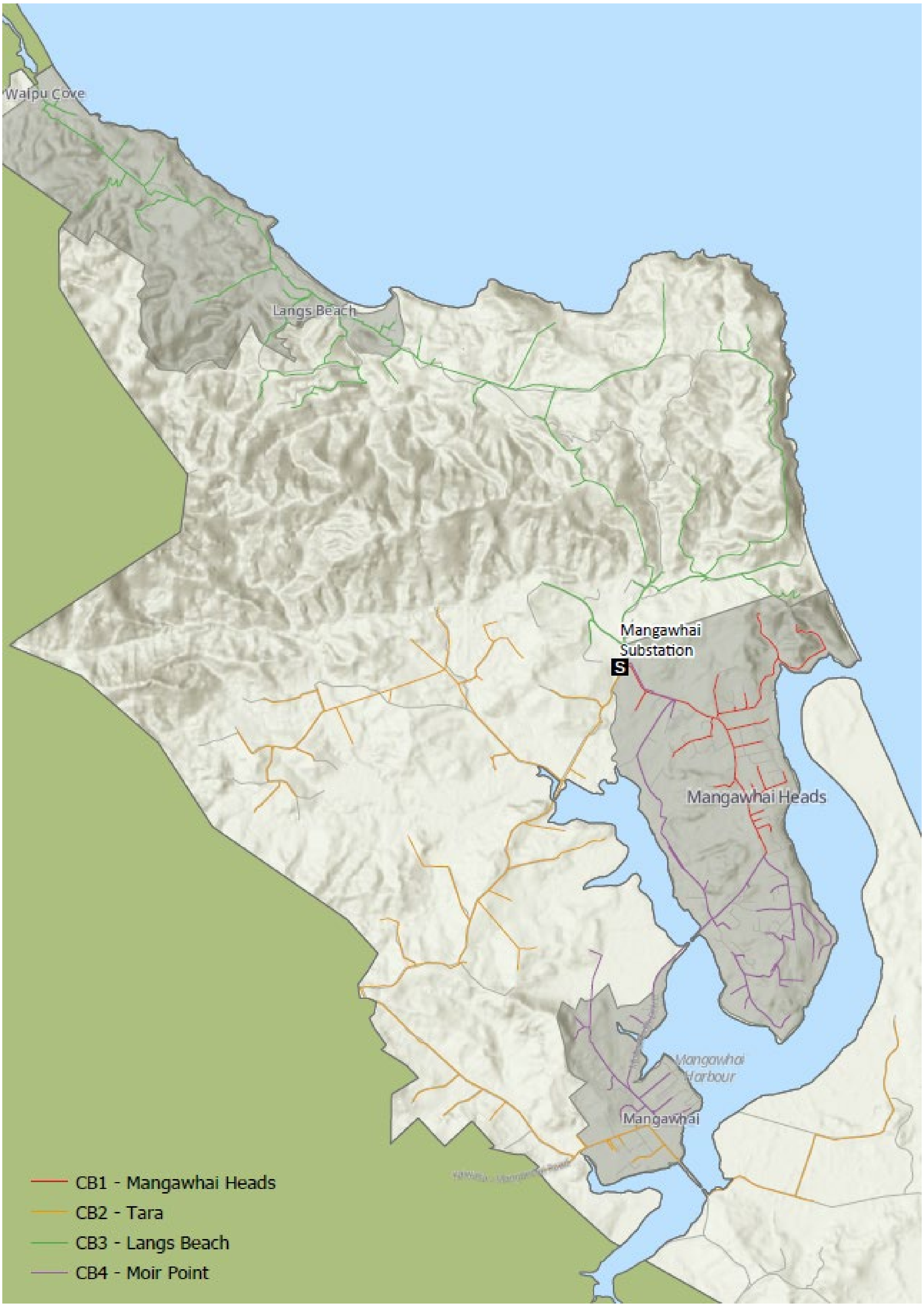


68. Forecasted capital investments

Driver	Description	Year
Aging asset	Kaiwaka 11kV switchboard replacement	FY 22 - FY24

69. Mangawhai zone substation

Mangawhai zone substation profile				
Transformer capacity			2 units 5MVA	
Peak load			7.4MW (for 3% of the year)	
Total Number of customers supplied			4,215	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
Mangawhai Heads	1	1,325	Overhead	Residential
Tara	2	790	Overhead	Residential
Langs Beach	3	703	Underground	Residential
Moir Point	4	1,397	Overhead	Residential



Mangawhai geographic feeder layout

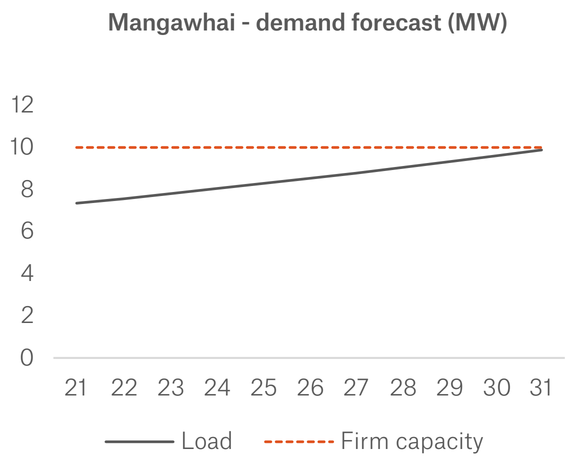
70. Mangawhai substation description

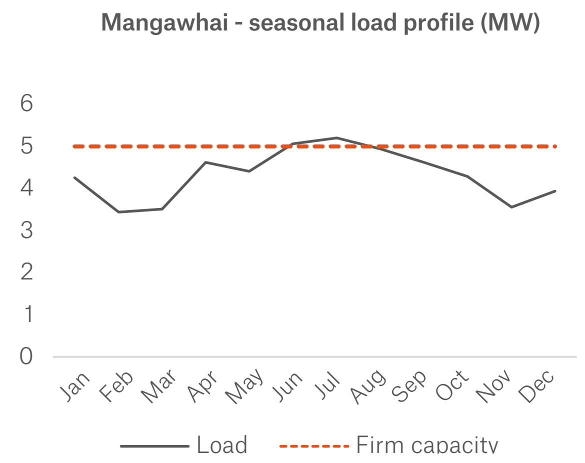
The load on this substation comprises primarily of coastal residential with holiday homes and rural lifestyle dominating. Some commercial connections are present and there is also some dairy farming in the Tara area. The urban areas include Mangawhai Heads, Mangawhai Village, Lang's Cove and Waipu Cove. The substation load is characterised by high peak demands during holiday periods. The load has grown at a higher rate in recent years compared to other parts of the Northpower network distribution areas. Further growth is expected in the future due to Mangawhai's proximity to Auckland.

