2023 Asset Management Plan

www.topenergy.co.nz

TOP ENERGY®
TePuna Hihiko

Introduction

It gives me great pleasure to present Top Energy's 2023 Network Asset Management Plan (AMP). Our AMP is prepared in compliance with the Commerce Commission's Electricity Distribution Information Disclosure Targeted Review Tranche 1 Amendment Determination 2022 and is the core asset management and operations plan for our electricity transmission and distribution network. It sets out our planned asset inspection, maintenance, development and replacement strategies, and the targeted service levels that we are planning to provide our consumers. It covers the planning period of 1 April 2023 to 31 March 2033 and replaces our 2021 AMP and our 2022 AMP Update

Ngawha Generation Limited have resource consent to construct a fifth unit (OEC5) at the Ngawha geothermal power station and, while no final decision has been made to proceed to construction, we have commenced planning for a possible 2028 commissioning. If this expansion is completed, the generating capacity of the power station will increase to 89MW, and all the electricity requirements of our consumers would be generated within our supply area. This should protect our consumers from much of the impact of rising transmission charges since, with the expansion of Ngawha, our transmission connection will almost exclusively be used to export energy south and the cost of this connection should be paid by the users of this exported energy. Energy imports into our supply area would only be required if one of the two larger units at Ngawha was out of service at a time of peak demand.

We have also signed agreements for the connection of three new solar farms, with a combined capacity of 67MVA, in the Kaitaia/Pukenui areas. Construction of the first of these developments has commenced and we expect all three farms to be completed and connected to our network within three years. Furthermore, the connection of small-scale solar generation behind the meter continues apace. Almost one in twenty of our consumers now have solar generation. This is the highest penetration of small-scale generation in the country, and the total installed capacity of these small units is over 9.3MW. To accommodate this growth, our network will need to transition from an electricity distribution network designed to transfer electricity in one direction from a centralised source to multiple consumers, to a technology enabled distributed energy system that allows multi-directional energy transfers between small generators and users. We will also need to adapt to the connection of batteries, the charging of electric vehicles, and potentially the emergence of home area networks, demand response and peer-to-peer energy markets. We have installed an advanced distribution management system that provides the capability needs to efficiently manage two-way power flows on a more complex network and are in the process of integrating this system with our other electronic asset management tools to enhance its functionality and increase our visibility of network behaviour.

Wiroa-Kaitaia 110kV Line

In December 2022, the Supreme Court dismissed the appeal by three property owners along the route of the proposed new Wiroa-Kaitaia 110kV line against the decision of the Minister of Land Information to allow us to compulsorily acquire line easements over their properties. This brings the legal proceedings to an end and clears the way for us to acquire the easements and finally secure the route for this line. While we will secure the route, we have deferred the construction of the line until after the end of the AMP planning period. The line was originally planned to eliminate the need for annual nine-hour maintenance supply interruptions that affected all consumers in our northern area. We have now achieved this for most customers through the installation of backup generation.

Construction of the line will not, in itself, enable the connection of further solar generation in the region. The three new solar farms in the Kaitaia area will fully utilise the available transmission capacity between Kaitaia and Kaikohe, and also the available spare capacity of the Kaikohe-Maungatapere line that connects our network to the Transpower grid. As there is already sufficient generation within our supply area to supply our summer daytime demand, there is no point in connecting additional utility scale solar generation to our network if the power cannot be exported south from Kaikohe. Expansion of the transmission capacity between our northern and southern areas is therefore contingent on a corresponding increase in the capacity of the Kaikohe-Maungatapere connection.

There is significant demand for the construction of solar farms in Northland because the sunshine hours are higher than most other parts of the country. The Government's decarbonisation objectives will not be achieved unless a way is found to relieve transmission constraints that are preventing the connection of renewable generation in areas such as Northland. To this end, we have formed a working party with Northpower, which faces similar issues, and Transpower. The working party is investigating how the capacity of the 110kV transmission network in Northland could be increased and, importantly, how this work might be funded. In deferring the construction of this line, we are not pre-empting the outcome of this investigation. We are simply seeking a joined-up strategy across the whole of Northland to enable further renewable generation growth utilising the existing double circuit 220kV line between Northland and Auckland.

Network Reliability

The other significant issue we have addressed in this AMP is reliability. The reliability of supply we provide our consumers is regulated by the Commerce Commission which specifies the minimum level of reliability we must provide our consumers. This includes, amongst other measures:

- The maximum time that supply to the average consumer can be interrupted in a single financial year as a result of faults on our network (duration).
- The maximum number of times that the average consumer can experience an unplanned supply interruption over the same period (frequency).

While the reliability and resilience of our transmission and subtransmission network has improved as a result of our investment over the past decade, the reliability of the distribution network has deteriorated to the point where we will breach our interruption duration threshold in the current FYE2023 year and are also at risk of breaching our outage frequency threshold.

More than 90% of these duration and frequency impacts are due to faults on the 11kV distribution network. Furthermore, half of these impacts are due to faults on a small number of long feeders that supply the more remote parts our supply area. In response to this problem, in April 2022 our Board approved the implementation of an 11kV distribution network reliability improvement plan. Under this plan we will:

- increase the rate at which we replace 11kV network assets that have reached the end of their economic life.
- Install new sectionalisers and reclosers to optimise the protection on long rural feeders and reduce the number of consumers affected by many faults.
- Construct normally open interconnections between feeders to enable restoration of supply to consumers downstream of a faulted switching zone before a fault is repaired.
- Provide a new injection point into the 11kV network using the tertiary winding of the 40/60MVA 110/33kV transformer at the Kaitaia transmission substation.
- Modify our vegetation management strategy to increase the focus on those parts of the network where there is a high prevalence of tree contact faults.
- Mobilise a new two-person vegetation management crew with a roving mandate and the ability to respond to reports of vegetation risk on parts of the network outside of our programmed vegetation control schedule.

Over the first part of the planning period this work has been funded by deferring the construction of the Wiroa substation, which was scheduled to commence in the current FYE2023 year. This project was planned to address an emerging capacity constraint resulting from ongoing high growth rates in the Kerikeri and Waipapa areas. We conducted a risk assessment of the impact of deferring the start of this project until FYE2028 and found that although the risk remains, it is relatively small. In the latter part of the period the improvement programme will be funded by reallocating part of the cost of the deferred 110kV line.

We have also adjusted the reliability targets in this AMP to levels that better reflect the reliability the network is able to deliver, given the weather conditions we typically experience.

Decarbonisation

There is sufficient capacity in our network to supply our expected near term demand growth and there is therefore little provision for capacity expansion projects in our capital expenditure (capex) forecast for the first four years of the planning period. However, we expect the current growth in demand to accelerate due in part to decarbonisation of the economy and the increased penetration of electric vehicles. This could lead to capacity constraints in the supply to communities currently served by the 11kV distribution network. In many cases, these constraints are best addressed by extending the reach of the subtransmission network though the construction of new 33kV subtransmission lines and zone substations. While it is not yet clear where and when these network extensions will be required, our capex forecast includes provision for this work, funded by reallocating part of the cost of the deferred Wiroa-Kaitaia line.

The challenges we face in developing and managing our network, and how we respond to these challenges, are further described in our corporate video, *Top Energy – Energy of the Future* which can be viewed on our website http://www.topenergy.co.nz. We invite all our stakeholders to watch this video.

In addition to the management of our network assets, we continue to develop the safety and asset management culture within Top Energy. We actively participate in industry safety initiatives, which require staff engagement at all levels and have the added benefit of sharing participants' experiences from across the industry. To succeed, the Company and all staff must maintain a proactive role in training, competency, peer support and guidance, and monitoring industry issues.

We hope that you find that this AMP shows that we continue to exercise prudent stewardship of our network assets for the long-term benefit of all our stakeholders and, in particular, the electricity consumers who rely on our network to meet their energy needs. We welcome your feedback on our asset management plans, or on any other aspect of Top Energy's business and performance. Feedback can be provided through the Top Energy website at http://www.topenergy.co.nz/contact-us-feedback.shtml or emailed to info@topenergy.co.nz.

Russell Shaw

Chief Executive, Top Energy Ltd

INTRODUCTION

Postscript: This AMP was submitted to the Top Energy Board for approval during the recovery period of Cyclone Gabrielle, the most severe cyclone that New Zealand has seen. The devastation from this cyclone has surpassed Dovi (2022), Gita (2018), Bola (1988) and Giselle (1968). The impacts of climate change are now with us, at a time when society now more than ever has a greater reliance on electricity. This reliance is only likely to increase as we continue to decarbonise the economy.

I would like to make it clear that this AMP does not include an allowance for adaptation or to 'harden the network' to make it more resilient to the extreme events that are becoming more frequent. We will conduct our own lessons-learnt review and over the next 12 months will feed these into our 2024 AMP Update.

In my opinion the country now needs to pause and think about what the essential infrastructure requirements will be for the future. A comprehensive review needs to take place nationally to establish and implement lessons from this event. Some initial thoughts on how the supply to the Far North can be improved are:

- The Tree Regulations are in desperate need of reform. The largest impact of Gabrielle has been from trees, most of which were within fall distance from our lines. While the Electricity (Hazards from Trees) Regulations 2003 allow us to trim trees that could grow *into* our lines, they do not permit us to trim trees that could potentially fall *onto* our lines. In the Far North, the urban centres of Kaitaia, Kerikeri and Kaikohe all remained with power largely due to tree trimming efforts in these towns.

- Ownership of service lines should be transferred to EDBs with a corresponding uplift in Regulated Asset Base, so an income stream is also created for their maintenance and renewal. Property rights like those we possess for pre-1993 lines should be included. Most customers are not aware that they own these lines, and many are unable to pay for repairs when they are damaged.

- The existing emergency centers across the Far North should have emergency power and communications links established prior to the next event. It is essential that these have satellite communications (Starlink or similar) solar, battery and local standby generation. These provide safe hubs for affected residents who suffer extensive damage to their properties or prolonged power outages.

- The regulatory framework needs to allow 'hardening of the network' to occur and recognise that this needs to be funded appropriately. For example, stronger structures, larger conductor, more insulated conductor in areas at risk of trees. This adaptation may require a measure of central funding to ensure intergenerational wealth issues are addressed in an area where energy poverty is prevalent.

- Low probability, high consequence failures should be considered on a region-by-region basis. Solutions should be implemented to address these, and they should again be centrally funded to reduce the intergenerational burden we already have as the costs of decarbonisation come to bear. We have seen the impact from Cyclone Gabrielle on the east coast in the Hawkes and Poverty Bays. Fortunately, the Far North was lucky this time with no failure of the single transmission line to the region. Potential solutions for the Far North could be the funding of a second 110kV line to Kaitaia to provide an alternative to the line through the Maungataniwha Range, as well as a second double circuit line from Kaikohe to Mangataupere. These new lines would address the low probability and high consequence risks and also enable significantly more renewable energy to be generated in the Far North.

In closing this late addition to the AMP, I would like to thank the consumers of the Far North for their support during this most recent event. Even when without power for two weeks, they have been supportive and grateful. I would also like to thank the other lines businesses and contractors in the sector who reached out and offered support, in particular the Scanpower staff who were first to arrive and the Connetics staff who managed to travel from Christchurch with the help of the NZ Defence Force and a C130 Hercules. Lastly, I want to thank our staff for their extraordinary efforts; they are the real heroes of the day. From the line mechanics to the network controllers, the arborists to the despatchers, all our staff have either worked directly to arrange and complete repairs or pivoted to support those who did. When the worst happens that's when our staff shine. We have a great team.

Table of Contents

TABLE OF CONTENTS

TABLE OF CONTENTS

1 Executive Summary

1.1 Overview

Top Energy Limited (TEL) is the electricity distribution business (EDB) that distributes electricity to more than 33,000 electricity consumers in the Far North District Council's territorial area, covering the mid- and far-north of the Northland region. We are a part of the Top Energy Group, which is ultimately owned for the benefit of our consumers by the Top Energy Consumer Trust (Trust). The Group, which employs around 165 people and is one of the biggest employers in our supply area, has three main operational activities:

- *Ngawha Generation Ltd (NGL)*, a separate legal entity which owns and operates the Ngawha geothermal power plant, with a current capacity of 57MW.
- *Top Energy Networks (TEN)*, a division of TEL, which manages the electricity distribution network.
- *Top Energy Contracting Services (TECS)*, a division of TEL, which provides contracting services to TEN.

TEL is subject to regulation by the Commerce Commission in accordance with the requirements of Part 4A of the Commerce Act, 1986. Therefore, we must publicly disclose information on the performance of our network assets in accordance with the Commission's Electricity Distribution Information Disclosure Targeted Review Tranche 1 Determination 2022. Furthermore, the reliability of the supply that we provide our consumers, and the prices that we charge for providing electricity distribution services, are regulated by the Commission's Electricity Distribution Services Default Price-Quality Path Determination 2020.

This Asset Management Plan (AMP) is the defining strategic and business planning document for the management of our network. It describes how we plan to develop and manage our network assets for the benefit of our consumers over the period 1 April 2023 to 31 March 2033. It sets out the ten-year capital and maintenance expenditures that we estimate will be needed to manage the network in a sustainable way. It lies at the heart of the management of our network assets and is the primary tool for planning the long-term development and maintenance of our network.

While the primary purpose of this AMP is to inform our consumers and other stakeholders of our asset management intentions, it has been prepared in accordance with the Commission's Information Disclosure Determination. It covers only our network assets and does not cover the assets of other divisions or entities of the Top Energy Group. It also does not cover privately-owned assets beyond a network user's connection to our network.

1.2 Asset Management Policy

Our formal network asset management policy sits below the overarching Group asset management policy in our quality system and has been developed in accordance with Top Energy's strategic objectives:

- To operate a successful business that optimises the long-term value of the Group for its shareholder.
- To operate a safety and organisational culture where all employees take responsibility for themselves and others to minimise the risk of injuries to consumers, staff, contractors, and the public.
- To achieve network quality standards that are acceptable to consumers.
- To operate in an environmentally sustainable manner, and to be responsive to the cultural and social needs of our community.
- To minimise the total delivered cost of electricity to our consumers.

Within this overarching strategic framework, Top Energy's mission is:

> *Creating long term value by transforming energy to our consumers and beyond.*

TEL's goal is to provide a safe, secure, reliable, and fairly priced supply of electricity to consumers in our supply area. To this end, we will manage our network assets for the long-term benefit of our existing and future consumers. We will achieve this by acting with integrity, in compliance with our legal obligations, and by developing and maintaining the assets in a manner that is sustainable over time, minimises environmental impacts, meets the reasonable expectations of our consumers in respect of the quality and reliability of the supply that we provide, and underpins the economic development of our supply area.

Safety

Safety is our highest priority. We will act in accordance with industry standard safe working practices and, in consultation with our employees and contractors, we will develop and adopt systems and procedures that minimise the risk of harm to people or property, in accordance with the Health and Safety at Work (General Risk and Workplace Management) Regulations 2016. We will consider the impact of all that we do on our employees, contractors, consumers, and the public.

Security

We will develop a network that is resilient to high impact, low probability events, by building in asset redundancy where this is appropriate, and by developing plans and procedures for responding to events that have a high impact on our consumers.

Reliability

We will manage our assets to ensure the reliability of supply that we provide meets the expectations of our consumers. We will achieve this using a range of strategies including targeted network development, more effective maintenance, and improved response to supply interruptions that occur.

Fair Pricing

We will achieve improvements to the security and reliability of our network at a rate that is financially sustainable and affordable to our consumers. We will also strive to continually improve the efficiency and cost effectiveness of our asset stewardship to increase the value we provide to our stakeholders.

New Technologies

We live in a time of technological change that has the potential to radically alter the way in which our consumers use the services we provide. We will monitor these developments, and their impact, and modify our asset management strategies as necessary so that we remain relevant to the consumers that we serve.

The strategies, objectives and plans set out in this AMP are consistent with, and evolve from, this asset management policy.

1.3 Network Description

Our electricity network stretches from Hukerenui, approximately 25km north of Whangarei, to Te Paki, 20km south of Cape Reinga. It supplies one of the more economically depressed areas of the country; an area that is sparsely populated and contains no dominant urban centre. Our network is predominantly rural, characterised by a low consumer density and an average consumption per consumer that is the second lowest in the country. Table 1.1 lists the key network parameters.

DESCRIPTION	QUANTITY
Area covered	6,822km^2
Consumer connection points	33,263(1)
Grid exit point	Kaikohe
Network peak demand (FYE2022)	77MW(2)
Electricity delivered to consumers (FYE2022)	330GWh
Number of distribution feeders	63
Distribution transformer capacity	283MVA(3,4)
Transmission lines (operating at 110 kV)	66km(3)
Subtransmission cables (33kV)	23km(3)
Subtransmission lines (33kV)	315km(3)

DESCRIPTION	QUANTITY
HV distribution cables (22, 11 and 6.35kV)	231km(3)
HV distribution lines (22, 11 and 6.35kV including single wire earth return)	2,573km(3)

Note 1: Average number of active connections FYE2022.
Note 2: Metered load as disclosed to the Commerce Commission.
Note 3: At 31 March 2022.
Note 4: Does not include 22/11 kV or SWER isolating transformers, or transformers not owned by TEN.

Table 1.1: Network parameters

We have a significant amount of embedded and distributed generation connected within our network, as shown in Table 1.2. Of note is the connection of small-scale, roof-top photovoltaic generation. Not only is the penetration[1] of small-scale generation higher than that of any other New Zealand EDB; it is also increasing at a faster rate than elsewhere.

TYPE OF GENERATION	NO OF INJECTION POINTS	CAPACITY (MW)
Geothermal	2[1]	57
Diesel	5	17.2
Photovoltaic	1,624[2]	9.3[2]

Note 1. All geothermal generation is located at Ngawha. However, OEC1-3 connect to the network at 33kV while OEC4 connects at 110kV.
Note 2: At 31 December 2022

Table 1.2: Embedded and Distributed Generation

1.4 Value of Network

The regulatory value of our fixed network assets, calculated in accordance with the Commerce Commission's Information Disclosure Requirements was $320.0 million at 31 March 2022, an increase of $17.8 million since 31 March 2021.

This increase in asset value was derived as shown in Table 1.3. The increase has largely been driven by the commissioning of new assets in accordance with our network development plan. The value shown in Table 1.3 is the regulatory asset value, which is different from the corresponding asset value shown in Top Energy's financial accounts, as the valuation methodologies differ.

	$000
Asset Value at 31 March 2021	**302,160**
Add:	
New assets commissioned	9,260
Indexed inflation adjustment	20,839
Asset allocation adjustment	11
Less:	
Depreciation	12,210
Asset disposals	10
Asset value at 31 March 2022	**320,021**

Table 1.3: Value of System Fixed Assets

1 In this context, penetration is the ratio of the number of small-scale photovoltaic connections to the number of consumers connected to our network.

1.5 Economics of Supply

Many of our distribution lines were built using subsidies provided by the Rural Electrical Reticulation Council (RERC). These were provided to assist with post-war farming productivity growth in remote areas and provide an electricity supply to consumers in sparsely populated rural areas that would have otherwise been uneconomic to service. Many of these lines are now reaching the stage where extensive rebuilding and refurbishment is required. We are obligated by Section 105(2) of the Electricity Industry Act 2010 to continue to provide a supply to consumers currently supplied from existing lines, although this continuing supply does not need to be a grid connection.

In 2009, prior to the passing of this Act, the Electricity Networks Association (ENA) created a working party to review the implications of this obligation. The working party defined lines as uneconomic if there were less than three connected low consumption consumers per km. Low consumption was defined either by the volume of energy delivered per year (less than 6,500kWh per consumer) or by the installed distribution transformer capacity (less than 20kVA per consumer); these criteria were based on an independent analysis of network costs undertaken by the then Ministry of Economic Development (now MBIE). Approximately 35% by length of our 11kV distribution network is uneconomic if the MBIE cost of supply criteria is applied. These lines supply just 9% of our consumers. While this study was undertaken almost 15 years ago, its findings still apply today.

In 2018, we investigated this issue further by developing a cost-to-serve model that looked at the costs we incur in supplying consumers in different parts of the network. Our modelling showed that the revenue received from consumers in the remote segments of our network is enough to cover the operating costs of the assets used to provide their supply but makes only a marginal contribution to the capital costs of these assets. Consumers connected to the more economic parts of our network therefore subsidise the capital costs we incur in maintaining supply to these consumers.

We keep abreast of the economics of using remote area power supplies instead of a network connection to service consumers in the most remote parts of our network, but have found this difficult to justify, primarily because line assets tend to be renewed incrementally as individual poles and pole top hardware fail.

1.6 Reliability of Supply

Our reliability of supply is regulated by the Commerce Commission under the Electricity Distribution Services Default Price-Quality Path Determination 2020. This sets a range of thresholds that define the minimum level of service we must provide our consumers. At present these thresholds all relate to reliability of supply and, if the reliability of supply we provide falls outside the specified threshold envelope, our asset management practices are likely to be investigated by the Commission and we could potentially be subject to legal sanctions.

We monitor the reliability of our network using the normalised measures of SAIDI and SAIFI that the Commerce Commission uses to monitor the reliability of the networks under its price-quality control regime. These are:

- SAIDI (System Average Consumer Interruption Duration Index), which is the number of minutes that the average consumer connected to our network is without supply. We measure reliability of supply over our standard financial year, which ends on 31 March, rather than a calendar year.
- SAIFI (System Average Interruption Frequency Index) is the number of times the average consumer's supply is interrupted over the measurement period. While an individual consumer can only be interrupted a whole number of times, SAIFI is measured as a real number to allow for averaging.

For unplanned interruptions, the determination provides for normalisation of the raw SAIDI/SAIFI impacts for assessment against the threshold. This is designed to limit the impact of events, generally severe storms, that are outside our reasonable control. We believe that setting reliability targets using the Commission's normalised measures provides a better indication of the effectiveness of our asset management strategies.

The impact of this normalisation process is to:

- Exclude interruptions originating from events outside our network.
- Limit the impact of unplanned interruptions during major SAIDI/SAIFI events to a boundary value, which reduces the impact of an extreme event on the overall measure. The SAIDI and SAIFI boundary values were determined by the Commission using a statistical analysis of the performance of our network over a ten-year historic reference period.

In the AMP, we set internal targets for both planned and unplanned interruptions for each year of the planning period. In our previous AMPs, these targets reflected an expected improvement in our reliability of supply due to our investment over the last decade in improvements in the resilience of our transmission and subtransmission network. While we have met our reliability improvement goals for the transmission and subtransmission network, the reliability of the 11kV distribution network has deteriorated over the last several years, in part due to climate change. As a result, we have breached our unplanned SAIDI threshold for the current FYE2023 year, and at the time of writing, are at risk of breaching our unplanned SAIFI threshold.

In response to this deteriorating reliability, we have changed our network development strategy to prioritise expenditure on our 11kV distribution network. Our objective is to make this part of our network more resilient to the weather conditions we now experience. Our revised development strategy is summarised in Section 1.7 below.

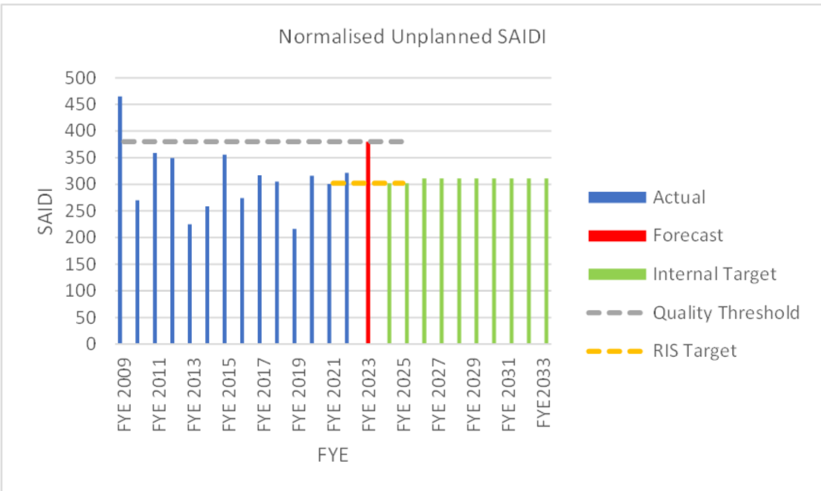
We have also adjusted our AMP reliability targets to better reflect the expected reliability of our network in a year of average weather conditions. The new unplanned SAIDI/SAIFI targets are based on the average annual performance of our network over the ten-year historic reference period used by the Commission in setting the thresholds for the current regulatory control period (RCP3).[2] This is consistent with the Commission's approach where the thresholds are set on the basis that there should be no material deterioration over time in the reliability of supply that we provide our consumers.

Our internal reliability targets for each year of the planning period are shown Table 1.4.

FYE	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Unplanned Interruptions										
SAIDI	302	302	311	311	311	311	311	311	311	311
SAIFI	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01
Planned Interruptions										
SAIDI	125	125	125	125	125	125	125	125	125	125
SAIFI	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Table 1.4: Reliability Targets

These targets for the impact of unplanned interruptions are shown in Figures 1.1 and 1.2 below, where they are also compared with the historic reliability of our network. In these figures we have normalised our historic raw performance using the Commission's approved normalisation methodology for RCP3, to provide a valid comparison between historic and targeted performance.



2 The current regulatory control period is RCP3, which covers the five-year period FYE2021-25.

Figure 1.1: Historical and Target Normalised Unplanned SAIDI

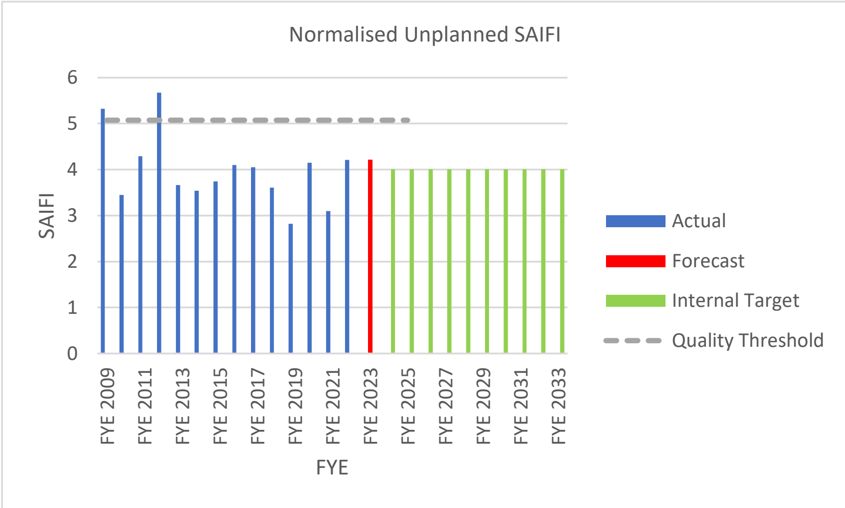


Figure 1.2: Historical and Target Normalised Unplanned SAIFI

We note the following in respect of these targets:

- The unplanned SAIDI target is the same as the target point in the Commission's quality incentive scheme, where there is no penalty or reward. The unplanned SAIFI target has been calculated the same way, although it is not included in the quality incentive scheme.
- After FYE2025, the targets have been set using the same approach, assuming the quality incentive scheme neutral point and thresholds that will apply during RCP4 will be calculated the same way. Should the Commission decide the change its approach, we will review our targets accordingly. The minor adjustment in the unplanned SAIDI target between RCP3 and RCP4 is due to our estimate of the impact of using a different historic reference period.
- There is a buffer between our new targets and the Commission's thresholds. Should our normalised reliability fall in this buffer zone we will miss our target but not breach the threshold. As the new targets are based on our average historic performance, we can expect to miss the target, on average, once every two years, assuming no change in overall network reliability. As we have experienced in the past, we expect a high level of year-on-year volatility in unplanned SAIDI and SAIFI, and our performance against the targets is best measured as our average annual performance over a longer period.
- There is no change in our planned SAIDI targets from that in the 2021 AMP and the 2022 AMP Update, notwithstanding an increase in the number of planned supply interruptions. Our raw planned SAIDI missed these targets in both FYE2021 and FYE2022, but the Commission allows the SAIDI impact of planned interruptions to be de-weighted if specified criteria for the prior notification of the interruption to affected consumers are met. When this normalisation approach was applied, our normalised planned SAIDI dropped below the AMP target in both years.
- There is no provision for the normalisation of planned SAIFI. Since we have missed our AMP planned SAIFI target in both FYE2021 and FYE2022, we have reset the targets to a level that reflects our performance over the two years.
- The Commission will only measure our performance against its planned SAIDI and SAIFI thresholds after the end of RCP3. The thresholds have been set at three times our average performance over the historic reference period, and our risk of exceeding either of these thresholds is very low.

1.7 Network Development

1.7.1 Introduction

The main objectives of our network development plan were to:

- Increase the capacity of the network to meet the growing demand for electricity in the Kerikeri area.
- Improve the supply security in the north of our supply area, which is supplied from Kaikohe over a single 110kV circuit, and which experienced extended supply interruptions when this line was taken out of service for maintenance.
- Improve the reliability of supply to consumers by developing our subtransmission and distribution networks to be more resilient to weather and equipment failures.

Since the plan was initiated, we have invested almost $200 million in capital expenditure on network improvement. This has allowed us to:

- Increase the capacity of our network in the Kerikeri area through the construction of a new 110kV line between Kaikohe and Wiroa, a new switching station at Wiroa and a new zone substation within Kerikeri town.
- Improve the fault resilience of our 33kV subtransmission network by upgrading the protection to form 33kV rings, so that faults affecting our larger zone substations no longer cause interruptions to supply.
- Install a new zone substation in Kaeo to improve the reliability of supply to consumers in the Whangaroa area.
- Construct a new double circuit 110kV transmission line to connect the new 32MW geothermal generator at Ngawha to the grid at Kaikohe.
- Install over 17MW of diesel generation at Kaitaia, Taipa, Omanaia and Pukenui to increase the resilience of the network to high impact events and improve the reliability of the supply we provide to our consumers.
- Replace assets that have reached the end of their economic life and rebuild the Moerewa and Omanaia zone substations. We have also completed partial rebuilds at Kawakawa and Waipapa.
- Increase our ability to remotely control the distribution network, so that supply can be restored more quickly to consumers not directly affected by a fault.

These investments have been effective. We have eliminated the need for annual nine-hour supply interruptions in our northern area for maintenance of the 110kV circuit supplying Kaitaia, and we have significantly increased the capacity of our network to supply the Kerikeri area, which continues to experience high growth rates. We have also improved the reliability of our transmission and subtransmission network to a point there the normalised unplanned SAIDI of both networks combined is typically about 25 minutes.

1.7.2 Network Development Objectives

Our network development objectives over this AMP planning period are to:

- Stabilise the deterioration in unplanned SAIDI and SAIFI due to faults on the 11kV distribution network, and then improve its reliability to the point where, over time, the normalised unplanned SAIDI and SAIFI across all voltages is no higher than that experienced over the Commission's historic reference period, when averaged over time.
- Provide for the connection of three new solar farms with a total capacity of 67MVA to our northern network. These will all be connected to our 33kV subtransmission network. The lines required to connect the new solar farms to our network will be funded by the developer. Ngawha Generation also has capacity for the possible installation of a second 32MW geothermal generator (OEC5) at Ngawha and this could be commissioned in FYE2028. The connection of the two 32MVA Ngawha generators to the Transpower grid is under review and this could result in some reconfiguration of the 110kV network in the southern area. The reconfiguration will not impact the development of our network in a material way, and the associated costs will be met by Ngawha generation.

- Provide the additional network capacity required to supply the continuing high growth in electricity demand in the Kerikeri and Waipapa areas. This requires the construction of the new Wiroa 110/33kV substation.
- Towards the end of this AMP planning period, provide for the expected growth in electricity demand resulting from decarbonization of the economy and in particular a substantial increase in the number of electric vehicles on the road. While our transmission and subtransmission networks have the capacity to meet this demand, we expect there to be localized demand growth in areas not currently served by our subtransmission network. The most cost-effective way of supplying much of this additional demand will be to extend the reach of the subtransmission network through the construction of new subtransmission lines and zone substations.

1.7.3 Distribution Network Reliability Improvement

This is the major focus of our network development plan, particularly over the first years of the planning period, as faults on the 11kV network are responsible for approximately 90% of our normalised unplanned network SAIDI.

Our planned capital expenditure on improving the reliability of the 11kV network includes:

- Increasing the rate at which we replace assets that are reaching the end of their economic life and are at risk of failing in service.
- Utilising the 11kV tertiary winding on the Kaitaia 40/60MVA 110/33kV transformer to provide an additional point of injection into the South Road and Oxford St feeders. This will be undertaken in FYE2024 and 2025.
- Optimising the protection on low reliability feeders, largely through the installation of reclosers at the tee points of long spurs.
- The construction of interconnections between neighbouring feeders, to allow supply to be restored to consumers downstream of a faulted switching zone before a fault is repaired.

The programme will focus on our most unreliable feeders. These are generally long feeders serving remote areas, which have a high fault exposure and high numbers of connected consumers.

1.7.4 Utility Scale Solar Generation

We have signed agreements for the connection of the following solar farms in the northern part of our network. The cost of the assets needed to connect these farms to our network will be paid by the developers and are included in our expenditure forecast as consumer connection capital expenditure.

Far North Solar Farm

A 20MW solar farm located adjacent to our Pukenui zone substation. It will be connected to the substation via an underground 33kV cable.

Twin Rivers Solar Farm

A 24MW solar farm located approximately 2.6km southeast of our Kaitaia 11kV substation. It will be connected to the Kaitaia 33kV substation bus via a new single circuit 33kV line running alongside SH1.

Kaitaia Solar Farm

This solar farm, which has been developed by Loadstone Energy, will be a 23MW installation located approximately 3.6km northwest of JNL Triboard Mill north of Kaitaia. It will be connected to our NPL substation at the mill site via a 33kV circuit comprised of a 2.8km overhead line and 0.9km underground cable.

At this point construction has commenced on the Kaitaia solar farm, and the Far North farm is committed for construction. We remain in touch with the Twin Rivers proponent and expect it to proceed in due course.

1.7.5 Wiroa 110/33kV Substation

To provide sufficient network capacity to supply the high level of demand growth in the Kerikeri and Waipapa areas, we plan to construct a 110/33kV injection point at our 33kV switching station at Wiroa. The new substation will have two transformers and will be supplied by two incoming circuits connected to Kaikohe.[3] Three-winding transformers are planned to provide for a future new point of injection into the 11kV network.

It was planned to start construction of this project in the current FYE2023 year to meet the forecast demand growth in the Kerikeri/Whangaroa area. This decision was made using a deterministic approach to network planning that required N-1security to be maintained at all levels of demand. However, at the beginning of the year, when it became apparent that the need to address the deteriorating reliability of the 11kV network was increasingly urgent, we undertook a risk assessment to determine whether this build could be deferred. This showed that:

- The risk of the constraint being breached was very low since not only did it require a fault on the double circuit Kaikohe Wiroa line, but this fault had to occur during a period of peak network demand. The Kaikohe Wiroa line is less than 10 years old and in very good condition. Furthermore, the period during which the demand exceeded the delivery capacity of the alternative Kaikohe-Mt Pokaka-Wiroa circuit is only a small percentage of the hours in a year.
- Nevertheless, should a fault occur at a time of peak demand, there would not be a complete loss of supply. Most of the load would still be supplied by the Mt Pokaka line but there would be a need for some managed load shedding by the control room. The required load shedding would be small at first but would increase over time as the demand in the Kerikeri/Whangaroa areas increased. Over the first few years, the energy that could not be supplied would be comparable to that of an 11kV feeder fault.

The timing of the build is therefore a risk management issue. The capital expenditure forecast in this AMP provides for construction over the three-year period FYE2028-30 with commissioning of the first transformer in FYE2029. This will be kept under review and a final decision on the timing of this project will be made on the basis of the demand growth in the area the new substation will supply.

1.7.6 Doubtless Bay

We think Doubtless Bay, which is currently supplied by the Taipa zone substation, is likely to be the first area where capacity constraints emerge due to demand growth driven by decarbonisation. The transformer is almost fully loaded and in poor condition, although it is currently supported by our mobile substation. The existing substation is not well placed to supply the load centres that it serves and there is a need to eventually relocate it, due to its closeness to the Taipa estuary and the risk of flooding as a result of sea level rise due to climate change.

Our plan is to replace Taipa with two new substations, one on the Karikari peninsula in the vicinity of Tokerau Beach, and the second at either Coopers Beach or Mangonui. The two substations would be served by the existing 33kV line feeding Taipa, and also by a new 33kV line into the Doubtless Bay area. This second line could be supplied from a tee point on the Church Rd-Pukenui line or from the Kaeo zone substation. We think the Tokerau substation will need to be constructed first, mainly because of its distance from Taipa.

Our capital expenditure forecast provides for:

- Replacement of the existing 5/6.5MVA transformer at Taipa with a 10/15MVA unit by FYE2030. It is envisaged that Taipa is only an interim location of this transformer, which would be relocated to the new Coopers Beach substation when this is constructed and the Taipa substation disestablished.
- Construction of the Tokerau substation by FYE2033.

There are a range of options for the configuration of the incoming 33kV supplies and no decision has been made on a preferred arrangement.

It is possible that a localised capacity constraint will emerge elsewhere on the network before a new substation is needed at Tokerau. In this event we would still need to replace the transformer because of its condition, but the remaining funds would be reallocated.

---

[3] The incoming double circuit line is currently operated as a single circuit and is energised at 33kV to supply Wiroa from Kaikohe. The two circuits will be split and energised at 110kV with the construction of the new substation.

1.7.7 Wiroa-Kaitaia 110kV Line

In December 2022, the Supreme Court rejected the appeal of three landowners along the planned route of this line against the decision by the Minister of Land Information to allow us to compulsorily acquire easements over their properties. This brings the legal proceedings to an end and clears the way for us to secure a route for this line. We will go ahead and secure the easements as permitted by the court.

We have deferred the construction of the line to beyond the end of the AMP planning period as the original purpose of this line was to eliminate the need for annual nine-hour supply interruptions to allow maintenance of the Kaikohe Kaitaia line. This has now been achieved through the installation of diesel generation.

More recently, it was thought that the line would allow the connection of additional solar generation in our northern area, over and above the 67MVA for which we have already signed connection agreements. However, this generation and a new 32MW OEC5 geothermal generator at Ngawha will use all the available spare capacity on the double circuit Kaikohe-Maungatapere line that connects our network to the Transpower grid. We are therefore unable to accept any more applications to connect utility scale solar generation anywhere on our network, as there is no capacity available to export this electricity south of Kaikohe.

As there is still significant demand for the installation of new solar generation in Northland, we have formed a working party with Transpower and Northpower to look at how additional transmission capacity might be provided, and importantly, how such projects could be funded. In the meantime, we have put our plans for the construction of this line on hold, so as not to pre-empt the outcome of this investigation.

1.7.8 Kaitaia Substation Transformer Upgrade

There are two 110/33kV transformers at Kaitaia substation. T1 is a 40/60MVA transformer that we installed about eight years ago while T5 is a 22MVA bank of single-phase units that are in relatively poor condition and nearing the end of their economic lives. The single phase T4 bank, which is identical to T5, is still in place and its three single phase units are available as spares, should there be a failure of one of the T5 units.

This arrangement provides adequate security to supply the 25MVA consumer demand in our northern area. In the event of a T1 transformer failure, the T5 transformer has sufficient capacity to supply the load, with some support from the local diesel generation at times of peak demand. However, it is too small to support the 67MW of solar farm generation for which connection agreements have recently been signed. Should the T1 transformer fail, most of this generation would need to be constrained off, until the transformer was replaced or repaired. The lead time for a new transformer, which could be required if there was a complete transformer failure and a spare unit was not available from Transpower as a temporary replacement, is up to 12 months.

The AMP capital expenditure forecast provides for the installation of a new 40/60MVA transformer to replace the small T5 bank. This is scheduled for commissioning in FYE2030.

1.7.9 Capital Expenditure Forecast

We categorise our capital expenditure as follows:

- *Customer Driven.* This covers expenditure required to connect new customers to the network. We have little control over this expenditure as we must respond to the demand for new connections. Much of this expenditure is funded by capital contributions. As shown in Figure 1.5, we are expecting a steady demand for new connections over the AMP planning period with the expenditure through to FYE2026 largely driven by the connection of the three new solar farms to the network.
- *Asset Life Cycle Replacement and Renewals.* We need to maintain our existing network in a condition that is fit for purpose. To do this, we replace, and in some cases refurbish, our existing assets as they reach the end of their economic service life. Over this AMP planning period our forecast expenditure on asset replacement and renewal is comprises 47% of our total capital expenditure. Most of this expenditure will be on the 11kV distribution network.
- *Capacity Augmentation.* This is the construction of new assets to meet any growth in demand for network services, while ensuring that spare capacity is available where required to maintain the resilience of the subtransmission network to unplanned equipment outages. As our network has sufficient capacity to meet our expected short-term demand growth, very little capacity expansion expenditure is likely to be needed in the first four years of the planning period. After that, we anticipate a need for capacity expansion as demand increases due to the decarbonisation of the economy, and a

need emerges to extend the subtransmission network to cater for load growth in areas presently supplied by the 11kV distribution network.

- *Reliability, Safety and Environment.* All our forecast expenditure in the category is on reliability improvement. In these projects the primary driver is reliability improvement, even if a capacity expansion is a secondary outcome. In our previous AMPs, construction of the new 110KV line into Kaitaia dominated this expenditure. Now this line has been deferred, much of this expenditure has been reallocated to projects within our 11kV reliability improvement plan, including the construction of new feeder interconnections and optimisation of the protection on our long rural feeders.