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

A new township is in the early planning stages which will connect into Moir Point feeder. It is possible that this new connection will require a feeder re-configuration to allow for future load growth on Moir Point feeder.

71. Substation load graphs





Due to difficulty in providing back feeding under contingency of Mangawhai Substation, there are several projects identified to address the issue as outlined below.

- Mangawhai backfeed constraint mitigation – the project will reconfigure one Ruakaka feeder in order to provide additional backfeed capacity to Mangawhai.
- New Maungaturoto to Mangawhai 34km 33kV subtransmission line – the project will involve acquiring the required easements in order to construct an additional 33 kV line to provide higher levels of security of supply to Mangawhai substation.
- Non-network hybrid solution – under consideration is the possible deployment of hybrid diesel generator/battery storage solution for temporary security of supply while the 33kV subtransmission line is constructed.

72. Forecasted capital investments

Driver	Description	Year
Security of Supply	Mangawhai back-feed constraint mitigation	FY22
Security of Supply	Maungaturoto to Mangawhai 34km 33kV subtransmission line easements	FY23 - FY25
Security of Supply	Maungaturoto to Mangawhai 34km 33kV subtransmission line construction	FY25 - FY28
Commentary		

73. Mareretu zone substation

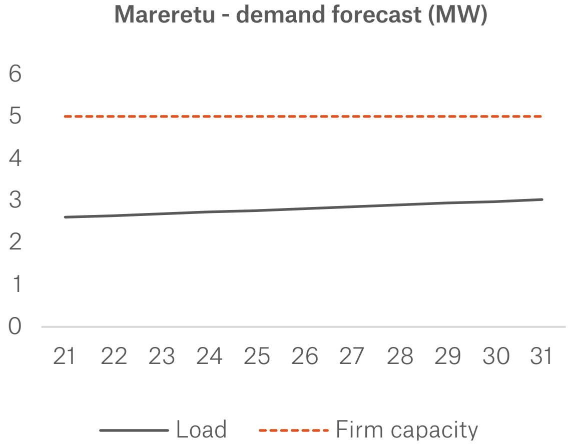
Mareretu zone substation profile				
Transformer capacity			1 unit 5MVA	
Peak load			2.6MW	
Total Number of customers supplied			2,060	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
Taipuha	1	453	Overhead	Residential/Commercial mix
Ararua	2	630	Overhead	Residential
Wairere	5	396	Overhead	Residential
Paparoa	6	581	Overhead	Residential

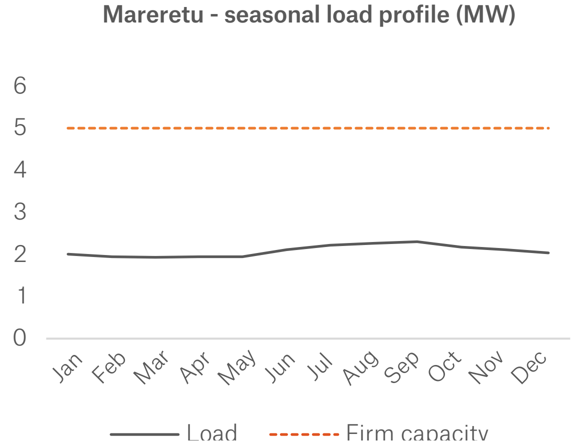
Mareretu geographic feeder layout

74. Mareretu substation description

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

75. Substation load graphs



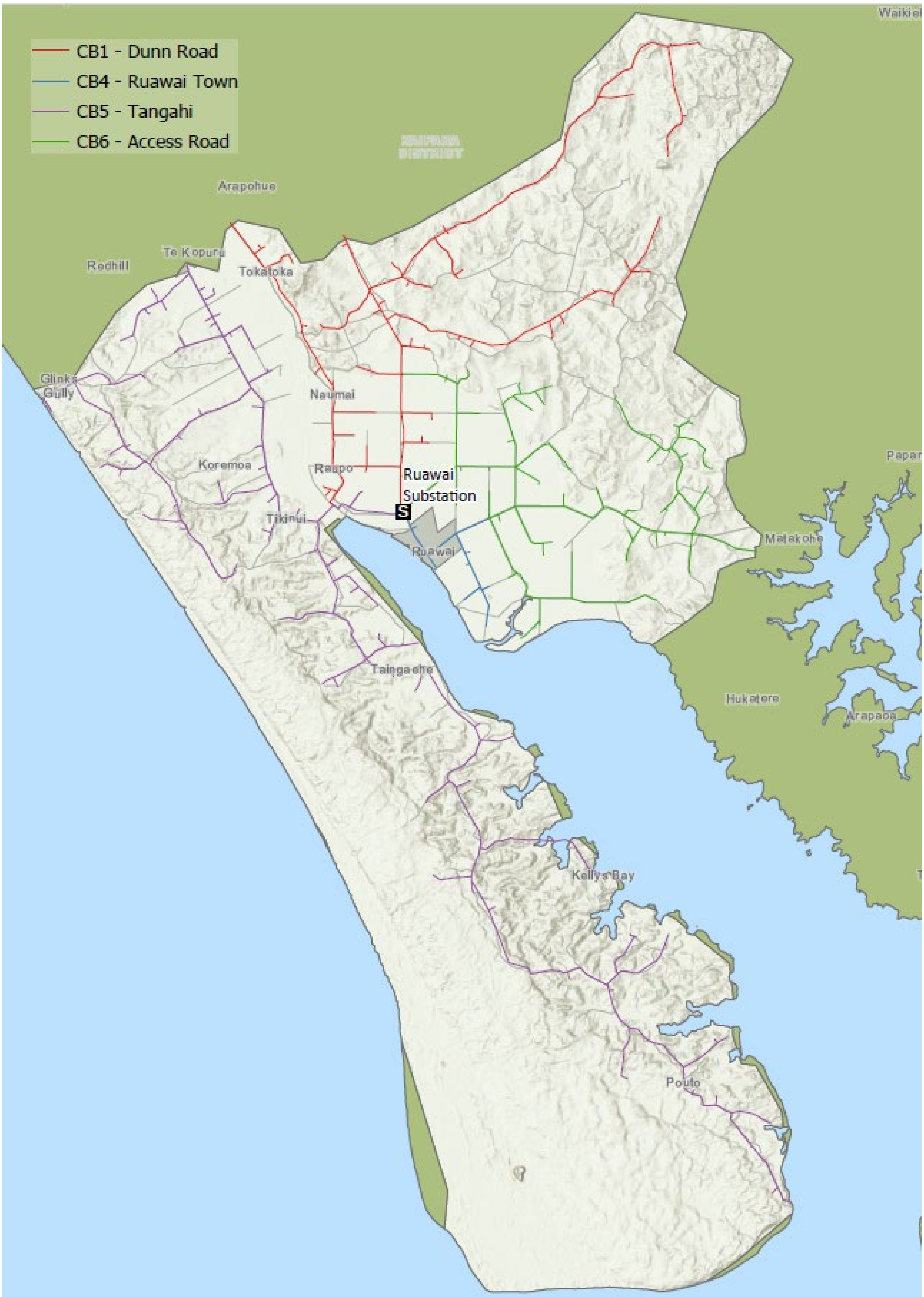


76. Forecasted capital investments

Solution	Description	Year
	None identified	-

77. Ruawai zone substation

Ruawai zone substation profile				
Transformer capacity			1 unit 5MVA	
Peak load			3.3MW	
Total Number of customers supplied			1,698	
11kV feeder name	Circuit breaker ID	Number of customers	Predominant construction of lines	Predominant customer type
Dunns Rd	1	373	Overhead	Residential/commercial mix
Ruawai Town	4	325	Overhead	Residential
Tangaihi	5	662	Overhead	Residential/commercial mix
Access Rd	6	338	Overhead	Residential/commercial mix



Ruawai geographic feeder layout

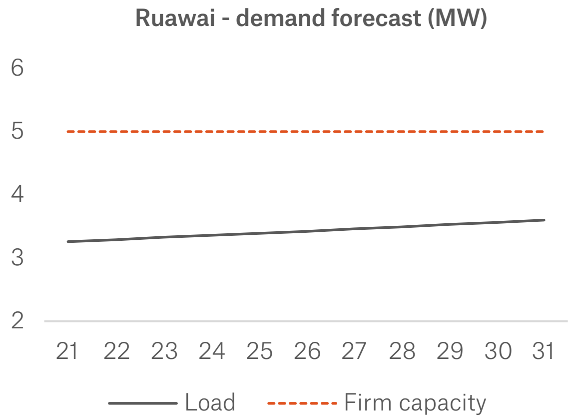
78. Ruawai substation description

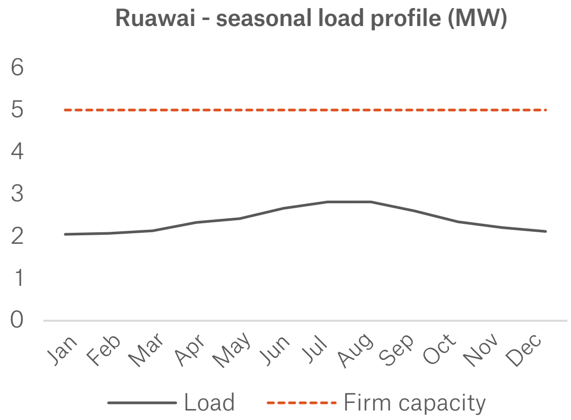
This substation supplies Ruawai town with demand dominated by the surrounding rural dairy farming area. Growth is low and this trend is expected to continue for the short to medium term.

Some load was transferred from the Dargaville area in 2015, which resulted in a fairly significant increase in substation peak load. The 11kV switchboard is planned to be replaced in FY23 for age reasons and at the same time the 5MVA transformer will also be replaced.

Ruawai has relatively low restorability due to the remote location along with being a coastal substation. A study has been conducted to mitigate this issue, which resulted in a potential 11kV reinforcement upgrade that would allow for stronger backstopping to the area.

79. Substation load graphs





80. Forecasted capital investments

Solution	Description	Year
Aging asset	Switchboard replacement	FY21 - FY23
Aging asset	Ruawai transformer replacement	FY21 - FY23
Security of Supply	Ruawai back-feed constraint mitigation	FY25


LEATHER PROTECTORS

Northpower

2021 – 2031
Asset Management Plan

Appendix C
Disclosure schedules

Table of contents

COMMERCE COMMISSION
NEW ZEALAND

EDB Information Disclosure Requirements

Information Templates for Schedules 11a–13

Company Name	Northpower 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

		Company Name	Northpower 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			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
7			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8		for year ended	31 Mar 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		**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10		Consumer connection	3,993	4,760	4,837	4,924	5,020	5,122	5,229	5,339	5,451	5,567	5,686
11		System growth	3,118	1,670	127	1,058	3,285	2,813	137	362	4,575	8,029	3,696
12		Asset replacement and renewal	13,814	18,933	20,746	20,753	16,320	14,557	11,502	14,270	12,432	11,621	11,729
13		Asset relocations	36	105	107	108	110	113	115	117	119	122	124
14		Reliability, safety and environment:											
15		Quality of supply	298	1,710	3,258	3,061	3,585	3,467	803	758	773	922	1,987
16		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	1,222	530	639	635	357	364	371	379	386	394	402
18		**Total reliability, safety and environment**	1,520	2,240	3,898	3,695	3,942	3,831	1,174	1,137	1,159	1,316	2,389
19		**Expenditure on network assets**	22,481	27,708	29,714	30,539	28,678	26,435	18,156	21,224	23,736	26,655	23,624
20		Expenditure on non-network assets	1,442	3,175	3,441	1,667	210	434	3,452	217	261	261	207
21		**Expenditure on assets**	23,923	30,883	33,155	32,206	28,888	26,869	21,609	21,441	23,998	26,916	23,831
22													
23	*plus*	Cost of financing	120	154	166	161	144	134	108	107	120	135	119
24	*less*	Value of capital contributions	3,418	3,500	3,553	3,613	3,679	3,750	3,824	3,900	3,978	4,058	4,140
25	*plus*	Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26													
27		**Capital expenditure forecast**	20,624	27,538	29,768	28,754	25,353	23,254	17,893	17,649	20,140	22,993	19,811
28													
29		Assets commissioned	18,974	25,335	27,387	26,454	23,325	21,393	16,462	16,237	18,529	21,153	18,226
30			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31		for year ended	31 Mar 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
32			**$000 (in constant prices)**										
33		Consumer connection	3,993	4,760	4,765	4,770	4,775	4,781	4,786	4,791	4,796	4,802	4,807
34		System growth	3,118	1,670	125	1,025	3,125	2,625	125	325	4,025	6,925	3,125
35		Asset replacement and renewal	13,814	18,933	20,440	20,104	15,525	13,586	10,528	12,806	10,938	10,023	9,917
36		Asset relocations	36	105	105	105	105	105	105	105	105	105	105
37		Reliability, safety and environment:											
38		Quality of supply	298	1,710	3,210	2,965	3,410	3,236	735	680	680	795	1,680
39		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment	1,222	530	630	615	340	340	340	340	340	340	340
41		**Total reliability, safety and environment**	1,520	2,240	3,840	3,580	3,750	3,576	1,075	1,020	1,020	1,135	2,020
42		**Expenditure on network assets**	22,481	27,708	29,275	29,584	27,280	24,673	16,619	19,047	20,884	22,990	19,975
43		Expenditure on non-network assets	1,442	3,175	3,390	1,615	200	405	3,160	195	230	225	175
44		**Expenditure on assets**	23,923	30,883	32,665	31,199	27,480	25,078	19,779	19,242	21,114	23,215	20,150
45													
46		**Subcomponents of expenditure on assets (where known)**											
47		Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
48		Overhead to underground conversion	550	100	100	100	100	550	550	550	550	550	550
49		Research and development	80	80	80	90	120	130	135	170	150	150	150