Our forecast total capital expenditure over the ten-year AMP planning period is $173 million. Figure 1.3 shows how this forecast is allocated over the four categories, and Table 1.5 quantifies this expenditure over the planning period.

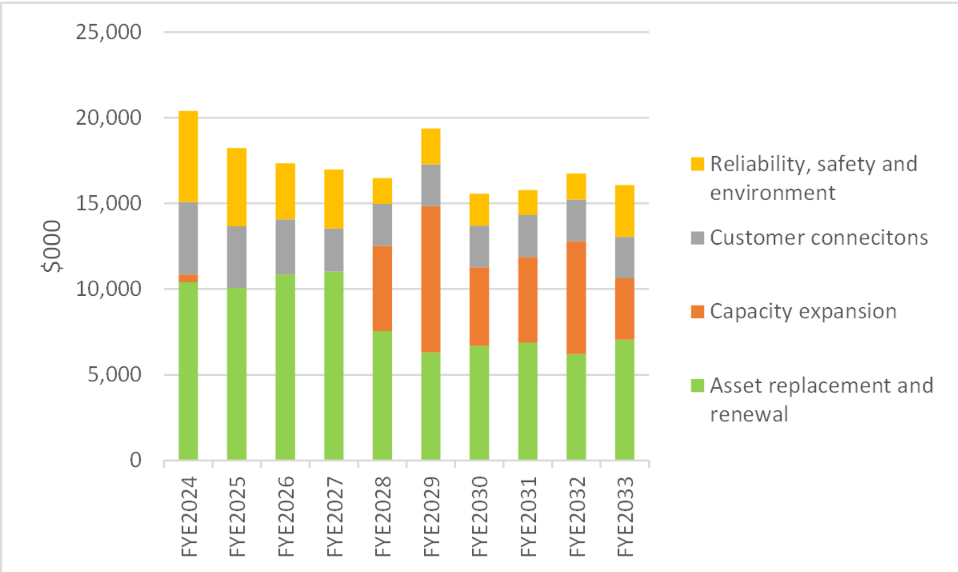


Figure 1.3: Allocation of Capital Expenditure by Category

$000 (in constant prices)	FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029-33	Total
Asset replacement and renewal	10,520	10,062	10,838	11,008	7,553	33,086	83,068
Customer connections	4,223	3,607	3,232	2,528	2,434	12,172	28,197
Capacity expansion	462				4,980	28,308	33,750
Reliability, safety, and environment	5,316	4,557	3,271	3,446	1,504	9,932	28,026
Total	**20,520**	**18,227**	**17,342**	**16,982**	**16,470**	**83,498**	**173,040**

Table 1.5: Network Capital Expenditure Forecast

1.8 Life Cycle Asset Management

We continue to develop and refine our business processes for the management of assets after they have been commissioned, through to replacement at the end of their economic life. Our overall objective is to target our maintenance expenditure on critical assets and assets identified as potentially showing signs of end-of life deterioration.

We have adopted the asset health indicators developed by the Electricity Engineers' Association (EEA) as a basis for assessing the condition of our various asset fleets and the need for asset renewal or replacement. Our assessments of asset heath are based on our regular asset inspections, but where it is not possible to determine the condition of an asset by visual inspection or by non-invasive testing of in-service asset, we use age as a proxy for condition. The asset renewal forecast in this AMP includes for the first time a separate provision for crossarm replacements, as we have found that crossarm failures are a significant cause of faults due to equipment failure.

1.8.1 Vegetation

Vegetation remains a significant cause of supply unreliability, primarily on the 11kV network and our vegetation management efforts continue. Both the Far North District Council and the New Zealand Transport Authority have no interest in trees growing within rural road reserves, which allows us to remove trees within these road reserves that could grow into our lines. Unfortunately, our vegetation management efforts are constrained by the Electricity (Hazards from Trees) Regulations 2003, and we look forward to the review of these regulations by the Ministry of Business, Industry and Employment

From FYE2024, we plan to move to a more targeted risk-based approach to vegetation management, where those parts of the network that have a high SAIDI impact are controlled more frequently and, where possible, more aggressively. This could mean, for example, that 33kV lines may be controlled less often where there is a parallel line that can seamlessly pick up the load in the event of a vegetation fault. On the other hand, parts of our long rural 11kV feeders that frequently experience vegetation faults could be controlled annually, rather than once every two years.

We also intend to mobilise an additional two-man vegetation control crew that will have a roving mandate. If a situation is reported where vegetation is growing into, or close to, a line before the line is scheduled for its cyclic vegetation control, the smaller crew will be dispatched to address the situation in isolation. This is anticipated to have a twofold impact:

- It will increase the implementation efficiency of the planned vegetation management effort by reducing the number of times that planned work is disrupted by the need to attend to more urgent situations.
- Over and above this, the SAIDI impact of vegetation faults is also expected to reduce due to both the additional vegetation control input and the ability to target higher risk situations more quickly and flexibly.

1.8.2 Power Transformers

In February 2023 we received an initial report from an external consultant on the condition of our zone substation power transformer fleet. Although not peer reviewed at this stage, the report indicated five transformers in unreliable condition, Pukenui, Taipa, Kawakawa T1 and Kaikohe T11 and T12 that need major maintenance to avoid replacement in the near future. A further 11 transformers were considered fatigued. The report found that many of our older transformers were in a poorer condition than implied by our regular oil testing regime, which we have used as the basis for assessing transformer condition. This is thought to be because oil purification treatment was applied to some of our older transformers some forty years ago and this has not been taken into account when interpreting the results of our oil tests. It is therefore possible that the condition of the transformer oil is not an accurate indicator of the condition of the paper insulation.

We are well placed in the event of an unexpected failure of one of these five transformers. Nevertheless, the consultant's report has highlighted the need for us to develop a power transformer fleet management strategy, which will identify the replacement or refurbishment requirements of individual transformers in the fleet and include a time-based programme for undertaking this work. The costs of this programme will be included in the expenditure forecasts in our 2024 AMP Update.

Of the five transformers categorised as unreliable, only Pukenui and Taipa are at single transformer substations. Pukenui has backup generation at the substation, while the mobile substation is stationed at Taipa on a permanent basis unless required for an emergency elsewhere on the network. Should the Pukenui transformer fail, we would replace it with one of the Moerewa transformers, and if the Taipa transformer failed we would replace it with one from Kaeo. Both replacement transformers are located at two-transformer substations and are in new condition. The other three transformers are in two-transformer substations and, should one fail, the second transformer would pick up the load. We note that the Kaikohe transformers are not fully loaded and more than 20% of the load on the Kawakawa substation should be transferred to Haruru before the FYE2024 winter.

1.8.3 Maintenance Expenditure

Our forecast total maintenance expenditure over the ten-year planning period is $62 million. Figure 1.4 shows how our maintenance expenditure forecast is allocated over the four maintenance categories and Table 1.6 quantifies this expenditure over the planning period. The asset renewal and replacement forecast includes the cost of remedying defects identified during asset inspections but does not include the cost of replacing a complete asset at the end of its economic life. These latter costs are included in the capital expenditure forecast.

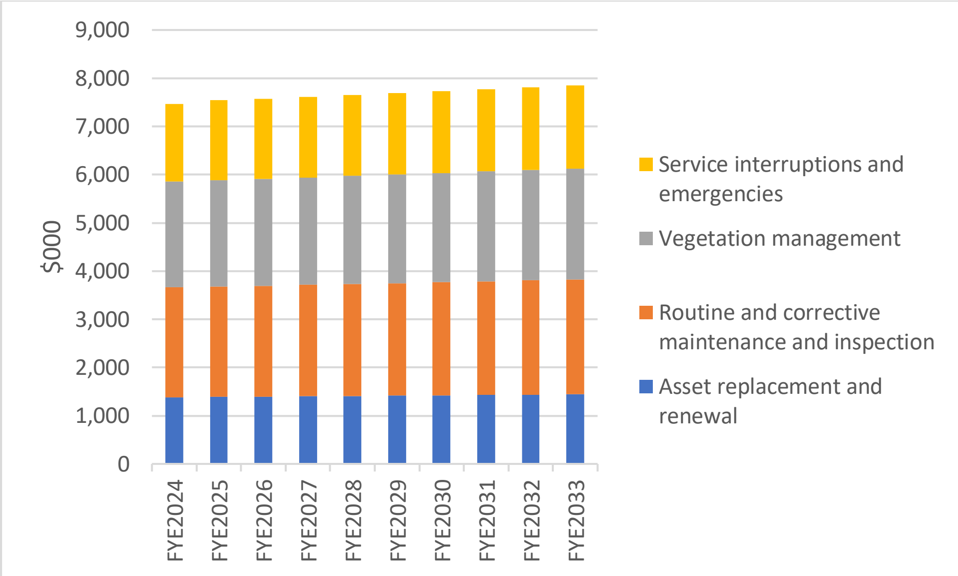


Figure 1.4: Allocation of Maintenance Expenditure by Category

$000 (in constant prices)	FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029-33	Total
Service interruptions and emergencies	1,381	1,387	1,394	1,401	1,408	7,149	14,120
Routine maintenance and inspection	2,238	2,290	2,301	2,313	2,324	11,796	23,262
Vegetation	2,197	2,208	2,219	2,230	2,241	11,377	22,472
Replacement and renewal	1,647	1,655	1,663	1,671	1,680	8,526	16,842
Total	**7,463**	**7,540**	**7,577**	**7,615**	**7,653**	**38,848**	**76,696**

Table 1.6: Maintenance Expenditure Forecast

1.9 Emerging Technologies

Ten years ago, the only generation embedded within our network was the 25MW Ngawha geothermal plant. We now have more than 9.3MW of small-scale solar generation injecting power into our network from over 1,600 injection points. We are also expecting to connect 67MW of utility-scale photovoltaic generation in the Kaitaia area. Our network will therefore need to transition from an electricity distribution system designed to transfer electricity in one direction from a centralised source to multiple consumers, to a technology enabled distributed energy system that allows multi-directional energy transfers between small generators and users. We will also need to adapt to the connection of batteries, the charging of electric vehicles, and potentially the emergence of home area networks, demand response and peer-to-peer energy markets.

The impact of these technologies and the rate at which they will emerge is unclear. Nevertheless, we need to be open to the application of these technologies by consumers connected to our network, and we also need to identify opportunities where the use of these technologies will enable us to develop and manage our network more cost effectively, for the benefit of our consumers. We have installed a new advanced distribution management system (ADMS), which provides the capability needed to efficiently manage two-way power flows in a more complex network. We are also in the process of gathering more accurate information on the connectivity of our low voltage network so the functionality of the ADMS can be extended, and the tool used more effectively.

Our policy on the introduction of new and emerging technologies is to closely monitor developments with the objective of being a fast follower, open to the introduction of technologies once we are confident that they will benefit our consumers. We are open to collaborating with third parties that want to trial new technologies on our network and have signed a memorandum of understanding with a third party to install and test a 280kVA/80kWh battery energy storage system (BESS) at our Taipa zone substation. The BESS will be owned by the third party but controlled by us from our control room. We will use it to provide real power and voltage support at times of peak demand.

2 Background and Objectives

2.1 Overview

Top Energy Ltd (TEL) was formed in 1993 and is an electricity generation and distribution business located in New Zealand's Far North District Council's geographical area. The business comprises two divisions:

- **Top Energy Network (TEN)**, which distributes electricity throughout the Far North.
- **Top Energy Contracting Services (TECS)**, which provides construction and maintenance services to TEN and other customers.

TEL is part of a Group which also consists of **Ngawha Generation Ltd (NGL)**, which owns and operates the 57MW Ngawha geothermal power station.

TEL is 100% owned by the Top Energy Consumer Trust (Trust), which holds the shares of the business for the benefit of electricity consumers connected to our electricity distribution network. The Group is a major contributor to the Far North community's financial well-being and employs approximately 165 staff. It is one of the largest employers in the region and is uniquely placed to act as a catalyst for developing the region's economic potential.

TEN's assets comprise a network of lines interconnecting approximately 33,260 individual connection points (ICPs) within our supply area together with recently installed backup diesel generation to provide network support. The network was constructed to supply these consumers from electricity sourced from the national transmission grid and, more recently, the Ngawha geothermal power station. However, recent developments in small scale photovoltaic generation technologies have resulted in approximately 9.5MW of localised generation dispersed across more than 1,650 injection points now connected to our network. This Asset Management Plan (AMP) covers the management of TEN's assets, which had a regulatory asset value of $320 million at 31 March 2022. This figure does not include assets owned by Top Energy's other operating divisions, which are not covered by this AMP.

Table 2.1 below shows the key parameters of our network and Table 2.2 overviews the current level of embedded generation.

DESCRIPTION	QUANTITY
Area covered	6,822km^2
Consumer connection points	33,263[(1)]
Grid exit point	Kaikohe
Network peak demand (FYE2022)	77MW[(2)]
Electricity delivered to consumers (FYE2022)	330GWh
Number of distribution feeders	63
Distribution transformer capacity	283MVA[(3,4)]
Transmission lines (operating at 110 kV)	66km[(3)]
Subtransmission cables (33kV)	23km[(3)]
Subtransmission lines (33kV)[5]	315km[(3)]
HV distribution cables (22, 11 and 6.35kV)	231km[(3)]
HV distribution lines (22, 11 and 6.35kV including single wire earth return)	2,573km[(3)]

Note 1: Average number of active connections FYE2022.
Note 2: Metered load as disclosed to the Commerce Commission.
Note 3: At March 2022.
Note 4: Does not include 22/11 kV or SWER isolating transformers, or transformers not owned by TEN.

Table 2.1: Network parameters.

TYPE OF GENERATION	NO OF INJECTION POINTS	CAPACITY (MW)
Geothermal	2[1]	57
Diesel	5	17.2
Photovoltaic	1,624[2]	9.3[2]

Note 1. All geothermal generation is located at Ngawha. However, OEC1-3 connect to the network at 33kV while OEC4 connects at 110kV.
Note 2: At 31 December 2022

Table 2.2: Embedded and Distributed Generation (at 31 January 2023)

2.2 Mission and Values

2.2.1 Group

The Board has approved a Strategy Map for the Group, which sets out the Group's mission, vision, and values and underpins everything that we do. This is shown in Figure 2.1. Each operating division within the Group has developed its own strategic vision, which interprets the Group's mission and vision in the context of the business unit's core activity, while maintaining the Group's values and high-level corporate objectives.

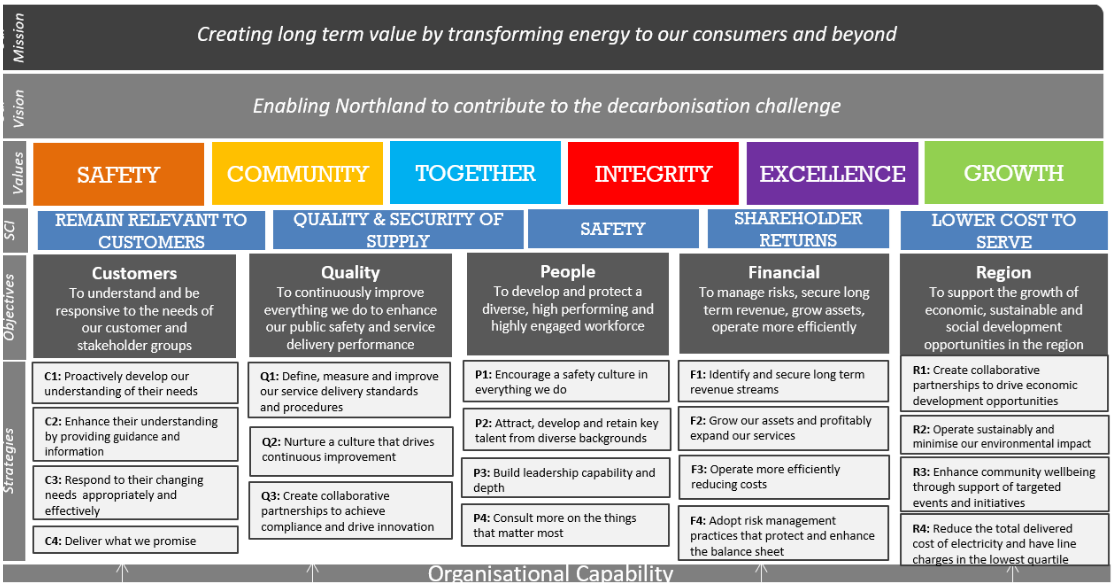


Figure 2.1 Group Strategy Map

2.2.2 Top Energy Network

TEN, as one of the Group's three business units, has developed the following mission and vision:

2.2.2.1 Goal

Our goal is to:

- *provide a safe, secure, reliable, and fairly priced supply of electricity to consumers in the Far North.*

Since the Trust exists for the benefit of our consumers, our goal is well aligned with the mission of the Group. While safety is not negotiable, our biggest challenges in delivering on our network goal are finding the appropriate balance between security, reliability, and price for the services that we provide, and adapting to the challenges of emerging technologies to remain relevant to the consumers we serve.

2.2.2.2 Vision

Our vision:

- *enabling two-way power flow to deliver our consumers' evolving energy needs.*

Electricity distribution has long been considered a natural monopoly as consumers have historically had little choice other than to source electricity from the grid. However, the reducing cost of photovoltaic generation has seen an increasing number of small-use consumers install their own generation, most typically rooftop solar, "behind the meter". This has blurred the distinction between a generator and a consumer, as many installations now connected to our network not only draw electricity from the network but also inject electricity into the network at times when the output of their installed behind-the meter generation exceeds their internal requirements. Furthermore, the advent of electronic time-of-use metering, coupled with continuing developments in communications and power control technologies, is making it possible for these small consumers to also become energy traders, selling their surplus electricity to retailers, to other users through peer-to-peer trading arrangements, or even to us for network support. Dynamic pricing and battery storage, including the utilisation of batteries in electric vehicles, enhances this arbitrage potential, as electricity generated when prices are low can be stored and injected back into the network at times of peak demand when prices are higher.

In this context, if we are to remain relevant to the electricity users we serve, we must transition from an electricity distributor to a network services provider, where our role is to provide a network that facilitates the dynamic flow of power to and from interconnected electrical installations. This transition is challenging the relevance of the monopolistic business and regulatory models that underpin our industry. We recognise this and are committed to adapting to emerging technologies and changing consumer behaviour, while at the same time improving our service to consumers. We welcome consumers and external parties introducing distributed generation and battery storage on our network and welcome any opportunity to collaborate with stakeholders on how our network might be developed to better support the application of the emerging technologies and strategies that are challenging our industry.

2.3 Network Development Achievements

In FYE2010, recognising that the reliability of supply provided by our network fell well short of stakeholder expectations Top Energy implemented a ten-year network development plan, known internally as TE2020, with the following objectives:

- Improving the reliability of supply provided by our network. The major focus of this initiative was to eliminate the need for regular maintenance outages of the single circuit Kaikohe-Kaitaia 110kV line, which necessitated nine-hour supply interruptions impacting more than 10,000 consumers, one third of our consumer base, located in the northern part of our supply area. This was a major concern to many of our stakeholders and the source of much community frustration.
- Addressing an emerging capacity constraint in the Kerikeri area, where the rate of population growth remains one of the highest in the country.

Since TE2020 was initiated, we have invested almost $250 million (nominal) on the development of our network. With this investment:

- We acquired the 110kV Kaikohe-Kaitaia transmission line and the Kaikohe and Kaitaia 110/33kV transmission substations from Transpower, so that we can better integrate these assets into our network development plans.
- We have increased the capacity of the network supplying the Kerikeri and Whangaroa areas through the construction of a new double circuit 110kV line between Kaikohe and Wiroa and a new 33kV switching station at Wiroa. This line is currently operating at 33kV, but the operating voltage will be increased to 110kV when a new 110/33kV transmission substation at Wiroa is energized.

- We have successfully negotiated the required easements with the majority of property owners over our planned route of a new 110kV line between Wiroa and Kaitaia. Unfortunately, we were unable to reach agreement with a small number of property owners along the route but were granted ministerial approval to compulsorily acquire the easements. Three of these property owners appealed this ministerial decision to the Supreme Court but the appeal was dismissed in December 2022, clearing the way for us to secure the route over the full length of the proposed line.
- We have installed a total of 16.4MW of diesel generation to provide a backup supply when the Kaikohe-Kaitaia 110kV line and our single circuit subtransmission lines are not in service. These generators are located at a new generator farm at Bonnetts Rd, west of Kaitaia, our Kaitaia construction and maintenance depot and at the Taipa, Pukenui and Omanaia zone substations. This has eliminated the need for planned supply interruptions for 110kV line maintenance and enabled supply to be restored after an unplanned interruption without waiting for the line to be repaired.
- We have upgraded the protection on our 33kV subtransmission network. This has allowed most of our subtransmission lines to be run in parallel or in a ring configuration so that most faults on our subtransmission network no longer cause a supply interruption.
- We have constructed new 33/11kV substations at Kerikeri and Kaeo to increase the capacity of the 11kV distribution network supplying these areas. This has increased the number of feeders in these areas, which has reduced the feeder length and also the number of consumers on each feeder, which in turn has improved the reliability of supply as fewer consumers are impacted by a fault.
- We have constructed a new 110kV line to deliver the energy generated by the recently commissioned 32MW OEC4 generator at the Ngawha power station to the Kaikohe 110kV bus.
- We have implemented an aggressive asset renewal programme on our 110kV and 33kV assets. This includes:
    - An ongoing programme of structure replacements and tower refurbishment on the 110kV Kaikohe-Kaitaia line.
    - Installation of a new 40MVA 110/33kV power transformer at Kaitaia.
    - Installation of a new indoor 33kV switchboard at Kaikohe.
    - Substation rebuilds at the Moerewa, Omanaia, Kawakawa and Waipapa substations to replace assets reaching the end of their economic lives and increase compliance with current environmental and safety standards. This included the replacement of aging transformers at Moerewa and Omanaia.
    - Refurbishment of the 33kV lines supplying the Pukenui and Taipa substations. Refurbishment of the line supplying the Omanaia substation is ongoing.

2.4 Key Asset Management Challenges

While the TE2020 investment described in Section 2.3 above has significantly improved the reliability and resilience of our transmission and subtransmission network, several key asset management challenges remain. These are discussed below.

2.4.1 Vulnerability of 110kV Line

Notwithstanding our ongoing programme of structure replacements and tower refurbishment, the 110kV line between Kaikohe and Kaitaia remains a major network vulnerability. There are two issues of concern:

- The line crosses the Maungataniwha Range, which is increasingly prone to slips. In 2014 a slip undermined the foundations of one of the towers and left the tower suspended by its conductors. Fortunately, this did not cause a supply interruption. This year a further slip occurred in the same vicinity. State Highway 1 is now closed for the second time in two years where it crosses the Range and is likely to remain closed for several months. It seems that this section of our line is becoming increasingly vulnerable, most likely due to climate change. Over this part of the route, the line is constructed on double circuit towers, with the two conductors on each phase bonded together to form a single circuit. Should more land slippage occur, Top Energy may need to consider putting each set of conductors on separate structures to enable supply to be restored more quickly should a structure failure occur.

- We are assessing the condition of the conductor, in part because the line, which was constructed by Transpower, is not fitted with vibration dampers. The line is now 45 years old, and the remaining life of the conductor is unclear. The expected life of aluminium conductor is about 55 years and, while there is no immediate concern, we consider it prudent to develop a long-term network development strategy that recognises that the conductor on this critical asset has a limited remaining life and provide for its eventual replacement. We plan to undertake a laser scan of a section of line conductor during the next maintenance outage to obtain an objective assessment of conductor condition. The results will be compared with those of a laboratory analysis undertaken some years ago, to assess the rate of conductor deterioration and form an objective view of when the conductor might need to be replaced.

The expenditure forecasts in this AMP provide for a continuation of the current level of maintenance of this line and a detailed assessment of conductor condition during FYE2024. However, it is not anticipated that the conductor will need to be replaced before the end of this AMP planning period. Furthermore, while the risk of a structure failure is acknowledged, the construction of additional structures at this point is not considered justified. The proposed Wiroa-Kaitaia line will mitigate this risk if it is built. In the unlikely event of a structure failure occurring in the meantime, diesel generation will be used until grid supply can be restored. We have an arrangement in place with Transpower, which can make a temporary structure available at short notice, should this be needed.

2.4.2 Network Reliability

As can be seen from Section 2.3, investment under the TE2020 network development initiative has focused on increasing the capacity and resilience of the transmission and subtransmission networks. This was not only necessary to address the network capacity issues but was also considered the most cost-effective approach to improving the resilience of the network and the reliability of supply to consumers over the medium term. Two initiatives, in particular, were expected to contribute to this reliability improvement goal.

- Elimination of the SAIDI/SAIFI impact of planned 110kV line maintenance outages through the provision of an alternative supply to the northern region when the existing 110kV line was out of service for maintenance. Our original plan was to construct a second line to provide the alternative supply, but when it became apparent that the delay in securing a suitable line route would be extensive, we pivoted to the alternative approach of installing backup diesel generation. We have now achieved our objective, and maintenance outages of this line do not require supply interruptions to customers (with the sole exception of the Juken New Zealand Triboard mill near Kaitaia, where we have a special arrangement in place with the customer).

- Upgrading the protection on our 33kV subtransmission lines so that the two incoming circuits feeding a single zone substation could be operated in a parallel rather than radial configuration. The intention was to eliminate the SAIDI/SAIFI impact of most 33kV faults because, if the circuits were operated in parallel, the load on a faulted circuit would seamlessly transfer to the parallel circuit, and no supply interruption would occur. This project was supplemented by the refurbishment of the 33kV lines supplying smaller substations where no parallel circuit is available.

  This project, which is now complete, has also been successful. The annual SAIDI impact of unplanned supply interruptions due to 33kV network faults has reduced from a typical 150 minutes in FYE2016 to about 25 minutes today.

Notwithstanding the success of these initiatives, our overall reliability of supply has started to deteriorate, and we have already breached the unplanned SAIDI threshold of the Commission's price-quality path in FYE2023. We are also at risk of breaching the unplanned SAIFI threshold. There are two main reasons for this:

- Elimination of the need for planned 110kV line maintenance interruptions has not had the expected impact on the measurement of reliability for the assessment of our compliance with the Commission's price-quality path. This is a result of the Commission's decision in 2019 to abandon its previous hybrid approach to measuring reliability, and to separately assess the impact of planned and unplanned interruptions when monitoring price-quality threshold compliance during RCP3. We had not anticipated this. We had expected that the significant reduction in the SAIDI/SAIFI impact of planned interruptions once we had completed the installation of our diesel generation, together with the improvement in the reliability of the 33kV network as a result of the protection upgrade, would be sufficient to avoid a threshold breach.

- The deterioration in the reliability of the 11kV network, due in part to changing weather conditions, has been higher than we anticipated.

A breach of the quality threshold embodied in the price-quality path places us at risk of enforcement action by the Commission and possible legal sanctions. Our mitigation response is to manage the reliability of the 11kV distribution network, since 110kV and 33kV network faults are no longer significant contributors to our overall network SAIDI and SAIFI. To this end, at the beginning of FYE2023 our Board decided to defer the construction of the Wiroa 110/33kV substation and reallocate the expenditure to the maintenance and renewal of the 11kV network through the implementation of an 11kV reliability improvement programme. Under this programme we plan to:

- Increase the rate at which we replace 11kV assets that are nearing the end of their economic life.

- Optimise the protection of selected long rural feeders to reduce the impact of faults. This will include the installation of more fuses and reclosers at the connection point of spur lines as well as optimising the grading between protection devices.

- Increase the number of interconnections between neighbouring feeders to improve our ability to restore supply downstream of a faulted switching zone before the fault is repaired.

The highest SAIDI impact on the 11kV network is due to faults on feeders supplying sparsely populated rural areas with a low socio-economic profile. These feeders are long, with high fault exposure and generally high numbers of connected consumers. They supply parts of region that are already uneconomic to serve and are not showing significant demand or consumption growth.

Responses to our consumer surveys have told us that consumers connected to these feeders are more concerned about price than they are about reliability. The objective of our reliability improvement plan is therefore to arrest the deterioration in the reliability of our 11kV network and stabilise it at a level consistent with the network's historic performance. This will mean an increased level of expenditure on 11kV reliability initiatives in the short to medium term but, when the reliability has stabilised, this expenditure will reduce as we switch our focus to maintaining, rather than improving, the level of service we provide.

Once the situation has stabilised, we will focus expenditure on the development of the transmission and subtransmission network to address the localised capacity constraint in the Kerikeri and Whangaroa areas and respond to the challenges of decarbonisation.

2.4.3 Decarbonisation

Decarbonisation of the economy is driving a range of asset management challenges. In the short term these are primarily related to accelerating demand for the connection of photovoltaic generation to our network, while in the medium term we anticipate a need to develop the network to accommodate a significant increase in the demand for electricity, due primarily to the electrification of the transport fleet. Examples of how decarbonisation is impacting our asset management planning are given below.

- Network capacity constraints have historically been the result of growth in consumer demand, and the demand forecast has therefore been the key input to determining the need for network capacity expansions. However, network constraints are now being caused by the demand for the connection of renewable generation rather than by growth in consumer demand. For example, the existing 110kV Kaikohe-Kaitaia line has a summer rating of 55MW and currently supplies a peak consumer demand of 25MW. This is more than adequate to provide for the foreseeable growth in demand. However, due to the demand for the generation of electricity powered by renewable resources, we have now signed connection agreements for the installation of 67MVA of utility scale solar generation in our northern area. This will fully utilize the capacity of the Kaikohe-Kaitaia line and also the spare capacity on the Kaikohe-Maungatapere connection to the Transpower grid. Therefore, while the demand for the connection of renewable generation to our network continues unabated, we are unable to accept further applications for the connection of utility scale solar generation.

- Embedding increased amounts of photovoltaic generation in our network will change the nature of our real time network management and our processing of new generation connections. We have prepared for this with the installation of our state-of-the-art advanced distribution management system (ADMS) and the appointment of a Distribution Systems Operations Manager, with responsibility for managing the control room and the real time operation of the network, and for the processing of new generation connection applications.

- In addition to the demand for the connection of utility scale photovoltaic generation, we are experiencing continuing demand for the connection of small-scale rooftop solar generation to the low voltage network and now have more than 9MW of small-scale solar generation embedded in our network. In Australia, a high penetration of rooftop solar generation has caused problems with the management of voltages on the low voltage network. While we have not experienced these issues to the same degree, we have on occasion had to tap down distribution transformers in response to overvoltage complaints arising from the level of power injection on the low voltage side of a transformer. Our ADMS has the functionality to provide greater visibility of the low voltage network, which will help us manage this issue, but we are unable to fully utilise this due to a lack of accurate data on our low voltage assets. Our capital expenditure forecast includes provision over a three-year period for a low voltage data capture programme to address this.

- Transpower is currently predicting that national electricity demand could increase by about 70% by 2050, due largely to the decarbonisation of industrial process heat and the electrification of transport. After remaining largely static between 2010 and 2017, electricity demand in our area is now growing again and this rate of growth is accelerating. As most industrial process heat in our area is already fuelled by biomass, we expect most of our growth to be due to the electrification of transport. This will be a combination of organic growth across the network due to increased EV home charging, as well as the spot loading of fast DC charging stations. At present there are 14 public fast EV chargers, with a total capacity of 550kW, connected to our network and we have had enquiries regarding the potential power supply for multi-unit, higher-capacity charging stations in Kawakawa, Waipapa and Kerikeri. With the electrification of the heavy transport fleet, we expect the demand of some future charging stations to be well over 1MW. There is also a potential demand for a charging station at Kerikeri Airport as electrified aircraft are one option being considered by Air New Zealand as it investigates the potential for decarbonising its short-haul fleet. This could be supplied at either 33kV or 11kV from the Wiroa substation, which is close to the airport.

- Our 33kV subtransmission network, apart from the capacity constraint into the Kerikeri area to be addressed by the Wiroa substation, and a potential voltage constraint in the Bay of Islands area, now has sufficient capacity to accommodate the expected demand growth through to 2050. However, much of our new demand could be in areas such as Opononi/Omapere and the Russell, Karikari and Purerua peninsulas, which are not served by the existing subtransmission network. In these areas, the capacity of the 11kV network is limited, and growth in demand may require the reach of the 33kV network to be extended through the construction of new subtransmission lines and zone substations. Unfortunately, the location and timing of this demand growth is still highly uncertain, making it difficult to plan for.

We anticipate the need for, and timing of, network capacity expansion to accommodate demand increases driven by decarbonisation will become clearer over time.

2.5 Purpose of this Plan

Top Energy's Statement of Corporate Intent (SCI) describes this AMP as the defining document for TEN, which sets out the ten-year capital and maintenance expenditure levels estimated to be required to ensure that the network is managed in a sustainable way. This AMP lies at the heart of our asset management process and is the primary tool for planning the long-term development and maintenance of our electricity network.

This AMP documents our planned processes and activities to develop, maintain and operate our electricity network so that it meets required levels of safety, service, and quality in a cost-effective manner.

In this context, the purpose of this AMP is to:

- Communicate to stakeholders our asset management strategies and action plans for the network, within the context of Top Energy's mission statement and corporate strategy.
- Define the services that we plan to provide, the measures used to monitor the quality of these services and the target performance levels for these services over the AMP planning period.
- Describe the capital and maintenance works programmes planned to meet the target service levels (including reliability of supply), provide for future growth in electricity demand, and estimate the cost of delivering these programmes.
- Demonstrate responsible management of the network infrastructure and show that funds are optimally applied to deliver cost-effective services that meet consumer expectations.
- Comply with clause 2.6.1 of the Commerce Commission's Electricity Distribution Information Disclosure (Targeted Review Tranche 1) Amendment Determination 2022. This AMP does not include the information in Clauses 17.1-17.6 of Attachment A of this Determination, which will be disclosed in a separate document, as provided for in clause 2.6.1A. The separate document will be disclosed on Top Energy's website on or before 30 June 2023.

2.6 Asset Management Policy

This AMP is guided by our network asset management policy. In summary, this policy requires us to develop an asset management plan that:

- Gives safety our highest priority. We must act in accordance with industry standard safe working practices and, in consultation with our employees and contractors, develop and adopt systems and procedures that minimise the risk of harm to people and property, in accordance with the Health and Safety at Work (General Risk and Workplace Management) Regulations 2016. We must consider the impact of all that we do on our employees, contractors, consumers, and the general public.

- Develops a network that is resilient to high impact, low probability events. We do this by building in asset redundancy where this is appropriate, and by developing and improving plans and procedures for effectively responding to events that exceed our normal response capacity.

- Improves our network's security and reliability at a rate that is both financially sustainable to the business and affordable to our consumers. We also strive to continually improve the efficiency and cost-effectiveness of our asset stewardship to increase the value that we provide to our stakeholders.

- Monitors the technological changes affecting our industry and is ready to modify our asset management strategies to remain relevant to the consumers that we serve.

We use the Commerce Commission's asset management maturity assessment tool (AMMAT) to assess the quality of the systems and processes that we use to implement this policy. Our current AMMAT assessment is shown in Schedule 13 of Appendix A.

2.7 Asset Management Objectives

Our asset management objectives are grouped into five separate focus areas to align with the Top Energy Group's corporate objectives shown in Figure 2.1. In the sections below, we show how these corporate objectives are reflected in TEN's operation and the way that we manage our physical network assets.

2.7.1 Consumers and other Stakeholders

Our corporate objective is to:

understand and be responsive to the needs of our customer and stakeholder groups.

We do this by:

- Proactively developing our understanding of our consumer and stakeholder needs. We do this formally through regular consumer surveys and informally though less structured interactions with stakeholders in the normal course of business. These stakeholder interactions are becoming increasingly important as we seek to better understand the impact of emerging technologies on consumer behaviour, and the impact that this could have on the future demand for our electricity distribution services and the way in which our network assets will be used.

- Responding to stakeholder needs appropriately and effectively.

- Increasing stakeholder understanding by providing guidance and information. We are also increasing the amount and timeliness of information to stakeholders through our website and other social media, including a real-time outage map. We have also communicated our asset management strategy and rationale through a video that has been positively received by our stakeholders.

Sections 2.10.3 and 2.10.4 identify our stakeholders, their interests, how we aim to accommodate those interests and how we attempt to resolve any stakeholder conflict that may occur.

2.7.2 Quality

Our corporate objective is to:

continuously improve everything we do to enhance public safety and our service delivery performance.

We do this by:

- Better defining, measuring, and improving our service delivery standards and procedures. We have successfully implemented an ISO 9001 certified quality management system. We have initiatives underway to implement safety-by-design across all our projects and to implement an integrated safety process and performance auditing programme. We are developing an integrated management system across the business, which will incorporate all our safety, quality, and risk management systems.

- Nurturing a culture that drives continuous improvement.

- Creating and maintaining collaborative partnerships to achieve compliance and drive innovation. We are actively involved with industry groups such as the Electricity Networks Association (ENA), the Electricity Engineers' Association (EEA), WorkSafe New Zealand, and the Business Health and Safety Forum to better understand our regulatory and legislative environment and work collaboratively towards the achievement of shared objectives. We also engage with other lines companies and digital technology providers where this helps us better serve our consumers.

2.7.3 People

Our corporate objective is to:

develop and protect a high performing and highly engaged workforce.

We do this through:

- Our processes for the recruitment and retention of key talent.
- Building leadership capability and depth.
- Consulting more on the things that matter most, through the deployment of an annual employee culture survey and the provision of increased support and accountability on managers and supervisors to run consultative team meetings.
- Investing in the development and training of our people by increasing our training budgets to a level above industry and national averages and establishing strategic training plans to meet our operational needs.

2.7.4 Financial

Our corporate objective is to:

manage risks, secure long-term revenue, grow assets and operate more efficiently.

We do this by:

- Securing our long-term revenue stream by implementing a pricing strategy designed to increase the certainty of our revenue levels.
- Delivering the key network projects identified in this AMP and being open to the investment in non-network alternatives, where these provide cost effective outcomes that better meet consumer needs.
- Operating more efficiently to reduce costs through the development and implementation of a standardised project management and delivery framework, identifying procurement and cost saving opportunities, and providing operations and financial management training to managers to enhance financial decision making.

2.7.5 Region

Our corporate objective is to:

support the growth of economic, employment and social development opportunities in the region.

We do this by:

- Providing network and non-network solutions that will underpin economic development by assisting investors, developers, and industry to fulfil their growth ambitions.
- Providing holiday work experience to tertiary students in accordance with our recruitment strategy.
- Participating in community events.
- Encouraging and supporting employees to volunteer for community emergency services.

2.8 Non-Network Developments

2.8.1 Embedded Geothermal Generation

The expansion of the Ngawha Geothermal Power Station to its current capacity of 57MW has shifted the centre of electricity supply to our consumers from remote generation located south of Auckland, to generation located close to our network. More than 95% of the electricity consumption in our supply area is now locally generated, and the primary function of the connection to Maungatapere is now to export electricity generated at Ngawha south for use by consumers outside our area.

Ngawha Generation has resource consent for the installation of a further 32MW generating unit at Ngawha, which would increase its maximum output to 89MW. We are currently assessing the potential impact of this additional generation on the network. Overall, the New Zealand power system is benefitting from increased base-load generation located north of Auckland as it will reduce the amount of energy that needs to be transmitted through the congested Auckland isthmus. However, the amount of electricity that can be exported south will be constrained by the capacity of Transpower's double circuit 110kV line connecting our Kaikohe substation to the Transpower grid at Maungatapere. This constraint is quantified and discussed further in Section 5.11.2.1.

2.8.2 Small Scale Photovoltaics

Over the past five years, the penetration of small-scale behind-the-meter solar panels has increased with recent larger installations on commercial premises giving the trend an upward trajectory, as shown in Figure 2.2. There is now a total of more than 9.5MW of solar generation embedded in our network, spread across more than 1,660 injection points. This is an increase of 2.3MW (32%) in just 12 months.

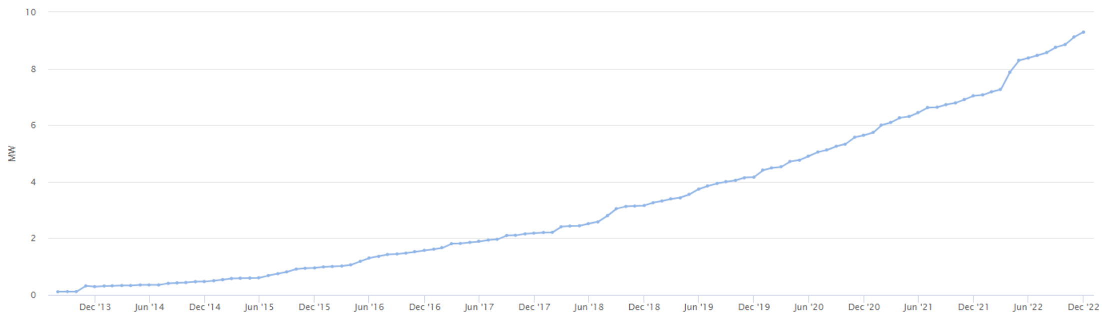


Figure 2.2: Growth in Photovoltaic Generation Connected to our Network

An installed photovoltaic generation capacity of 9.5MW is significant and contributes both to the reduction of imported energy from the grid and increased energy export at times when our demand is low. We also have the largest penetration of distributed generation injection points as a percentage of the total number of connection points on the network (4.8%) of any New Zealand EDB and, as can be seen from Figure 2.3 below, this penetration rate is currently increasing as fast as any other EDB.