Company Name: **Northpower 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		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
50												
51		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
52	for year ended	**31 Mar 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**
53	**Difference between nominal and constant price forecasts**	**$000**										
54	Consumer connection	-	-	71	154	245	341	443	548	655	765	878
55	System growth	-	-	2	33	160	188	12	37	550	1,104	571
56	Asset replacement and renewal	-	-	307	648	796	971	974	1,464	1,494	1,598	1,812
57	Asset relocations	-	-	2	3	5	8	10	12	14	17	19
58	Reliability, safety and environment:											
59	Quality of supply	-	-	48	96	175	231	68	78	93	127	307
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	-	9	20	17	24	31	39	46	54	62
62	**Total reliability, safety and environment**	-	-	58	115	192	255	99	117	139	181	369
63	**Expenditure on network assets**	-	-	439	954	1,398	1,762	1,538	2,177	2,852	3,665	3,650
64	Expenditure on non-network assets	-	-	51	52	10	29	292	22	31	36	32
65	**Expenditure on assets**	-	-	490	1,006	1,408	1,791	1,830	2,199	2,884	3,701	3,682
66												

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
67	for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
68	**11a(ii): Consumer Connection**						
69	*Consumer types defined by EDB**	**$000 (in constant prices)**					
70	Capital contributions (Network)	300	505	510	515	520	526
71	Capital contributions (Customer)	3,440	3,500	3,500	3,500	3,500	3,500
72	Transformer Acquisition Cost	739	800	800	800	800	800
73	Transformer Credits from Upgrades	(581)	(130)	(130)	(130)	(130)	(130)
74	Ripple relay purchases	95	85	85	85	85	85
75	**include additional rows if needed*						
76	**Consumer connection expenditure**	3,993	4,760	4,765	4,770	4,775	4,781
77	*less* Capital contributions funding consumer connection	3,440	3,500	3,500	3,500	3,500	3,500
78	**Consumer connection less capital contributions**	553	1,260	1,265	1,270	1,275	1,281
79	**11a(iii): System Growth**						
80	Subtransmission	-	-	-	-	-	700
81	Zone substations	2,700	500	-	900	2,000	1,800
82	Distribution and LV lines	332	1,120	75	75	1,075	75
83	Distribution and LV cables	-	-	-	-	-	-
84	Distribution substations and transformers	86	50	50	50	50	50
85	Distribution switchgear	-	-	-	-	-	-
86	Other network assets	-	-	-	-	-	-
87	**System growth expenditure**	3,118	1,670	125	1,025	3,125	2,625
88	*less* Capital contributions funding system growth	-	-	-	-	-	-
89	**System growth less capital contributions**	3,118	1,670	125	1,025	3,125	2,625
90							

Company Name: **Northpower 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			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
92		for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
93	**11a(iv): Asset Replacement and Renewal**		**$000 (in constant prices)**					
94		Subtransmission	152	731	2,600	3,102	500	1,316
95		Zone substations	5,067	10,332	10,327	9,537	7,347	5,187
96		Distribution and LV lines	5,801	5,249	5,449	5,449	5,674	5,399
97		Distribution and LV cables	582	340	340	340	350	350
98		Distribution substations and transformers	711	669	646	699	666	719
99		Distribution switchgear	1,405	1,333	1,078	978	988	616
100		Other network assets	96	281	1	1	1	1
101		**Asset replacement and renewal expenditure**	13,814	18,933	20,440	20,104	15,525	13,586
102	*less*	Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
103		**Asset replacement and renewal less capital contributions**	13,814	18,933	20,440	20,104	15,525	13,586
104								

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
106		for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
107	**11a(v): Asset Relocations**							
108		*Project or programme**	**$000 (in constant prices)**					
109		Minor capital expenditure (relocation)	36	55	55	55	55	55
110		Roading works asset relocations	-	50	50	50	50	50
114		**include additional rows if needed*						
115		All other project or programmes - asset relocations	-	-	-	-	-	-
116		**Asset relocations expenditure**	36	105	105	105	105	105
117	*less*	Capital contributions funding asset relocations	-	-	-	-	-	-
118		**Asset relocations less capital contributions**	36	105	105	105	105	105
119								

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
121		for year ended	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**
122	**11a(vi): Quality of Supply**							
123		*Project or programme**	**$000 (in constant prices)**					
124		New Reclosers	-	-	-	55	-	-
125		Whangarei City additional 11kV RMU's	-	100	-	-	-	56
126		11KV Automation at mid and end point of feeder	-	180	180	180	180	-
127		DSUB MDI Meters (CBD)	12	-	-	-	-	-
128		Minor capital expenditure (reliability, safety, environment)	194	100	100	100	100	100
		Overhead to underground conversion	92	100	100	100	100	550
		Maungatapere 33kV Bus Outdoor-to-Indoor Conversion	-	-	-	-	-	-
		Maungaturoto to Mangawhai 34km 33kV Line	-	200	800	-	3,000	2,500
		Maungaturoto to Mangawhai 34km 33kV Line Easements	-	800	1,000	1,000	-	-
		LV Automation	-	30	30	30	30	30
		Kensington 110kV Bus Re-configuration and Tx CBs	-	200	1,000	1,500	-	-
129		**include additional rows if needed*						
130		All other projects or programmes - quality of supply	-	-	-	-	-	-
131		**Quality of supply expenditure**	298	1,710	3,210	2,965	3,410	3,236
132	*less*	Capital contributions funding quality of supply	-	-	-	-	-	-
133		**Quality of supply less capital contributions**	298	1,710	3,210	2,965	3,410	3,236
134								