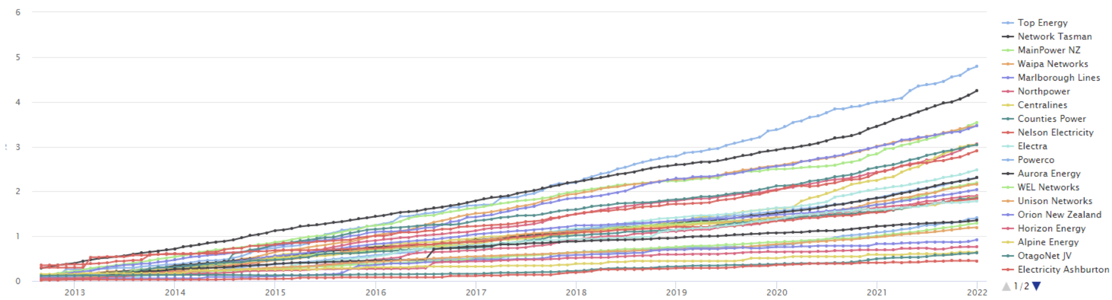


Figure 2.3: Solar Penetration by EDB

We estimate that in the middle of a cloudless summer day, up to 20% of the electricity consumed within our network area is supplied by small-scale behind-the-meter photovoltaic generation.

Our ADMS is being developed further to provide greater visibility of the low voltage network. To take full advantage of this additional functionality, we require more accurate data on our low voltage assets, and our capital expenditure forecast includes provision a low voltage data gathering project to address this.

2.8.3 Utility Scale Photovoltaics

We have signed agreements for the connection of the following solar farms in the northern part of our network. The cost of the assets needed to connect these farms to our network will be paid by the developers and are included in our expenditure forecast as consumer connection capital expenditure.

Far North Solar Farm

A 20MW solar farm located adjacent to our Pukenui zone substation. It will be connected to the substation via an underground 33kV cable.

Twin Rivers Solar Farm

A 24MW solar farm located approximately 2.6km southeast of our Kaitaia 11kV substation. It will be connected to the Kaitaia 33kV substation bus via a new single circuit 33kV line running alongside SH1.

Kaitaia Solar Farm

This solar farm, which has been developed by Loadstone Energy, will be a 23MW installation located approximately 3.6km northwest of Juken NZ Triboard Mill north of Kaitaia. It will be connected to our NPL substation at the mill site via a 33kV circuit comprised of a 2.8km overhead line and 0.9km underground cable.

At this point the Kaitaia and Far North solar farms are committed for construction, although we remain in touch with the Twin Rivers proponent and expect it to proceed in due course. Interest in the connection of solar farms in our northern area remains strong but, as noted in Section 2.4.3, we are unable to accept any further connection applications due to capacity limitations.

2.8.4 Electric Vehicles

The Government is strongly promoting the introduction of electric vehicles, because of New Zealand's high proportion of electricity generation from renewable resources. As can be seen from Figure 2.4 below, there has been an exponential increase in the number of battery and plug-in hybrid electric vehicles first registered in New Zealand to addresses in our supply area.

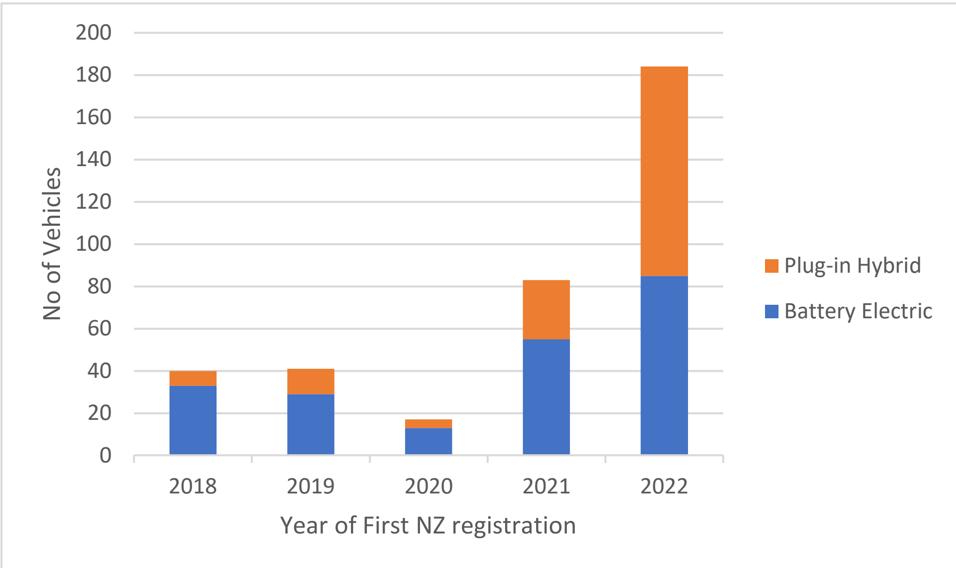


Figure 2.4: New BEV and PHEV Registrations – Far North District Council Area

2.9 Rationale for Asset Ownership

Our rationale for asset ownership is derived from our mission statement, which as noted in Section 2.2.2, is to:

> *provide a safe, secure, reliable, and fairly priced supply of electricity to consumers in the Far North.*

Our intention is to own only the assets needed to deliver on this mission with the lowest long-term cost.

Until recently, the economies of scale in electricity generation were substantial, the demand for electricity was growing exponentially, and technologies for storing large quantities of electricity were not available. In this situation, the most economic approach to providing an electricity supply to individual consumer premises was to use a network of conductors and transformers to deliver electricity, sourced from a relatively small number of large generators and interconnected by a centralised transmission grid. This industry paradigm is now changing to the extent the installation of traditional network assets may not always be the most cost-effective solution. Traditional network assets are expensive to install and have lives of forty years or more. It is only cost-effective to use such assets to meet today's distribution requirements where there is a degree of confidence that the installed network capacity is likely to be required for the life of the asset, or if there is no suitable lower-cost alternative that will fully meet consumer requirements.

While we know that our industry will be significantly affected by the introduction of emerging technologies, the timing and nature of these impacts is far from clear. In this environment, the risk of asset stranding, where an asset becomes redundant part way through its life, could be reduced through the installation of lower-cost alternatives with a shorter life, on the basis that by the end of their life, the future of the industry should be clearer. These assets could then be replaced with solutions that better meet our stakeholders' long-term requirements.

We are open to the use of non-network solutions to meet the needs of our consumers. This approach has already involved the installation of diesel generation to provide supply security to our northern area in the absence of a second incoming 110kV circuit and at zone substations supplied by a single incoming 33kV circuit. We are also working with a provider who is planning to install a 280kVA/100kWh battery/inverter storage system at our Taipa substation as a trial.

As emerging technologies become more mature, we expect our consumers to become less reliant on traditional network assets to meet their energy requirements. As we transition to a distributed energy services operator the nature of our asset base will change, and we will not necessarily own all the assets that we manage. Some will be owned by our consumers, and some will be provided on a competitive basis by third parties.

2.10 Asset Management Planning

The key internal planning documents with a direct link to this AMP are our:

- Statement of Corporate Intent (SCI), which outlines our overarching corporate objectives and strategic performance targets for the coming year. It incorporates the outcome of an annual strategic business review and formally documents an agreement between the Top Energy Board and the shareholder, and so requires the approval of the Trust.
- Annual Plans, which are short-term operating documents that detail how the funds will be used within the budget set out in this AMP and approved by the Board. Annual Plans are prepared for maintenance, vegetation management and capital works delivery. They provide more detail than described in this AMP on how budget funding will be used. For example, the vegetation management plan identifies the feeders that will be the focus of the vegetation management effort in a particular year. Annual Plans are approved by our executive management team, but do not require Board approval.

- Business Cases, which are prepared for all projects or programmes with an estimated cost of more than $500,000. These are prepared throughout the year and require Board approval before a project or programme can commence.

In addition, there are a range of internal and external documents and systems that influence the content of the AMP. Internal documents and systems include our:

- Quality System, which is certified as compliant with ISO 9001 and externally audited on a regular basis. It includes the policies, procedures and work instructions that underpin all that we do.
- Risk Register, which identifies key risks that our business faces, given the architecture and condition of our network fixed assets. Mitigation of these risks is a key driver of our capital expenditure (capex), and operations and maintenance expenditure (opex) on network assets.
- Emergency Preparedness Plan, which details the plans and procedures we have in place to ensure electricity supply is maintained or restored as quickly as possible, following emergency circumstances and events that the network is not designed to withstand.
- Safety Management System, which details the processes and procedures in place to ensure the safety of our employees and contractors working on the network.
- Public Safety Management System, which specifies the processes and procedures in place to ensure that our assets do not present a risk or hazard to the general public.
- Northland Region Civil Defence Emergency Group Plan (NRCDEGP), which describes procedures for the response to a civil defence emergency in the Northland region. It identifies interdependence issues between our network and other lifelines and the role of Top Energy in response to a civil defence emergency. The response procedures include the operation of injection equipment and support delivery to ensure the functioning of the MEERKAT community warning system.

The external documents that influence the strategies and action plans described in this AMP include the Commerce Commission's price-quality path that applies to the operation of the network. This is defined in the Commission's Electricity Distribution Services Default Price-Quality Path Determination 2020. The development of the asset management strategies and action plans described in the AMP is also restricted by the requirements of the different legal and regulatory instruments that govern our operations. These include technical standards relating to electricity supply, public safety, employee and contractor health and safety, and environmental protection.

2.10.1 Preparation of the AMP

This AMP is both a strategic and an operational document. It is strategic, in that it sets out our plans for the management of our network assets over a ten-year planning period. It is operational, in that the plans and budgets within the AMP for the first year of the ten-year planning period form the basis for the Annual Plans that control our asset management expenditure for FYE2024. In subsequent years, the content becomes progressively more strategic.

The SCI provides the context for the AMP, which in turn provides the context for the Annual Plans. All documents are interdependent and prepared in parallel using a largely iterative process.

At a strategic level, the SCI details the funding available to resource the action plans and strategies set out in the AMP. These funds are reliant on the revenue that we expect to earn, the return that the shareholder requires, and the need to maintain a prudent debt-equity ratio. The SCI also sets out the target levels of service for the first three years of the planning period. These are an outcome of the strategies and plans detailed in the AMP.

The AMP strategies and plans are prioritised within the available funding. They are also influenced by factors that impact our operation, including:

- The capacity of the existing network assets to accommodate localised growth in demand.
- The needs of consumers and other network stakeholders.
- The cost of meeting legal and regulatory requirements.

- The assessment of potential risks to the smooth operation of the network, and the need to plan for and mitigate these risks.

The AMP takes account of our ability to deliver planned outcomes and maximise the investment of funds and other available resources in a way that optimises benefits to stakeholders.

Preparation of these key planning documents commences more than six months prior to the start of each financial year. The process begins with a reassessment of the environment in which the business operates and how this might influence our strategic corporate objectives. It also includes a review of our forecast of the demand for electricity and the performance of the existing network asset base. As a result of this review, we prioritise our capex and opex requirements. These activities lead to the development of initial plans that consider operational constraints at a high level.

The process then enters an iterative refinement phase, where the impact of constraints on the deliverability of these initial plans is analysed in more detail. The AMP is refined, and the impacts that these refinements may have on our SCI and Annual Plans are considered, which may result in further adjustments. The iterative process continues until a set of plans result that are consistent with one another, align with our mission and accommodate all key constraints.

The final plans are subject to review and approval by our executive management team. The SCI and the AMP are formally approved by the Board in March, prior to the commencement of each financial year.

2.10.2 Planning Periods Adopted

This AMP is dated 1 April 2023 and relates to the period from 1 April 2023 to 31 March 2033. It was approved by the Board on 27 March 2023 and replaces all previously published AMPs and AMP Updates.

2.10.3 Key Stakeholders

Engagement with stakeholders is ongoing and the outcomes of this engagement provide critical inputs to the development of asset management plans at all levels. We engage with stakeholders through the following forums:

- Meetings and informal discussions.
- Discussions with major consumers.
- Industrial seminars and conferences.
- Consumer surveys.
- Enquiries and/or complaints.
- Discussions with the Trust.
- Reviews of major events such as storms.
- Specific project consultation.
- Meetings with suppliers.
- Performance review and management for internal and external contractors.
- Papers and submissions.
- Website and social media.
- Local media.

Table 2.3 below indicates how the AMP incorporates the expectations of stakeholders. Each year, the published AMP is made available to all stakeholders for their information. Feedback is welcomed.

Where conflict arises between our asset management requirements and stakeholder expectations, we engage with the affected stakeholders and attempt to achieve an acceptable outcome. In these situations, the following considerations apply:

- Safety is always our highest priority.
- The needs of all affected stakeholders are considered.

- Alignment with the Trust objectives as published in the SCI.

Our approach is to work with all parties involved to ensure there is a complete understanding of all the issues and to seek alignment, or at least common ground, and work towards a mutually acceptable solution. Our experience is that this will usually resolve the issue. However, if agreement cannot be reached, we will proceed in a manner that we believe is fair to all affected parties and is consistent with Top Energy's group values and objectives.

2.10.4 Stakeholder Interests

Table 2.3 below identifies our key stakeholders and their individual interests and summarises the process that Top Energy has in place to accommodate their expectations.

STAKEHOLDER	EXPECTATIONS	ACTIONS
NETWORK USERS	Fair price	• We set prices at or below a level consistent with the revenue cap determined by the Commerce Commission in applying its price-quality regulatory framework. • We continually strive to improve our operating efficiency in the expectation that, over time, network users will benefit through lower prices for the services we provide. • Network losses are a cost to consumers. We measure these losses and expect they will reduce over time as our network is developed. We calculate loss factors for different parts of the network in accordance with the methodology approved by the Electricity Authority. • We actively manage GXP demand using our water heater control system to ensure transmission connection costs are minimised without adversely impacting the quality of supply as perceived by consumers. • We minimize the cost of improvements to the reliability and capacity of our network by using new technologies and non-network alternatives, such as embedded generation, where this is practicable.
	Reliability	• We continually measure and review reliability against the SAIDI and SAIFI targets detailed in the AMP.
	Quality	• We identify areas within the network where the quality of supply does not meet technical standards through internal modelling and monitoring of consumer complaints, and we implement improvement projects as a result.
	Resilience	• We set security standards for the transmission and subtransmission networks and have implemented augmentations to ensure these standards are met or exceeded. • We have a documented Emergency Preparedness Plan that sets out the procedures we will follow if an emergency arises due to a low probability event that exceeds our normal response capacity.
	Flexibility	• We are flexible and endeavour to meet the requirements of individual consumers to the extent that this is cost-effective using a shared network.
	Emerging technologies	• We facilitate the application of emerging technologies that provide opportunities for consumers to use our network in new and innovative ways.
	Communications	• An external call centre has been contracted to ensure consumers are directed to the appropriate point of contact for quick and efficient service. • We closely monitor consumer expectations through regular surveys and other communication channels and endeavour to meet these expectations in the planning and operation of the network. • We communicate with our consumers through our interactive outage app., website, social media, and local media.
	Embedded generation	• We welcome the connection of embedded generation where network capacity is available and will negotiate with proponents to achieve an outcome that meets their requirements, where this does not reduce the level of service that we provide to other network users.
RETAILERS	Communications	• We share information on network outages and other relevant issues with retailers in accordance with standard industry protocols.

STAKEHOLDER	EXPECTATIONS	ACTIONS
	Use of system agreements	• We negotiate use of system agreements with retailers in good faith and in accordance with the requirements of the Electricity Authority.
	Simple tariff	• Our tariff structure is developed in conjunction with retailers and reflects the business needs of all parties. • We coordinate the timing of any tariff changes with retailers.
	Allocation of losses	• We calculate loss factors for different parts of the network in accordance with the methodology approved by the Electricity Authority.
	Metering and billing	• We rely on retailers' systems to reconcile revenue.
BOARD AND TRUST	Safety	• Safety is our highest priority. We operate a safety management system that has been developed in accordance with the requirements of the Health and Safety at Work Act 2015, the expectations of WorkSafe New Zealand and industry guidelines and practices. • We cultivate a culture of safety within the business and actively participate in industry safety initiatives. • We monitor safety outcomes and report these monthly to the Board.
	Return on investment	• Our asset management activities are consistent with a corporate strategic plan designed to ensure that our operations are financially sustainable. • We report financial outcomes monthly to the Board. This report includes a comparison against the budgets in this AMP.
	Economic development	• Consistent with the objective of supporting economic development within our supply area, we negotiate with potential new industrial and commercial consumers to identify an economic supply solution that meets their specific requirements without disadvantaging consumers already connected to our network.
	Reliability	• Our reliability improvement expenditure is targeted at initiatives that are expected to improve reliability of supply. • We report the reliability of our network monthly to the Board. This includes a comparison of actual reliability against the reliability targets in this AMP.
	Accountability	• Our employees' key performance indicators are linked to the achievement of asset management service levels.
	Legal and regulatory compliance	• Our internal standards, policies and procedures ensure compliance with all legal and regulatory requirements. • We monitor changes to the legal and regulatory regime within which we operate and modify our asset management plans, processes and procedures as necessary to maintain compliance.
	Asset management	• We manage our assets in accordance with this AMP, which is prepared in accordance with the corporate strategy agreed with the Trust by the Board and reflected in the SCI.
	Social responsibility	• Our capital contribution scheme is designed to ensure equitable sharing of the costs of new construction installed for the benefit of individual consumers.

STAKEHOLDER	EXPECTATIONS	ACTIONS
COMMERCE COMMISSION	Price	• We set prices at or below a level consistent with the revenue cap determined by the Commerce Commission in applying its price-quality regulatory framework. and confirm compliance annually through our audited regulatory compliance statement.
	Quality	• We set internal reliability targets consistent with the standards set by the Commission under its price-quality regulatory regime and monitor our performance against these targets monthly through our Board reports. • We compare our reliability of supply with the standard set by the Commission under its price-quality regulatory regime annually through our audited regulatory compliance statement.
	Information disclosure	• We keep records of our financial performance and the performance of our network assets, and we disclose this information annually in accordance with the Commission's requirements.
ELECTRICITY AUTHORITY	Price	• We are transitioning over time to a more cost-reflective pricing structure in accordance with a formalized plan to guide this transition.
	Legal compliance	• We manage our business in accordance with the Electricity Industry Participation Code and provide the Electricity Authority with information required under the Code.
	Retail competition	• We provide the installation control point (ICP) and metering data required for the operation of the competitive retail electricity market. • We treat all retailers using our network on a similar basis to ensure that the market operates in our area across a level playing field.
MBIE	Energy monitoring	• We provide the Ministry of Business, Industry and Employment (MBIE) with the statistical data and other information it requires to undertake its role of monitoring and regulating the use of energy in New Zealand.
TRANSPOWER	Grid management	• We cooperate with Transpower to facilitate the management of its assets that are located within our 110kV substations. • We regularly provide Transpower with updated information on our forecast peak demand and our connection point requirements. • We use Transpower's standards as the benchmark for determining the maintenance requirements of our 110kV assets. • We comply with Transpower requirements for the disconnection of load in emergency situations to ensure the security of the power system.
WORKSAFE NEW ZEALAND	Safety	• We manage all work on our network in accordance with the industry standard safety requirements approved by WorkSafe. • We participate in industry forums on the development of safety standards to protect industry workers and the general public. • We cooperate with WorkSafe in its accident reporting and investigation requirements.
STAFF	Health and safety	• We have a safety management plan in place to ensure the safety of our staff. This complies with industry standards and requirements and is regularly reviewed.
	Job security and satisfaction	• We strive for a motivated staff with high levels of job satisfaction that can meet stakeholder expectations. We regularly survey staff to monitor satisfaction with their work and working environment and undertake improvement initiatives if needed. • We have training and development, and recruitment plans in place so that relevant skill sets will be available when required.

STAKEHOLDER	EXPECTATIONS	ACTIONS
	Training	• We regularly survey staff to monitor satisfaction with their work and working environment and to identifying areas where skill development or support may be necessary. • This AMP reflects the skill set required of our work force, which inputs to our Training and Development Plan. We monitor staff training hours both individually and collectively.
PUBLIC	Vegetation control is fair	• We implement our vegetation management programme in accordance with the Electricity (Hazards from Trees) Regulations 2003. • We target expenditure on vegetation to achieve improvements in reliability of supply.
	Safety	• We implement an NZS 7901 compliant public safety management system to ensure that operation of our network assets does not pose reasonably avoidable risk or hazard to the public. This is subject to regular audit.
	Land access rights upheld	• We comply with relevant regulations and consult with landowners and occupiers as appropriate before undertaking work that requires access to private property.

Table 2.3: Accommodation of Stakeholder Interests

2.10.5 Accountabilities and Responsibilities for Asset Management

The Trust is the sole shareholder of Top Energy Ltd, which holds its shares on behalf of electricity consumers connected to the Top Energy network. The Trust appoints the Top Energy Board of Directors (Board) to govern Top Energy and protect the shareholder's interests.

The Board governs our asset management effort through the development of Top Energy's strategy, approval of this AMP and of individual project business cases for projects with an estimated cost of $500,000 or more. It also actively monitors the ongoing operation of TEN and TECS, and provides input into development of the strategic performance targets in the SCI.

The Top Energy Group structure is shown in Figure 2.5.

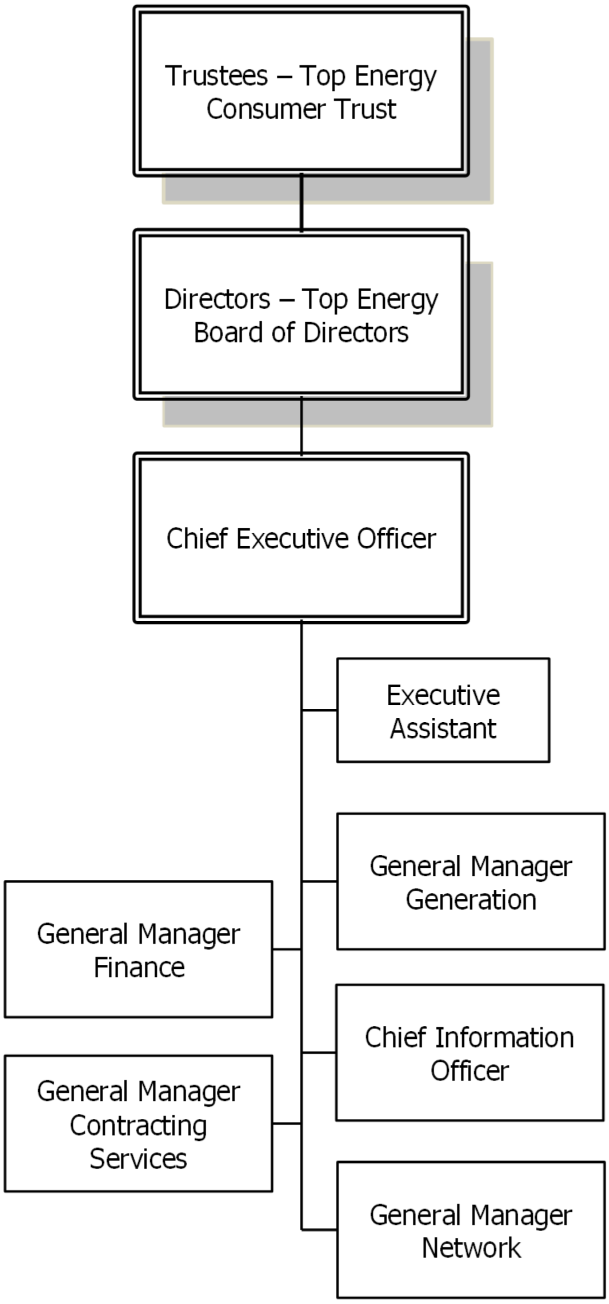


Figure 2.5: Top Energy Structure

BACKGROUND AND OBJECTIVES

At the executive level, the Chief Executive Officer (CEO) is appointed by the Board and has overall responsibility for our network asset management effort. TEN is responsible for managing the network assets covered by this AMP and is managed by the General Manager Network, who reports to the CEO and follows the strategies and policies approved by the Board. The General Manager Network is a member of Top Energy's executive management team and presents a monthly report on our network operations directly to the Board.

TEN is responsible for ensuring that the network assets are developed, maintained, renewed, and operated for long-term sustainability. This includes:

- Determining expenditure requirements.
- Maintaining asset records, developing, and setting standards.
- Operating the network in a safe manner to minimise outages.
- Monitoring performance.
- Making investment recommendations.
- Managing risk.
- The ongoing management of the network assets within approved renewal, maintenance, capital, and operational expenditure budgets.

TEN is responsible for preparing this AMP and implementing the network budgets. We are required to report any material variances from the budgets in terms of both scope and finance to the Board monthly, including variances related to projects with an approved budget of more than $500,000. Variances related to projects with an approved budget of $500,000 or less are discussed and agreed between the General Manager Network and the CEO and may be raised for Board approval if they are considered significant.

Apart from specialist maintenance activities and larger construction projects subject to competitive tender, work on the distribution network is undertaken by TECS, which employs approximately 65 staff including supervisors, technicians, and line mechanics.

TECS operates from purpose-built depots in Kaitaia and Puketona. While TECS is also a division of Top Energy, work contracted-out to TECS is managed by TEN as if TECS was an external contractor operating under an arms-length relationship. The nature of the formal relationship between TEN and TECS is discussed further in Section 2.17.4 and is regularly reviewed. The cost of field work is comparatively benchmarked against current industry costs to ensure the efficiency of works delivery is maintained. The Trust and the Board believe that this arrangement is in the best interest of the shareholder since, with this model, the interest of the asset manager and service provider are aligned.

Specialist work outside the skill set of TECS staff is outsourced to external contractors and supervised directly by relevant TEN maintenance, planning or programme delivery managers.

Maintenance work on the transmission network, including the 110kV transmission line, the 110kV substation assets, and the 33kV assets at Kaikohe and Wiroa substations, is undertaken by Northpower under a maintenance contract that requires maintenance standards equivalent to those required by Transpower.

TEN has overall responsibility for the safety of all personnel working on the network, including contractors. Consistent with industry safety standards, we implement an Authorisation Holders Certificate (AHC) assessment process to ensure the competence of field staff (both internal and external) is compliant with company and industry requirements. Employees and contractors' staff are required to be reassessed every 12 months and hold an AHC to work on the network.

Staff must provide relevant training records, workplace audits and operational evidence to prove their competency in undertaking specific tasks. AHC holders are only allowed to perform tasks to the level permitted by their AHC. The assessment and approval for issuing an AHC to an individual is by recommendation of the Network Performance Manager and with the consent of the General Manager Network.

BACKGROUND AND OBJECTIVES

TEN currently has a staffing establishment of 48 full-time equivalents and is structured as outlined in Figure 2.6 below.

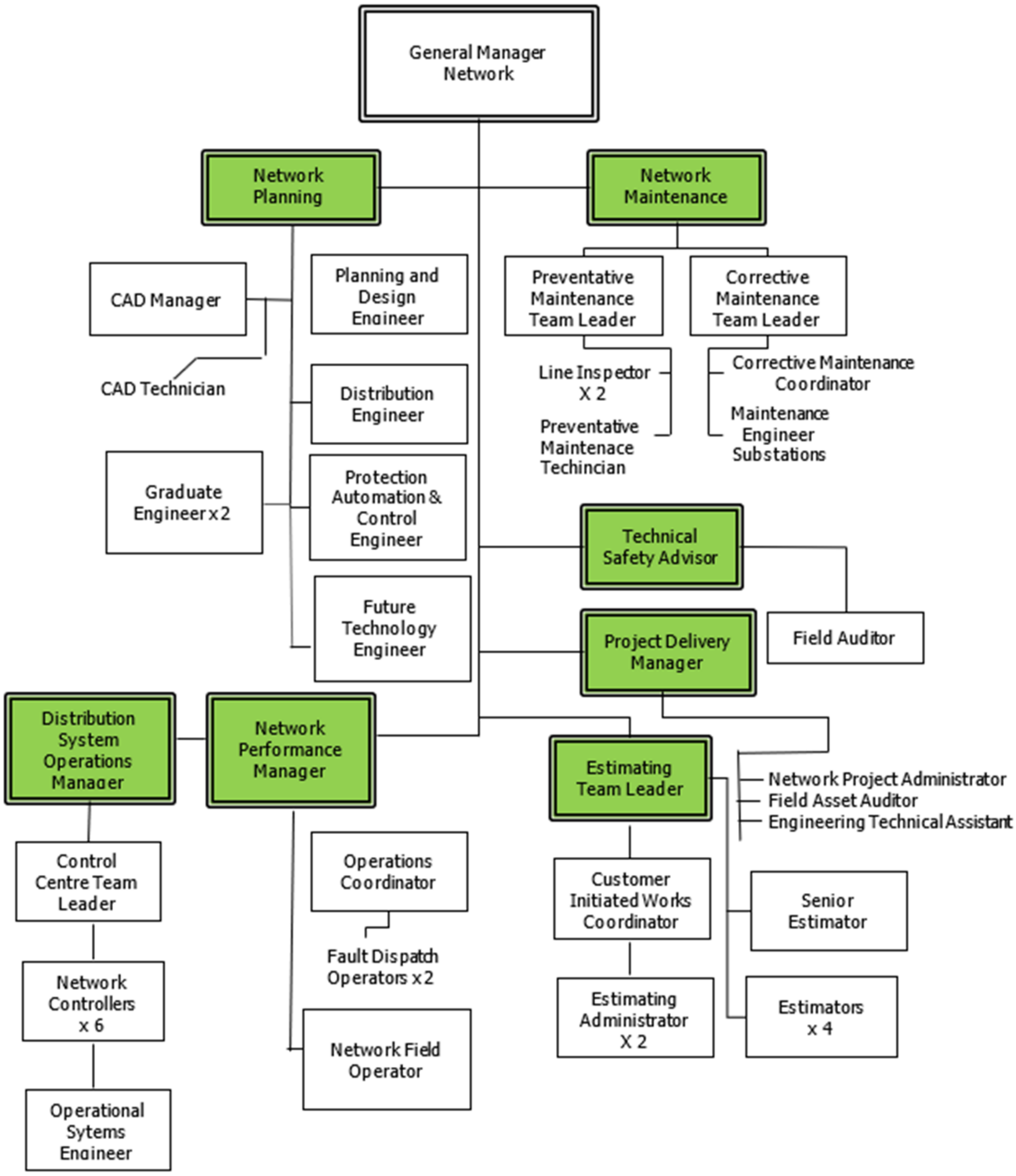


Figure 2.6: Top Energy Networks – Structure

The key responsibilities of our Networks management team are:

Position	Accountability
General Manager Network	To control the network budget that governs TEN's activities.
Maintenance Manager	To control the maintenance and renewal budget.
Planning Manager	To control the capital budget.
Project Delivery Manager	To manage the delivery of the capital investment programme budgets individually assigned for each project.
Technical Safety Advisor	To ensure compliance with regulations and to minimise the safety risk to staff, contractors, and the public.

Position	Accountability
Network Performance Manager	To manage dispatch, faults, and compliance, focused on safety and reliability of supply
Distribution System Operations Manager	To manage the real time operation of the network, including power flow, consumer demand and generation.
Engineers	Delegated authority to manage projects to individual budgets.

Table 2.4: Top Energy Networks Division Responsibilities

Individual order approval levels are:

Position	Delegated Approval Level
CEO	$1 million
General Manager Network	$100,000
Section Managers	$50,000

Table 2.5: Top Energy Order Approval Levels

2.11 Asset Management Systems

We use a range of information and telecommunications systems critical to the asset management process. This section outlines our present and future development plans for information systems.

2.11.1 System Control and Data Acquisition

We went live with our new Advanced Distribution Management System (ADMS) in January 2020. The ADMS currently delivers:

- Supervisory Control and Data Acquisition (SCADA) of applicable network assets.
- Outage Management System (OMS).
- Vehicle tracking integration.
- Electrical Distribution Network Access Request (EDNAR).

The OMS combines real time inputs on the state of the network from our SCADA system with the customer connectivity information in our Geographic Information System (GIS) to predict the location of faults and to automatically calculate the SAIDI and SAIFI impact of supply interruptions. This has resulted in improved reliability reporting. The OMS also provides the data for our web-based Outage Centre, where customers can view current planned and unplanned outages, as well as subscribe for future outage notifications.

Our operational groups are continuously adapting existing and developing new processes to take advantage of the ADMS functionality and capability.

The ADMS has significant additional functionality and capability that is planned to be implemented over the next five years. These are commonly referred to as the Distribution Management System (DMS) components. This functionality will be added progressively as the software is customised to our network and our operators are familiarised with each new function as it is brought online:

- Advanced Meter Interface (AMI). Utilises the data and capability of smart meters to improve the OMS outage status, coverage and prediction accuracy and performance.

- Distribution Power Flow Analysis (DPF). This provides a real-time capacity and constraints model of the network, using inputs from SCADA, the GIS and potentially our SAP Asset Management System (AMS). It provides a predictive load flow modelling function for planning the operation of the network by making real-time information on network status available to operators. As noted in Section 8.3, we are currently populating this module with accurate system data.

• Switching Advisor (SA). Delivers enhanced shutdown planning services and workflow management to optimise the operation and management of the network.

• Automated Planned Restoration Service (APRS). Leverages DPF to minimise outage impact and improve response and recovery times.

• Adaptive Network Management (ANM). Leverages DPF to provide automated control of embedded generation plants based on current network conditions and constraints. The need for this capability will be driven by customer demand.

We expect the ADMS to be a key tool in developing a network that is open to the use of new technologies and in facilitating our transition from a distributor of electricity to a manager of a distributed energy system. The system has been future-proofed, and modules to support Distributed Energy Resource Management (DERM) and Demand Response Management (DRM) are being developed by our ADMS vendor. These will be added as required.

2.11.2 Accounting/Financial Systems

The Group uses SAP for the management of expenditure, capital accounts, estimating capital jobs, inventory, orders, accounts payable and accounts receivable, and uses Payglobal for processing all salaries.

We report actual versus budget performance monthly by general ledger category and individual projects. The senior management team also receives monthly reports of:

- Profit and loss reconciliation by division.
- Consolidated profit and loss.
- Consolidated balance sheet.
- Consolidated cash flow.
- Capital and maintenance expenditure.

We also use ancillary electronic databases and spreadsheets to analyse the performance of the company.

2.11.3 GIS System

We replaced our Hexagon G/Technology Geographic Information System (GIS) with GE Smallworld Electric Office GIS in March 2022. Smallworld Electric Office is an engineering asset register that provides an end-to-end spatial representation of assets, their connectivity and their relationship with one another and consumers. This powerful solution enables our staff to plan, build, operate and maintain the network efficiently. As a result, our power system engineers can use network resources more cost-effectively, ensuring services to customers are provided and maintained more quickly and efficiently.

Our GIS is currently integrated with the following business applications:

- *Advanced Distribution Management System (ADMS).* The GIS is the master for all network electrical and physical connectivity data. Each relevant change in the GIS is automatically sent to the ADMS using the Common Information Model (CIM) standard. This ensures the ADMS is constantly and consistently kept up to date.

- *Permissions and Easements.* SharePoint is used for storing details and agreements relating to easements and general property access rights.

- *ICP Management.* Axos Registry Manager integrates with the national registry to manage and report on moves, additions, and changes to consumers' Installation Control Points (ICPs).

Further integration development is underway to align our asset maintenance and finance system (SAP) and our power system analysis software (DigSilent Power Factory).

2.11.4 Network Analysis System

We use the DigSilent Power Factory power systems analysis package for load flow, voltage profile and protection design.

2.11.5 Consumer Management System

We contract an external call centre to handle consumer calls. The call centre uses its customer management system to provide details about consumer calls and call statistics.

2.11.6 Drawing Management System

We use Autodesk AutoCAD to generate construction drawings for subdivisions and new capital works.

These drawings include:

- Standard line construction drawings.
- Zone substation building and site plans.
- Specialised equipment drawings.
- Procedures manual diagrams.
- Control circuit and wiring diagrams.

2.11.7 Maintenance Management System

We use the SAP asset management software modules as a repository for asset condition data and the basis for our maintenance planning and management. Each individual asset is assigned to a maintenance and inspection plan detailed within SAP, according to the type of asset, the required inspection frequency, and the asset location. Asset inspections are undertaken both internally by TEN and externally by contractors; our asset inspectors work systematically through each inspection plan and, as each asset is inspected, asset condition and other relevant data (such as defects requiring remediation) are downloaded directly into the SAP database using hand-held data input devices.

Assets are inspected according to a time-based inspection regime. The frequency of inspection under this programme is based on the expected rate of asset deterioration and a risk-based assessment of the consequences of an asset's failure. When an asset is assessed as potentially requiring replacement before its next scheduled inspection, it is transitioned into our defects management system and inspected more frequently until the asset is replaced. Our inspection and defects management regimes are discussed further in Section 6.1.2.

2.12 Asset Data Accuracy

Top Energy maintains a dedicated GIS team responsible for ensuring that asset data is accurately recorded and maintained.

GIS data is considered accurate in the following areas:

- 11kV lines and associated equipment.
- Transformers (overhead and ground mount).
- Line switchgear and equipment.
- 33kV zone substations.
- 33kV lines.
- 33kV switchgear.
- Transmission assets transferred from Transpower.
- Other technical equipment, including SCADA.
- 11kV cable and related equipment, including switchgear.
- 33kV cable and related equipment, including switchgear.

For these asset types, individual assets down to mother/child connectivity levels are identified, and attributes and capacity are recorded.

Data gaps and errors still exist with:

- Low voltage systems.
- Consumer points of connection (i.e. three-phase, single phase, underground or overhead).

These issues arose because the data on approximately 30% of the low voltage network was not collected during the data gathering exercise that was undertaken to initially populate the GIS database. In FYE2023 we commenced an LV data capture project that will gather accurate data on our LV assets across the whole network. This data will be input into the GIS system and will also be used to extend the ADMS functionality to include management of the low voltage network. This is discussed further in Section 8.3.

2.13 Asset Management Processes

2.13.1 Asset Inspections and Maintenance Management

The asset inspection programme described in Section 2.11.7 is uploaded into, and managed through, SAP. Our visual asset inspections are complemented by a structured, non-invasive condition assessment programme that targets key assets (e.g., power transformers) as well as items that are prone to failure (e.g., cable terminations). A more detailed description of the maintenance policies for specific asset types is provided in Section 6.

Defects are prioritised and packaged into work orders by TEN staff. These maintenance work packages, which are designed to ensure that all defects in a particular area that require a maintenance intervention are remedied at the same time, are passed to TECS for implementation. Quality and efficiency of defect remediation by TECS are monitored through selective auditing and monthly reporting. Defect management is discussed further in Section 6.1.2.3.

We receive regular reports from TECS on maintenance work completed. These are used as the basis for Board reporting on maintenance completion and expenditure against the maintenance budget.

We also operate a 24-hour emergency maintenance service to provide prompt repair of network faults and to attend to defects that pose an immediate threat to public safety.

2.13.2 Network Development Planning and Implementation

Our network development plan is strategic in nature. It is reviewed annually at both a strategic and detailed planning level. However, the availability of funding is the major constraint on the rate at which it can be implemented.

At the strategic level, the development plan is reviewed for continuing alignment with the Board's mission and values, and also with consumer expectations, taking due account of the dynamic environment in which we operate, and our ability to fund the substantial investment required.

DigSilent analysis is used to reassess the current plan against any revised assumptions to ensure the plan efficiently and effectively addresses security, reliability, and capacity issues. Our network development plan, load forecasting and the development of the network capital investment strategies are discussed in greater detail in Section 5.

2.13.3 Network Performance Measurement

We use our ADMS to automatically calculate the SAIDI and SAIFI impact of supply interruptions caused by network faults occurring at 11kV and above. An interruption starts when the operation of protection equipment is time-stamped by the system. If the protection operation is not automatically timestamped, it is assumed to start when we are first advised of the outage. The ADMS subsequently tracks and timestamps the operation of all switching/protection equipment until supply is restored to all affected consumers. It then traces sections of the network that are disconnected from supply, or reconnected by each switching operation, and counts the ICPs affected by each operation. This allows the system to calculate the customer interruption minutes for each step of each event. THE ADMS uses this information to automatically determine total SAIDI and SAIFI for the interruption, based on the actual switching record created in response to the event. The Network Operations team performs daily checks of the system and reviews each event to ensure quality and accuracy of reporting is maintained.

Annual audits of interruption impacts are also carried out by an external auditor, as required by the Commerce Commission to support its assessment of regulatory compliance.

Network performance measurement and tracking is the responsibility of the Network Operations team. Monthly fault statistics, together with SAIDI, and SAIFI performance, are prepared for inclusion in the General Manager Network's monthly Board report.

2.14 Assumptions and Uncertainties

The network development plan and other asset management strategies described in this AMP are strategic and Top Energy's Board and executive management have endeavoured to ensure that, not only are they consistent with stakeholder expectations, but also that they are affordable and deliverable. A funding plan has been prepared and debt funding has been secured to ensure that Top Energy will be able to complete the investment programme described in this AMP.

Notwithstanding this, the strategies and action plans are predicated on a range of assumptions and, as with all major investment programmes, there are risks and uncertainties that may impact the timely completion of the action plans in the manner described in this AMP. These are discussed in Table 2.6 below.

ISSUE	ASSUMPTION	BASIS FOR THE ASSUMPTION	POTENTIAL IMPACT OF UNCERTAINTY
ELECTRICITY SALES	This AMP assumes that the forecast volume of energy delivered will materialise. The network development plan has been prepared on the basis that the cost of developing the network can be partly financed by revenue from electricity volumes delivered.	We have developed a funding plan based on a combination of increased bank borrowings and revenues from electricity sales. This funding strategy is designed to keep increases in line charges as low as possible and ensure the costs are shared with future consumers, who will also benefit from our current investments.	As we are subject to a revenue cap, we can increase prices to recover revenue shortfalls due to lower energy delivery volumes. However, the extent to which we can do this is limited. Our supply area includes some of the most economically deprived areas in the country and we expect to encounter significant consumer resistance to high price increases. This risk is exacerbated by the current economic environment. The connection of new block load that are not provided for in this AMP may also change our network development plans. We will work with proponents seeking to connect to our network to meet their requirements in a cost-effective manner.
REGULATORY CONTROL	Regulatory controls will continue to encourage investment in infrastructure, asset replacement and maintenance of existing assets to provide target service levels and an adequate return on the investment.	The assumption aligns with the government's energy policy to encourage efficient investment in infrastructure.	Our network development plan can only be implemented in accordance with the schedule in this AMP if the line charge increases required to fund the investment are permitted by the Commerce Commission. The Commission has been supportive of our network development initiatives, and we expect this support to continue.
DEMAND SIDE MANAGEMENT AND PEAK CONTROL	The industry and its regulators will continue to recognise the importance of demand side management and peak demand control, and retailers will offer pricing structures that penalise low power factor loads and discourage the use of electricity during times of peak demand.	Power systems must be designed to meet peak demand. Increased power system efficiency and minimisation of investment comes largely from minimising demand. Control of power factor is directly related to power system efficiency and is a demand side management tool. Losses and investment are minimised if power factors are close to unity and demands are controlled. Hence an industry structure that does not incentivise demand management will increase the required network capacity.	If our ability to effectively control peak load is reduced, we may need to increase the capacity of the parts of the distribution network to address voltage issues on long rural feeders. This would utilise funds currently budgeted for other activities. This medium-term risk is particularly related to the uptake of electric vehicles. There will need to be incentives in place to encourage the charging of vehicles at times when the demand for electricity is low, if investment in the distribution network to accommodate new electric vehicle load is to be minimised. While we do not own the control relays installed across our network, we are encouraged by recent activity in industry forums and are confident that

ISSUE	ASSUMPTION	BASIS FOR THE ASSUMPTION	POTENTIAL IMPACT OF UNCERTAINTY
			regulators recognise the importance of demand management.
ASSET CONDITION	Assumptions have been made in forecasting asset replacement and renewal expenditure beyond the first five years of the planning window.	The forecasts are largely based on defect rates gathered during routine asset inspections, together with adjustments as necessary to accommodate estimated changes in failure rates with changes in the age profile of assets in a specific category. Our adoption of the asset health indicators recommended by the Electricity Engineers' Association has improved our knowledge of the condition of our assets. This has been supported by the introduction of SAP, which has permitted the collection of more useful information on the condition of individual assets and has also allowed asset maintenance (including replacement and renewal) expenditure to be better targeted at assets known to require renewal or replacement.	Equipment failures cause approximately a third of our unplanned supply interruptions and a third of our unplanned SAIDI. However, it is a fault cause that can be difficult to target through a reliability improvement programme since these faults can occur anywhere on the network in a largely random fashion. If renewal and reliability expenditure is insufficient to ensure that assets are renewed or replaced before they reach the end of their economic life, the fault frequency will increase, and these measures will be less effective in improving overall network reliability. That said, we are confident that the forecast asset replacement expenditure in this AMP is sufficient to prevent a significant deterioration in the overall health of our asset base.
FAULT AND EMERGENCY MANAGEMENT	The weather is the biggest factor in fault and emergency maintenance. Storms that involve wind speeds greater than 75km/hr have been shown through post-fault analysis to have a significant effect on our network.	Post-fault analysis following major storm events. We think the frequency and intensity of major storm events is increasing, and this is impacting the reliability of supply through our network.	Variability of weather conditions inevitably means there is volatility in the annually reported SAIDI and SAIFI. SAIDI and SAIFI targets presented in the AMP represent a trend line and year-on-year volatility around the trend is to be expected. The reliability targets in this AMP reflect the average level of reliability the network has delivered over a ten-year reference period.
UTILITY SCALE PHOTOVOLTAIC GENERATION	The volatility of the output of connected utility-scale solar farms will not generate voltage stability problems.	System studies undertaken by our external engineering consultant have confirmed that the solar farms for which connection agreements have been signed can be operated without impacting other network users.	If the findings of these studies are not reflected in practice, then we may need to fund the cost of remediation measures.
SMALL-SCALE PHOTOVOLTAIC GENERATION	The output of behind-the-meter small-scale photovoltaic generation will not create voltage stability issues on the low voltage network.	While the penetration of photovoltaic generation is high compared to other New Zealand EDBs, it remains low compared to Australia. While some localised issues have	We may need to fund localised corrective measures if significant issues arise.

ISSUE	ASSUMPTION	BASIS FOR THE ASSUMPTION	POTENTIAL IMPACT OF UNCERTAINTY
		emerged of our network, their impact has been minor and readily corrected.	
CONTRACTOR AVAILBILITY	Contractors are available to augment TECS capacity.	The capital projects incorporated into the 11kV reliability improvement plan are labour intensive and exceed the delivery capacity of TECS. Our plan is to engage external contractors to complete the work programme.	There appears to be a shortage of external contracting capacity with the skills we require. If we are unable to recruit the contractors we need, the rate at which we can implement this plan will reduce.
INFLATION	Except where otherwise shown, cost estimates in the AMP are presented in real New Zealand dollars in FYE2024. Where these cost estimates are expressed in nominal New Zealand dollars, an annual inflation rate of 4% for capital expenditure and 5% for operational expenditure is assumed for FYE2025. We assume an inflation rate of 3% for FYE2026 and 2% thereafter for both expenditure categories.	2% is the mid-point of the Reserve Bank's long-term target consumer price index (CPI) inflation rate of 1-3%. Cost increases have been well above 2% over the last three years due to the impact of Covid 19, labour shortages and supply chain issues. These increased costs have been incorporated into the expenditure forecasts in this AMP. While inflation remains at a historically high level, Treasury and the Reserve Bank expect it to moderate over time and fall back within the Reserve Bank's target range by about the end of FYE2025. The difference in the assumed FYE2025 inflation rates is due to operational expenditure having a higher labour cost component, and in the short term we expect labour costs to increase at a high rate than the cost of materials. Nevertheless, we see little point in attempting to develop a more accurate forecast, given the length of the planning period and the high levels of uncertainty in other elements of the AMP.	If actual costs are higher than assumed in the forecast, then the volume of work we can undertake in a financial year may reduce. This could slow the implementation of the capital and maintenance plans set out in this AMP. The Incremental Rolling Incentive Scheme (IRIS) that is incorporated into the default price-path determination may mitigate some of this impact.

Table 2.6: AMP Assumptions and Uncertainties

2.15 Asset Management Strategy and Delivery

2.15.1 Asset Management Strategy

The key objective of our asset management strategy is to provide the reliability of supply expected by our consumers and to develop a network that meets the needs of network users when technologies that are currently emerging become mature. This is being done by:

- Implementing an 11kV network development plan to arrest the current deterioration in the reliability of the 11kV network and stabilise network reliability at its average historic level. This involves a stream of incremental upgrades to the distribution network, targeted at reducing the number of consumers affected by a fault, the time required to locate a fault and restore supply to consumers outside the faulted switching zone.
- Accelerating the replacement of assets that require renewal as they near the end of their economic life.
- Targeting vegetation management at trees that are a safety hazard and on those parts of the network where vegetation has the most impact on supply reliability.
- improving the efficiency of the maintenance effort by focusing on high SAIDI impact assets that are most likely to fail in service, due either to their age, or to their condition, as assessed by our maintenance inspections.

The detailed network development and lifecycle asset management plans in Sections 5 and 6 of this AMP describe how we are implementing this strategy.

Our strategy is consistent with the overarching corporate mission statement described in Section 2.2 and underpins the longer-term development of the economically depressed Far North region. While the bulk of the asset management capital expenditure has historically been on network development, our focus is now changing and expenditure on maintenance and, most particularly, asset renewal is increasing. Our maintenance management system is described in Section 2.11.7 and programmes for the proactive replacement of assets at risk of premature failure, due to accelerated deterioration or systemic design weaknesses, are described in Section 6.

2.15.2 Contingency Planning

Our control room staff are developing system operating procedures that document the optimal response to potential faults that would have a high SAIDI impact.

We also have a documented Emergency Preparedness Plan setting out processes for the response and management of serious incidents and events. We proactively anticipate and plan for foreseeable emergencies and this planning has resulted, for example, in the construction of a mobile substation and the installation of diesel generators.

2.15.3 Asset Management Implementation

The General Manager Network has overall responsibility for asset management implementation and controlling expenditure on network development and maintenance. Asset management procedures are documented in our ISO 9001 certified quality system and our NZS 7901 certified public safety management system.

Apart from 110kV asset maintenance and larger construction projects, most work on the network is undertaken by TECS. A documented Service Level Agreement, discussed further in Section 2.17.4 and based on the asset manager-service provider model, define the roles and responsibilities of TEN and TECS. Project work is managed directly by TEN staff using standard project management processes while maintenance work is aggregated by TEN into maintenance work packages and passed to TECS, for implementation. Asset inspections are undertaken by both internal and external resources.

2.15.4 Corrective and Preventive Action

Our ISO 9001 certified quality management system defines the business processes in place for determining preventive and corrective actions. When an unexpected asset problem is identified, the process owner undertakes a root cause analysis, determines appropriate corrective actions, and tracks these through to close-out. The process works well when a major incident arises. We continue to develop a culture that encourages our staff to proactively identify issues and implement incremental process improvements.

2.16 Information and Data Management

A mature process is in place for the management of GIS data, described in some detail in Section 2.12. Processes for the management of maintenance data in SAP have matured and we have specified measurement points and asset condition criteria for the different asset types. The quality of the dataset is improving over time as assets are progressively inspected and data input specifications are refined and improved.

2.17 Asset Management Documentation, Controls and Review

We use the following documents and processes to control our asset management activities:

2.17.1 Asset Management Policy

Our documented network asset management policy, which is discussed in Section 2.6, underpins all our asset management effort. This network-specific policy is a component of our ISO 9001 certified quality system and sits below the more generic asset management policy that relates to all assets managed by the Top Energy Group. The policy, while it has existed for some years, has only recently been integrated into our formal quality system.

2.17.2 Asset Management Plan

This AMP is the document central to the implementation of our asset management system and meets the requirement of ISO 55000 for an organisation to have documented asset management plans. The AMP is also consistent with the structure of the standard, in that Section 2 covers strategic issues in some detail and Sections 5 and 6 provide the detailed action plans derived from these strategies.

We have qualitative objectives derived from the corporate mission statement and these are discussed in detail in Section 2.7, but we still need to develop a formal process for evaluating how well we are achieving these. This could mean developing quantified measures that we can use to track the progress we are making towards those objectives described in Section 2.7 that we consider most critical to achieving our corporate mission.

The quantified supply reliability indicators set out in Section 4 of this AMP are central to our overarching asset management strategy, in that all our asset management activities are designed to ensure that our consumers receive a quality of supply that matches their needs and expectations. We have also developed quantified measures to cover performance in other areas, including health and safety. In addition, we have developed leading indicators of our asset management performance – these include indicators relating to the completion of planned asset inspections and defect management backlogs.

2.17.3 Annual Plans

Annual plans are prepared for maintenance, vegetation management and capital works delivery. These describe the work programmes and budgets for the first year of the AMP planning period. These are based on the approved budget in the AMP but include more detail. For example, the vegetation management plan identifies the actual feeders that will be targeted by the vegetation management effort in a particular year.

2.17.4 Service Level Agreement

The service level agreement (SLA) between TEN and TECS is integral to the implementation of the action plans set out in this AMP. The SLA, which was updated in February 2020:

- Defines the relationship between the two business units, based on an asset manager–service provider model.
- Specifies the different responsibilities of the two parties.
- Defines key performance indicators that measure the extent that each party fulfils its obligations.
- Specifies the information that TEN must provide to TECS and when it is to be provided.
- Details the TECS service response to cover the delivery of the annual work programme in accordance with agreed targets.

All planning of capital works, asset inspections and maintenance requirements is undertaken by TEN. The resulting design and delivery documentation from TEN enables TECS to develop an annual work programme and to ensure that resources are available to undertake the required work.

2.17.5 Documentation of the Asset Management System

Our quality management system was certified as compliant with ISO 9001 early in FYE2016. This system documents many processes and procedures relevant to asset management and in particular the implementation of this AMP.

2.17.6 Legal Compliance Database

The General Manager Finance is responsible for ensuring Top Energy meets its legal obligation and maintains relevant records through a database that can automatically email staff responsible for legal compliance. The database does not capture changes to technically focused regulations, such as the Safety Rules, but the General Manager Network and his staff monitor such changes through their membership and engagement with relevant industry bodies and respond as necessary. We are confident that any change in a law or regulation that impacts the way we manage our network assets will be identified and actioned in a timely manner.

2.17.7 Audit

Our NZS 7901 certified public safety management system and ISO 9001 certified quality system both require independent external audit. These systems strengthen our internal auditing of our asset management activities and the field activities undertaken by TECS and our external contractors.

2.17.8 Continual Improvement

There is a commitment to continual improvement within TEN and the wider Top Energy Group. The successful introduction of our public safety management system, and the ISO certified quality management system that we are not required by regulation to introduce, is testimony to our continual improvement culture. This is driven by our Board and executive management team.

The preparation and ongoing improvement of this AMP is accorded a high priority with input from the Board to provide the strategic direction at an early stage of its development. We have engaged an external consultant with a good knowledge of our network to help prepare this AMP. This enables us to prepare and fully update a comprehensive document without our own key staff being unduly diverted from other work.

2.18 Communication and Participation Processes

2.18.1 Communication of the AMP to Stakeholders

Our SCI identifies this AMP as the defining document for the management of our network and all senior managers within TEN are involved in its preparation.

We actively encourage external stakeholders to review and comment on the content of the AMP. We distribute the AMP widely within the organisation and publish the AMP online on our website. A copy is kept in the reception area of our head office in Kerikeri for anyone to view. We are also happy to provide a printed copy on request.

2.18.2 Management Communication and Support

Our executive management has undertaken a formal engagement process consulting both internal and external stakeholders and through this process, we have gained an understanding of stakeholder expectations regarding the reliability of their electricity supply. We seek feedback on significant changes to our network development strategy. We have gained broad acceptance of the network development plan described in this AMP from those involved in the consultation.

External communication of our asset management plan has largely focused on vegetation management and the total cost of our network investment programme. Vegetation management is easily understood by consumers, as it is visible and its impact on improving reliability is well known. Communicating the cost of our network investment programme signals to stakeholders the level of service delivery that is to be expected over time.

Going forward, the Board and senior management have committed to communicating more openly about other elements of our asset management and in particular our maintenance initiatives.

2.18.3 Communication, Participation and Consultation

Ongoing communication of asset management issues with external stakeholders, by the CEO and TEN's senior managers, continues to support our operational and organisational objectives. Top Energy has also upgraded its website to include a video on the future of energy in our supply area and real time information on planned and unplanned interruptions to supply.

Communication with Top Energy employees occurs regularly through CEO presentations to staff at head office and depots, as well as in team meetings. The CEO also presents to stakeholders, community organisations and media to convey key information, including our network investment and asset management programme.

2.19 Capability to Deliver

The investment programme described in this AMP continues to be strategic. We developed this programme in consultation with our local community and with the full support of the Trust, the Board, and the Executive Management Team. Top Energy and its shareholder have demonstrated an ability to successfully undertake challenging projects for the benefit of our stakeholders. The successful construction, commissioning, and operation of OEC4 at Ngawha Power Station with the involvement of local iwi is testimony to this.

The challenges in delivering the projects and programmes described in the AMP include:

- Financing.
- Engineering.
- Construction.

These are each discussed in the following sections.

2.19.1 Financing

As result of our investment in network assets through the implementation of our network development plan, the disclosed regulatory value of our network assets has increased from $97 million on 31 March 2004 to $320 million on 31 March 2022.

With the help of external consultants, Top Energy maintains a financing plan to fund our ongoing investment programme. This includes:

- Revenues from line charges.
- Bank borrowings.

There is a balance between the ability to increase line charges so that they remain affordable to our consumers and the level of debt that represents sustainable long-term borrowing.

2.19.2 Engineering

The design of the network development works within this AMP requires specialist engineering skills and resources, which are outsourced where these are not available internally. These costs are included in our estimated project costs.

2.19.3 Construction

Construction of the works described in this AMP is undertaken by TECS where it has the skills and resources available. In general, line construction and cable laying are undertaken internally, while the construction of new substations is outsourced.

As the capital expenditure forecast in this AMP has increased expenditure on the development of the 11kV network, we are planning to outsource some of this work to supplement the TECS resource.

2.20 Public Safety Management Issues

The passing of the Health and Safety at Work Act 2015 has raised awareness of the risk that the operation of an electricity network can create for the public, and the liability of the company and its directors if they fail to take reasonable precautions to mitigate these risks. We have reviewed the safety of our network in response to the Act and identified two significant issues that are discussed below.

2.20.1 Single Wire Earth Return Lines

The single wire earth return (SWER) system was invented by Lloyd Mandeno, who was the consulting electrical engineer engaged by the Bay of Islands Electric Power Board to set up the original electricity distribution system in our area. Consequently, SWER lines were used extensively in the reticulation of our supply area and many such lines remain. However, the load is now getting too high for the SWER lines in some areas.

SWER lines also pose a public safety risk because, unlike two and three wire lines, the earth system carries the full load current. If the earth resistance is too high, the earth potential can rise to hazardous levels creating a risk of shock and possibly death to persons and stock that come into contact with these assets. While we design and install SWER earthing systems to mitigate these risks, for example by ensuring the resistance is low when an earth connection is installed and encasing earth wires in conduit where they are accessible from the ground, such precautions cannot be relied on to provide complete protection. We have undertaken an inventory of our SWER lines to identify those lines that pose an excessively high public safety risk and should be upgraded to two- or three-wire. We now also require any new consumer wanting to connect to our SWER network to install a two-wire line so that when we upgrade, we do not have to fund the cost of upgrading that consumer’s private line.

2.20.2 Private Lines

Many of the private lines in our area are in poor condition. These lines are not regularly inspected and there are no systems in place for ensuring they are maintained in a safe condition. The Commission’s view is that this is not our role, and we are therefore unable to fund such inspections. It is the line owner’s responsibility to ensure that they are maintained in a safe condition.

Top Energy’s preference is to assume ownership of newly installed 11kV service lines to prevent this situation in the future. Existing service lines are fused and labelled when the opportunity arises.

3 Asset Description

3.1 Overview

3.1.1 Distribution area

Top Energy owns and manages the northern-most electricity distribution network in New Zealand, covering an area of 6,822km^2. The area is bounded by both the east and west coasts, and the territorial local authority boundary of the Far North District Council in the south.

Most of our supply area is rural. There is no single dominant urban area, and urban development is spread amongst several small towns with populations between 1,000-7,000 people and numerous smaller settlements. Coastal settlements, especially on the eastern and north-eastern coasts, are growing at a faster rate than the district average. Most inland towns, including Kawakawa, Moerewa and Kaikohe, have relatively static or, in some instances, declining populations.

Our supply area is separated by the Maungataniwha Range into two distinct geographic areas. The northern area, which includes Kaitaia, Taipa and the Cape Reinga peninsula, is supplied from our 110kV Kaitaia substation located at Pamapuria, approximately 10km east of Kaitaia. The larger and more populous southern area, which includes Rawene, Kaikohe, Kawakawa, Moerewa and the coastal towns of Kaeo, Kerikeri, Paihia and Russell, is supplied from the 110kV Kaikohe substation and grid exit point (GXP). A single circuit 110kV line owned by Top Energy connects the two substations; there is currently no other 110kV or 33kV interconnection between the two geographic areas.

Compared to New Zealand as a whole, our distribution area is notable for the high proportion of people who are unemployed or on low incomes. The average quantity of electricity supplied to each active connection point is the second lowest in the country.

3.1.2 Network Characteristics

Electricity from the national transmission grid is delivered to our Kaikohe substation through a double circuit 110kV Transpower-owned transmission line supplied from Maungatapere. Electricity from our 57MW Ngawha geothermal power station, situated about 7km southeast of Kaikohe, is also delivered to Kaikohe though one 110KV and two 33kV subtransmission circuits. We supply our northern area from Kaikohe through our 110kV Kaikohe-Kaitaia line.

A 33kV subtransmission network delivers electricity from our Kaikohe and Kaitaia 110kV substations to 13 zone substations - four in the northern area and nine in the southern. These zone substations supply 63 distribution feeders that operate at 11kV (except for a section of the Rangiahua feeder that has been uprated to 22kV). In rural areas, many spur lines fed from the three-phase distribution feeder backbones are two wire single phase or single wire earth return (SWER).

The distribution feeders supply distribution transformers that convert the electricity to low voltage (LV) for supply to consumers. Our LV distribution is at 400V three-phase, 460/230V two-phase and 230V single phase.

We have now installed a total of 17.2MW of diesel generation to increase our network resilience. This can supply all small use consumers in our northern area when the incoming 110kV circuit from Kaikohe is out of service.

We acquired our Kaikohe and Kaitaia 110kV substations, and the 110kV interconnecting line between the two substations from Transpower on 1 April 2012. As these assets are no longer part of the national grid, we can incorporate them into an integrated development plan that will more efficiently meet the long-term needs of our consumers. Our double circuit 33kV line between Kaikohe and Wiroa has been built to 110kV construction and is planned to eventually form part of a 110kV ring, which will provide a high-capacity network backbone interconnecting the Kaikohe, Kaitaia and Kerikeri load centres. A section of one circuit of this line has already been energised at 110kV to provide a connection between the newly commissioned OEC4 generator at Ngawha and the Kaikohe 110kV switchyard.

During FYE2022, we supplied an average 32,537 active connections. The maximum demand on our network was 77MW and the total energy delivered to consumers was 330GWh.

3.1.3 Grid Exit Point

Our one GXP is the termination of the Transpower 110kV Maungatapere-Kaikohe double circuit line. Transpower retains ownership of the two 110kV circuit breakers at Kaikohe that terminate these circuits. Each incoming 110kV circuit has a winter rating of 77MVA. Generation from Ngawha reduces the loading on these circuits.

3.1.4 110kV System

There are two single-phase 110/33kV transformer banks at Kaikohe: one rated at 30MVA and the other at 50MVA. At current loads, support from our Ngawha geothermal power station would be required should the larger of these transformer banks be out of service at times of peak demand.

The 110kV circuit between Kaikohe and Kaitaia has a winter rating of 68MVA, which is sufficient to supply the foreseeable Kaitaia consumer load. However, as discussed in Section 5.11.2.2, we have now signed agreements to connect utility scale solar farms in the Kaitaia area to our network and the 55MVA summer rating of this line will limit the amount of electricity from these developments that can be exported south. Therefore, we are unable to accept any further applications for the connection of utility scale generation to our northern area.

At Kaitaia, there is a newly installed three-phase transformer rated at 40/60 MVA. There is also an older transformer bank of single-phase units with a rating of 22MVA, which is insufficient to supply the total load at times of peak demand. Should the larger transformer fail, which is unlikely as it is still in as new condition, we will use our diesel generation to ensure that the smaller transformer bank is not overloaded at times of peak demand.

3.1.5 33kV Subtransmission System

We have two 33kV subtransmission networks, one serving our northern area and the second serving the south, supplied from our Kaitaia and Kaikohe 110kV substations respectively. The outdoor 33kV switchyard at Kaikohe was replaced in FYE2015 with a new indoor switchboard.

Our 33kV subtransmission networks and the locations of the zone substations they supply are shown geographically in Figures 3.1 and 3.2 below. Approximately 94% of our subtransmission system is overhead. Underground 33kV cable is used within substations or on new circuits when an overhead line route is not available.

.

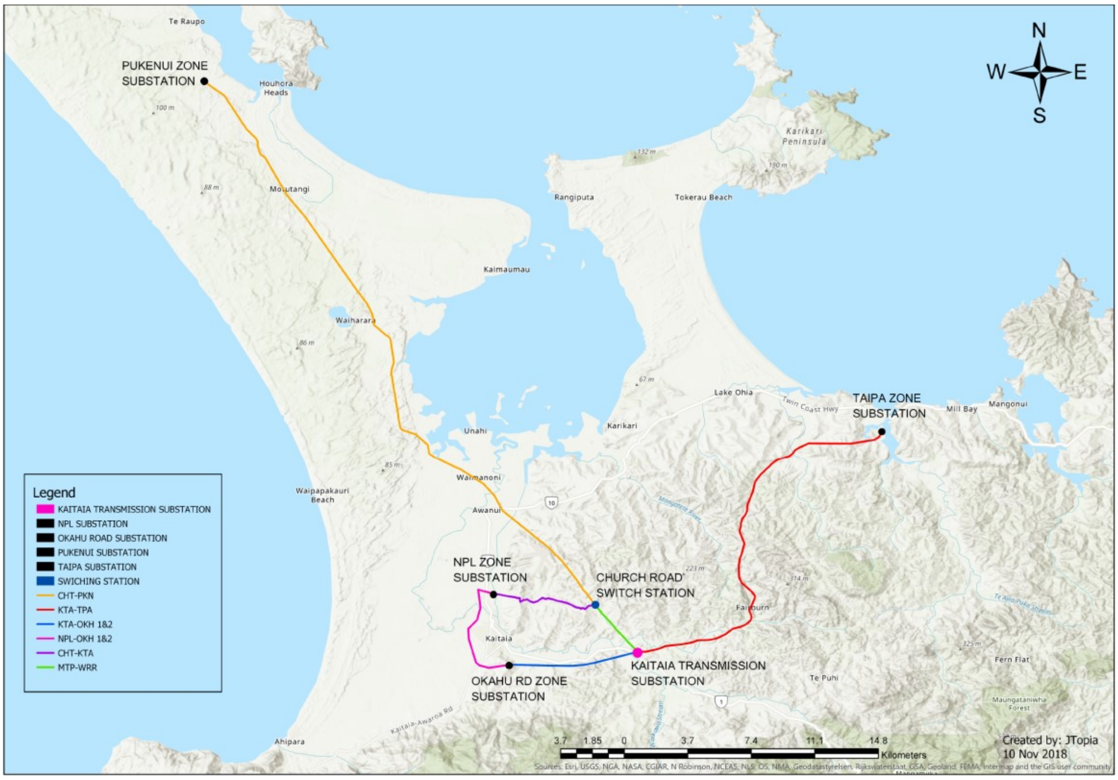


Figure 3.1: **Subtransmission Network – Northern Area**

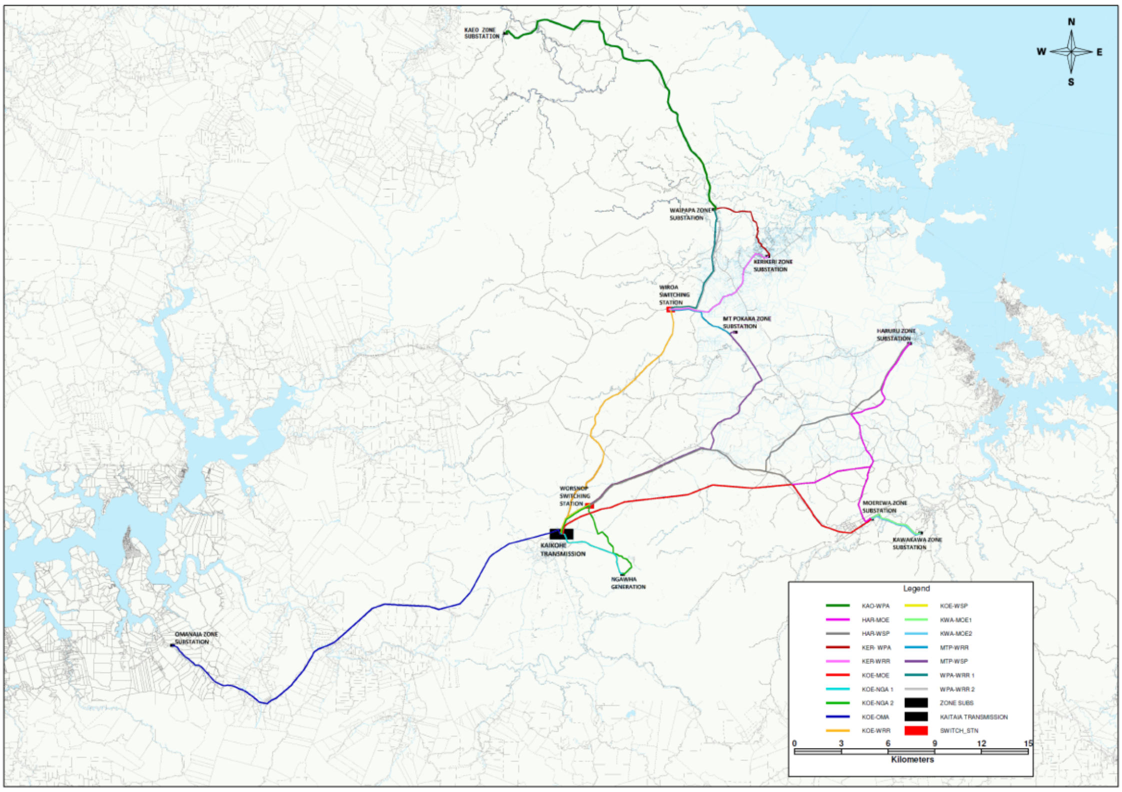


Figure 3.2: **Subtransmission Network – Southern Area**

Table 3.1 below shows the transformer capacity at each zone substation. The limiting factor that determines transformer capacity is the temperature of the transformer oil. Most transformers are fitted with radiators for air cooling; the capacity of a transformer is increased if the transformer is fitted with fans to force air through the coolers (air forced or AF) or with pumps to pump oil through the radiators (oil forced or OF), rather than rely on natural circulation. Most transformers, therefore, have two ratings, one for natural cooling and a higher one if forced cooling is used.

SUBSTATION	UNIT	NOMINAL RATING (MVA)	MAXIMUM CAPACITY (MVA)
Southern Area			
Kaikohe	T11	11.5/23	17[1]
	T12	11.5/23	17[1]
Kawakawa	T1	5/6.25	6.25
	T2	5/6.25	6.25
Moerewa	T1	3/5	5
	T2	3/5	5
Waipapa	T1	11.5/23	23
	T2	11.5/23	23
Omanaia	T1	3/5	5
Haruru	T1	11.5/23	23
	T2	11.5/23	23
Mt Pokaka	T1	3/5	5
Kerikeri	T1	11.5/23	23
	T2	11.5/23	23
Kaeo	T1	5/10	10
	T2	5/10	10
Northern Area			
Okahu Rd	T1	11.5	11.5
	T2	11.5	11.5
Taipa	T1	5/6.25	6.25
Pukenui	T1	5	5
NPL	T1	11.5/23	23
	T2	11.5/23	23

Note 1: The transformer would need to be fitted with oil pumps to deliver its full force-cooled rating. These are not required to supply the current peak demand.

Table 3.1: Zone Substation Security

Now that we have diesel generation available to provide network support in addition to our feeder transfer capability, we have developed our transmission and subtransmission networks to the point where, following a single element interruption, we can restore supply to all but two large consumers, either uninterrupted or after a short interruption of less than one hour. The two consumers where this does not apply have accepted a lower level of security. The security level we now provide at individual substations is discussed in detail in Section 5.1.2.

We also have a 33/11kV, 7.5MVA mobile substation that can be relocated within 12 hours in the event of a transformer failure at one of our single transformer substations. While we now have diesel generation available at all but one of these substations, the availability of the mobile substation avoids the need for this generation to be run for extended periods. The mobile substation is located at Taipa on a semi-permanent basis where it provides backup to the permanent transformer.

3.1.6 Diesel Generation

The locations and capacities of the diesel generation connected to our network are shown in Table 3.2.

Location	No of Units	Rated Capacity (MW)	Comment
Pukenui substation	1	1	Provides support to the northern area when the 110kV line is out of service, and also provides local substation support when the transformer or incoming line is out of service.
Bonnetts Rd	8	8	Bonnetts Rd is a standalone generator farm 2km west of Kaitaia. These generators provide support to the northern areas when the 110kV line is out of service.
Kaitaia depot	3	3	Provides support to the northern area when the 110kV line is out of service.
Taipa substation	2	3.2	These units were installed in FYE2014 to provide local support when the transformer or incoming line is out of service. They also provide support to the northern area when the 110kV line is out of service.
Omanaia substation	2	2	These are the only diesel generators in our southern area. They provide local support when the incoming 33kV line or transformer is out of service.
Total	**16**	**17.2**	

Table 3.2: Diesel Generation Installed for Network Support

3.1.7 Distribution Network

Our distribution system consists of 63 predominantly rural feeders which are 93% overhead. Underground cable is used in commercial areas and newer subdivisions. The system operates at 11kV, except for 20km of the Rangiahua feeder, which has been upgraded to 22kV. Figures 3.3 to 3.15 show the extent of the distribution system supplied from each of our zone substations.

The distribution network supplies approximately 6,100 transformers, which are of three types:

- Distribution transformers, which provide the low voltage supplied to consumers.
- Step-up transformers, which form the interface between the 22kV section of the Rangiahua feeder and the 11kV distribution network.
- Isolating transformers, which connect SWER lines to the core 11kV distribution network.

Notwithstanding our extensive LV cabling, 85% of distribution transformers are pole mounted, although pole mounting of transformers is now limited to ratings up to 100kVA due to seismic constraints. Ground mounted transformers are generally enclosed in steel cabinets, which may also house 11kV switches depending on the application. Only five distribution transformers that are not installed within consumer premises are located within purpose-built substation buildings.

Figures 3.3 – 3.15 below show the coverage of the distribution feeders supplied from each of our zone substations.