Company Name	**Northpower 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		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
136	for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
137	**11a(vii): Legislative and Regulatory**						
138	*Project or programme**	$000 (in constant prices)					
139	[Description of material project or programme]	-	-	-	-	-	-
140	[Description of material project or programme]	-	-	-	-	-	-
141	[Description of material project or programme]	-	-	-	-	-	-
142	[Description of material project or programme]	-	-	-	-	-	-
143	[Description of material project or programme]	-	-	-	-	-	-
144	**include additional rows if needed*						
145	All other projects or programmes - legislative and regulatory	-	-	-	-	-	-
146	**Legislative and regulatory expenditure**	-	-	-	-	-	-
147	*less* Capital contributions funding legislative and regulatory	-	-	-	-	-	-
148	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
149							
150		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
151	**11a(viii): Other Reliability, Safety and Environment**						
152	*Project or programme**	$000 (in constant prices)					
153	Zone Substations Risk Mitigation	13	-	-	-	-	-
154	Zone Substations Security Improvement	27	90	90	75	-	-
155	Provision for fibre	797	50	50	50	50	50
156	SCADA comms transfer to dark fibre	-	-	100	100	-	-
157	Ground mounting of 2/4 pole distribution transformers	359	290	290	290	290	290
	SMART Distribution system (load monitoring)	26	100	100	100	-	-
158	**include additional rows if needed*						
159	All other projects or programmes - other reliability, safety and environment	-	-	-	-	-	-
160	**Other reliability, safety and environment expenditure**	1,222	530	630	615	340	340
161	*less* Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
162	**Other reliability, safety and environment less capital contributions**	1,222	530	630	615	340	340
163							
164		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
165	for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme**	$000 (in constant prices)					
169	Research and Development (component testing)	30	30	30	30	50	50
170	Aerial Imagery (GIS)	-	-	40	-	-	50
171	Engineering hardware/Software	50	-	-	-	55	-
172	Research and Development (new technology)	50	50	50	60	70	80
173	Minor capital expenditure (non-network assets)	25	25	25	25	25	25
	Data)	-	700	-	-	-	-
174	**include additional rows if needed*						
175	All other projects or programmes - routine expenditure	-	-	-	-	-	-
176	**Routine expenditure**	155	805	145	115	200	205
177	**Atypical expenditure**						
178	*Project or programme**						
179	ADMS (Advanced Distribution Management System)	852	1,565	945	-	-	-
180	AMS (WASP replacement and CBRM software)	-	200	2,300	1,500	-	-
181	LV network operational management system	100	-	-	-	-	-
182	Faults Management System	-	300	-	-	-	-
183	ESRI Geospatial Tool Sets	85	80	-	-	-	-
	Mobile Substation / Step-Up / STATCOM	-	-	-	-	-	200
	Gentrack	150	-	-	-	-	-
	Development of customer systems and interfaces	100	225	-	-	-	-
184	**include additional rows if needed*						
185	All other projects or programmes - atypical expenditure	-	-	-	-	-	-
186	**Atypical expenditure**	1,287	2,370	3,245	1,500	-	200
187							
188	**Expenditure on non-network assets**	1,442	3,175	3,390	1,615	200	405

Company Name	**Northpower 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	2,150	2,742	2,783	2,830	2,882	2,938	2,995	3,055	3,116	3,179	3,243
11	Vegetation management	2,820	2,889	2,932	2,982	3,037	3,095	3,156	3,219	3,284	3,350	3,417
12	Routine and corrective maintenance and inspection	3,320	3,438	3,189	3,290	3,323	3,564	3,373	3,672	3,665	3,857	3,639
13	Asset replacement and renewal	2,734	2,569	2,607	2,651	2,700	2,752	2,695	2,465	2,514	2,565	2,616
14	**Network Opex**	11,024	11,638	11,511	11,754	11,942	12,349	12,220	12,411	12,579	12,950	12,915
15	System operations and network support	3,396	3,050	3,095	3,148	3,206	3,267	3,332	3,398	3,466	3,536	3,607
16	Business support	13,710	13,194	13,392	13,620	13,870	14,136	14,415	14,702	14,996	15,297	15,605
17	**Non-network opex**	17,106	16,244	16,487	16,768	17,076	17,404	17,747	18,100	18,462	18,833	19,212
18	**Operational expenditure**	28,130	27,881	27,998	28,521	29,018	29,753	29,966	30,511	31,041	31,783	32,127

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	2,150	2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742
23	Vegetation management	2,820	2,889	2,889	2,889	2,889	2,889	2,889	2,889	2,889	2,889	2,889
24	Routine and corrective maintenance and inspection	3,320	3,438	3,142	3,187	3,161	3,326	3,087	3,295	3,225	3,327	3,077
25	Asset replacement and renewal	2,734	2,569	2,569	2,569	2,569	2,569	2,467	2,212	2,212	2,212	2,212
26	**Network Opex**	11,024	11,638	11,341	11,386	11,360	11,526	11,185	11,138	11,067	11,170	10,920
27	System operations and network support	3,396	3,050	3,050	3,050	3,050	3,050	3,050	3,050	3,050	3,050	3,050
28	Business support	13,710	13,194	13,194	13,194	13,194	13,194	13,194	13,194	13,194	13,194	13,194
29	**Non-network opex**	17,106	16,244	16,244	16,244	16,244	16,244	16,244	16,244	16,244	16,244	16,244
30	**Operational expenditure**	28,130	27,881	27,585	27,630	27,604	27,769	27,428	27,382	27,311	27,413	27,164
31	**Subcomponents of operational expenditure (where known)**											
32–33	Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
34	Direct billing*	-	-	-	-	-	-	-	-	-	-	-
35	Research and Development	-	-	-	-	-	-	-	-	-	-	-
36	Insurance	-	-	-	-	-	-	-	-	-	-	-

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

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	-	-	41	88	141	196	254	313	374	437	501
43	Vegetation management	-	-	43	93	148	206	267	330	395	461	528
44	Routine and corrective maintenance and inspection	-	-	47	103	162	238	286	377	440	530	562
45	Asset replacement and renewal	-	-	39	83	132	183	228	253	302	353	404
46	**Network Opex**	-	-	170	367	582	823	1,035	1,273	1,511	1,781	1,995
47	System operations and network support	-	-	46	98	156	218	282	349	416	486	557
48	Business support	-	-	198	426	676	942	1,221	1,508	1,802	2,103	2,411

Company Name: **Northpower Ltd**
AMP Planning Period: **1 April 2021 – 31 March 2031**

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref	Voltage	Asset category	Asset class	Units	Asset condition at start of planning period (percentage of units by grade)							
7					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.	2.32%	4.56%	37.46%	51.32%	4.33%	-	2	2.0%
11	All	Overhead Line	Wood poles	No.	11.04%	5.31%	39.82%	42.85%	0.98%	-	2	8.0%
12	All	Overhead Line	Other pole types	No.	29.17%	18.75%	38.54%	12.50%	1.04%	-	2	30.0%
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	1.02%	23.02%	44.22%	30.06%	1.68%	-	3	9.8%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	100.00%	-	-	-	3	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	4.28%	88.89%	6.83%	-	3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	98.87%	1.13%	-	-	4	26.5%
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	-	-	-	100.00%	-	-	4	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	100.00%	-	-	4	-
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	-	-	-	100.00%	-	-	4	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	5.00%	-	35.00%	60.00%	-	-	4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-		100.00%	-	-	4	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	62.50%	31.25%	6.25%	-	4	25.0%
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	16.67%	83.33%	-	-	4	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	58.06%	41.94%	-	-	2	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	55.06%	41.57%	3.37%	-	2	-
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	100.00%	-	-	4	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	60.00%	40.00%	-	-	2	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	10.46%	10.46%	16.34%	51.63%	11.11%	-	4	22.2%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	-	4	-
35												