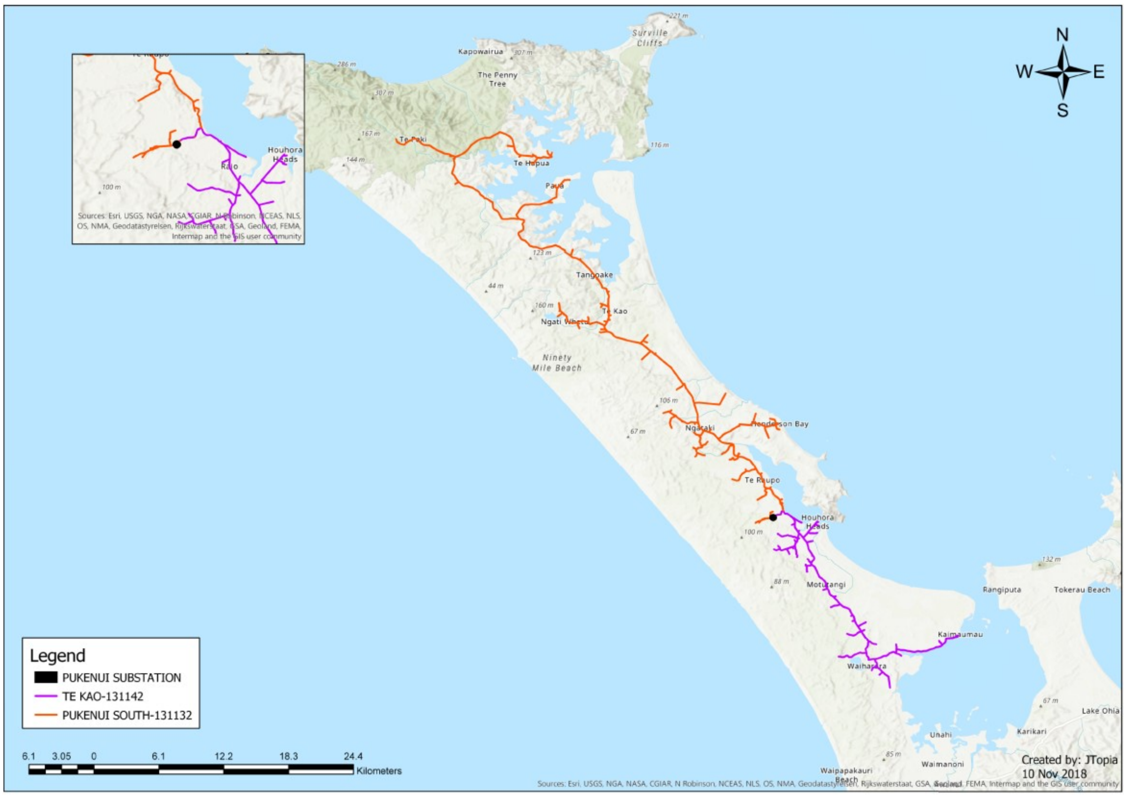


Figure 3.3: Geographic diagram of the Pukenui zone substation

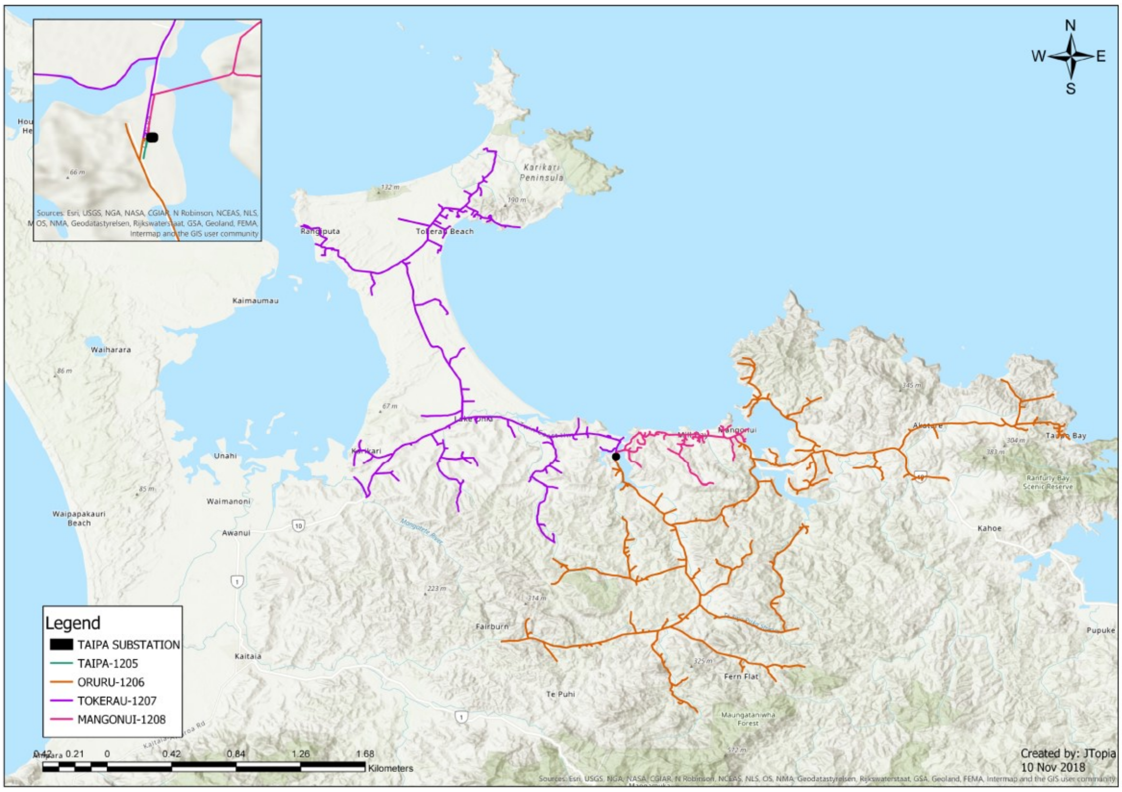


Figure 3.4: Geographic diagram of the Taipa zone substation

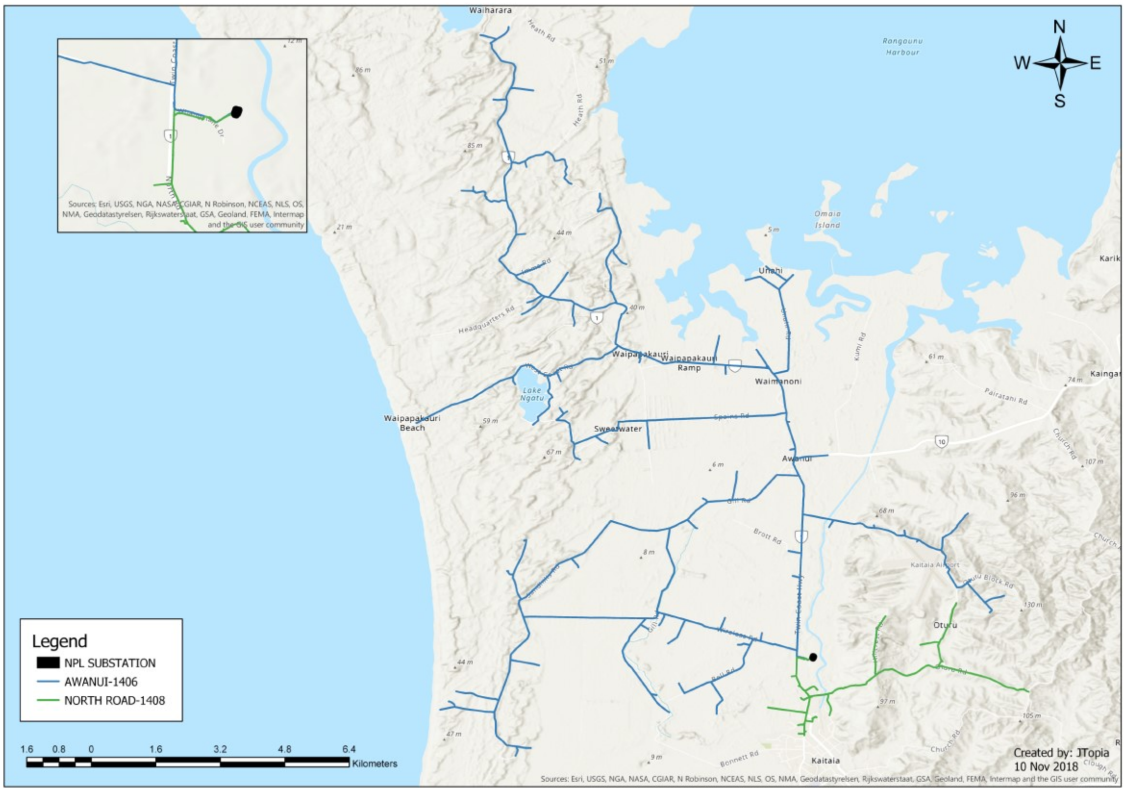


Figure 3.5: Geographic diagram of the NPL zone substation

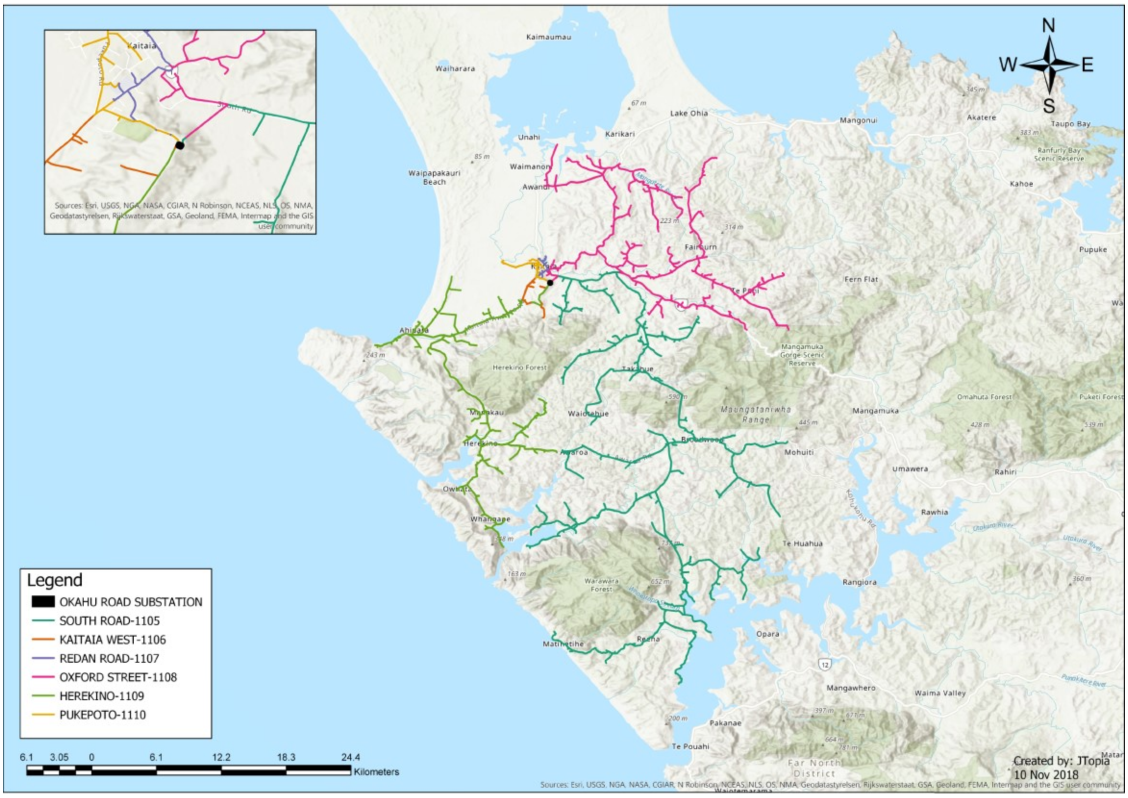


Figure 3.6: Geographic diagram of the Okahu Road zone substation

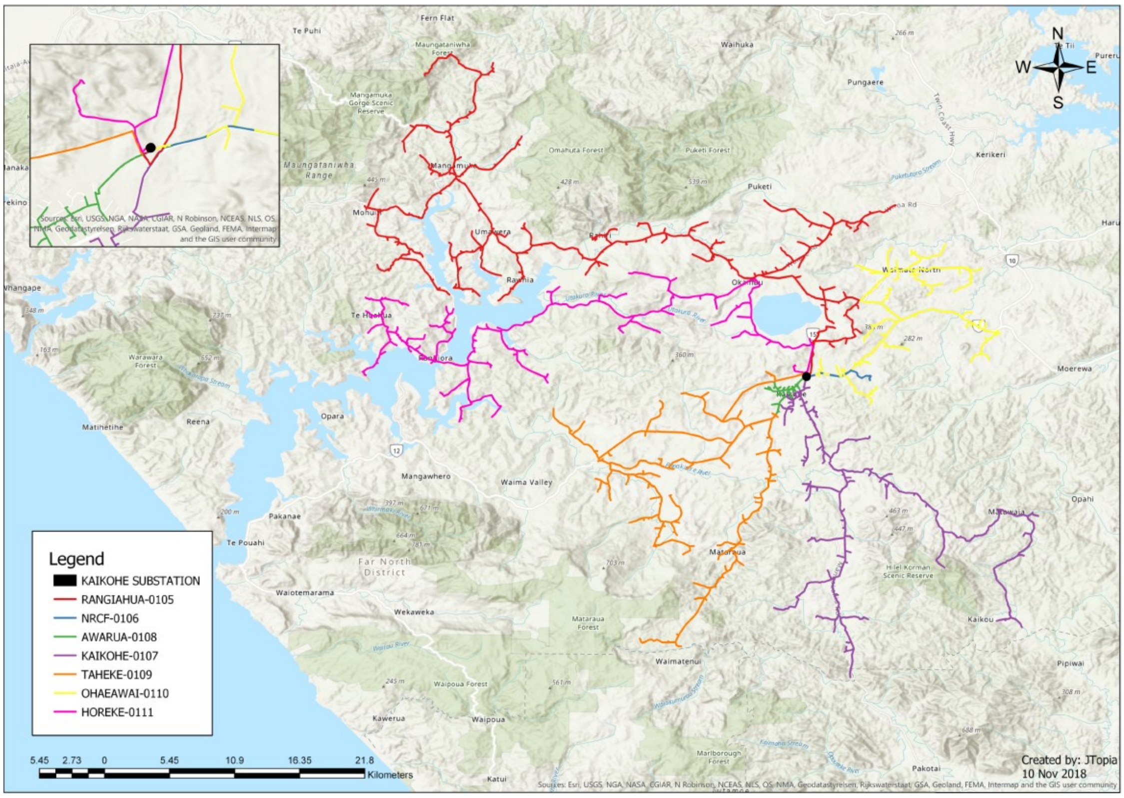


Figure 3.7: Geographic diagram of the Kaikohe zone substation

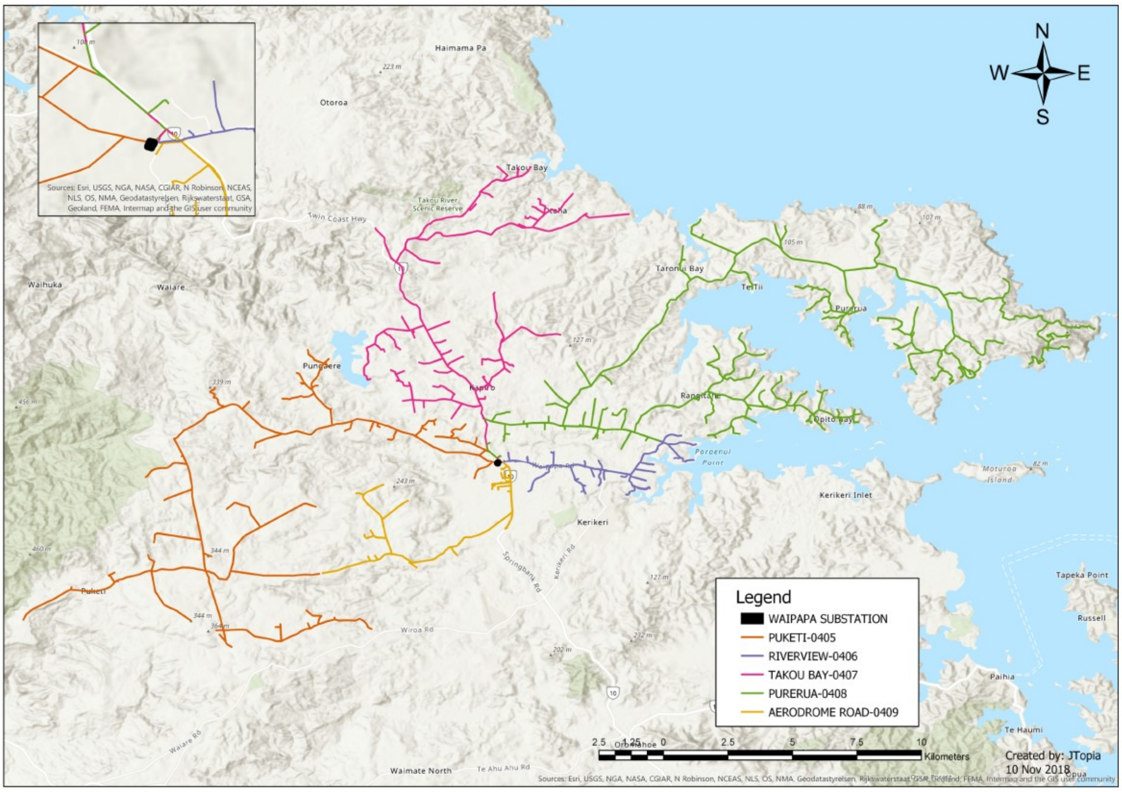


Figure 3.8: Geographic diagram of the Waipapa zone substation

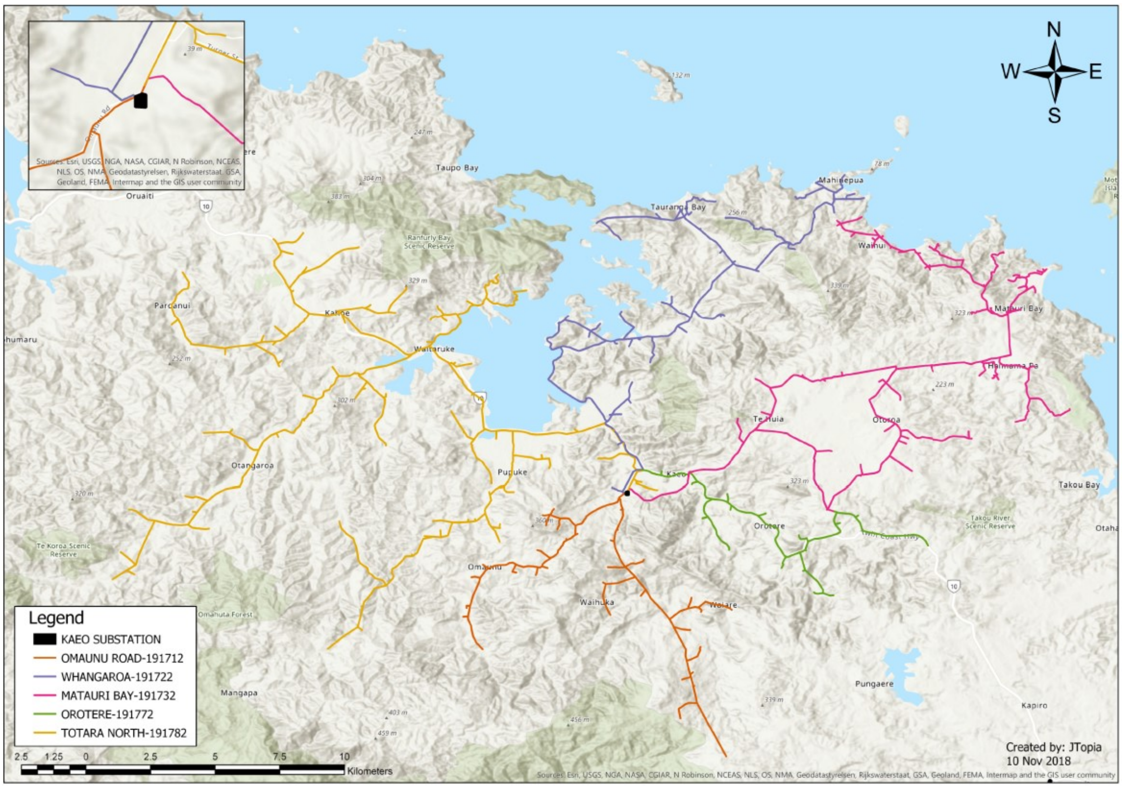


Figure 3.9: Geographic Diagram of the Kaeo Substation

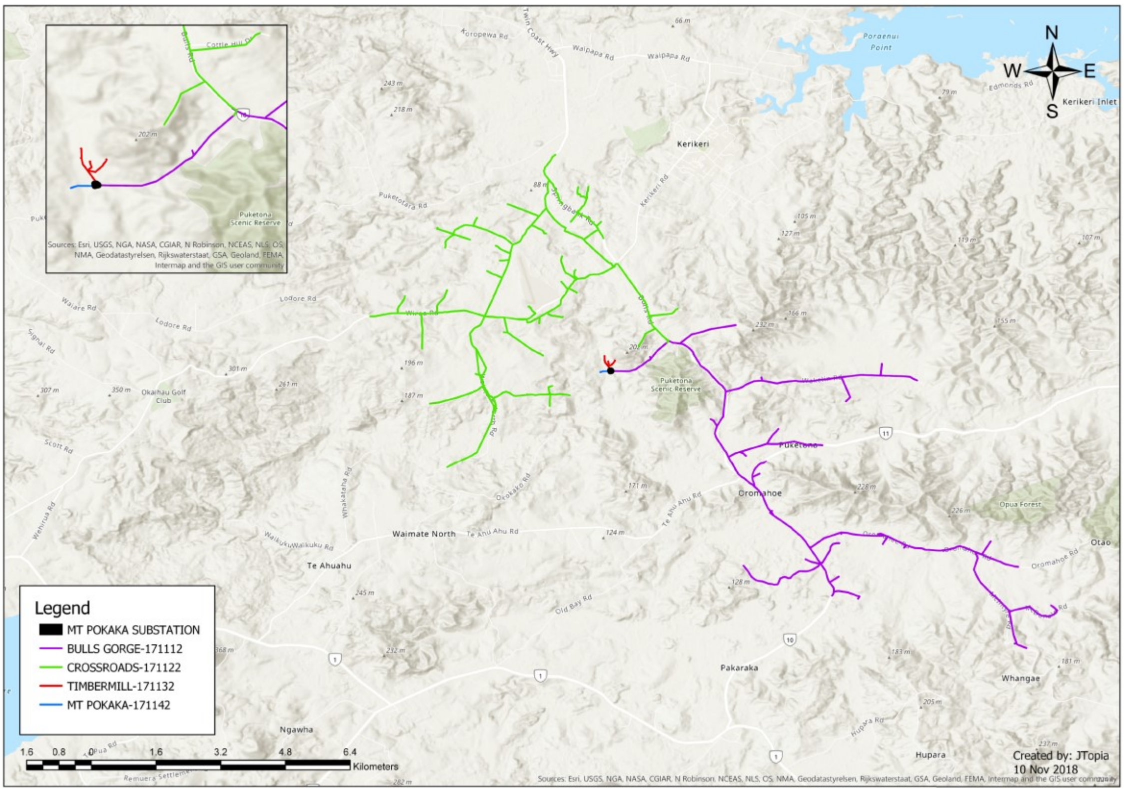


Figure 3.10: Geographic diagram of the Mt Pokaka zone substation

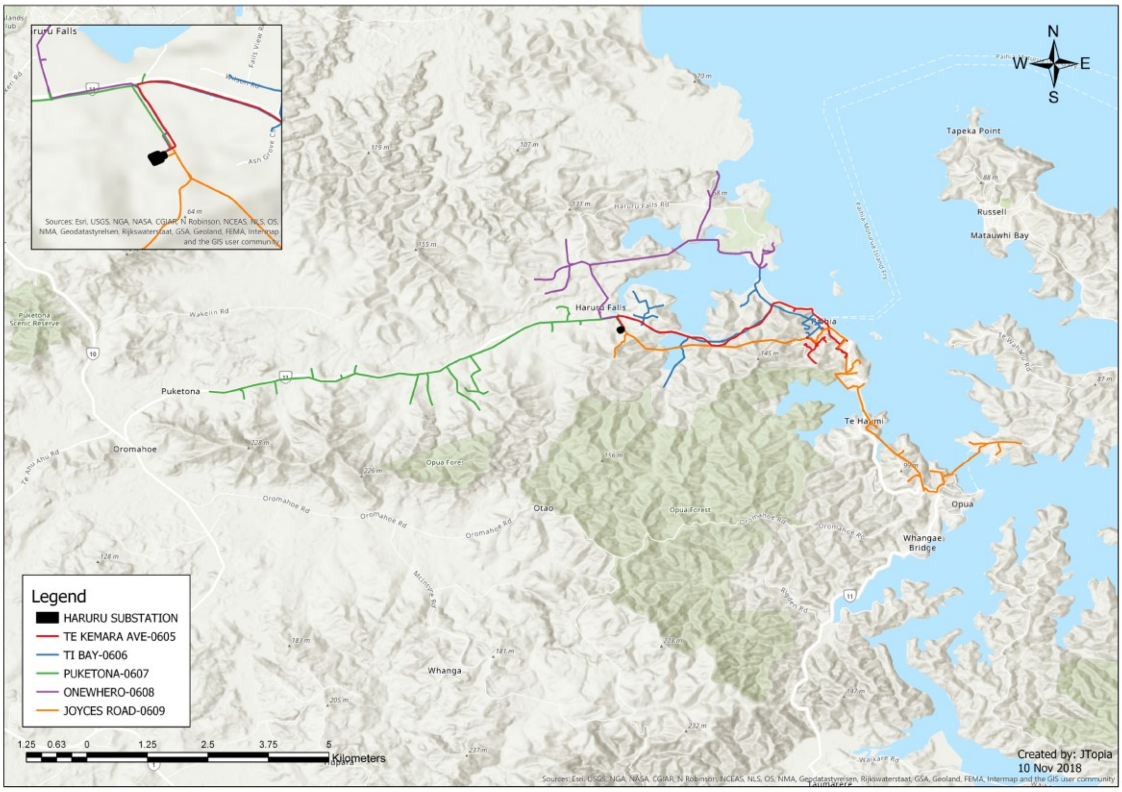


Figure 3.11: Geographic diagram of the Haruru zone substation

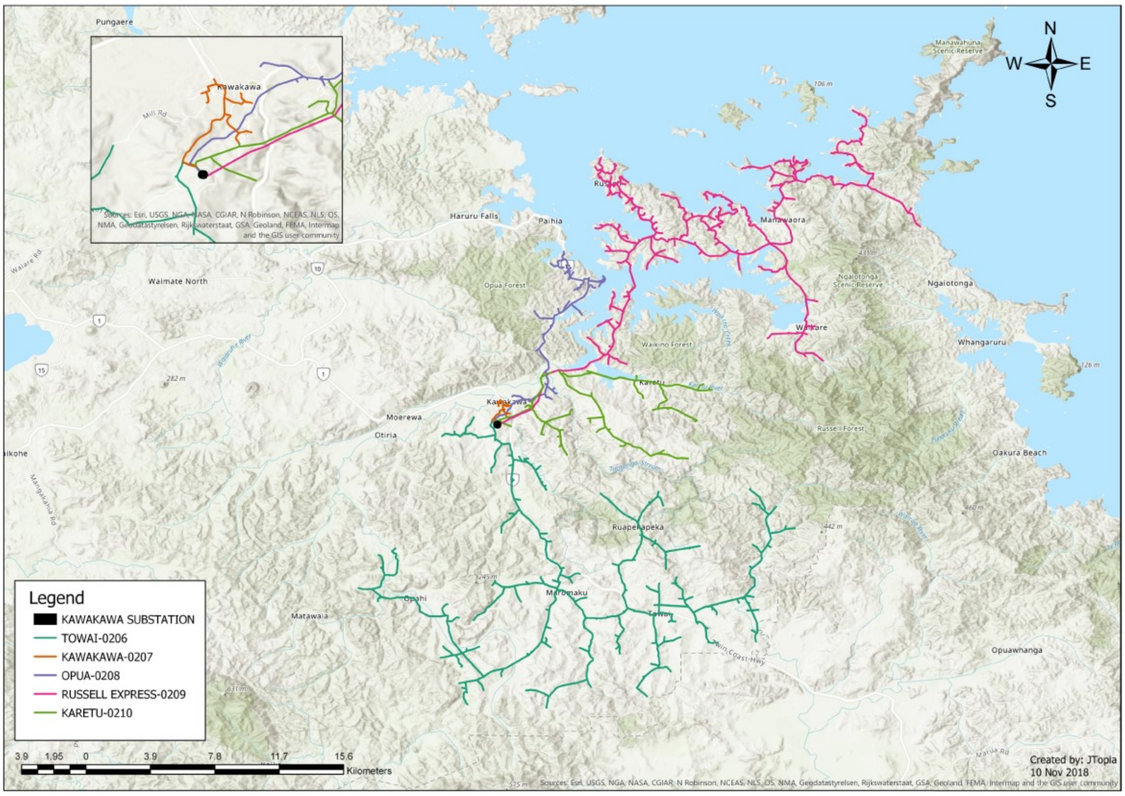


Figure 3.12: Geographic diagram of the Kawakawa zone substation

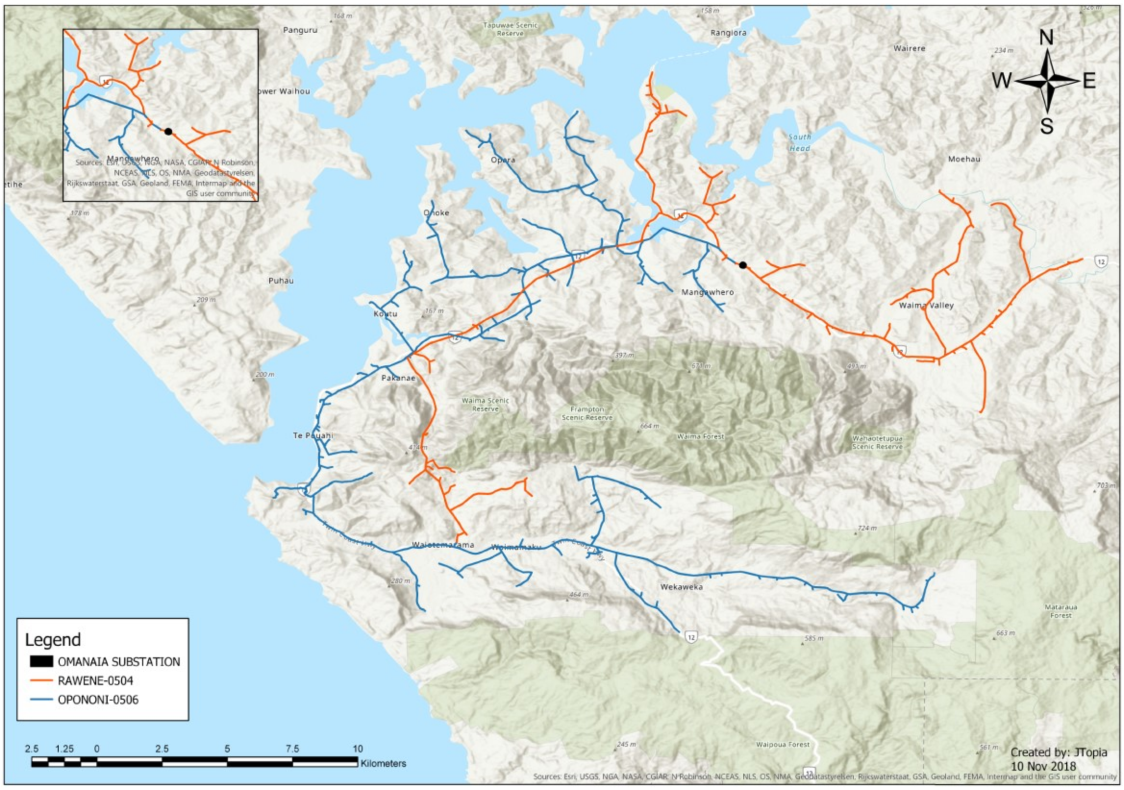


Figure 3.13: **Geographic diagram of the Omanaia zone substation**

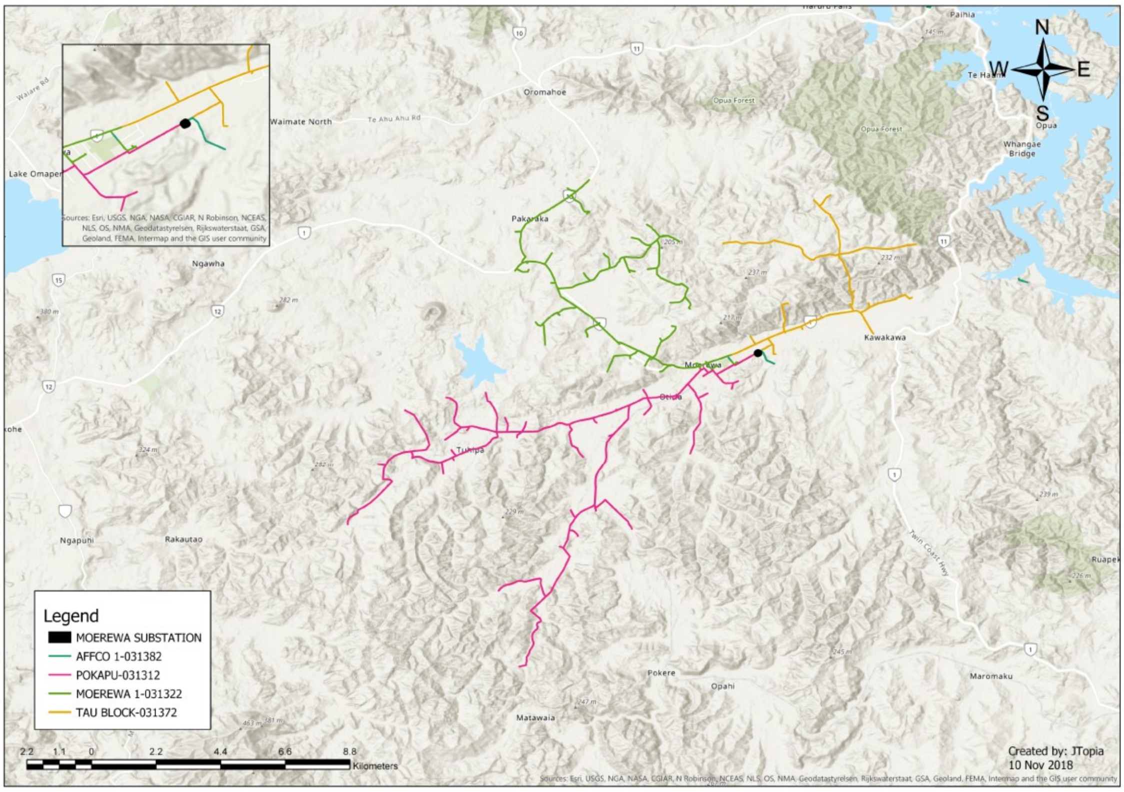


Figure 3.14: **Geographic diagram of the Moerewa zone substation**

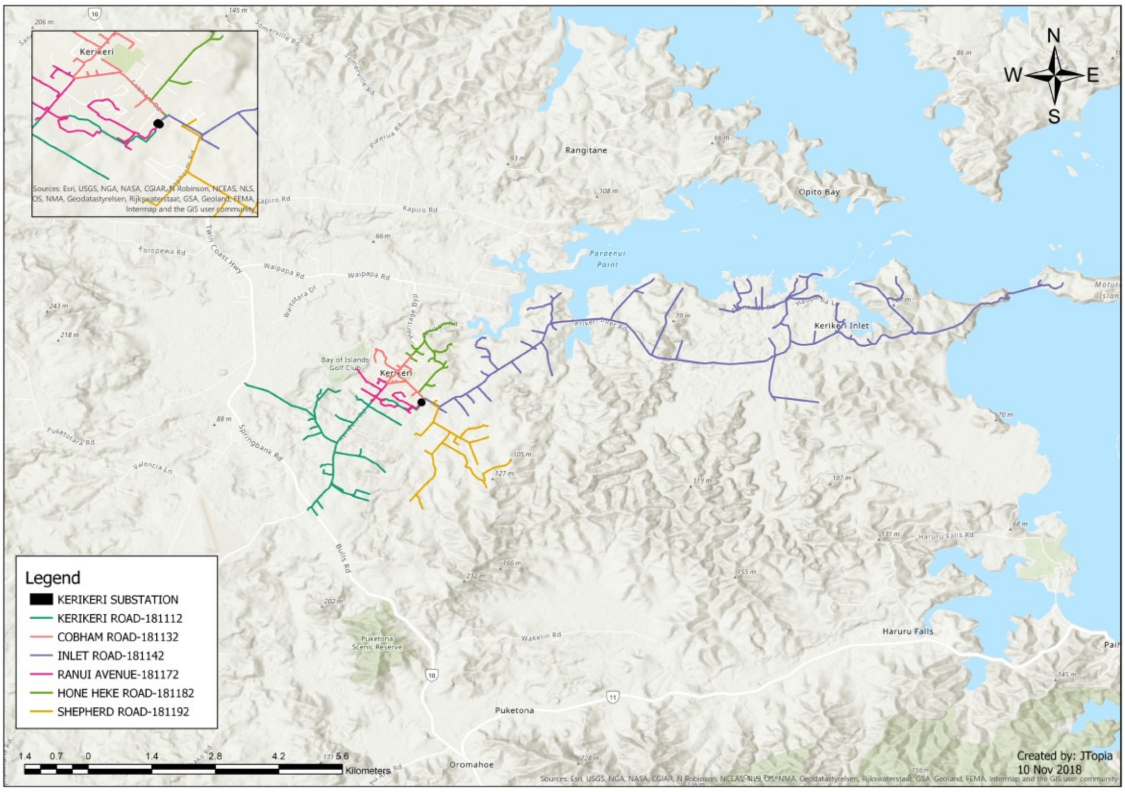


Figure 3.15: Geographic Diagram of the Kerikeri Zone Substation

3.1.7.1 Submarine Cables

Our distribution network includes two 11kV submarine cables, both feeding the Russell Peninsula. The first cable is laid across the Waikare Inlet and is a three-core, 70 mm^2 copper cable around 1.5 km long and was livened in 1975. It has been through 47 years of its nominal 70-year economic life.

The second cable is across the Veronica Channel between Opua and Okiato Point and is a three core, 150 mm^2 copper cable, livened in 2007.

There are also two consumer-owned 11kV submarine cables supplying islands within the Bay of Islands.

3.1.8 Low Voltage

Low voltage can be supplied at 400V three phase, 460/230V two phase or 230V single phase, although three-phase is not available to consumers supplied from a two-wire 11kV spur line or a SWER line.

For more than 40 years, we have required new developments and subdivisions to be underground, which has resulted in a high percentage of underground distribution at LV level and a corresponding low level of LV faults. Most LV road crossings are also underground. Our preferred LV arrangement in urban areas is looping between network pillars. This allows for the rapid identification and sectionalisation of the system in the event of localised network faults. There are limited interconnections available between transformers at the LV level, apart from the Kaikohe, Kaitaia, Kerikeri, Russell and Paihia urban areas.

3.1.9 Protection Assets

We use a mixture of protective devices including:

- Electromechanical and electronic relays.
- Numerical relays.
- Integrated protective devices such as fuses, pole top reclosers and sectionalisers.
- Indoor and outdoor circuit breakers with either local or remote-control functionality.

These devices are used to detect and isolate a fault as quickly as possible to maintain public safety and ensure that damage is minimised. Protective devices that carry the full load current (including fuses, reclosers and circuit breakers) are considered primary assets, whereas protection relays, which function using measured values of current and voltage, are classified as secondary assets.

Our network is on the fringe of the transmission grid and is characterised by very low fault currents. This affects the reliability of protection; particularly where traditional electromechanical protection relays are used. We have replaced most electromechanical protection relays in our zone substations and have also installed fibre-optic cable on most 33kV subtransmission lines, so that these lines now have differential protection, which continuously compares the current entering and leaving a circuit and is therefore more effective in situations where the fault current is low. This allows the subtransmission lines and transformers at a substation to be operated in parallel, so that a single subtransmission fault will not result in a supply interruption.

3.1.10 SCADA and Communications

We use a GE PowerOn Advanced Distribution Management System (ADMS) to monitor the state of our network in real time and allow key network assets including 110kV and 33kV circuit breakers as well as some sectionalisers and reclosers located in the field to be remotely controlled from our network control room in Kerikeri. This also incorporates an outage management system that combines real time inputs on the state of the system with connectivity data from our GIS to predict the location of faults and automatically calculate the SAIDI and SAIFI impact of supply interruptions. It also generates switching schedules to support the control room operators in the management of network outages.

The architecture consists of distributed data collection and operation via an Ethernet wide area network (WAN). Communication is usually direct with protection and measurement transducers in zone substations and high voltage switching device locations. The systems include:

- Microwave link equipment operating at speeds from 256kB up to 10MB from each control or monitoring point to either Maungataniwha (northern GXP network) or Mt Hikurangi (southern GXP network).
- A leased 2MB link from Maungataniwha to Mt Hikurangi.
- Fibre-optic cable along subtransmission line routes.
- A front end in the control centre comprising of an iPower HMI system and backup servers at Ngawha Power Station, connected via the Ethernet WAN.

We have also installed a standby control room at the Ngawha power station.

The existing analogue radio communications system functionality is fit for purpose. Although not committed, we are currently investigating a digital platform that would provide extra functionality.

3.1.11 Load control system

Our load control system operates by injecting a control signal into the electricity supply, which is detected by control relays located at the controlled load. We own and operate three Zellweger static ripple injection plants and injection is at 317Hz into our 33kV subtransmission system. The plants are located at our Kaikohe and Okahu Road substations, with a standby plant at Waipapa substation. These are operated from the network control room via our SCADA system. The Kaikohe plant was commissioned in 2007 and is rated at 80kVA, while the Okahu Rd plant (commissioned in 1991) is rated at 30kVA. The standby Waipapa plant was commissioned in 1981 and is also rated at 30kVA.

The load control plants are used to manage demand by allowing the control of a range of load types (particularly water heating) to actively manage our peak transmission charges and potentially defer capital investment on the network. The control relays installed in the field at the points where the controllable load is connected are owned by energy retailers, so we are reliant on retailers continuing to support the system to capture the benefit of demand management.

3.1.12 Load characteristics and large users

We have five large consumers:

- Juken New Zealand (JNL) Mill near Kaitaia (≈ 7MVA)
- AFFCo Meat Works near Moerewa (≈ 2MVA)
- Mt Pokaka Timber Products Ltd, south of Kerikeri (≈ 1MVA)
- Immery's Tableware near Matauri Bay (≈ 1MVA)
- Northern Regional Corrections Facility (NRCF) at Ngawha (≈ 0.6MVA)

JNL, AFFCo and Mt Pokaka all have dedicated distribution feeders from zone substations located at, or close to, their sites. Immery's Tableware is supplied from its local distribution feeder, while NRCF has a dedicated 11 kV feeder from the Kaikohe zone substation. Almost 20% of the energy delivered through our network supplies these five largest consumers.

Our other consumers are predominantly residential or rural, with dairy sheds comprising a significant proportion of the rural load. There is no predominant urban centre in our supply area, and light commercial and industrial loads are generally concentrated within small towns and settlements dispersed throughout our supply area.

We currently supply 14 public electric vehicle fast charging stations dispersed across our network as shown in Figure 3.16 below. (Note that some locations shown have two chargers).

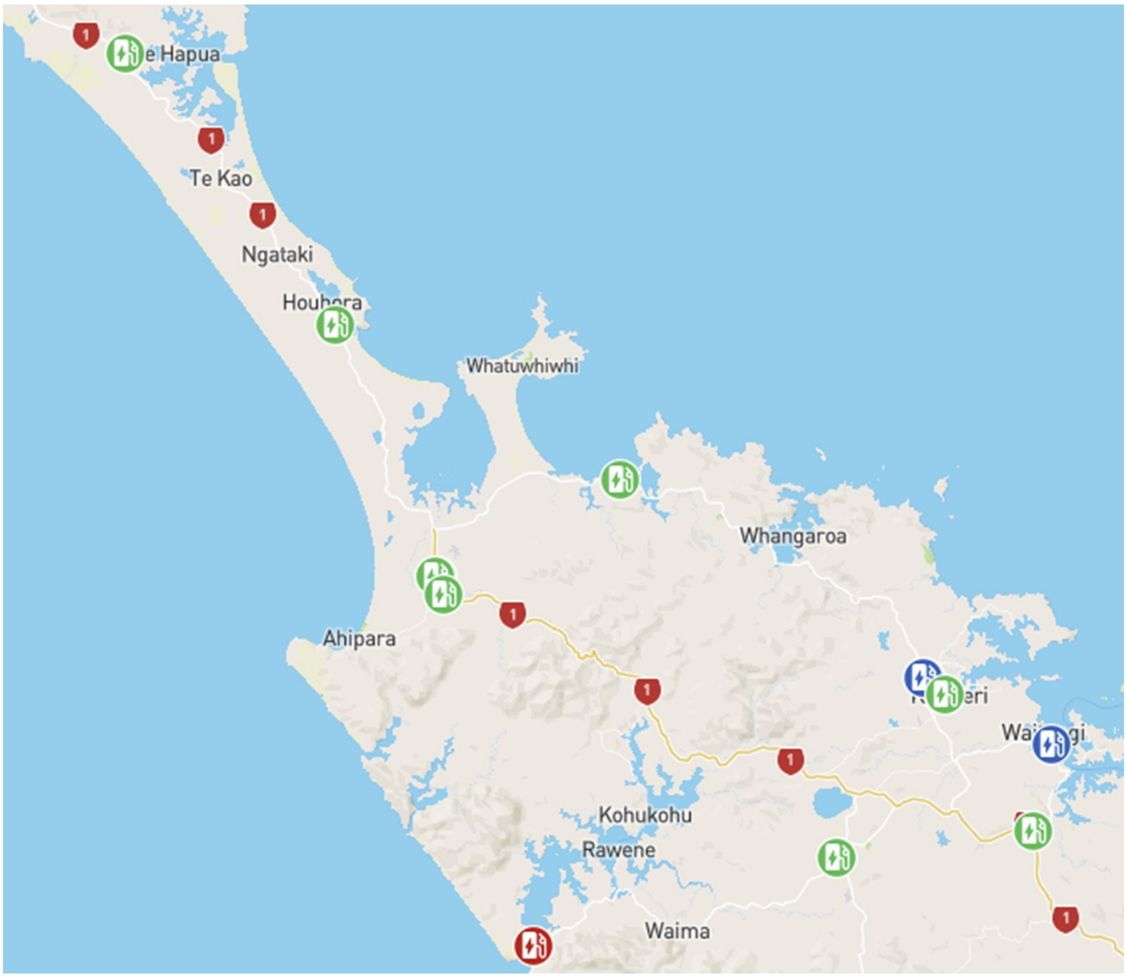


Figure 3.16: Public Electric Vehicle Charging Station Locations

3.1.13 Economics of Supply

Many of our distribution lines were built using subsidies provided by the Rural Electrical Reticulation Council (RERC). These were provided to assist with post-war farming productivity growth in remote areas and provide an electricity supply to consumers in sparsely populated rural areas that would have otherwise been uneconomic to service. Many of these lines are now reaching the stage where extensive rebuilding and refurbishment is required. We are obligated by Section 105(2) of the Electricity Industry Act 2010 to continue to provide a supply to consumers currently supplied from existing lines, although this continuing supply does not need to be a grid connection.

In 2009, prior to the passing of this Act, the Electricity Networks Association (ENA) created a working party to review the implications of this obligation. The working party defined lines as uneconomic if there were less than three connected low consumption consumers per km. Low consumption was defined either by the volume of energy delivered per year (less than 6,500kWh per consumer) or by the installed distribution transformer capacity (less than 20kVA per consumer); these criteria were based on an independent analysis of network costs undertaken by the then Ministry of Economic Development (now MBIE). Approximately 35% by length of our 11kV distribution network is uneconomic if the MBIE cost of supply criteria is applied. These lines supply just 9% of our consumers. While this study was undertaken almost 15 years ago, its findings still apply today.

In 2018 we investigated this issue further by developing a cost-to serve model that looked at the costs we incur in supplying consumers in different parts of the network. Our modelling showed that the revenue received from consumers in the remote segments of our network is enough to cover the operating costs of the assets used to provide their supply but makes only a marginal contribution to the capital costs of these assets. Consumers connected to the more economic parts of our network therefore subsidise the capital costs we incur in maintaining supply to these consumers.

3.2 Asset Quantities

The quantities and average age of our network assets are shown in the tables below. Age profiles, asset health assessments and asset maintenance strategies are detailed in Section 6.