Company Name: **Northpower Ltd**

AMP Planning Period: **1 April 2021 – 31 March 2031**

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
36					Asset condition at start of planning period (percentage of units by grade)							
37												
38	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.	2.44%	14.63%	39.02%	34.15%	9.76%	-	4	36.60%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2.56%	3.11%	34.12%	53.86%	6.35%	-	4	12.00%
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	0.43%	0.04%	4.63%	82.06%	12.84%	-	3	0.40%
44	HV	Distribution Cable	Distribution UG PILC	km			26.10%	71.49%	2.41%	-	2	0.74%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	100.00%	-	-	-	-	1	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	9.38%	-	-	81.25%	9.38%	-	4	9.38%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-	-	-	4	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	6.46%	2.93%	11.91%	69.00%	9.70%	-	3	5.84%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	20.00%	26.67%	33.33%		20.00%	-	2	66.67%
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	0.91%	0.91%	7.31%	78.08%	12.79%	-	4	7.30%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	6.34%	3.48%	16.08%	62.28%	11.82%	-	3	1.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	2.85%	6.78%	19.93%	58.71%	11.73%	-	3	4.00%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	16.67%	66.67%	16.67%	-	4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	14.41%	11.86%	26.27%	44.92%	2.54%	-	4	4.20%
55	LV	LV Line	LV OH Conductor	km	1.01%	2.71%	46.49%	46.33%	3.46%	-	4	1.08%
56	LV	LV Cable	LV UG Cable	km	0.04%	0.25%	9.61%	74.10%	16.00%	-	2	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	14.10%	8.10%	37.36%	35.40%	5.04%	-	2	-
58	LV	Connections	OH/UG consumer service connections	No.			0.01%	21.16%	78.83%	-	3	0.05%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	2.33%	0.29%	14.58%	71.14%	11.66%	-	2	13.55%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	100.00%	-	-	4	-
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	100.00%	-	-	4	7.41%
62	All	Load Control	Centralised plant	Lot	33.33%	33.33%	33.33%			-	4	33.33%
63	All	Load Control	Relays	No.	28.66%	10.33%	32.25%	27.63%	1.14%	-	3	0.10%
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	N/A	-

Company Name: **Northpower Ltd**
AMP Planning Period: **1 April 2021 – 31 March 2031**

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
8										
9	Alexander Street	13	15	N-1	13	87%	15	87%	No constraint within +5 years	Load transfer to new Maunu Substation
10	Bream Bay	5	10	N	3	45%	10	55%	No constraint within +5 years	Additional Transformer in FY25 for N-1 security
11	Dargaville	11	15	N-1	2	72%	15	75%	No constraint within +5 years	
12	Dargaville 110/50/66 kV	11	35	N-1	2	31%	35	32%	No constraint within +5 years	
13	Hikurangi	6	5	N-1 Switchable	3	112%	10	79%	No constraint within +5 years	Transformer upgrade in FY22
14	Kaiwaka	2	5	N-1 Switchable	2	46%	5	63%	No constraint within +5 years	
15	Kamo	12	15	N-1	4	77%	15	82%	No constraint within +5 years	
16	Kensington (Regional)	63	50	N-1	19	127%	100	67%	No constraint within +5 years	Transformer upgrade in FY24
17	Kioreroa	9	20	N-1	5	46%	20	46%	No constraint within +5 years	
18	Mangawhai	7	10	N	2	74%	10	87%	Other	Security of supply
19	Mareretu	3	5	N	2	52%	5	56%	No constraint within +5 years	
20	Maungatapere	7	8	N-1	6	89%	8	87%	No constraint within +5 years	Load transfer to new Maunu Substation
21	Maungatapere (Regional)	41	30	N-1	19	136%	100	43%	No constraint within +5 years	Transformer upgrade in FY26
22	Maungaturoto	6	8	N-1	2	82%	8	85%	No constraint within +5 years	
23	Ngunguru	3	4	N	1	90%	5	75%	No constraint within +5 years	Transformer upgrade in FY22
24	Onerahi	7	15	N-1 Switchable	3	50%	15	53%	No constraint within +5 years	
25	Parua Bay	3	4	N	2	88%	5	75%	No constraint within +5 years	Transformer upgrade in FY23
26	Poroti	3	5	N-1 Switchable	3	61%	5	66%	No constraint within +5 years	
27	Ruakaka	7	10	N-1	4	71%	10	82%	No constraint within +5 years	
28	Ruawai	3	5	N	3	61%	5	65%	No constraint within +5 years	
	Tikipunga	15	20	N-1	9	73%	20	79%	No constraint within +5 years	
	Whangarei South	10	10	N-1	7	104%	10	99%	No constraint within +5 years	Load transfer to new Maunu Substation. Propose upgrade in FY28

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Company Name: **Northpower Ltd**
AMP Planning Period: **1 April 2021 – 31 March 2031**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
7		**12c(i): Consumer Connections**						
8		*Number of ICPs connected in year by consumer type*			Number of connections			
9			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
10		for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
11		*Consumer types defined by EDB**						
12		Very large industrial	-	-	-	-	-	-
13		Commercial and Industrial (demand based ND9)	-	1	1	1	1	1
14		Mass market	924	942	961	981	1,000	1,020
17		**Connections total**	924	943	962	982	1,001	1,021
18		**include additional rows if needed*						
19		**Distributed generation**						
20		Number of connections	171	174	178	181	185	189
21		Capacity of distributed generation installed in year (MVA)	0.90	0.92	0.94	0.96	0.97	0.99
22		**12c(ii) System Demand**						
23			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
24		**Maximum coincident system demand (MW)** — for year ended	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26
25		GXP demand	171	179	181	183	185	187
26	*plus*	Distributed generation output at HV and above	9	4	4	4	4	4
27		**Maximum coincident system demand**	180	182	185	187	188	190
28	*less*	Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
29		**Demand on system for supply to consumers' connection points**	180	182	185	187	188	190
30		**Electricity volumes carried (GWh)**						
31		Electricity supplied from GXPs	934	1,136	1,160	1,185	1,209	1,235
32	*less*	Electricity exports to GXPs	-	-	-	-	-	-
33	*plus*	Electricity supplied from distributed generation	19	19	20	20	20	21
34	*less*	Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
35		**Electricity entering system for supply to ICPs**	953	1,156	1,180	1,205	1,230	1,256
36	*less*	Total energy delivered to ICPs	905	1,122	1,144	1,167	1,191	1,214
37		**Losses**	48	34	35	37	39	41
38								
39		**Load factor**	61%	72%	73%	74%	74%	75%
40		**Loss ratio**	5.1%	2.9%	3.0%	3.1%	3.2%	3.3%