3.2.1 Poles and Structures

Type	Quantity (No.)	Average Age (yr)	Expected Life (yr)
Steel	123	14	60-80
Concrete	35,280	37	
Wood	1,172	42	35-45
Fiberglass	11	5	15-20
Fiberglass	**36,586**	**37**	-

Table 3.3: Network Pole and Structure Quantities

3.2.2 Overhead Conductor

Asset	Quantity (cct-km)	Average Age (yr)	Expected Life (yr)
110kV Kaikohe-Kaitaia line	56	45	50-60
110kV Ngawha-Worsnops line	10	4	
33kV	315	35	
Distribution (excluding SWER)	2,045	41	
SWER	450	51	

Asset	Quantity (cct-km)	Average Age (yr)	Expected Life (yr)
LV	218	42	
Subtotal	**3,094**	**42**	-

Table 3.4: Network Overhead Conductor Quantities

3.2.3 Underground Cable

Asset	Quantity (cct-km)	Average Age (yr)	Expected Life (yr)
33kV	23	9	55
Distribution	225	18	45-70
LV (excluding streetlight)	680	29	45-55
Streetlight	318	32	45-55
TOTAL	**1,146**	**29**	-

Table 3.5: Network Underground Cable Quantities

3.2.4 Other Assets

Asset	Quantity (No)	Average Age (yr)	Expected Life (yr)
Pole-mounted distribution transformers	5,137	24	45
Ground-mounted distribution transformers	894	18	45
Voltage regulators	12	7	45-55
Zone substation buildings	35	37	50+
Power transformers	28	33	45-60
Outdoor 110kV circuit breakers	10	27	40
Indoor 33kV circuit breakers	44	9	60
Outdoor 33kV circuit breakers	43	20	40
11kV circuit breakers	115	33	45-60
33kV switches – pole mount	188	22	35
33kV switches – ground mount	48	3	45-60
Outdoor distribution switches / links	1,443	21	35
Sectionalisers / reclosers	353	14	40
Ring main units	207	12	40
Underground service fuse boxes	12,224	27	45
Protection relays	472	11	20-40
Capacitor Banks	19	33	40

Table 3.6: Other Network Asset Quantities

3.3 Regulated Asset Value

In accordance with the Commerce Commission's information disclosure requirements, Top Energy disclosed that its regulated asset base was valued at $320.0 million at 31 March 2022, an increase of $17.8 million since 31 March 2021. This total was derived as shown in Table 3.8 and reflects the value of the assets commissioned in FYE2022 as part of our network development programme.

	$000
Asset Value at 31 March 2021	**302,160**
Add:	
New assets commissioned	9,230
Indexed inflation adjustment	20,839
Asset allocation adjustment	11
Less:	
Depreciation	12,210
Asset disposals	10
Asset value at 31 March 2020	**320,021**

Table 3.7: Value of System Fixed Assets

The asset value shown in Table 3.8 is the value of our regulatory asset base, as measured in accordance with the Commerce Commission's information disclosure requirements. It differs from the value of our distribution assets as shown in our annual report for two reasons: firstly, the valuation rules for information disclosure differ from those for financial accounts; and secondly, the regulatory asset base includes assets such as the land and buildings (e.g. substation control buildings), which form an integral part of the network, but are recorded under other asset categories in the Group financial accounts. Neither value includes works that are under construction but have yet to be commissioned.

Table 3.9 disaggregates the value of system fixed assets shown in Table 3.8 into its main asset categories.

	$000
Transmission and subtransmission lines	65,191
Subtransmission cables	9,805
Zone substations	43,651
Distribution and low voltage lines	82,729
Distribution and low voltage cables	40,918
Distribution substations and transformers	36,265
Distribution switchgear	33,100
Other network assets	5,324
Non-network assets	3,038
Total	**320,021**

Table 3.8: Disaggregated Value of System Fixed Assets at 31 March 2022

4 Level of Service

4.1 Introduction

Our relatively low network reliability is in part a consequence of our fringe location at the end of the grid, where we remain reliant on a single double circuit radial connection to a mesh node of the Transpower network. A rural network of similar size located within the meshed core of the transmission system would have more grid connections and backup options. Another disadvantage has been our highly dispersed population, spread over a large supply area with no dominant urban centre.

Furthermore, our grid connection at Kaikohe and the 110kV transmission line route over the Maungataniwha range are no longer optimally located to serve our present load. They were constructed during an era when Kaikohe and Kaitaia were the hub of both economic and population growth within our supply area. Over the last thirty years, there has been a steady decline in the growth of both towns, whilst there has been significant growth in Kerikeri, the Bay of Islands and the eastern coastal peninsulas. In recent years Kerikeri and its surrounds has been one of the fastest growing population centres in the country and is now the dominant load centre in our supply area.

A major driver for the TE2020 network development plan we have implemented since FYE2010 has been to augment our subtransmission network to provide the capacity required to accommodate this demographic shift. This capacity augmentation will be completed with the commissioning of a new 110/33kV substation at Wiroa. Construction of this substation, which will provide sufficient transmission capacity to supply the expected consumer demand in the Kerikeri area beyond 2050, is tentatively scheduled to commence in FYE2028.

At the same time, we have improved the reliability and resilience of our transmission and subtransmission network by installing backup generation, installing upgraded protection so the 33kV subtransmission circuits can be operated in parallel, and refurbishing those 33kV subtransmission lines for which there is no parallel circuit. These investments have reduced the unplanned SAIDI impact of our subtransmission system from a typical 150 minutes to around 25 minutes. Realistically, there is little scope for further improving the reliability of the transmission or subtransmission networks and, going forward, investments targeting network reliability will focus on the 11kV distribution network.

4.2 Consumer Orientated Service Levels

4.2.1 Unplanned Interruptions

The service level targets included in this AMP are limited to the normalised SAIDI and SAIFI measures used by the Commerce Commission to monitor the reliability of our network under its price-quality regime. These are:

- **Unplanned SAIDI:** System Average Interruption Duration Index. This is the accumulated total time that the average consumer connected to the network is without supply in any measurement year due to faults originating within the network. The units are minutes.
- **Unplanned SAIFI:** System Average Interruption Frequency Index. This is the total number of supply interruptions that the average consumer connected to our network will experience in a measurement year due to faults within the network. The units are outages per consumer per year. While an individual consumer can only experience a whole number of outages, the target is set as a real number to allow for the effect of averaging.

The Commission has chosen these internationally accepted measures because it believes they are effective indicators of how well an EDB provides a reliable electricity supply to consumers.

In measuring our performance for internal management purposes and setting our own targets, we use the normalising approach taken by the Commerce Commission in measuring the reliability of supply provided by all the EDBs that it regulates under the default price-quality path regime[4]. Normalisation of the raw performance measures is designed to limit the impact on the measure of network reliability of events that are outside our reasonable control. We believe that setting targets using normalised measures provides a better indication of the success of our asset management strategies because normalisation limits the extent to which severe storm events, which are outside our control and response capacity, impact the measured performance.

In the normalisation process, any rolling 24-hour period where the aggregate unplanned network SAIDI or SAIFI from all supply interruptions that commence during the period exceeds a predetermined boundary value is categorised a SAIDI or SAIFI major event. The SAIDI or SAIFI impact of all interruptions during a major event is normalised back to $^{1}/_{48}$ of the boundary value (unless the SAIDI or SAIFI impact of the individual interruption is lower than this).[5] The normalisation process is designed so that the aggregate normalised SAIDI or SAIFI over any rolling 24-hour period cannot exceed the boundary value. Furthermore, SAIDI and SAIFI are normalised independently, so you can have a SAIDI major event without a corresponding SAIFI event and vice-versa.

The normalisation process can have a significant impact on the reported reliability in years where reliability is poor due to the number of abnormally severe storms. For example, in FYE2015 our raw SAIDI was 1,837 minutes, primarily due to a major weather event that lasted three days. Normalisation, using the Commission's current approach (which did not apply at the time), would have reduced this to 356 minutes.

Under its price-quality regime, the Commission sets a normalised SAIDI and SAIFI threshold for each regulated EDB. These reflect the average annual normalised reliability of the network over the ten-year period FYE2010-19, but also include a margin to provide for volatility. Should we breach a threshold in any year, the Commission will investigate our management of the network and has the power to impose a civil penalty. Our normalised SAIDI and SAIFI thresholds and boundary values are shown in Table 4.1.

	Threshold	Boundary Values
SAIDI	380.24	27.92
SAIFI	5.0732	0.2284

Table 4.1: Current Unplanned Interruption Reliability Limits and Boundary Values

The indicators measure only interruptions that originate within our network. Interruptions that originate outside the network, such as an automatic under-frequency load shedding event, or loss of the grid connection to Maungatapere, are not included. Interruptions lasting less than one minute are also excluded, irrespective of cause. These interruptions are generally caused by a transient event, such as a lightning strike or debris blown across a line, and supply is restored by an automatic system reclosure without the need for operator intervention.

Our internal unplanned SAIDI and SAIFI targets for each year of the planning period are shown in Table 4.2 and are shown graphically in Figures 4.1 and 4.2, which also compare the targets with the historical reliability[6]. The basis for setting these targets is described in Section 4.3.1.

We have changed our internal unplanned SAIDI and SAIFI targets from those in our 2021 AMP and 2022 AMP Update. This is discussed in Section 8.

4 Trust owned EDBs that do not operate generation are exempt from regulation under the default price-quality path but must disclose details of their operations in accordance with the information disclosure requirements. Currently, the normalisation methodology used for price-quality path compliance assessment is different from that used for information disclosure.

5 Periods are rolled forward in half hourly increments starting on the hour and half-hour. Interruptions that occur within the same half-hour period are aggregated and treated as a single interruption for normalization purposes.

6 The Commission's current normalisation methodology only came into effect in RCP3. In Figures 4.1 and 4.2 the normalised outcomes shown for the years prior to FYE2021 have been reverse engineered by applying the current normalisation methodology to the raw interruption data.

FYE	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Unplanned SAIDI	302	302	311	311	311	311	311	311	311	311
Unplanned SAIFI	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01	4.01

Note: Targets are raw performance normalised in accordance with the Commerce Commission's FYE2021-25 DPP normalisation methodology.

Table 4.2: Consumer Service Level Targets

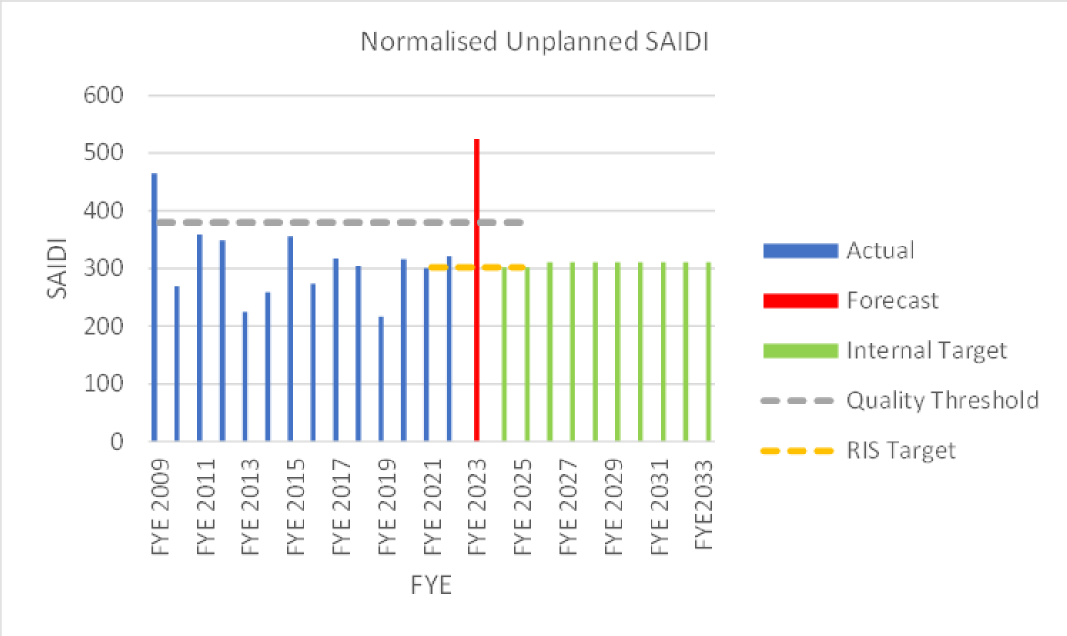


Figure 4.1: Historical and Target Unplanned SAIDI

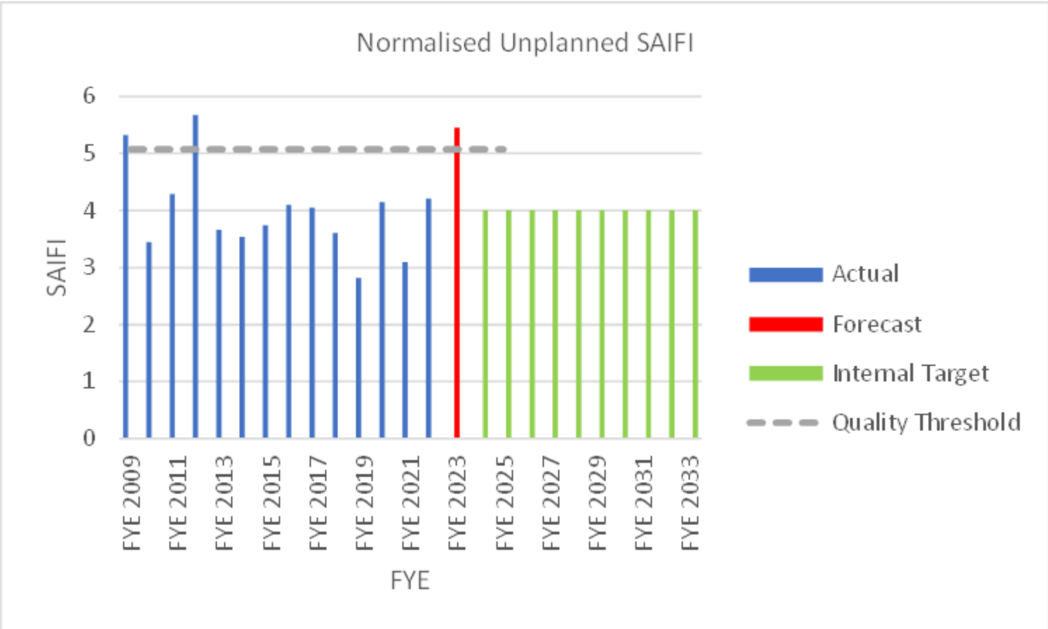


Figure 4.2: Historical and Target Unplanned SAIFI

4.2.2 Planned Interruptions

While planned interruptions are disruptive to consumers, they are less so than unplanned interruptions because consumers are given advance notice of the outage and can plan accordingly. With generation installed at Kaitaia, Omanaia, Pukenui and Taipa, planned interruptions should now normally only be required for work on the 11kV distribution network[7].

For RCP3, the Commission has not set an annual limit for the impact of planned interruptions but has set aggregated planned SAIDI and SAIFI limits for the whole regulatory period. As compliance will only be assessed at the end of the period, EDBs are free to use up this allowance at any time over the period. Our limit is 1,905.36 SAIDI minutes and 7.63 SAIFI interruptions, which is calculated as three times our average annual planned SAIDI and SAIFI over the FY 2010-19 period aggregated for five years.

For internal management purposes we have set an annual planned SAIDI target equal to our average performance over the FY 2010-19 period[8]. In a change from the target in the 2021 AMP and the 2022 AMP Update, we have doubled the internal planned SAIFI to 1.0 interruptions per year to better reflect our actual performance over the period FYE2021-23. Given the buffer allowed by the Commission, this does not imply a material increase in the risk of breaching the threshold.

Given that planned interruptions on our transmission and subtransmission networks are now unlikely, these targets will allow us to increase our level of maintenance on the 11kV network without increasing our consumers' exposure to planned interruptions above historic levels. These targets are shown in Table 4.3. Assuming the SAIDI target is met exactly, the aggregate SAIDI impact of planned interruptions over the RCP3 regulatory period will be 625 minutes, less than one third of the 1,905.36 minutes set by the Commission. The aggregate SAIFI impact will be 5 interruptions over the regulatory period, only 66% of the regulatory threshold.

FYE	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Planned SAIDI	125	125	125	125	125	125	125	125	125	125
Planned SAIFI	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Table 4.3: Targets for the Impact of Planned Interruptions

4.3 Asset Performance and Efficiency Targets

We have developed targets to reflect our asset performance and efficiency to ensure that our asset management strategies result in effective utilisation of our asset base.

The targets for loss ratio and the ratio of operational expenditure to total regulatory income are based on indicators that reflect the effectiveness of our management of the network assets for the benefit of electricity consumers in our supply area.

4.3.1 Loss ratio

Network losses are a function of network length and load. We have a high loss ratio (defined as the ratio of energy losses to the energy flowing into the network), as is typical in a rural network.

Energy losses are measured as the difference between the energy flowing into the network and the energy sold out. They include both technical losses, due to the loss of energy flowing through the physical network, and non-technical losses, due to factors such as incorrect metering installations, meter errors and theft. In our case, the relatively poor loss ratio is primarily driven by technical losses, which result from the high network loading and rural nature of the network.

From 1996 to 2001, our network loss ratio was approximately 10%. In subsequent years, the loss ratio improved to between 8% and 9%. However, in FYE2013, there was a step increase to 9.5%, as losses in our newly acquired transmission assets were included for the first time. Over time, distribution losses should decrease incrementally as we continue our investment in network development. Nevertheless,

7 The one exception to this is the Juken New Zealand mill. Generation was not installed at Kaitaia to supply the mill operations during an outage of the 110kV Kaikohe-Kaitaia line. An arrangement is in place with the customer to ensure the mill operations are shut down during a planned interruption of this line.

8 These are rounded values. The reliability incentive scheme has a planned SAIDI component with a target SAIDI of 127.02. This is the neutral level, for which no reward or payment will apply.

there is a limit to the extent the losses can be mitigated, as a large proportion of losses are on the low voltage network and these losses cannot easily be reduced.

We can expect losses to reduce once the 110/33kV Wiroa substation is commissioned, and to reduce further if the 110kV Wiroa-Kaitaia line is constructed. The transition to a distributed energy system may also reduce losses because the power flows within the network are the net balance between generation and consumption, and the generation is closer to the load.

FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029	FYE2030	FYE2031	FYE2032	FYE2033
9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%

Table 4.4: Target Loss Ratios

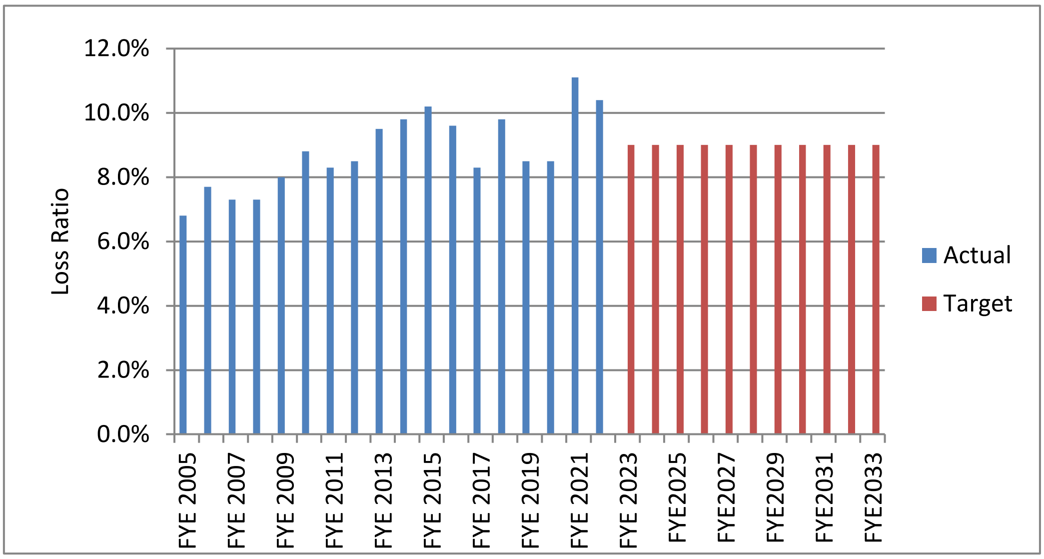


Figure 4.3: Loss Ratios of Top Energy since FYE2004

4.3.2 Cost Performance

Ideally, any financial performance indicator should be directly measurable for performance against a specific target and also be independent of the annual effects of inflation. We use the ratio of total operational expenditure to total regulatory income, since this metric is independent of inflation as both numerator and denominator are financial measures. It is therefore preferred over other, possibly more meaningful, alternatives such as the ratio of operational expenditure to circuit length, where the impact of inflation would need to be considered in setting forward targets. The disadvantage of this measure is that total regulatory income is not a direct measure of the size of the asset base and therefore it could be argued that the ratio is not a direct measure of asset management efficiency. Nevertheless, regulatory income is indirectly related to the size of the asset base, and the measure reflects the portion of the revenue from the provision of distribution line services that is allocated to operating expenditure, which is directly relevant to consumers. All else being equal, a smaller ratio reflects greater efficiency in the day-to-day management of assets.

We believe that metrics related to capital expenditure are not good indicators of asset management efficiency at a time when we are implementing an extensive network development programme, because of the potential variability of capital expenditure from year to year.

Our targets for the ratio of total operational expenditure to total regulatory income are shown in Table 4.5.

FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029	FYE2030	FYE2031	FYE2032	FYE2033
33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%

Table 4.5: Targets for Ratio of Total Operating Expenditure to Total Regulatory Income

Figure 4.4 compares these targets with our actual performance against this measure since 2008. The increase in operational expenditure for the three years from FYE2011 is apparent as we implemented our vegetation management and reliability improvement programme. Operational expenditure has now reverted to more normal and sustainable levels, and this is reflected in the forward targets.

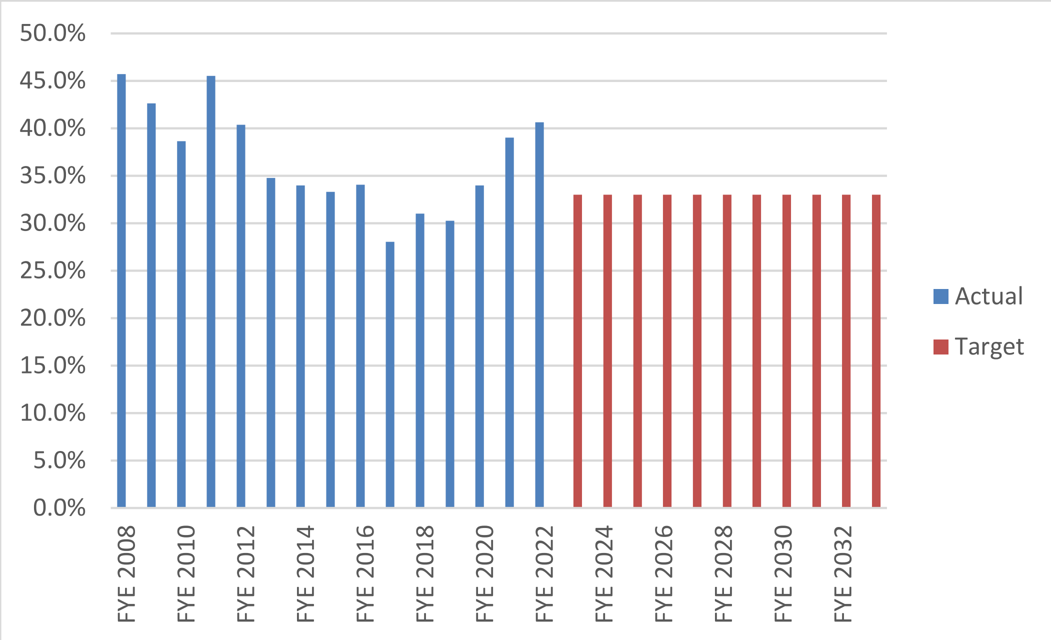


Figure 4.4: Ratio of Total Operating Expenditure to Total Regulatory Income since FYE2008.

4.4 Justification for Service Level Targets

4.4.1 Supply Reliability Targets

The SAIDI and SAIFI service level targets measure the effectiveness of our asset management strategies, which have been developed to reflect the outcome of our stakeholder consultation process and other internal business drivers. They reflect our current performance and have been derived as follows.

4.4.1.1 Unplanned SAIDI and SAIFI

The targets reflect the average annual unplanned SAIDI and SAIFI over the ten-year historic period used as the basis for setting the quality thresholds for RCP3. For unplanned SAIDI through to the end of RCP3 in FYE2025, this is equivalent to the neutral or zero-impact unplanned SAIDI in the Commission’s quality incentive scheme (QIS). This is consistent with the basis for the Commission’s approach to setting the reliability parameters; they were set at a level that did not reflect a material change from historic performance. From the start of the RCP4 regulatory period in FYE2026, when the Commission’s historic reference period will have moved forward five years, we have increased the SAIDI target by approximately 3% to reflect the increased SAIDI impact of unplanned interruptions over the last few years. This assumes that the Commission will set its RCP4 price-path quality parameters using the same methodology as RCP3. It does not reflect a “material” deterioration in performance as it is within the Commission’s materiality threshold of 5%.

As the QIS does not include unplanned SAIFI, there is no corresponding SAIFI zero-impact level. However, the AMP SAIFI target in Table 4.2 has been set the same way, except there is no change in the target impact between RCP3 and RCP4, since a deterioration in our unplanned SAIFI performance has not been experienced to the same extent.

Going forward, our Board has decided that the SAIDI and SAIFI targets included in both the Statement of Corporate Intent and the AMP will be determined on the assumption of no material deterioration in performance, which will be measured using the same methodology used by the Commission in setting its price-quality path parameters. The targets above assume no change between regulatory periods but, should the Commission change its approach, we will review our targets and adjust them accordingly.

4.4.1.2 Planned Interruptions

As discussed in Section 4.2.2, we have set our targets for planned interruptions based on our average historic performance. As we no longer work on live assets, we are reliant on planned interruptions to maintain our 11kV network assets. Therefore, we do not think targets that severely limit our ability to arrange planned interruptions are in the long-term interest of our consumers.

Nevertheless, we have reassessed the appropriateness of the planned SAIDI and SAIFI targets in the 2021 AMP and 2022 AMP Update on the basis of our actual outcomes in the FYE2021 and FYE2022 assessment periods. We found that, in both years, both targets were exceeded when assessed against the raw SAIDI and SAIFI impacts. However, in the Commission's RCP3 determination there is a provision for de-weighting the SAIDI impact of planned interruptions by 50% when specified criteria for the prior notification of affected consumers are met. In both years the SAIDI, after normalising to include the de-weighting, was below the AMP target of 125 minutes, so we don't consider any adjustment to this target is necessary.

There is no provision for de-weighting in the assessment of planned SAIFI and we have therefore increased the planned SAIFI target from 0.5 to 1.0 to better reflect our planned SAIFI outcomes in the first two RCP3 assessment periods. As there will still be a 33% buffer between the aggregated new target levels and the planned SAIDI threshold even though the targets have been relaxed, a threshold breach is unlikely.

4.4.2 Justification for Asset Performance and Efficiency Targets

4.4.2.1 Loss Ratio

Our loss ratio targets reflect the performance of the network and include the losses on the 110kV transmission system. The commissioning of the second 110kV line to Kaitaia was expected to result in a material improvement to the loss ratio, but this has now been deferred beyond the end of the AMP planning period. It can be seen from Figure 4.3 that there was a significant and unexpected increase in losses in FYE2021 and FYE2022. The reason for this is not clear but we think it might be in part due to the impact of the Covid lockdowns and the changes these triggered in the pattern of electricity consumption across our network. We note the decrease in losses in FYE2022 and see no basis for any adjustment to the current AMP target level.

4.4.2.2 Ratio of Total Operational Expenditure to Total Regulatory Income

As can be seen from Figure 4.4, this ratio has increased significantly in FYE2021 and FYE2022. There was a 17% decrease in total regulatory income in FYE2021 due to both the Covid driven reduction in electricity sales and the reduction in line charges due to the Commission's RCP3 price-quality path determination.[9] At the same time the reduction in total operational expenditure was only 4%.

There was a recovery in electricity sales in FYE2022, which in turn drove an increase in regulatory income. However, the increase in operational expenditure was significantly greater, most likely due to increases in labour costs due to the well documented inflationary pressures.

FYE2021-22 has been a period of an unusually high level of economic volatility, and it is difficult to forecast where the situation will stabilise once this volatility eases. While an adjustment to the target is likely justified, we think it premature to determine the appropriate amount, so have left the target unchanged in the meantime.

---

9 Top Energy 2021 Annual Report noted that lines revenues were reduced by 15% on 1 April 2020 (p24).

5 Network Development Planning

5.1 Planning Criteria

Planning criteria for our network development projects are governed by legislative and internal requirements, such as voltage compliance and security of supply, and technical constraints such as maximum current ratings. While load growth and the need to meet maintain network resilience are the main factors that drive these requirements, network development is also driven by our response to the asset management challenges discussed in Section 2.4.

5.1.1 Voltage Criteria

We use the following design voltage limits.

- 33kV subtransmission: +4.5%, -10% of nominal voltage.
- 11kV distribution: +2%, -5% of nominal voltage.
- LV network: ±4% of nominal voltage up to legal point of supply.

The voltage limits defined above allow our voltage control equipment, such as on-load tap changers in zone substation power transformers, voltage regulators and capacitors on distribution feeders, to keep voltages within statutory limits at all levels of demand.

Our voltage compliance related projects are mainly justified by the following benefits from improved voltage levels or voltage control:

- The ability to meet statutory voltage limit requirements.
- Improvement in distribution circuit capacity.
- Improvement in back-feed ability to other distribution circuits in a contingency situation.
- Reduction of power losses.

Because of the length of our feeders, low voltage is generally the first indicator of an emerging network capacity issue and therefore the most common driver for augmentation projects on our 11kV and LV networks.

5.1.2 Security of Supply

The level of security that we provide in the event of an unplanned single-element fault on our transmission or subtransmission networks is summarised in Table 5.1. Our objective is to restore supply to all affected consumers within one hour following such an incident, unless otherwise agreed with a consumer.

Substation	Target Restoration Time	Comment
Kaitaia	1 hour	Supply restored using diesel generators at Kaitaia depot, Bonnetts Rd, Taipa and Pukenui. Supply to JNL will be restored to allow an orderly plant shutdown and then disconnected until the fault is repaired. Note: The ability to start the Kaitaia generators within the target restoration time following an unplanned loss of supply has still to be tested. The control room is preparing a standard operating procedure and switching sequence for this situation.

Substation	Target Restoration Time	Comment
Kaikohe Kawakawa Kerikeri Moerewa NPL Okahu Rd Waipapa	-	No interruption. These substations all have two transformers and two incoming lines.
Omanaia Pukenui Taipa	1 hour	These substations have a single transformer and single incoming line. Supply restored using diesel generators located at the substation. There is insufficient generation capacity at Taipa to supply the full substation load at time of peak demand but supply to most consumers can be restored by transferring some load to adjacent substations.
Kaeo	1 hour	This substation has two transformers but only one incoming line. In the event of an incoming line fault, most of the load can be transferred to adjacent substations, but at times of peak demand it might not be possible to fully restore supply to all consumers before the fault is repaired.
Mt Pokaka	1 hour	This substation has one incoming line and one transformer. In the event of either a transformer or line fault, supply can be restored to all small use consumers by transferring their load to adjacent feeders. We have an agreement with the Mt Pokaka mill that supply will not be fully restored until the mobile transformer is put into service. This could take up to 12 hours

Table 5.1 Transmission and Subtransmission System Security

We own and operate a 7.5MVA 33/11kV mobile substation, which limits the maximum total outage duration should all transformer and generation capacity be lost at any substation. This will be used in the event of a transformer failure at any of our four single-transformer zone substations to avoid the need to run generators continuously for extended periods of time and to restore system security to normal levels until the fault is repaired. The time required to relocate this unit from its present location to provide backup at another substation is up to 12 hours. This includes the time required for packing, travelling from one zone substation to another, and the time required for assembling and connecting the unit at its new location. Transformer failures are rare but, if one occurs, the repair or replacement time is potentially up to 12 months.

The 11kV distribution network is operated in a radial configuration, which means that there will be a supply interruption every time there is a fault. The number of consumers affected will depend on the fault location. We have normally open interconnections between some feeders, which allow us to reroute supply around a faulted switching zone to restore supply to downstream consumers before the fault is repaired. The availability of such an alternative supply depends on the fault location but, in general, the likelihood reduces as the distance of the fault from a zone substation increases. Supply cannot be restored to consumers in remote locations or on the edge of the network until a fault is repaired.

5.1.3 Asset Capacity Constraints

For design purposes, we consider the different capacity constraint levels on primary assets for normal operation and contingent operation and apply the more restrictive of the two. These are shown in Table 5.2.

ASSET TYPE	CONDITION	PERCENT OF NOMINAL CURRENT RATING	
		Normal operation	Contingent operation
Transformers	Nominal	100	125 for one hour
Overhead Conductors	Still air 30 degrees	75	100
Underground cables	In duct	75	100
Circuit Breakers	Nominal	75	100

Table 5.2: Design Capacity Limits

5.1.4 New Equipment Standards

To maximise cost efficiencies and reduce the required number of spares, we have adopted equipment supply standards for the capacity and rating of stock issue equipment, such as power transformers, conductors, cables, and poles.

Distribution transformers follow the ISO standard sizing. Pole mounting of new transformers is now limited to those rated 100kVA and below for seismic reasons. Transformers may be single-, two-, or three-phase according to consumer or load requirements. Appropriately rated isolating transformers are used to isolate SWER circuits from the rest of the network. Pad (berm) mounted transformers are steel cabinet enclosed units and may include switch units (total pad type) depending on the application.

XLPE cables are now used as standard for all voltages. HV cables and larger LV cables are aluminium and 33kV cables are single core for flexibility and ease of installation. LV copper cables in the smaller sizes are used for consumer connections.

Wood poles are being progressively phased out of the network. New concrete poles are all pre-stressed 'I' section poles and are generally used at subtransmission voltage and below. Steel poles are now used for 110kV transmission lines[10] and will also be used for new subtransmission lines in locations where our standard concrete poles do not meet the design requirements.

Overhead conductors are generally all aluminium conductor (AAC), except where long spans demand higher tensions. For these applications, the equivalent steel reinforced aluminium (ACSR) conductor is used. However, all aluminium alloy conductor (AAAC) has now been adopted as standard for new lines rated at 11kV and above, while new low voltage overhead lines use 95mm^2 covered aerial bundled conductor (ABC).

Zone substation transformers have been standardised as 11.5/23MVA units, except for small sites where this capacity is not warranted, and 5/10MVA and 3/5MVA transformers are used. Transmission transformers with a 110kV primary winding are standardised at 40/60MVA. In our view, given the small number of power transformers in the fleet, this relatively small number of standard power transformer ratings is justified as it ensures that assets are interchangeable between sites.

Network development is planned around our standard asset sizes. In selecting the appropriate size, the forecast peak load under contingency conditions at the end of what we consider a reasonable planning period is the basis for design. In situations where the appropriate asset size is unclear, or where there is a high level of uncertainty in the demand forecasts, we prefer to install a higher capacity asset on the basis that the incremental cost of the additional capacity is much smaller than the cost of installing a new asset, should the smaller asset become fully loaded.

5.2 Energy Efficiency

Given the current electricity industry structure, we are not responsible for the cost of losses on our network. Nevertheless, as a responsible EDB, we recognise that the energy efficient operation of our

10 The Kaikohe-Hariru section of the 110kV Kaikohe-Wiroa line uses concrete poles. This section was constructed before the decision was made to use steel poles for 110kV construction.

network is in the long-term interest of all stakeholders. Our network losses increased after the acquisition of the Transpower assets since the losses from these 110kV assets had to be included in the measure for the first time. These losses were previously attributed to Transpower. The following initiatives are in place to promote energy efficiency:

- While loss minimization is not the primary objective of our network development, we expect some reduction in network losses over the medium term will be a positive outcome from our ongoing investment in the network.
- Our distribution network was constructed with long feeders, with augmentation generally being triggered by a need to reduce voltage drop. We have reduced the feeder length and the load on some feeders with the construction of new zone substations at Kerikeri and Kaeo. Nevertheless, long distribution feeders with high losses remain on many parts of the network.
- With the recent commissioning of OEC4, the Ngawha geothermal power station provides more than 95% of the energy requirements of our consumers. The power station displaces generation located south of Auckland and eliminates most of the losses that would be incurred in transmitting this power from the alternative point of generation to the grid exit point at Kaikohe.
- We actively control consumers' hot water heating and other load at times of peak demand to ensure more efficient use of the available network capacity. Load control is estimated to reduce our network maximum demand by more than 10MW. This action reduces the losses on our network, given the high proportion of losses that occur at times of peak demand.
- Our standard specification for power and distribution transformers includes industry standard clauses relating to the minimization of transformer losses and the cost of losses is considered during tender evaluation.

5.3 Policy on Acquisition of New Assets

We maintain a system of procurement authorisation for individuals within the overall business plan. A job authority system controls authorisation of expenditure on major projects.

5.4 Project Categorisation

Capital expenditure is broadly categorised as follows:

Category 1: Asset Replacement and Renewal

Our stakeholders expect us to maintain a network that is fit for purpose – both safe and reliable. We apply the industry standard practice of monitoring asset condition using asset health indicators and apply management strategies appropriate to an asset's position in its lifecycle. As an asset approaches the end of its service life, we assess its criticality in respect of the safety risk and the outage impact of an in-service failure. Asset replacement and renewal programmes are prioritised by risk, which is a function of both the probability and consequence of an in-service asset failure.

Category 2: Network Development

Projects that are designed to maintain or increase the capacity of the network or sustain the standards to which the network is developed are categorised as "development". For internal budgeting and prioritisation purposes, we also categorise network capacity upgrades and network extensions to enable the connection of new consumers as "network development". This expenditure is driven by growth and is differentiated from new build funded by consumers.

Category 3: Reliability Safety and Environment

Projects involving the installation of new assets where the main driver is improving the safety and reliability of the network rather than the replacement of assets that are nearing the end of their economic life are categorised as Reliability, Safety and Environment, consistent with the definition used by the Commerce Commission. Typical projects falling into this category are the installation of reclosers and other protection equipment to improve the performance of 11kV feeders and the installation of new normally open interconnections between adjacent feeders.

Category 4: New Technology

We have adjusted our strategy towards the implementation of new technology to one of being a fast follower rather than a leader. Therefore, while we will continue to monitor the development of these technologies and their potential application to our network, we are no longer forecasting expenditure on experimental projects designed to test different approaches to new technology implementation. Expenditure in this category is now limited to data collection projects that will enable us to fully capture the efficiencies available from utilisation of our new ADMS system. Information technology projects such as ADMS and GIS installation are classified as non-system expenditures.

Due to the investment undertaken over the last decade under our TE2020 programme, our subtransmission network has sufficient capacity to supply our forecast demand increases over the first half of the planning period and our immediate priority is to arrest the deterioration in the reliability of the 11kV network. Therefore, almost all forecast capital expenditure in the early part of the planning period that is not customer driven is categorised as either Asset Renewal, or Reliability Safety and Environment. During the second half of the planning period, we expect demand growth due to population growth, increased subdivision activity, and the impact of decarbonisation, to cause localised capacity constraints on the 11kV network. In most situations, these will be best addressed by extending the reach of the subtransmission network, rather than reconductoring existing 11kV assets. This will involve the construction of new subtransmission assets. Recognising the lead times involved in the construction of new subtransmission lines and substations, we anticipate a need for this work to start about the middle of the planning period and this is reflected in our capital expenditure forecast.

Within this broad framework, our capital expenditure is further categorised into major projects and capital upgrades. Major projects are one-off, individually designed, major augmentations or upgrades to the network. These projects are allocated individual budgets and generally have long lead times. Capital upgrades are smaller, have shorter lead times and are managed within budget envelopes.

As capital expenditure budgets are limited, project prioritisation is one of the key functions of asset management planning. Prioritisation determines the ranking of one project or capital upgrade compared to another in the most practical and feasible way possible. It also determines whether a project or programme is included in the AMP and the timing of its implementation.

5.4.1 Major Projects

Major projects are prioritised by the Network Planning Manager and his staff, with the objective of meeting the strategic objectives approved by the Board (and set out in this AMP) with the least lifecycle cost. Some involve augmentations to our transmission and subtransmission networks with the objective of providing a resilient network backbone that provides the security of supply our consumers require and has sufficient capacity to meet the demand for network services in an uncertain environment. Others involve distribution network upgrades or refurbishments, that are specific to identified lines or substations and large enough to be scoped and managed as major projects.

5.4.2 Renewal and Upgrade Capital Programmes

These capital expenditure programmes generally have shorter lead-times and are managed within budget envelopes. They include:

- Asset replacement or refurbishment programmes, which are targeted at assets that have deteriorated to the stage where their reliability cannot be assured and where their failure could have significant consequences for our consumers. Priorities are based on asset health, life cycle, criticality, defect, risk and safety management processes, performance, and gap analysis.
- Reliability improvement initiatives, such as the installation of remote-controlled switches or the installation of fault detectors. These are prioritised by assessing the improvement to SAIDI that they will deliver for the expenditure required.

5.5 Demand Forecasting Methodology

5.5.1 Overview

Load forecasting is performed to provide an estimate of future demand, which is essential for prudent planning. Electricity demand is largely dependent on:

- Economic conditions.
- Weather patterns.
- Technology release and adaptation into society (e.g., photovoltaic cells, heat pumps EVs etc.).

5.5.2 Forecast Methodology

We use our SCADA system data, which provides the average current in each feeder for each half-hourly period, as the base data for the forecast. This enables us to determine the maximum half-hourly demand at each zone substation. Peaks, due to the network not being in its normal operating state, are identified and removed. The forecast incremental growth rates at each substation are based on historic trends for the substation, which in some cases are modified to take account of econometric or other factors that are expected to impact the demand for electricity in a localised area. We then overlay on this base forecast major new block loads that have been consented and are likely to proceed within a firm timeframe.

5.6 Demand Forecasts

5.6.1 Forecast Peak Demand over Planning Period

Using the methodology described above, the winter peak demand forecasts for each substation, and for the network, are shown in Tables 5.3 and 5.4 below. The peak demands shown in the table are net of the peak demand reductions that we can achieve though the operation of our load control system. At present, apart from household photovoltaic systems, there is no embedded generation within our network that supplies an internal consumer load and therefore has the potential to reduce peak network demand. Apart from Pukenui, all our zone substations have winter peaks, so small-scale photovoltaics are unlikely to have a material impact on our peak demand until the penetration of battery storage systems in domestic consumer installations becomes significant.

	FYE 2024	FYE 2025	FYE 2026	FYE 2027	FYE 2028	FYE 2029	FYE 2030	FYE 2031	FYE 2032	FYE 2033
Southern Area										
Kaikohe	9.8	9.9	10.0	10.1	10.2	10.3	10.4	10.5	10.6	10.7
Kawakawa	5.4	5.5	5.5	5.6	5.6	5.7	5.7	5.8	5.8	5.9
Moerewa	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Waipapa	10.5	11.0	11.6	12.2	12.8	13.4	14.1	14.8	15.5	16.3
Omanaia	2.7	2.8	2.8	2.8	2.8	2.9	2.9	2.9	3.0	3.0
Haruru	7.2	7.3	7.5	7.6	7.8	7.9	8.1	8.3	8.4	8.6
Mt Pokaka	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Kerikeri	8.3	8.7	9.0	9.4	9.7	10.1	10.5	10.9	11.4	11.8
Kaeo	3.7	3.8	3.8	3.9	3.9	3.9	4.0	4.0	4.0	4.1
Northern Area										
Okahu Rd	9.5	9.5	7.1	7.1	7.2	7.3	7.4	7.4	7.5	7.6
Kaitaia			2.5	2.5	2.5	2.6	2.6	2.6	2.6	2.6
Taipa	6.4	6.4	6.5	6.6	6.6	6.7	6.8	6.8	6.9	7.0
NPL	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0

	FYE 2024	FYE 2025	FYE 2026	FYE 2027	FYE 2028	FYE 2029	FYE 2030	FYE 2031	FYE 2032	FYE 2033
Pukenui	9.5	7.0	7.1	7.1	7.2	7.3	7.4	7.4	7.5	7.6

Table 5.3: Zone Substation Demand Forecast (MVA)

The demand forecasts for the transmission substations and for the total network are shown in Table 5.4 below.

	FYE 2024	FYE 2025	FYE 2026	FYE 2027	FYE 2028	FYE 2029	FYE 2030	FYE 2031	FYE 2032	FYE 2033
Kaikohe	53	54	56	57	58	60	30	30	31	32
Wiroa							31	32	33	34
Kaitaia	26	26	26	27	27	27	27	28	28	28
NETWORK	77	78	80	81	83	84	86	88	89	91

Note 1: Estimated from SCADA data. May not correspond to disclosed demand in FYE2021 information disclosure, which is derived from metered data.

Table 5.4: 110kV Transmission Substation and Network Demand Forecast – Winter (MVA)

5.6.2 Uncertainties in the Demand Forecast

The demand forecasts in Tables 5.3 and 5.4 form the basis of our network development expenditure forecast.

The forecast assumes:

- Continuing high rates of growth in demand in the Kerikeri and Waipapa areas.
- Moderate rates of demand growth in the rest of the eastern seaboard, including the Russell peninsula, Paihia, Whangaroa, Taipa and Kaitaia.
- Moderate growth in incremental demand in the Kaikohe area due to the energy park and some new water pumping load. To date most of the development in the energy park has been horticultural and we have assumed this load can be supplied at 11kV. There is a 33kV line close to the energy park, which will be used to supply a new 33kV substation should this be required.
- A load transfer of 1.5MVA from Kawakawa to Haruru in FYE2024 due to the completion of the 11kV upgrade to enable the load on the Russell peninsula to be shared between the Russell Express and Joyces Rd feeders.
- A load transfer of 2.5MVA from the Okahu Rd to Kaitaia substation in FYE2026 due to the provision of a new injection point into the 11kV northern network using the tertiary winding of the 40/60MVA 110/33kV transformer. This tertiary winding is rated at 10MVA.
- Commissioning of the Wiroa substation by winter FYE2030. Our capital expenditure forecast assumes the first of the two transformers at this substation will be commissioned by the end of FYE2029.
- Little growth in industrial demand except around the Waipapa area. The peak demand of our largest consumer, JNL, is now only 7MVA compared to about 10MVA some years ago. While its peak demand had remained steady, JNL's energy consumption has reduced by almost 20% or 10GWh between 2018 and 2022. While there may be some recovery now that the Covid pandemic is receding, there was still a drop of 5GWh between 2018 and 2019.

The load forecasts in Tables 5.3 and 5.4 relate to consumer loads only and ignore the 67MVA of new utility scale solar generation. As discussed elsewhere in this AMP, this will fully load the 110kV Kaikohe-Kaitaia line and will also increase the load on the Kaitaia 110/33kV transformers.

There is strong subdivision demand particularly around Kerikeri. Subdivisions are treated as incremental demand growth rather than new block loads as the load on new subdivisions develops gradually as houses are built and occupied. We have similarly treated new EV fast charging stations as incremental demand rather than new block loads. While some new charging stations are rated at up to 300kW, the probability that they will be fully utilised during periods of peak network demand is low. The charging rate of most EVs is controlled to limit battery temperature and reduces as the battery state of charge increases. We therefore think the increase in demand from new EV charging stations will be incremental.

No new block loads have been included in the forecast. We know of possible new block loads in our supply area that have been consented or are close to being consented. These are shown in Table 5.5. However, we have not received any formal applications to provide supply and it is still uncertain if these will go ahead. If they do proceed, the timing and magnitude of the additional demand still needs to be confirmed. Our existing transmission and subtransmission networks have the capacity to accommodate new block loads. Any new lines or augmentations to 11kV feeder capacity needed to connect these developments to our existing subtransmission infrastructure, would be funded by a developer capital contribution.

Load		MW	Comment
Kaikohe irrigation		2-3	This would require an upgrade to the 11kV Ohaeawai feeder.
Kaitaia irrigation		2-3	This would require a new 11kV feeder from the NPL substation due to the location of the pumping stations.
Ngawha energy park		5	The tenants that have already signed up have only a small energy requirement and can be supplied from the Ohaeawai feeder. As the load grows a dedicated 11kV feeder or a 33kV substation could be required. The 33kV substation would be connected into one of the existing lines between the Ngawha Power Station 33kV switchyard and Kaikohe.

Table 5.5: Potential Block Loads

The Northland iwi have yet to negotiate a treaty settlement with the Government that, when finalised, could inject well over $200 million into the Northland economy. As the negotiations have still to commence and no firm plans for development are available, our forecast makes no provision for the economic stimulus that an eventual treaty settlement could provide to our supply area.

We have also not made any provision for the impact of emerging technologies on electricity demand since the impact of these technologies, which are discussed in Section 5.7 is still highly uncertain.

5.7 New Technologies and Non-Network Solutions

5.7.1 Introduction

EDBs have traditionally relied on poles and wires to distribute electrical energy and assumed power flow would be in one direction – from generator to the customer. However, with generation becoming more widely distributed across and within the network, these assumptions do not necessarily hold true any longer. Consequently, we are closely monitoring and assessing the application of non-network alternatives to supply customers with power. Equally, the impacts of these technologies on the network are also being monitored.

5.7.2 Long Range Wireless Transmission Technology

This technology, although in its infancy, is currently being developed in New Zealand by Emrod. It uses electromagnetic waves (microwave beams) to transmit energy through the air between antennae and was described in an article in the 15 October 2022 edition of the *New Zealand Listener*. Emrod collaborated with Powerco to try to demonstrate the technology in an outdoor environment, but the attempt was not successful due to weather-related equipment damage. In the *Listener* article Powerco stated that a successful demonstration of the technology was likely still some time away and it was not yet considering how the technology would integrate into its network.

Top Energy will keep abreast of the development in a bid to better understand the technology, but we think its implementation is well outside the AMP planning period.

5.7.3 Remote Area Power Supplies:

More traditional remote area power supplies (RAPS) consist of a solar array, battery bank and a diesel or gas generator. They are viewed as a potential solution for customers who are supplied via a long line that is in a deteriorated condition and uneconomic to replace. The intent would be to install a RAPS and remove the uneconomic line.

We have studied the applicability of this technology to our network in several applications. These studies have applied various criteria to determine a project's viability including:

- Customer location (end of a line).
- Line length potentially to be removed.
- Condition of the line to be removed.
- Line route environmental factors.
- Number of connected consumers.
- Reliability and/or where a single supply circuit is prone to interruption.
- Location specific risks (e.g., vegetation and/or forestry).
- Access.

Finally, we have tested the viability of a potential project using a financial model that compares the lifecycle cost of the project with the cost of replacing and maintaining the existing line, including taking into account any asset replacement and refurbishment already undertaken on the line as a reactive measure in the recent past.

We have found that this last factor, where a line typically has already had a degree of replacement and refurbishment undertaken as a reactive measure, continues to tip the balance away from adopting RAPS as an economic alternative to lines. To date, no potential site has been identified that stands up to this level of scrutiny. This is before customer consultation has commenced. Apart from a small number of enthusiastic adopters of new technologies, consumer acceptance of non-line alternatives is unlikely to be positively received unless suitable inducements are offered. This will reduce the viability of RAPS even further. We estimate the standard residential install cost of a RAPS to be close to $100,000, and the ongoing maintenance costs of a RAPS are not insignificant. The economic lives of RAPS assets are also much shorter than that of an upgraded distribution line, further reducing the economic potential of RAPS when assessed on a lifecycle cost analysis.

Nevertheless, we will continue to evaluate on a case-by-case basis situations where a RAPS could be a viable and economic alternative.

5.7.4 Batteries

Battery storage, particularly when coupled with photovoltaics, is not entirely new, as small DC systems have been commonly used for many years. However, use of battery storage in the world of AC power is relatively new, being driven largely by reductions in battery costs and solar panels, and improvements in battery efficiency and inverter technology. Battery storage transforms the way in which solar (or wind) power generation can be used, enabling generated power to be made available when it is needed, rather than when it is generated (depending on the capacity of the batteries installed). Batteries behind the meter, to store energy generated during the day for use in the evening when demand is higher, have become more prevalent in domestic photovoltaic installations.

Batteries open up all sorts of opportunities for EDBs because of their potential to:

- Reduce system peak demand.
- Morph generation profiles to suit load requirements.
- Smooth peaks and troughs in generation due to cloud cover (solar) or gusts (wind).
- Reduce the network impact of EV charging.
- Provide ride through inertia during system faults.
- Provide backup supply during outages.

We currently have few network constraints where batteries could provide a potential solution. However, there is potential for batteries to be used to manage transients where utility scale photovoltaic generation is connected to our network. None of the three utility-scale solar farms to be connected to our northern network incorporate a battery as the proponents have stated that they can meet the required dynamic response without one and this has been confirmed by our own consultant. Should the commissioning tests show this is not the case, the solar farms will not be allowed to connect. In this event a battery could be a potential solution, but it would need to be provided by the solar farm developers.

As noted in Section 2.9, we are working with a provider of battery energy storage systems, who is planning to install a 280kVA/100kWh battery inverter system at our Taipa substation as a trial. While we are providing an LV connection for the battery and will control the system remotely from our control room, it is the battery provider that is designing and driving the project.

While the cost of battery storage is reducing rapidly, cost is still the inhibiting factor to the widespread and large-scale uptake of battery installations. For example, with an installed battery cost currently about $1.2 million per MWh, the installation of a 30MWh battery in the Kaitaia region would cost $36m, but the battery would provide only two hours of peak backup.

5.7.5 Other Energy Storage Options

Other forms of energy storage, such as pumped hydro, compressed gas, flywheel etc, exist and some of these are mature in their development. However, they are all variously expensive to implement or narrow in their application and have little applicability to the management of distribution networks.

5.7.6 Network Support

If privately owned generation or other equipment such as battery storage seeks to connect to the network and has a network benefit, we will negotiate on a case-by-case basis to find a commercial solution that recognises the network benefit of the connection. We are open to negotiating with investors where such generation would improve supply reliability or defer the need for network augmentation to meet localised incremental load growth. This could be an opportunity for a business considering the installation of generation as a backup in the event of an interruption to the network supply. Areas where such generation or utility scale battery storage could potentially provide distribution network support include:

- The north-east coast, including the Karikari and Purerua peninsulas, where holiday and tourism ventures are driving development.
- North of Kaitaia, where irrigation-driven load growth is occurring.
- The Russell peninsula, where the summer peak demand is approaching the limits of 11kV distribution.
- Both North and South Hokianga.

5.7.7 Other Fuels

Two further technical developments which may have an impact on electricity networks are the manufacture and use of methanol and hydrogen for the transport industry, as the manufacture of both fuels is electricity intensive. Methanol is likely to only be an interim fuel while electric and hydrogen powered vehicle technology matures.

Hydrogen powered vehicles are like battery EVs in that the motive power is provided by an electric motor. However, whereas in a battery EV the energy is stored in a battery, in a hydrogen powered vehicle it is stored in a pressurised hydrogen tank. The hydrogen is then converted to electricity by a fuel cell within the vehicle. Hydrogen vehicles can be refuelled in minutes and can travel longer distances than battery EVs, which makes hydrogen an attractive option for powering the heavy transport fleet. Its main disadvantage is the need to use electricity to produce the hydrogen that is then converted back to electricity, which reduces the end-to-end efficiency of the process. Hydrogen is also only attractive as a fuel if it is manufactured using electricity generated by renewable resources.

A network of hydrogen refuelling stations is currently being built in New Zealand by a private developer. Four are currently under construction and 24 are planned by 2026, one of which is likely to be in Whangarei. The developer plans to expand this network to 100 by 2030, which could include one or more refuelling stations in our supply area.

5.7.8 EDB Asset Management Technologies

In essence, electricity and its distribution has changed little since its inception. Poles, wires, and cables still carry electricity from generator to consumer, as they always have. However, the technologies used by EDBs to manage this function have changed and continue to change rapidly. Drones now make possible faster and more accurate capture of asset information using aerial photography and can also be used to locate faults. Sophisticated protection systems isolate faults quickly and safely and pinpoint their location. Smart grids enable automatic recovery from faults and restore power to customers in shorter periods of time. Digital maps and digital data entry have replaced their paper equivalents, and control and monitoring via the internet is becoming the norm.

We have already adopted many of these technologies and are assessing others for their suitability and relevance to our day-to day network management. Our ADMS is being bedded into our real-time network control, fibre-optic communication is in use universally for both voice and data communication, sophisticated protection systems utilising fibreoptics are now standard, electronic field devices are now used to remotely access and enter asset data and our paper records are steadily being replaced by digital equivalents.

5.8 Embedded Generation Policies

Our approach to the connection of embedded generation by external parties is based on the following principles.

- Distributed generation can connect to our network on fair and equitable terms that do not discriminate between different distributed generation schemes. We will ensure that these are as clear and straightforward as possible, subject to our obligation to maintain a secure and safe distribution network.
- We will process all distributed generation applications as quickly as possible and in full consultation with the proponent.
- Distributed generation must comply with industry-standard technical and safety requirements, and all relevant legislation and regulation.
- We may need to limit the capacity of distributed generation that can connect to the network. In such a situation, access to spare capacity will be given on a first come-first served basis and the cost of any capacity upgrade needed to overcome a capacity limitation shall be funded by the proponent.

Our policy and requirements for the connection of embedded and distributed generation are available on our website. Nevertheless, proponents seeking to connect generators larger than 10kW to our network should contact us to discuss their specific requirements.

As noted in Section 5.11.2.1 below, connection agreements have now been signed for 89MW of geothermal generation and 67MW of utility-scale solar generation. This exceeds our peak network demand and, on a summer day when the solar generation is generating at full capacity and our internal network demand is relatively low, is expected to fully utilise the capacity of the Kaikohe-Maungatapere connection to the Transpower grid. Any new generation connected to our network is therefore likely to be frequently constrained off over the summer. That said, spare capacity would be available when the output of the solar generation is low, and we are open to the connection of generators that can work around this constraint. This particularly applies to generation that can provide network support, as discussed in Section 5.7.6.

5.9 Demand Management

Demand side management (DSM) is the management of a consumer's demand to avoid overloading the network. It typically involves shifting a consumer's peak away from the time of the network peak to reduce the magnitude of peak network demand. This can defer the need for capital investment to increase network capacity, and potentially also reduce the transmission charges we pass through to our consumers. DSM can also reduce the need to install diesel generation for network support. Our consideration of the need for a network augmentation incorporates an assessment of any identified DSM opportunities that could defer or reduce the cost of an augmentation.

We use the following DSM options to manage demand in different operating conditions.

- **Direct Load Management:** We routinely control water heating load through our ripple-frequency controlled load management system. Daily peak load shedding is based on the GXP peak load. Under emergency conditions, where network components are out of service, we also use the system to reduce load and maintain supply for as many consumers as possible. Load control relays also delay the restoration of hot water load for a short period after a total loss of supply to reduce switching spikes and avoid equipment overload. We estimate that direct load management reduces the actual peak demand on the network by more than 10MW.
- **Under-Frequency Load Shedding:** In order to prevent a total power system collapse following a major grid disturbance, Transpower requires automatic tripping of a percentage of each EDB's network load when an under-frequency event occurs.

  This event, for example, could be the failure of a major generation in-feed or the loss of the HVDC link between the North and South Islands. To comply, our network has been configured so that the load to be shed is split into two blocks. These blocks trip after a pre-set delay, dependant on the levels of frequency excursion on the system. Table 5.6 shows the operating arrangements of these two load blocks.

Frequency Excursion	Tripping Time - Seconds	
	Block 1	Block 2
47.8Hz	4	15
47.5Hz	4	4

Table 5.6: Emergency Load Shedding Specification

Block 1 amounts to approximately 35% of our network maximum demand and Block 2 is approximately a further 20% of our demand.

The development of a market-based system by Transpower to provide load reduction in the event of an emergency loss of generation has provided an opportunity for the use of our ripple control system. As yet, we do not participate in this demand side management opportunity, due to the limited load available to be shed within the required response time. We offer different DSM options to our major industrial consumers but are currently unable to provide a price incentive that is sufficient for them to modify their demand.

5.10 Smart Metering

Smart metering measures consumption over half-hourly periods, permitting the introduction of tariff structures that discourage the consumption of electricity during periods of peak demand. Meter readings are downloaded over a communication link, avoiding the cost of monthly meter reading visits. We have installed a radio frequency (RF) mesh communication network within our supply area to enable smart meter data to be downloaded automatically and Contact Energy (our incumbent retailer) is replacing its mechanical meters with smart meters. Approximately 70% of our consumers have smart meters installed.

Smart meters can be programmed to automatically advise our control room when supply is lost. Our capex forecast provides for a data gathering exercise to enable us to extend our ADMS functionality to include active real time management of the LV network. Access to smart meter data would further enhance this capability. The disaggregated demand data available using such meters would also enable more effective management and planning of our network.

However, we do not own the meters and would need to agree terms and condition under which retailers would allow us to access their meter data if we were to use it. Many retailers have been reluctant to make this data available and the right of EDBs to access it is an issue the industry is currently addressing. Nevertheless, we are exploring how we would use this smart meter data should it become available, and this is discussed in Section 8.3.

5.11 Network Constraints

5.11.1 Types of Constraints

The three factors that can limit the capacity of our network to provide an acceptable level of service to network users are:

- Voltage.
- Thermal capacity.
- Security.

5.11.1.1 Voltage

Voltage constraints are caused by the dynamic response of the system to power being taken from, or injected into, the network. Low voltage can occur at the ends of lines when they are heavily loaded, and high voltage can occur at times of low load and/or at points of high generation injection. Consumer demand for electricity on our network varies both by season and by time of the day. The network must be capable of maintaining the voltage at consumer points of supply within regulatory limits irrespective of the level of demand. Since voltage drop increases with line length and our rural network is characterised by long lines, low voltage at times of peak demand is usually the first indicator of a network capacity constraint.

To reduce these constraints on 33kV and 11kV systems, voltages are regulated at key points of the network using transformer tap changers at zone substations or voltage regulating transformers strategically located across the network.

Voltage constraints can appear on the LV network due to the limited ability to dynamically adjust the voltage at this level. In Australia, management of voltages on LV networks with a high number of consumers with rooftop photovoltaic generation has become a significant issue. In New Zealand this is less of a problem due to the lower penetration of distributed generation connected to the LV network. However, we have the highest penetration of small-scale photovoltaic generation of any EDB in the country and have already received some complaints of power injection into the LV network affecting the quality of supply experienced by adjacent consumers. To date, the problems that have arisen have been minor and easily resolved, but we expect the issue to become more serious over time. On 1 April 2021 we introduced an energy injection charge of 0.5c per kWh exported into the LV network, to ensure recovery of the incremental network costs of investigating and mitigating the impact of uncontrolled intermittent generator connections.

5.11.1.2 Equipment Rating

An equipment rating constraint will occur when the current in a line, cable or item of equipment exceeds its rating. Current ratings can vary according to use or application, environment (hot or cold etc), time (short or long duration), equipment life expectancy, thermal response (heating of conductors causes them to sag) etc.

An equipment rating constraint may manifest itself in several forms and have one or more different causes. Of particular interest are:

- Thermal constraints where exceeding a current rating will cause the equipment to overheat, which will degrade the material and shorten equipment life. An example would be transformer rating constraints, or an underground cable’s thermal capacity.

- Regulatory constraints where the power flow in a line causes the line to perform in a substandard manner. An example would be a line where the conductor sags at high loads so ground clearance is compromised.
- Power transfer constraints, where the ability to transfer power from one feeder to another is compromised because the rating of the interconnection between the two feeders is insufficient.

5.11.1.3 Security

A security constraint relates to the alternative source of supply should a fault on the primary supply occur. It may be a full constraint where no alternative exists, or a partial constraint which limits supply due to capacity or voltage regulation limitations on the alternate supply. Security constraints are of most concern on the transmission and subtransmission networks because faults on these networks can affect large numbers of consumers.

5.11.2 Known Constraints

5.11.2.1 Maungatapere-Kaikohe 110kV line

The double circuit 110kV line between Kaikohe and Maungatapere is owned by Transpower and is the only connection between our network and the national transmission grid. The line is used to export electricity generated within our supply area at times when this generation exceeds the consumer demand on our network. Once the generation for which we have signed connection agreements is commissioned, the total utility scale generation connected to our network will be 156MW (89MW geothermal and 67MW solar), well above the amount of generation required to supply the local demand in our supply area. When both Kaikohe-Maungatapere circuits are in service there will be sufficient line capacity for all this excess generation to be exported south, although over the summer there will be times when the capacity of both circuits will be fully utilised. If one circuit is out of service, generation will need to be constrained off at certain times over the summer. This is shown in Table 5.7 below, where it is assumed that the anytime minimum demand occurs in the middle of the night when the solar farms are not generating.

Period	Line Capacity (MVA)	TE Minimum Demand	Maximum Unconstrained Generation	Total Generation Capacity OEC1-5 and Solar	Maximum Generation Constrained Off
Summer Night	63/65[1]	21	84	89	5
Winter Night	77/80[1]	24	101	89	-
Summer Day	63/65[1]	29	92	156	64

Note 1: The two ratings are because the two lines have slightly different configurations.
Note 2: The summer anytime minimum demand occurs at night when the solar farm will not be generating.
Note 3: The winter anytime demand occurs in the late evening after dark, so solar farm will not be generating.

Table 5.7: Transmission Constraints Kaikohe-Maungatapere (MVA, with one circuit out of service).

Implications

- Assuming all planned new generation projects proceed, when one circuit is out of service generation may need to be constrained off during the day, when the solar farms are generating. The size of this constraint will peak over the summer, when up to 64MW of local generation may need to be constrained off.
- There could also be a relatively small constraint on the dispatch of Ngawha generation overnight during the summer.
- OEC5 at Ngawha will fully utilise the capacity of the Kaikohe-Maungatapere line that is currently unused over the summer when the solar farms are generating at full capacity (as the 64MVA of constrained-off generation is equal to the full capacity of the second circuit). This means that we are unable to accept any more applications for the connection of new generation anywhere on the network, unless the proponent is willing to accept the constraints discussed in Section 5.8 above.

Likelihood

- The likelihood of a single circuit constraint is low, as the loss of a single circuit is a rare event. Transpower aims for one unplanned interruption every five years.
- This is comparable to the risk of a complete loss of the grid connection, most likely caused by a grid event south of Maungatapere. Ngawha cannot operate without a grid connection and connected photovoltaic generation would also need to be shut down.

Mitigation

- The ability to constrain generators off is being written into new embedded generation contracts.
- We will coordinate the timing of line maintenance outages with Transpower. These need to occur over the winter when the output of the solar generation is low.
- Given the very low likelihood of the loss of one circuit and the high cost of a second line (more than $100 million), there are no plans to construct a second Kaikohe-Maungatapere line. However, Transpower is investigating the implementation of a thermal upgrade of the existing circuits. This is likely to involve increasing the conductor tension over those parts of the line with the lowest ground clearance to enable the conductor to be run at a higher temperature, without the increased sag breaching ground clearance requirements. A thermal upgrade could increase the summer capacity of both circuits to 170MVA.

5.11.2.2 Kaitaia-Kaikohe 110kV Line

The single circuit 110kV line between Kaikohe and Kaitaia is the only substantive connection between the northern and southern areas of our network. The line will be used to export electricity generated by solar farms connected to our northern area south, to the extent that the amount of electricity generated exceeds the electricity demand in our northern area. A constraint will arise if:

- The line is out of service, in which case the amount of solar generation would theoretically be limited to the northern area demand. However, in this situation the solar farms would need to be constrained off, as solar generation is non-dispatchable and the speed of response of our diesel generation will be too slow to respond to variations in solar farm output.
- The line is in service, but the amount of solar generation exceeds the sum of the line capacity and local load. This is shown in Table 5.8.

Period	Line Capacity (MVA)	Northern Area Demand Minimum (MVA)	Maximum Unconstrained Generation (MVA)
Winter Day	68	10.6	79
Summer Day	55	10.4	66

Table 5.8: Transmission Constraints KOE – KTA

Likelihood

- While it is theoretically possible for the line capacity to be exceeded if all three solar farms were generating at full capacity and the local load at Kaitaia was minimum, the likelihood of all this happening simultaneously is low. In any case the extent to which the line capacity was exceeded would be small so the amount of generation that would need to be constrained off is small.

Implications

- The major impact of this constraint is our inability to permit the connection of more generation in our northern area while the constraint persists. There is ongoing demand for the connection of additional solar generation, but we are unable to accommodate this. There is also a consented 30MVA wind farm at Ahipara, but we understand the proponent no longer wants to proceed.

Mitigation

- Constraining generation off.
- Limiting the connected capacity or triggering a network upgrade at generators' cost
- Second 110kV Kaikohe to Kaitaia circuit. This would fully mitigate this constraint but the amount of additional generation that could be connected to our northern area would still be constrained by the limited capacity of the Kaikohe-Maungatapere grid connection. A thermal upgrade of this connection would mitigate this constraint. As discussed in Section 5.12.3.1 below, we have removed the Wiroa-Kaitaia line from our capital expenditure forecast pending clarification of the availability of external funding sources.

5.11.2.3 Pukenui 33kV

The Far North Solar farm has a capacity of 20MVA and is located close to the Pukenui substation. It will be connected to the substation via a new 33kV line, and the generation will be exported south via the incoming 33kV Kaitaia-Pukenui single circuit line, which has a capacity of only 20MVA. The local Pukenui demand is only 2MVA, so there is no capacity for the connection of additional solar generation to the Pukenui substation. This would be the case even if the Kaikohe-Kaitaia and Kaikohe-Maungatapere line constraints were removed.

Likelihood

- High, given the strong demand for the connection of solar generation in our northern area.

Mitigation

- Connection of additional local load.
- Triggering network upgrade at generator's cost.
- Encouraging the proponent to find an alternative site that avoids this constraint.

5.11.2.4 Kaitaia 110/33kV Transformers

There are two 110/33kV transformers at the Kaitaia substation, a relatively new 40/60MVA transformer (T1) and an older 22MVA single phase transformer bank (T5) that is nearing the end of its economic life. In the event of a failure of the T1 transformer, the T5 bank has sufficient capacity to supply consumer demand, with support from our diesel generation at times of peak demand. However, its rating is insufficient to accommodate the 67MW of solar generation soon to be connected in the Kaitaia area.

Likelihood

- Low, as power transformer failures are rare events. The T1 transformer has been in service for only eight years of its expected 50-year life and is in good condition.

Implications

- Should there be a failure of the T1 transformer, most of the new solar farm generation would need to be constrained off until a replacement transformer of sufficient capacity could be installed. If a suitable transformer could not be found as a temporary replacement, this could be up to a year.

Mitigation

- Replace the existing T5 transformer at Kaitaia with a new 40/60MVA transformer, identical to T1. This is currently planned for FYE2029.

5.11.2.5 Kaikohe Transformers

There are two 110/33kV transformers at Kaikohe, one rated at 39MVA and the other at 30MVA. Ngawha generators OEC1-3 inject power directly into the 33kV network, but if all these generators and one of these transformers are out of service at the same time, there is a capacity shortfall as all the southern area demand would need to be supplied through the remaining in-service transformer. This is more severe when the larger unit is out of service as shown in Table 5.9 below.

Period	Transformer T1 Capacity (MVA)	Transformer T2 Capacity (MVA)	Max Southern Demand (MVA)	% half hours demand exceeds T2 capacity
Winter	39	30	47	40%
Summer	39	30	36	15%

Table 5.9: 110kV Transformer Capacity Constraint - Kaikohe

Likelihood

The likelihood of this constraint materialising is very low, provided prudent asset management practices are applied to both the network and generators. It is an N-2 contingency in that it requires a simultaneous outage of more than one critical plant item at a time of peak demand. The network is not normally designed to cater for N-2 contingencies.

Mitigation

- Ensuring both transformers are well maintained to reduce the risk of failure.
- Ensuring that the transformers are only taken out of service for maintenance when Ngawha is running and at times of low network demand.
- Ensuring that Ngawha is taken out of service at low load times, and for as short a time as possible.
- Construction of the Wiroa 110/33kV substation. The first of the planned two transformers at this substation is planned for commissioning in FYE2029 and this will fully mitigate the constraint.
- In the unlikely event that this situation arose load control would be needed, either by using our hot water control system or by rationing power to non-essential loads.

5.11.2.6 Voltage Constraint at Waipapa and Kaeo Substations

The Wiroa 33kV switching station is supplied by two incoming 33kV lines – the double circuit 110kV line from Kaikohe, which is currently configured as a single circuit and operated at 33kV, and the older 33kV Kaikohe-Mt Pokaka-Wiroa circuit. This second line is longer and has smaller conductors. If the 110kV line is out of service at times of peak network demand, the load on the Kerikeri, Waipapa and Kaeo substations will all be supplied via Mt Pokaka and the 33kV voltage at Kaeo and potentially Waipapa will fall below acceptable levels. Consumers north and west of Kerikeri will experience low voltage unless load is shed.

Likelihood

- Low, since the Kaikohe-Wiroa line is still in very good condition and load would only need to be shed if the event occurred at times of peak demand.

Implications

- This is only a partial constraint. The load at risk will not be the full Kerikeri/Whangaroa area demand but the difference between this demand and the load that can be supplied by the Mt Pokaka circuit. Initially this would be low but would progressively increase as the load in the area grew. The timing of the Wiroa build is therefore a risk management decision related to the probability of the event occurring (low) and the consequences (initially small but increasing over time). Probabilistic planning of this nature is now accepted industry practice.

Mitigation

- Construction of Wiroa 110kV substation – this will fully mitigate the risk and the first of the two transformers is currently planned for commissioning in FYE2029.

- In the event of an unplanned outage of the 110kV line at times of peak network demand rotational load shedding may be needed. Supply to critical loads will be maintained.
- Ensuring that maintenance work, such as vegetation management, on the 110kV line is undertaken at times of low network demand.

Note

- When the Kaikohe-Wiroa line is taken out of service prior to being connected and energized at 110kV for the commissioning of the Wiroa 110/33kV substation, any fault on the Kaikohe-Mt Pokaka-Wiroa circuit will cause a full supply interruption in the Kerikeri and Whangaroa areas. This will be a risk, irrespective of load or of the timing of the Wiroa build. It may be possible to partially mitigate this risk by splitting the Kaikohe-Wiroa line into two circuits and initially energising only one circuit at 110kV, but the feasibility of this approach has still to be investigated.
- Ensuring that the existing 110kV line operating at 33kV is uprated to 110kV operation over the summer when the demand on the network is lower would reduce the likelihood of a supply interruption occurring to the extent that a fault on the Mt Pokaka line is more likely over winter. It would also reduce the energy not supplied due to the interruption.

5.11.2.7 Taipa Generation Constraint

The Taipa substation has a single transformer, a single incoming 33kV line and two diesel generators with a combined capacity of 3.6MVA. Hence, in the event of a loss of the incoming line or the transformer, there is a supply shortfall of up to 1.9MVA.

Likelihood

- There is a medium to high likelihood of this situation arising.
- An N-2 scenario with a medium probability of occurring is an unplanned 33kV line fault when one of the generators fails to start or is out of service.

Mitigation

- It is possible to transfer approximately 3MVA onto adjacent feeders such as Totara North. This will fully mitigate the loss of the incoming 33kV line if both generators are in service.
- If one generator is out of service when there is an incoming 33kV line fault, then there could be a capacity shortfall of up to 0.7MVA. Some load shedding would be required but supply to essential loads would be maintained.
- Plan 33kV line, transformer, or generator shutdowns for periods of low demand.
- The installation of a neutral earthing transformer to reduce the likelihood of a Taipa transformer fault is planned for FYE2024, and the mobile substation has been relocated to Taipa to back up the substation transformer. We plan to leave it there unless it is required elsewhere on the network.

5.11.2.8 Taipa Transformer Constraint

The peak demand at the Taipa substation measured by our SCADA system is 6.3MVA, close to the rated capacity of the 5/6.5MVA transformer. This measured peak demand has only occurred for short periods in any one day. To date it has not exceeded the transformer's continuous rating and is well within its short-term contingency rating shown in Table 5.2. Nevertheless, there is a potential for the transformer rating to be exceeded in the short to medium term.

Likelihood

- Low. Our mobile substation has now been relocated to Taipa on a semi-permanent basis and will only be moved in the unlikely event it is required elsewhere on the network. The subtransmission network upgrades completed under the TE2020 programme have reduced the probability that the mobile substation will be needed elsewhere.

The condition of the Taipa transformer is of increasing concern, although a transformer failure is still considered unlikely. Should a failure occur, the capacity of the mobile substation is sufficient to supply all the Taipa substation load.

Mitigation

- A replacement transformer at Taipa in provided for in the capital expenditure forecast and is scheduled for commissioning in FYE2029.
- A new substation at Tokerau Bay is also included in the capital expenditure forecast and currently scheduled for completion in FYE2033. This will offload the Taipa substation.

5.11.2.9 Potential Feeder Capacity Constraints

While our 11kV feeders have sufficient capacity to accommodate incremental demand growth and increased small-scale solar penetration, they may not have the capacity to supply localised new block loads. Potential loads for which there is a capacity shortfall are shown in Table 5.10.

Development	Feeder	Demand	Mitigation	Constraint	Development Probability
Kaikohe irrigation	Ohaeawai	2-4 MW	Feeder upgrade	Capacity Voltage	Medium
Kaitaia irrigation	Awanui	2-4MW	New feeder	Capacity	Medium
Tokerau - Resort	Tokerau	5MW	New substation and 33kV line	Capacity Voltage	Low
Hokianga Wind	Herekino	5MW	Feeder upgrade	Capacity	Low
Energy Park	Ohaeawai	5MW	New 11kV feeder or 33/11kV substation	Capacity	Some low-load development confirmed. Low probability of new substation or feeder being required.

Table 5.10: Potential Feeder Capacity Constraints

Likelihood

- While the probability of any individual development is considered no higher than medium, the probability of at least one of the developments proceeding in due course is high.

Mitigation

- The developer will need to fund the cost of any feeder upgrade through a capital contribution.
- Alternatively, the developer will limit the size of any new load to within the spare capacity of the feeder.

5.11.2.10 Substation Transfer Capacity Constraints

As shown in Table 5.1, zone substations have now been upgraded so that supply can now be restored to all consumers within 1 hour in the event of a foreseeable N-1 contingency.[11],[12] However, in the event of an unforeseeable high impact low probability (HILP) event that disables the entire substation, the amount of load that can supplied from alternative substations varies, as shown in Table 5.11. The network is not designed to withstand such an event and, if one did occur, the Emergency Preparedness Plan described in Section 7.3.3 would be activated.

---

11 An N-1 contingency is when one network element (e.g. transformer or incoming subtransmission line) associated with the substation is disconnected due to a fault.

12 The exception is Mt Pokaka, where supply cannot be restored to the mill within one hour if the mobile substation is located elsewhere. The customer has agreed to this level of security.

Table 5.11 shows the proportion of each substation's current peak demand that can be supplied from neighbouring substations.

Substation	Peak Demand (MVA)	Summer Peak (MVA)	Shoulder Peak (MVA)	Transfer Capacity (MVA)	% Peak Demand
Kaikohe	9.3	6.2	8.1	1.0	10%
Kawakawa	6.0	5.5	5.4	2.5	37%
Moerewa	3.4	3.5	3.9	3.3	100%
Waipapa	9.7	5.1	6.9	7.6	78%
Omanaia	2.8	2.0	1.9	2.3[1]	85%
Haruru	7.0	4.5	4.8	1.5	20%
Mt Pokaka	2.5	2.1	2.2	1.5	60%
Kerikeri	7.7	5.0	6.0	6.0	78%
Kaeo	3.7	3.0	3.4	4.0	100%
Okahu Rd	9.5	5.9	6.7	3.7	44%
Taipa	6.3	4.9	4.6	3.0	48%
NPL	11.1	10.9	10.7	4.3	39%
Pukenui	1.9	1.9	1.9	1.8	95%

Note 1. Transfer capacity is onsite generation, supplemented by a small amount of 11kV load transfer from Kaikohe.

Table 5.11: Substation Transfer Capacity

Mitigation

- Generation at Kaitaia Depot will also support the NPL substation.

5.11.2.11 Feeder Transfer Capacity Constraints

While distribution feeders are generally operated in a radial configuration, it should ideally be possible to back feed a feeder from an adjacent feeder in the event of a fault. In our supply area interconnectivity is limited.

- Some feeders, particularly in urban locations, can be fully supported by adjacent feeders (green in Figures 5.1 and 5.2).
- Some feeders, particularly those along main roads in rural areas, can be back fed from an adjacent feeder, but the capacity is limited and insufficient to provide full back feed at times of peak demand (amber in Figures 5.1 and 5.2).
- For geographic reasons much of the network cannot be back fed, (red in Figure 5.1 and 5.2). While faults on spurs located within this "red" network cannot be back fed, in some situations it may be possible to restore supply following a fault located elsewhere on the feeder, depending on the feeder backbone from which the network is supplied.

This is a common situation with rural networks but, arguably, is exacerbated in our network by the legacy factors discussed elsewhere in this AMP, where the limited points of injection to the 11kV network have resulted in many long radial feeders with a high number of connected consumers.

Implications

- Care must be exercised when operating the network as the ability to transfer load between feeders depends on location and time of day.
- Supply resilience varies across the network.
- Lack of back feed capability increases SAIDI.

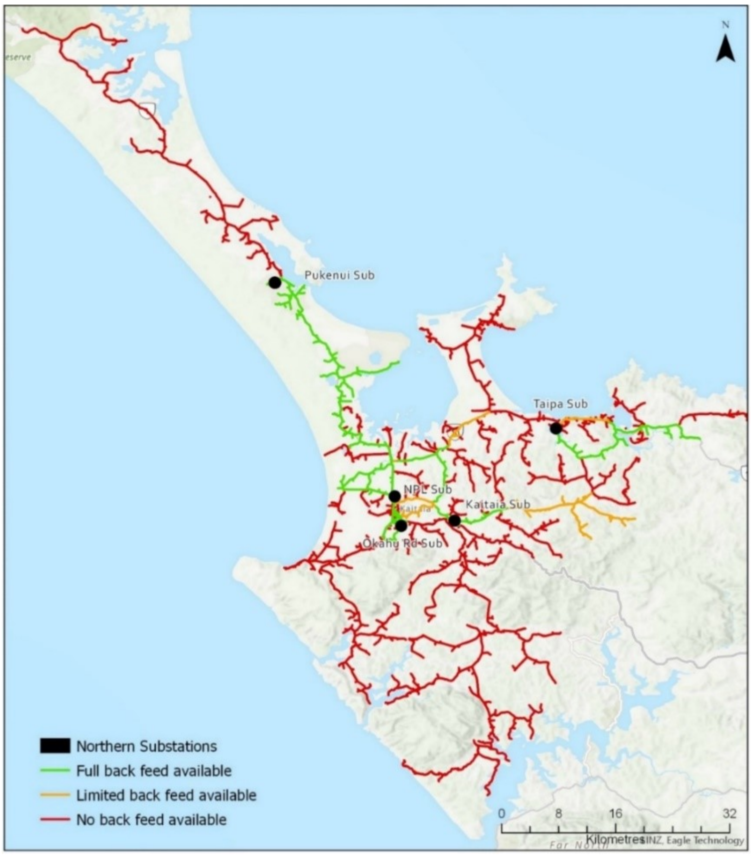


Figure 5.1: **Map of Feeder Interconnectivity in the Northern Region**

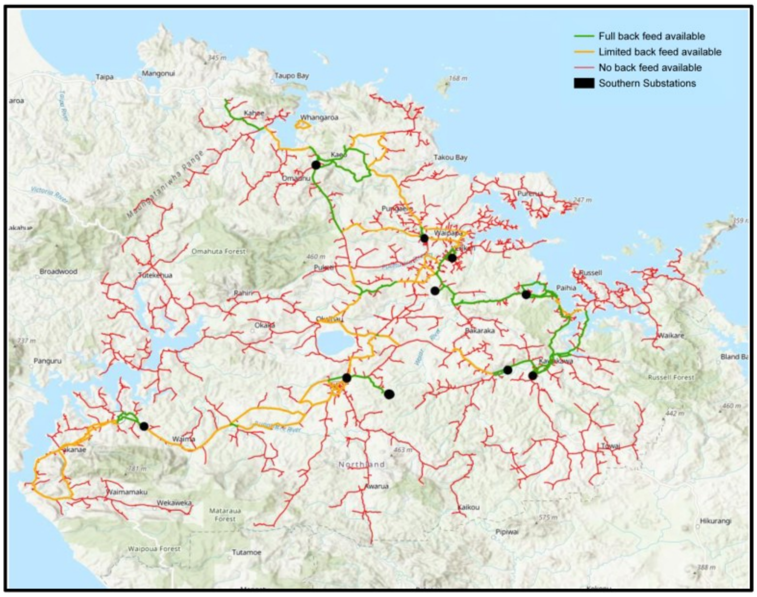


Figure 5.2: **Map of Feeder Interconnectivity in the Southern Region**

Mitigation

- The capital expenditure forecast in this AMP includes several normally open feeder interconnections as part of our 11kV reliability improvement plan.
- The DPF module currently being added to our ADMS will assist our control room operators determine in real time the ability to interconnect feeders based on the actual network loads.