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

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 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)	120.0	120.0	120.0	120.0	120.0	120.0
12	Class C (unplanned interruptions on the network)	150.0	105.0	100.0	100.0	100.0	100.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.50	0.50	0.50	0.50	0.50	0.50
15	Class C (unplanned interruptions on the network)	2.75	2.75	2.75	2.75	2.75	2.75

Company Name	Northpower Ltd
AMP Planning Period	1 April 2021 – 31 March 2031
Asset Management Standard Applied	ISO55000

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

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

Question No.	Function	Question	Score 2018	Score 2021	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	1	2	Asset Management Policy is approved by GM Network and forms part of our controlled document (managed through our Quality Management System). It is an overarching policy which informs our asset management strategies, and is considered in investment decisions. Policy has been communicated to wider staff through our QMS system.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (e.g., as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	3	Our electricity network strategy, outlined in the AMP, has at its core delivering a consistent, safe and cost effective supply of electricity to our customers by using good asset management practices. The strategy gives effect to our shareholders' expectations (as set out in our SCI), as well as our risk management policy. We consider stakeholder feedback, including through informal and formal channels, in developing our strategy. Our common management systems are certified to ISO 9001, ISO 14001 and we have developed an asset management maturity roadmap to align our approach to ISO55001.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (e.g., as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	3	We have documented asset management strategies for our asset classes, which consider lifecycle and planning management, and asset information including age and condition. Our strategies also outline the performance criteria that we will measure and monitor against.		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.

Company Name	Northpower Ltd
AMP Planning Period	1 April 2021 – 31 March 2031
Asset Management Standard Applied	ISO55000

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

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

26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3	3	Our asset management work plan is documented in broad terms within our AMP. Detailed work plans are documented in the annual work plan, project definition documents, detailed project scopes and in our preventative and corrective maintenance plans. Asset management plan documents are made available to stakeholders as appropriate to their role within the asset management system. For lower cost, high volume items, the plan is expressed in terms of expenditure, rather than volumes.		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	**Northpower Ltd**
AMP Planning Period	**1 April 2021 – 31 March 2031**
Asset Management Standard Applied	**ISO55000**

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.

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Company Name	**Northpower Ltd**
AMP Planning Period	**1 April 2021 – 31 March 2031**
Asset Management Standard Applied	**ISO55000**

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	Northpower Ltd
AMP Planning Period	1 April 2021 – 31 March 2031
Asset Management Standard Applied	ISO55000

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score 2018	Score 2021	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	2	3	The AMP is available in our intranet and published on our website. Prior to the commencement of a financial year, projects and programs for delivery are discussed with stakeholders, including our contractors. Delivery progress against Plans are monitored monthly and action taken to ensure as far as reasonably practicable that the annual capex and opex programs of works are delivered successfully. Reporting is undertaken at an operational and governance level against delivery plans.		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	3	Overall responsibility of delivery of the AMP is documented to reside with the GM Network (roles are further defined in section 2 of the AMP). A RACI matrix is developed within the Network team which articulates responsibility and accountability. Process owners are defined in the management system. The Delegated Authorities Policy outlines financial authorities for the AMP delivery programme. Northpower has, and continues to, strengthen its asset management capabilities, and business structure have been realigned to ensure better flow and segregation of accountability. This includes additional investment in asset management, engineering and project management capability over the last three years. In addition, the service level agreement with the field service provider documents delivery responsibilities. This has been reset, with revised key performance metrics.		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.

Company Name	Northpower Ltd
AMP Planning Period	1 April 2021 – 31 March 2031
Asset Management Standard Applied	ISO55000

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

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

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	3	There is a formal service level agreement (SLA) in place with principal contractor. A robust governance structure is in place with monthly reporting on progress to the plans. Supplier arrangements are in place for key equipment and materials. Competitive commercial processes relating to procurement for large projects and critical network assets are well established. Smarter systems relating to electronic data capture, data management and information systems have been implemented and continue to be developed.		It is essential that the plan(s) are realistic and can be implemented, which requires appropriate resources to be available and enabling mechanisms in place. This question explores how well this is achieved. The plan(s) not only need to consider the resources directly required and timescales, but also the enabling activities, including for example, training requirements, supply chain capability and procurement timescales.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team. If appropriate, the performance management team. Where appropriate the procurement team and service providers working on the organisation's asset-related activities.	The organisation's asset management plan(s). Documented processes and procedures for the delivery of the asset management plan.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	3	3	Northpower has well documented emergency and incident response procedures, including: a Co-ordinated Incident Management Plan for major events impacting network operations; a suite of network contingency plans used to assist in major unplanned events that significantly disrupt electricity supply; a revised Business Continuity plan and processes for events which disrupt business operations; such as the current impacts of Covid-19. Northpower is an active member of the Northland Lifelines group and is active in the regional CDEM group. Northpower has a dedicated strategic spare store and a documented process for managing these. We regularly review and update our contingency and disaster recovery plans to ensure they remain relevant and appropriate. We conduct an annual test of our recovery plans under different desktop scenarios to ensure effectiveness and familiarity with those involved in any recovery process. We have adequate staff and contractor resources available for these events (through the wider Northpower Group), standby generators available, a backup control centre at a remote location. Most staff can work remotely if required.		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.

Company Name	Northpower Ltd
AMP Planning Period	1 April 2021 – 31 March 2031
Asset Management Standard Applied	ISO55000

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.

Company Name	**Northpower Ltd**
AMP Planning Period	**1 April 2021 – 31 March 2031**
Asset Management Standard Applied	**ISO55000**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	The organisation has not considered the arrangements needed for the effective implementation of plan(s).	The organisation recognises the need to ensure appropriate arrangements are in place for implementation of asset management plan(s) and is in the process of determining an appropriate approach for achieving this.	The organisation has arrangements in place for the implementation of asset management plan(s) but the arrangements are not yet adequately efficient and/or effective. The organisation is working to resolve existing weaknesses.	The organisation's arrangements fully cover all the requirements for the efficient and cost effective implementation of asset management plan(s) and realistically address the resources and timescales required, and any changes needed to functional policies, standards, processes and the asset management information system.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
33	Contingency planning	What plan(s) and procedure(s) does the organisation have for identifying and responding to incidents and emergency situations and ensuring continuity of critical asset management activities?	The organisation has not considered the need to establish plan(s) and procedure(s) to identify and respond to incidents and emergency situations.	The organisation has some ad-hoc arrangements to deal with incidents and emergency situations, but these have been developed on a reactive basis in response to specific events that have occurred in the past.	Most credible incidents and emergency situations are identified. Either appropriate plan(s) and procedure(s) are incomplete for critical activities or they are inadequate. Training/ external alignment may be incomplete.	Appropriate emergency plan(s) and procedure(s) are in place to respond to credible incidents and manage continuity of critical asset management activities consistent with policies and asset management objectives. Training and external agency alignment is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	**Northpower Ltd**
AMP Planning Period	**1 April 2021 – 31 March 2031**
Asset Management Standard Applied	**ISO55000**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score 2018	Score 2021	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	3	The GM Network is responsible for delivering the requirements of the asset management strategy, objectives and plans. In turn, responsibilities are delegated to members of the Network Leadership team to with clearly defined responsibilities and objectives. These responsibilities are supported by a delegated authorities policy, with clearly defined levels of financial authority. Most delivery activities are contracted out to experienced field service providers, and governed through service level agreements that define accountabilities and responsibilities.		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 e.g., 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	3	Management oversight at an Executive level monitors achievement of asset management activities. This includes reporting on key metrics, including delivery and performance, and these are also reported to the Board monthly. There is a process for establishing the need for additional employees for internal resourcing, as well as increases in delivery resources and budgets. Peak workloads are managed through sourcing additional contractors who can carry out the work. Regular meetings with our core contractors include discussion and visibility of future work plans and resourcing requirements.		Optimal asset management requires top management to ensure sufficient resources are available. In this context the term 'resources' includes manpower, materials, funding and service provider support.	Top management. The management team that has overall responsibility for asset management. Risk management team. The organisation's managers involved in day-to-day supervision of asset-related activities, such as frontline managers, engineers, foremen and chargehands as appropriate.	Evidence demonstrating that asset management plan(s) and/or the process(es) for asset management plan implementation consider the provision of adequate resources in both the short and long term. Resources include funding, materials, equipment, services provided by third parties and personnel (internal and service providers) with appropriate skills competencies and knowledge.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	3	3	A range of strategies are employed to communicate the importance of meeting asset management requirements. This includes monthly reporting against performance targets, weekly meetings with senior leadership teams to discuss asset management requirements and ensure we are on plan, regular meetings with our delivery contractor at which asset management requirements are discussed. Key deliverables and progress against plan, as well as core asset management issues are communicated at regular all team meetings.		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 (e.g., 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.

Company Name	Northpower Ltd
AMP Planning Period	1 April 2021 – 31 March 2031
Asset Management Standard Applied	ISO55000

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

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

45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3	3	Compliance is ensured by service level agreement (SLA) and contracts for field services and construction works. The majority of outsourced work is undertaken by Northpower Contracting under a SLA which outlines respective responsibilities and KPI's to support performance. Control processes include formal project specifications and documentation, HSQE audits. Project managers are accountable for ensuring compliant delivery of outsourced activities. The Contracts and Services Manager is accountable for assessing performance of contractors under the relevant agreements.		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 (e.g., 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.

Company Name	Northpower Ltd
AMP Planning Period	1 April 2021 – 31 March 2031
Asset Management Standard Applied	ISO55000

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.

Company Name	**Northpower Ltd**
AMP Planning Period	**1 April 2021 – 31 March 2031**
Asset Management Standard Applied	**ISO55000**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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.

Company Name	Northpower Ltd
AMP Planning Period	1 April 2021 – 31 March 2031
Asset Management Standard Applied	ISO55000

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score 2018	Score 2021	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	2	3	Department managers identify human resource requirements. Key competencies are documented in job profiles and competence is assessed during regular performance reviews. Northpower has training budgets allocated and each employee is encouraged to have a personal development plan. We have invested in the training of engineering cadets to meet future resourcing requirements. Staff resources over the past three years have been scaled up to reflect our commitments to lift our asset management approach and work load. External reviews of Northpower's asset management capabilities are carried out regularly and these help identifying gaps in capability that help form our resourcing needs. We recognise that additional resourcing is likely required to meet asset delivery plans and have developed approved contractor frameworks to enable additional contractors on the network.		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	3	As per question 48 above. Competencies are identified in the job design process, and included in position descriptions. Competency is regularly reviewed against the requirements of the job profile and training needs identified. Competencies are defined for certain field based activities, and managed through our Learning Management System (this includes records of learning and verifications). Specialised training is provided for Control Operators. Staff or contractors not holding the mandatory competencies are unable to undertake the associated activities.		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (e.g., 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.

Company Name	Northpower Ltd
AMP Planning Period	1 April 2021 – 31 March 2031
Asset Management Standard Applied	ISO55000

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

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

50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	2	3	Service provider training and competence is managed through established competency frameworks. These are subject to regular audit. Asset management skills and competencies are documented in job descriptions and reviewed during annual performance reviews. Staff are encouraged to have a personal development plan and development and training opportunities are discussed with each employee. Staff are expected to attend relevant courses or seminars to upskill as needed. Staff new to the industry are assisted with their development by exposure to engineering projects and related tasks under the guidance of senior staff.		A critical success factor for the effective development and implementation of an asset management system is the competence of persons undertaking these activities. organisations should have effective means in place for ensuring the competence of employees to carry out their designated asset management function(s). Where an organisation has contracted service providers undertaking elements of its asset management system then the organisation shall assure itself that the outsourced service provider also has suitable arrangements in place to manage the competencies of its employees. The organisation should ensure that the individual and corporate competencies it requires are in place and actively monitor, develop and maintain an appropriate balance of these competencies.	Managers, supervisors, persons responsible for developing training programmes. Staff responsible for procurement and service agreements. HR staff and those responsible for recruitment.	Evidence of a competency assessment framework that aligns with established frameworks such as the asset management Competencies Requirements Framework (Version 2.0); National Occupational Standards for Management and Leadership; UK Standard for Professional Engineering Competence, Engineering Council, 2005.

Company Name	**Northpower Ltd**
AMP Planning Period	**1 April 2021 – 31 March 2031**
Asset Management Standard Applied	**ISO55000**

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.

Company Name	Northpower Ltd
AMP Planning Period	1 April 2021 – 31 March 2031
Asset Management Standard Applied	ISO55000

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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.

Schedule 14a: Mandatory Explanatory Notes on Forecast Information

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

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.
2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

3. In the box below, comment on the difference between nominal and constant price capital expenditure for the disclosure year and 10 year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts
The differences between nominal and constant prices is based on the application of an escalation factor using Reserve Bank's 10 year inflationary outlook in Table 2.12 of its Monetary Policy Statement, November 2020.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11b)

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the disclosure year and 10 year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts
The differences between nominal and constant prices is based on the application of an escalation factor using Reserve Bank's 10 year inflationary outlook in Table 2.12 of its Monetary Policy Statement, November 2020.

Schedule 17: Certification for Year-beginning Disclosures

Clause 2.9.1

We, Mark Trigg and Richard Booth, being directors of Northpower Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a. The following attached information of Northpower Limited prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b. The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c. The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Northpower Limited's corporate vision and strategy and are documented in retained records.

Director:	Mark Trigg	Director	Richard Booth
Date:	30 March 2021	Date:	30 March 2021

Northpower

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