5.11.2.12 Sub-Optimal Conductors Along Feeders

Standards have been established for conductor sizes along a feeder to optimise losses, manage voltage limits and provide appropriate network capacity. Generally, the front end of feeder backbones from the substation to about one third along its length uses the largest standard conductor, the next third and spur lines use a medium sized conductor and the end of lines, as well as SWER lines and short spurs the smallest size. Since the early days of the network the sizes of standard conductors have been increased, as the load increased, and the network extended. Consequently, older undersized conductor has been replaced with the new standard size of the day.

Unfortunately, not all spans of substandard conductor were changed to the new size when upgrade work was undertaken, and so there are now many short lengths of small conductor throughout the network. For example, there were 12 spans of 35mm^2 copper conductor through the middle of Moerewa. This conductor has recently been replaced with 157mm^2 aluminium conductor.

As an example, Figure 5.3 below shows locations within a portion of the network around Kaikohe, Moerewa and Kawakawa where there is undersized conductor. In some instances, these sections are of considerable length and close to the substation source.

Short sections of undersize conductor will only have a small impact on feeder capacity or voltage limits and therefore will not create a significant network constraint. Nevertheless, progressive replacement of sub-optimal feeder conductor is being undertaken. This is predominantly to rid the network of old galvanised steel and copper conductors because of rust and age embrittlement and consequent high risk of failure. There is also a risk of overheating and excessive sagging during high load times. This can cause heat cycling stresses, hot joints, and other potential failure modes.

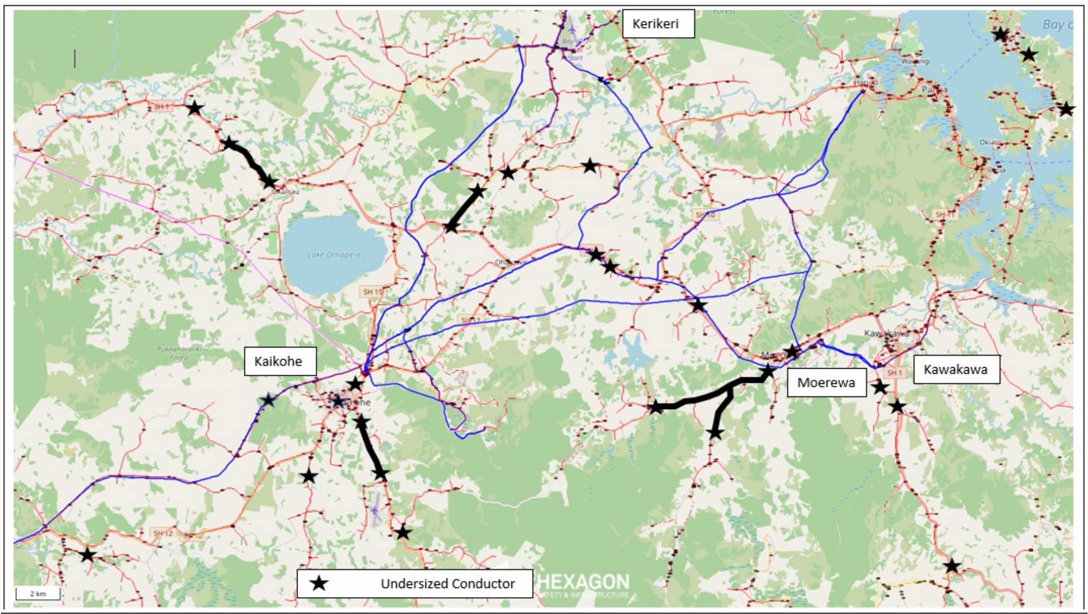


Figure 5.3: A Typical Area of the Network showing Locations of Sub-optimal Conductor

Mitigation

Our capital expenditure forecast provides a total of $5.8 million expenditure on conductor replacement over the 10-year AMP planning period, sufficient for the replacement of 40km of conductor. In addition, we have allocated $11.3million to the reconstruction of the two and three wire 11kV network and $5.7 million to SWER rebuilds.

5.12 Network Development

Network development includes all capital expenditure on network assets. In this section, our planned network development over the AMP planning period is presented in the context of the development categories discussed in Section 5.4.

Over the first five years of the planning period our network development focus will be on asset renewal and reliability projects. The network has sufficient capacity to accommodate our forecast short-term growth in consumer demand, and the need to stabilise the deteriorating reliability of the 11kV network is more urgent. The exception to this is an increased demand for new customer connections, including the connection of the three new solar farms, all of which will be connected directly to our 33kV subtransmission network. Much of this work will be funded by customer capital contributions.

During the latter half of the planning period, in part due to the increased penetration of EVs, we expect the localised electricity demand in some communities to have increased to the point where it exceeds the capacity of the 11kV network that currently supplies them. It is premature to forecast when and where this growth will occur, so our capex forecast includes a provision for unspecified capacity expansion projects to accommodate the expected increase in demand. These projects would be implemented towards the end of the AMP planning period.

5.12.1 Asset Life Cycle Renewals

Assets that are at the end of their lifecycle and are still required to meet our service delivery targets need to be replaced. If the rate at which assets are replaced is insufficient, there will be a decline in performance as the condition of the asset base deteriorates over time. This will result in a deterioration of the quality of supply due to an increase in the number of outages caused by equipment failures and increased fault response and equipment repair costs. We use the Asset Health Indicator (AHI) process described in Section 6 as a tool for measuring asset condition and prioritising assets for replacement.

Issues, such as the criticality of a particular asset and the duration of end-of-life unreliability period for different asset classes, influence the type and quantity of assets that we should renew over the period of this plan. For example, concrete poles deteriorate slowly whereas wooden poles, because of their faster loss of strength, must be replaced more quickly after end-of-life condition indicators are first identified.

Asset renewal expenditure is given a high priority to reassure stakeholders that our asset base is being sustained in a fit-for-purpose state and that the number of unplanned interruptions caused by equipment failure does not increase over time.

Over the ten-year planning period of this AMP we have forecast a total of $82.1 million[13] on renewal and replacement capital expenditure.

5.12.1.1 Faults

Most faults are caused by the failure of an asset component, such as a crossarm, in which case the cost of the repair is accounted for as operational expenditure. However, some faults require the replacement of a complete asset (e.g., a pole, transformer, or pillar), in which case the cost of the repair is capitalised. We have forecast expenditure of just over $1.1 million per year based on our historic capital expenditure on fault response, as shown in Table 5.12.

$000	FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029-33	Total
Subtransmission	56	56	56	56	56	278	558
Zone substations	-	-	-	-	-	-	-
Distribution and LV lines	662	662	662	662	662	3,308	6,618
Distribution and LV cables	55	55	55	55	55	273	548
Distribution substations and transformers	166	166	166	166	166	830	1,660

13 This assumes today's prices and makes no provision for inflation. It includes reactive expenditure to remedy faults and defects.

$000	FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029-33	Total
Distribution switchgear	165	165	165	165	165	824	1,649
Other network assets	-	-	-	-	-	-	-
Total	1,103	1,103	1,103	1,103	1,103	5,513	11,028

Table 5.12: Fault Driven Asset Renewal and Replacement Capital Expenditure Forecast

5.12.1.2 Defects

As described in Section 6.1, we operate a structured asset inspection and defect management programme, where defects are identified, recorded, and programmed for remediation. While most defects identified by these inspections require the repair or replacement of asset components, our inspection also identifies assets that require complete replacement. In most cases, these replacements are programmed into the asset health driven replacement programme described in Sections 5.12.1.3, but sometimes a defect is identified where, for safety or other reasons, asset replacement outside of this programme is required. We maintain a special asset replacement budget to cover these situations. Our forecast capital expenditure on defect remediation is shown in Table 5.13.

$000	FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029-33	Total
Subtransmission	143	143	143	143	143	714	1,429
Zone substations	71	71	71	71	71	357	712
Distribution and LV lines	756	756	756	756	756	3,781	7,561
Distribution and LV cables	71	71	71	71	71	357	712
Distribution substations and transformers	143	143	143	143	143	714	1,429
Distribution switchgear	214	214	214	214	214	1,071	2,141
Other network assets	28	28	28	28	28	141	281
Total	1,428	1,428	1,428	1,428	1,428	7,140	14,280

Note: Totals may not add due to rounding

Table 5.13: Defect Driven Asset Renewal and Replacement Capital Expenditure Forecast

5.12.1.3 Proactive Asset Replacement and Renewal

In addition to the reactive replacement of individual assets that have failed in service or are identified as defective and requiring replacement by our asset inspection programme (Sections 5.12.1.1 and 5,.12.1.2 above), we also operate a proactive programme of asset replacement and renewal. This has two components:

- The refurbishment of identified subtransmission and distribution lines or line sections. These are usually lines in poor condition with many components showing fatigued or end of life symptoms. These are managed as capital projects and all defective assets and asset components are systematically replaced as part of a project.
- The proactive replacements of assets across the network to maintain the health of the asset fleet at an acceptable level. These replacements are treated as a programme with the aim of replacing a certain number of assets of each type in a year. A provision is made in the forecast for these replacements, without necessarily specifying the locations of the individual assets to be replaced. Programmes are managed within a budget envelope.

Table 5.14 below breaks down our forecast expenditure over the AMP planning period for the replacement and renewal of all our network assets by asset type. While the larger and more significant capital projects are individually identified the forecast covers all proactive condition driven replacements, irrespective of whether the replacement is through a capital project or a programme.

$000	FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029-33	TOTAL
SUBTRANSMISSION							
Kaikohe-Omanaia	466						466
Kawakawa-Haruru	426		411				837
Turntable Hill-Moerewa	526						526
Worsnops-Old Bay Rd				435	386		821
Okahu Rd-NPL		393					393
Waipapa-Waimate Nth Rd						379	379
Wiroa-Springbank Rd		379					379
33kV insulator replacement		75	72	72	72	144	435
110kV poles and hardware	860	664	635	638	638	3,189	6,614
110kV tower refurbishment		185	178	178	178	533	1,252
TOTAL SUBTRANSMISSION	**2,318**	**1,696**	**1,296**	**1,323**	**1,274**	**4245**	**11,624**
DISTRIBUTION AND LV LINES							
Line Reconstruction							
Herekino feeder pole top asset replacement	500		481				981
Opononi feeder rebuild		591	480				1,071
South Rd-Takahue Saddle rebuild		544					544
Paua 11kV network upgrade	510						
Motukaraka rebuild						595	595
Taheke-Rahauwahia Rd pole top assets				534			534
Tokerau 11kV feeder refurbishment	710						
Other pole top asset replacements		285	1,366	1,376			3,027
Other line refurbishment	130			303	303	3,519	4,125
Subtotal – Line Reconstruction	**1,850**	**1,420**	**2,327**	**2,213**	**303**	**4,114**	**12,227**
Conductor							
Ohaeawai feeder reconductoring				548			548
Oruru feeder reconductoring			423				423
Rawene feeder reconductoring	418	418					836
Other reconductoring projects	327	400	147	409	383	2,213	3,879

NETWORK DEVELOPMENT

$000	FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029-33	TOTAL
3,879Subtotal - Conductor	**745**	**818**	**570**	**957**	**383**	**2,213**	**5,686**
SWER							
Kohukohu SWER replacement		326	339	427	410		1.502
Makene Rd SWER rebuild				707			707
Whangape SWER rebuild			515				515
Other SWER projects	181			538	776	1,472	2,967
Subtotal - SWER	**181**	**326**	**854**	**1,672**	**1,186**	**1,472**	**5,691**
Poles							
Te Kao pole replacement			498				498
Te Paki pole replacement				418			518
Other concrete pole replacements	383	388	388	388	388	1,698	3,633
Other wood pole replacements	856	831	831	831	831	4,154	8,334
Subtotal - Poles	**1,239**	**1,219**	**1,717**	**1,637**	**1,219**	**5,852**	**12,883**
TOTAL - DISTRIBUTION LINES	**4,015**	**3,783**	**5,468**	**6,479**	**3,091**	**13,651**	**36,487**
DISTRIBUTION CABLES							
Omanaia feeder – split and underground one cct			420				420
Underground Rainbow Falls RD	263						263
TOTAL – DISTRIBUTION CABLE	**263**		**420**				**683**
DISTRIBUTION SUBSTATIONS AND TRANSFORMERS							
Pole mounted transformers		68	65	65	65	65	328
Transformer earth remediation	119	118	114	114	114	342	921
Transformer kiosk refurbishment	293	293					586
Replacement of voltage regulators	400	703	450			808	2,361
TOTAL – DISTRIBUTION TRANSFORMERS	**812**	**1,182**	**629**	**179**	**179**	**1,215**	**4,196**
DISTRIBUTION SWITCHGEAR							
RMU Refurbishment	400	365	365	365	365	1,096	2,954
TOTAL - DISTRIBUTION SWITCHGEAR	**400**	**365**	**365**	**365**	**365**	**1,096**	**2,954**
OTHER NETWORK ASSETS							
11kV Capacitors	35	35	34	34	34	68	240

$000	FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029-33	TOTAL
Protection	147	372					519
SCADA		101	97	97	80	160	744
TOTAL – OTHER NETWORK ASSETS	**182**	**508**	**131**	**131**	**114**	**228**	**1,294**
TOTAL – PROACTIVE REPLACEMANT OF ALL NETWORK ASSETS	**7,990**	**7,532**	**8,308**	**8,477**	**5,03**	**20,435**	**57,766**

Note: Totals may not add due to rounding

Table 5.14: Capital Expenditure Forecast for the Proactive Replacement of Network Assets

5.12.1.4 Consolidated Asset Renewal and Replacement Capital Expenditure Forecast

Table 5.18 below consolidates the forecast asset renewal and replacement capital expenditure forecasts in Sections 5.12.1.1 – 5.12.1.3 into the asset categories used by the Commerce Commission for information disclosure.

$000	FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029-33	Total
Subtransmission	2,517	1,895	1,495	1,522	1,473	5,237	14,139
Zone substations	71	71	71	71	71	357	712
Distribution and LV lines	5,433	5,201	6,886	7,897	4,509	20,740	50,666
Distribution and LV cables	389	126	546	126	126	630	1,943
Distribution substations and transformers	1,121	1,491	938	488	488	2,759	7,285
Distribution switchgear	779	744	744	744	744	2,991	6,744
Other network assets	210	536	159	159	142	369	1,575
Total	**10,520**	**10,062**	**10,838**	**11,008**	**7,553**	**33,086**	**83,188**

Table 5.15: Consolidated Asset Renewal and Replacement Capital Expenditure Forecast

5.12.2 Network Capacity Expansion

Our network capacity expansion plan documents our expectations regarding demand growth and network extensions. These in turn drive the need for upgrades and reconfiguration of the network to deliver on our quality of supply standards, such as security and voltage regulation. New large connections potentially challenge the capability of the network to deliver at short notice. Our planning therefore considers contingent capacity and “what-if” scenarios to communicate potential issues with developers.

Over the first half of the AMP planning period, most of our capacity expansion work involves the provision of new customer connections, and in particular the connection of the three new solar farms in our northern area.

5.12.2.1 Customer Connections

This relates to new assets required to connect new customers to the network. It is largely funded by capital contributions. Our total forecast expenditure on customer connections and our forecast recovery in capital contributions is shown in Table 5.16. Much of this expenditure is for the connection of the three new solar farms to our subtransmission network.

$000	FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029-33	Total
Customer driven-funded by capital contribution	3,500	3,001	2,626	1,921	1,921	9,605	22,574
Customer driven-funded by Top Energy	723	607	607	607	513	2,566	5,623
TOTAL – CUSTOMER CONNECTION	**4,223**	**3,607**	**3,232**	**2,528**	**2,434**	**12,172**	**28,197**

Note: Totals may not add due to rounding

Table 5.16: Consumer Connection Expenditure Forecast

5.12.2.2 Wiroa 110/33kV Substation

To address the potential voltage constraint at Kaeo and Waipapa discussed in Section 5.11.2.6, we plan to construct a 110/33kV injection point at our existing 33kV switching station at Wiroa. The new substation, which we plan to construct over FYE2028-30, will have two transformers with an 11kV tertiary winding to provide for a future new point of injection into the 11kV network.

It was planned to start construction of this project in FYE2023, based on the forecast demand growth in the Kerikeri/Whangaroa area and a deterministic approach to network planning that required N-1 security to be maintained at all levels of demand. However, at the beginning of the year, when it became apparent that the need to address the deteriorating reliability of the 11kV network was increasingly urgent, we undertook a risk assessment to determine whether this build could be deferred. This showed that:

- The risk of the constraint being breached was very low since, not only did it require a fault on the double circuit Kaikohe-Wiroa line, but this fault had to occur during a period of peak network demand. The Kaikohe-Wiroa line is less than 10 years old and in very good condition. Furthermore, the period during which the demand exceeded the delivery capacity of the alternative Kaikohe-Mt Pokaka-Wiroa circuit is only a small percentage of the hours in a year.
- Nevertheless, should a fault occur at a time of peak demand, there would not be a complete loss of supply. Most of the load would still be supplied by the Mt Pokaka line but there would be a need for some managed load shedding by the control room. The required load shedding would be small at first but would increase over time as the demand in the Kerikeri/Whangaroa areas increased. Over the first few years, the energy that could not be supplied would be comparable to that of an 11kV feeder fault.

The timing of the build is therefore a risk management issue. Our capital expenditure forecast provides for construction to occur over the three-year period FYE2028-30, but this will be kept under review based on the demand growth in the area the new substation will supply.

5.12.2.3 Kaitaia Substation Transformer Upgrade

There are two 110/33kV transformers at Kaitaia substation. T1 is a 40/60MVA transformer that we installed about eight years ago, while T5 is a 22MVA bank of single-phase units that are in relatively poor condition and nearing the end of their economic lives. The single-phase T4 bank, which is identical to T5, is still in place and its three single phase units are available as spares, should there be a failure of one of the T5 units.

This arrangement provides adequate security to supply the peak 25MVA consumer demand in our northern area. In the event of a T1 transformer failure, the T5 transformer has sufficient capacity to supply the load, with some support from the local diesel generation at times of peak demand. However, it is too small to support the 67MW of solar farm generation for which connection agreements have recently been signed. Should the T1 transformer fail, most of this generation would need to be constrained off until the transformer was replaced or repaired. The lead time for a new transformer, which could be required if there was a complete transformer failure, and a spare unit was not available from Transpower as a temporary replacement, is up to 12 months.

The AMP capital expenditure forecast provides for the installation of a new 40/60MVA transformer to replace the small T5 bank. This is scheduled for commissioning in FYE2030.

5.12.2.4 Doubtless Bay Development

There is a need to eventually relocate the Taipa zone substation due to its closeness to the Taipa estuary and the risk of flooding as a result of sea level rise due to climate change. This is discussed in Section 7.6.2. There is also a potential tsunami risk. Our initial plan to address this was to relocate the substation to a new site owned by Top Energy in Garton Rd, Oruru and to supply the new substation from our planned new 110kV Wiroa-Kaitaia line.

We have now reviewed this plan for the following reasons.

- While the load at Taipa has been relatively static for some years, there has been recent growth in demand and indications are that this growth could accelerate due to subdivision development and increased EV penetration. The Taipa transformer is now fully loaded and in fatigued condition, so there is a need to address this in the medium term.
- The Garton Rd site is further away from the two load centres currently served by the existing substation, namely the Karikari peninsula and Coopers Beach/Mangonui. This would mean longer 11kV feeders and potentially lower 11kV reliability. Furthermore, with the deferral of the Wiroa-Kaitaia line build, it is unclear that the planned incoming supply to Garton Rd will be available when required.

We are now proceeding on the basis that Garton Rd is not the optimal location for a new substation, and Doubtless Bay would be better served if Taipa was replaced by two new substations, one on the Karikari peninsula in the vicinity of Tokerau Beach, and the second at either Coopers Beach or Mangonui. The two substations would be served by the existing 33kV line feeding Taipa, and possibly by a new 33kV line between a tee point on the Church Rd-Pukenui line at Awanui and Tokerau. An additional 33kV line would connect these substations to eventually form an Awanui-Tokerau-Coopers Beach-Kaitaia ring. An alternative option would be to supply the second 33kV line into the Doubtless Bay area from our Kaeo zone substation, through the construction of a new Kaeo-Mangonui/Coopers Beach line. This would provide a 33kV connection between our northern and southern areas, which would be beneficial if the Wiroa-Kaitaia line build is deferred for an extended period.

The timing of this work and the optimal sequencing of the different projects associated with this development is unclear at this stage and will depend not only on the rate of demand growth in the Doubtless Bay area, but also on the relative growth rates on the Karikari peninsula and in the Coopers Beach/Mangonui area. We think it more likely that the Tokerau substation will need to be built first, as this load centre is further from Taipa and because the Tokerau feeder is one of the ten least reliable feeders on our network.

Our capital expenditure forecast provides for:

- Replacement of the existing 5/6.5MVA transformer at Taipa with a 10/15MVA unit by FYE2030. It is envisaged that Taipa is only an interim location for this unit, which would be relocated to the new Coopers Beach/Mangonui substation when this is constructed and the Taipa substation disestablished.
- Construction of the Tokerau substation by FYE2033. Two options have been identified for this project:
    - Construct the substation and supply it from a new 33kV line from Awanui.
    - Construct a new 33kV line between the Taipa substation and the Tokerau substation site. Operate this line initially as an express 11kV “subtransmission” feeder supplying an 11kV switchboard at the Tokerau site.

  The first option would provide a second subtransmission line into Doubtless Bay, which would mean that supply to the area would not be fully dependent on the existing Kaitaia-Taipa circuit. Should one line fail, some of the load it supplied could be restored through 11kV load transfers from the substation still in service. A disadvantage of this option is that it would likely preclude an incoming supply from Kaeo.

An incremental development of the substation through the construction of an 11kV "subtransmission" feeder supplying an 11kV switching station would have a significantly lower initial capital cost. The new line would reinforce the supply capacity to the peninsula, albeit by less than a new substation. This would be constructed later when the load warranted it. The Taipa-Tokerau line would eventually be incorporated into the Awanui-Tokerau-Coopers Beach-Kaitaia 33kV ring. Both options would result in a similar improvement in the reliability of the 11kV network supplying the Tokerau peninsula.

While provision has been made for this work in the capex forecast no decision has been made on which option should proceed.

5.12.2.5 Decarbonisation Load Growth

Towards the end of the planning period, we expect demand growth to accelerate due in part to the increased penetration of EVs. Some of this growth will be due to the installation of high-capacity fast chargers, which are spot loads where any network reinforcement will be paid for by the developer. However, the majority will be incremental as most EV charging will continue to be done at home.

While the existing subtransmission network generally has sufficient capacity to supply this expected increase in demand, this is not true of the 11kV network, which will need to be reinforced if it is supply localised demand growth in locations that are not close to our zone substations. Often, this is most effectively achieved by increasing the points of injection, which involves the construction of new subtransmission lines and zone substations. In many cases this development can be incremental as suggested for Tokerau, through the initial operation of new 33kV lines at 11kV to defer the construction of new substations.

We have identified several locations in our supply area where we think reinforcement of this nature might be required, but at this point it is difficult to forecast when this could be required at different locations. We have therefore prepared a capex forecast that makes provision for such reinforcement, without being specific as to when and where it will be needed.

5.12.2.6 Network Capacity Expansion Expenditure Forecast

Our capital expenditure forecast for network capacity augmentation project is shown in Table 5.17.

$000	FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029-32	Total
SUBTRANSMISSION							
New 33kV line - unspecified location						2,727	2,727
New 33kV line - Tokerau						4,764	4,764
TOTAL - SUBTRANSMISSION						**7,491**	**7,491**
ZONE SUBSTATIONS							
New T2 40/60MVA 110/33kV transformer - Kaitaia					465	3,588	4,052
New 10/15MVA 33/11kV transformer - Taipa					829	1,466	2,295
Tokerau zone substation						5,581	5,581
Wiroa 110/33kV substation					3,686	7,117	10,802
New zone substation – unspecified location						3,067	
TOTAL – ZONE SUBSTATIONS					**4,980**	**20,819**	**25,798**

$000	FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029-32	Total
DISTRIBUTION LINES							
Martin's Rd Reconductoring	362						
Russell reinforcement	100						
TOTAL – DISTRIBUTION LINES	**462**						
TOTAL – CAPACITY EXPANSION	**462**	**-**	**-**	**-**	**4,980**	**28,308**	**33,750**

Note: Totals may not add due to rounding

Table 5.17: Network Capacity Augmentation Forecast

5.12.3 Reliability Safety and Environment

Our network development programme for the last two regulatory periods has focused on rehabilitating our subtransmission network, adding new zone substations, the installation of upgraded protection systems to improve the security of the 33kV system and, most recently, the installation of diesel generation to secure those parts of the subtransmission system that are vulnerable through a lack of redundancy.

5.12.3.1 Kaitaia-Wiroa 110kV Line

On 22 December 2022 the Supreme Court issued a judgement denying the appeal of three property owners against the Minister of Land Information's decision to allow Top Energy to compulsorily acquire easements for the construction of the Wiroa-Kaitaia line across their properties. As there is no further right of appeal, there is now no impediment to prevent us from finally securing the full route for the line. We will go ahead and secure the route, even though construction has now been deferred until after the end of the AMP planning period, as discussed below.

This project was initiated in 2012 after Top Energy acquired the Kaikohe-Kaitaia 110kV line from Transpower. The main objective was to eliminate the need for the regular nine-hour supply interruptions that affected more than 10,000 consumers in the north of our supply area. This was becoming a political issue. There was general agreement within the community that the level of service we were able to provide was substandard and something needed to be done. It was also considered that building the line over a new route closer to the east coast was a prudent decision, as the line would better serve that part of our supply area where the highest long-term population and economic growth was expected to occur.

The first stage of the line between Kaikohe and Wiroa was completed in FYE2015 and increased the capacity of the network to supply the increasing demand in the Kerikeri and Waipapa areas. It was never envisaged that it would take a further eight years to secure a route for the remainder of the line. When it became apparent that the delay in securing the line route would be extensive, we pivoted to the installation of diesel generation to appease ongoing community concern over our failure to address the extended supply interruptions. We deferred the line build, with an expected project completion date of FYE2030.

Diesel generation is not an optimal solution as it is inconsistent with New Zealand's decarbonisation objective. Furthermore, the resilience to faults on the existing Kaikohe-Kaitaia line is still limited, as the diesel generation is offline when the 110kV circuit is in service. Hence an unplanned interruption of the 110kV circuit supplying Kaitaia will still result in a loss of supply to all our northern consumers. It then will take some time to restore supply to many consumers, as the generators need to be loaded up gradually for technical reasons. Fortunately, unplanned 110kV interruptions are relatively infrequent.

More recently there has been strong demand for the connection of utility-scale solar farms to our northern area, and as discussed above, we have signed agreements for the connection of 67MVA of solar generation to our northern subtransmission network. This will fully utilise the capacity of the Kaikohe-Kaitaia line. While the construction of the Wiroa-Kaitaia circuit would mitigate this constraint and allow more generation to be connected and exported south as far as the Kaikohe grid connection, it would not mitigate the constraint on the grid connection to Maungatapere. This is discussed in Section 5.11.2.1.

Relieving the constraints that are preventing additional renewable generation being connected to our northern network is therefore not something we can do alone, as there is no point in providing additional capacity within our network, if Transpower does not do likewise. To this end, Top Energy and Northpower are working with Transpower on the concept of establishing a Renewable Energy Zone (REZ) based in Northland. The three parties have received dozens of enquiries from generation developers interested in connecting either to the grid or to local distribution network, with proposals totalling nearly two gigawatts of renewable energy generation. The objective of the REZ is to develop a coordinated transmission system upgrade strategy for the region, which would be largely funded by the renewable generation developers that would use the additional capacity. However, the concept will only work if a way can be found to remove first mover disadvantage, where a system capacity augmentation is funded by the first user, and subsequent users then benefit at little additional cost.

The REZ concept went out for consultation to the public and interest groups. The consultation received a total of 75 responses, 83% of which gave partial or full support for the proposal. However, there are a range of legal and regulatory impediments that must be overcome, and these are being systematically worked through. This is a critical issue for the country, since it is difficult to see how the Government's decarbonisation objectives can be achieved, unless a process is developed that ensures equitable funding of the transmission and distribution network upgrades that will be required.

In the meantime, we have further deferred the construction of the Wiroa-Kaitaia line to beyond the planning period of this AMP. As noted above, we will go ahead and secure the line route as we fully expect the line will eventually be needed. However, as decarbonisation of the economy is now a significant driver for this line, we consider it premature to proceed until the REZ concept has been further developed and potential funding mechanisms are clearer.

5.12.3.2 11kV Reliability Improvements

In April 2022, the Board approved a proposal to defer the construction of the Wiroa substation and reallocate the expenditure to a range of initiatives designed to improve the reliability of our 11kV distribution network. Over 90% of our total network SAIDI is now due to faults on the 11kV network and its reliability has been progressively deteriorating, to the point where in the FYE2023 year we have breached the Commerce Commission's price-quality-path SAIDI threshold. It is imperative that we stabilise the situation.

Our capital expenditure 11kV reliability improvement programme involves increasing the rate at which we replace assets that are reaching the end of their economic life and at risk of failing in service and other initiatives designed to reduce the SAIDI and SAIFI impact of faults that do occur. These latter initiatives are categorised as reliability, safety, and environment (RSE) projects.

Our 11kV RSE projects include:

- Utilising the 11kV tertiary winding on the Kaitaia 40/60MVA 110/33kV transformer to provide an additional point of injection into the South Road and Oxford St feeders. This will be undertaken in FYE2024 and FYE2025.
- Optimising the protection on low reliability feeders, largely through the installation of reclosers at the tee points of long spurs.
- The construction of interconnections between neighbouring feeders to allow supply to be restored to consumers downstream of a faulted switching zone before the fault is repaired.

The focus of the programme is on our most unreliable feeders. These are generally long feeders serving rural areas, which have a high fault exposure and high numbers of connected consumers.

5.12.3.3 Reliability Safety and Environment Expenditure Forecast

$000	FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029-33	Total
SUBTRANSMISSION							
Property rights for 110kV Wiroa-Kaitaia line	27	30					57
TOTAL - SUBTRANSMISSION	**27**	**30**					**57**
ZONE SUBSTATIONS							
Kaitaia 11kV injection point	736	631					1,367
Minor reliability improvements	109	307	38	38	38	198	728
TOTAL – ZONE SUBSTATIONS	**845**	**938**	**38**	**38**	**38**	**198**	**2,095**
DISTRIBUTION LINES							
11kV feeder interconnections	1,934	1,556	705	889	465	4,106	9,655
Other power quality upgrades	380	363	349	349	603	1,743	3.787
TOTAL - DISTRIBUTION LINES	**2,314**	**1,919**	**1,054**	**1,238**	**1,068**	**5,849**	**13,442**
DISTRIBUTION CABLE							
Russell 11kV reinforcement						2,054	2.054
TOTAL - DISTRIBUTION CABLE						**2.054**	**2,054**
DISTRIBUTION SWITCHGEAR							
New autoreclosers and sectionalisers for feeder protection	1,194	632	1,148	1,195			4,169
Group fusing and autolinks	226	81	216	77	216	666	1,482
Remote control switches	19	151	145	145	145	145	750
TOTAL – DISTRIBUTION SWITCHGEAR	**1,439**	**864**	**1,509**	**1,417**	**361**	**811**	**6,401**
OTHER NETWORK ASSETS							
Communications upgrades	163	357	273	387	37	111	1,328
LV data capture	280	290	290	290			1,150
Protection upgrades	136					908	1,044
Miscellaneous	111	158	107	75			451
TOTAL - OTHER NETWORK ASSETS	**690**	**805**	**670**	**752**	**37**	**1,019**	**3,973**
TOTAL – RELIABILITY SAFETY & ENVIRONMENT	**5,316**	**4,557**	**3,271**	**3,446**	**1,504**	**9,932**	**28,026**

Note: Totals may not add due to rounding.

Table 5.18: Reliability Safety and Environment Capital Expenditure Forecast

5.12.4 Consolidated Capital Expenditure Forecast

The allocation of our capital expenditure forecast to the different capital expenditure categories is shown in Table 5.23 and graphically in Figures 5.4 and 5.5. Asset renewal makes up 47% of the forecast and reliability improvement a further 16%. This is consistent with our commitment to maintain our existing assets in a condition that is fit for purpose and to address the deteriorating reliability of the 11kV distribution network.

$000	FYE2024	FYE2025	FYE2026	FYE2027	FYE2028	FYE2029-33	Total
Asset replacement and renewal	10,520	10,062	10,838	11,008	7,553	33,086	83,068
Customer connections	4,223	3,607	3,232	2,528	2,434	12,172	28,197
Capacity expansion	462				4,980	28,308	33,750
Reliability, safety, and environment	5,316	4,557	3,271	3,446	1,504	9,932	28,026
Total	**20,520**	**18,227**	**17,342**	**16,982**	**16,470**	**83,498**	**173,040**

Table 5.19: Consolidated Capital Expenditure Forecast.

.

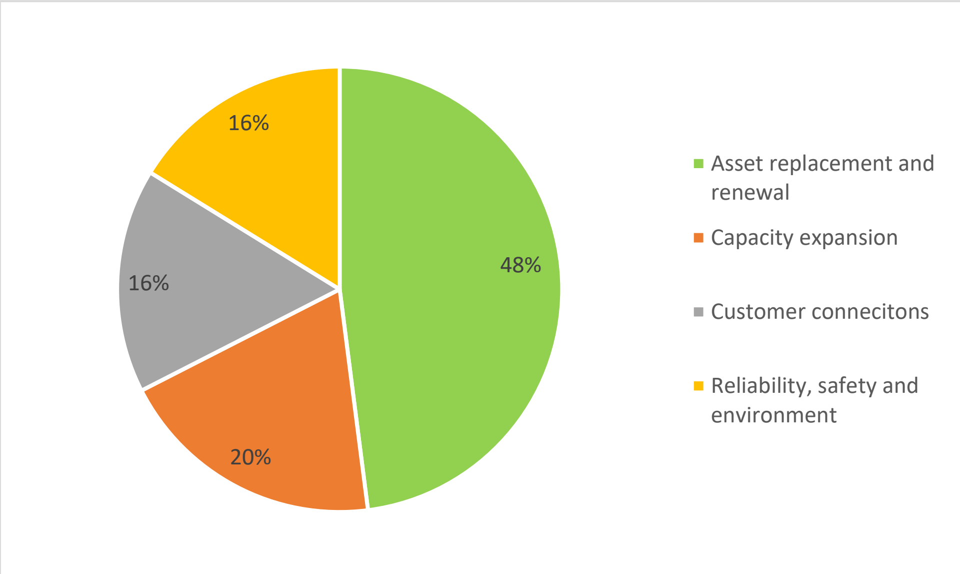


Figure 5.4: Allocation of Capital Expenditure to Expenditure Categories

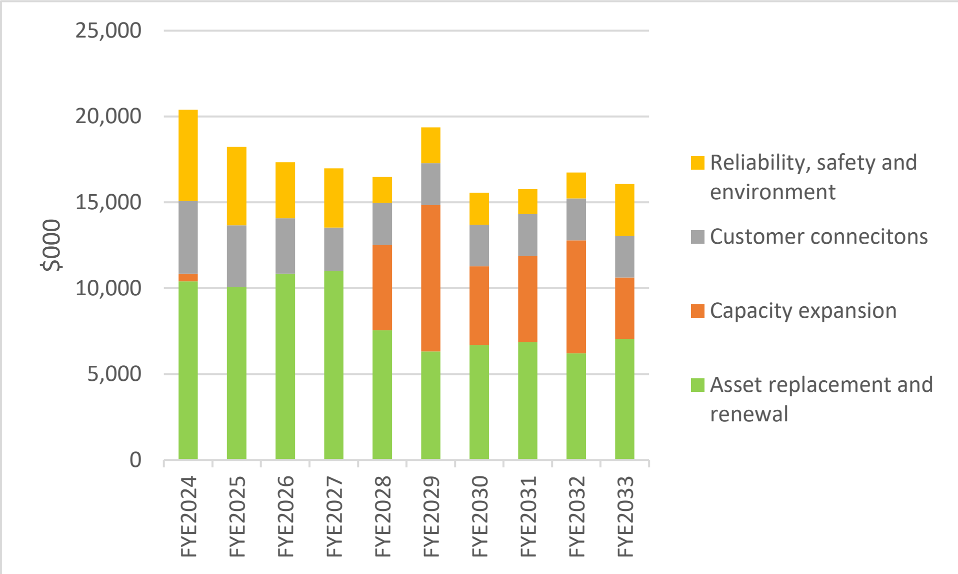


Figure 5.4: Distribution of Capital Expenditure by FYE

6 Lifecycle Asset Management

This section of the AMP outlines the policies, strategies, and practices that we use to ensure that assets deliver acceptable performance and can be operated safely over their full economic service life.

6.1 Maintenance and Renewal Planning Criteria and Assumptions

Our lifecycle asset management practices are planned to deliver the required level of service for the lowest possible lifecycle asset cost. We use a risk-based approach where we control our risk exposure by:

- Ensuring our assets do not pose a safety risk to the public or to our employees and contractors.
- Focusing our maintenance effort on critical assets, where criticality is a function of both the probability and consequence of an asset failure.

Our forecast maintenance costs are categorised as follows:

6.1.1 Service Interruptions and Emergencies

Our service interruptions and emergency expenditure forecast provides for the reactive maintenance or, if necessary, replacement of assets where immediate and unplanned intervention is required to address critical safety issues or to maintain supply to consumers. This work is driven by unexpected asset failures, which can result from third-party interference such as a car hitting a pole, foreign interference from birds or animals, damage from lightning or storms, or asset component failures. The forecast, which is based on costs incurred in previous years, has two elements; an opex element that covers the repair or replacement of components and a capex element that covers the replacement of complete assets.

Our Kerikeri control room is staffed at all times, and field staff are on standby outside normal working hours to attend to service interruptions and emergencies. The cost of operating our control room is included in the system operations and network support forecast and is not considered a lifecycle asset management cost.

6.1.2 Routine and Corrective Maintenance and Inspection

Our routine and corrective maintenance and inspection programme is designed to ensure that assets continue in service for their expected economic life. It includes targeted asset inspections and non-invasive condition assessments, together with invasive maintenance interventions to reduce the likelihood of premature failure of key assets. In line with our risk-based maintenance philosophy, the programme is driven by asset health and criticality; it focuses on assets where end-of-life drivers are most likely to be present, and also on assets where an unexpected failure would result in widespread supply interruptions or a high safety risk.

6.1.2.1 Asset Health Indicators

We use the EEA's Asset Health Indicator (AHI) Guide to describe the condition of an asset. This uses the five-point categorisation shown in Table 6.1.

EEA Asset Health Indicator Guide	
H5	As new condition - no drivers for replacement
H4	Asset serviceable – no drivers for replacement, normal in-service deterioration
H3	End-of-life drivers for replacement present, increasing asset related risk
H2	End-of-life drivers for replacement present – high asset related risk
H1	Replacement recommended

Table 6.1: Asset Health Indicator Categorisation

Under the EEA classification, the transition between H4 and H3 marks the "onset of unreliability", which is the point at which an asset starts to deteriorate, and closer monitoring of its condition is justified.

6.1.2.2 Risk Based Inspection and Maintenance

All assets are visually inspected in accordance with a time-based inspection program, where the frequency of inspection depends on the type of asset, its location, and the expected rate of deterioration. Under our public safety management system, assets in locations frequented by the public are inspected more often. During the inspection, the inspector notes any asset defects and determines whether the asset is likely to remain in service until the next programmed inspection. Where it is determined that an asset may not survive until its next programmed inspection, it is diverted into the defect management system described in Section 6.1.2.3. Assets rated H1-H3 under the EEA's asset health indicator categorisation system fall into this category.

6.1.2.3 Defect Management

The objective of our defect management system is to ensure that:

- Assets exhibiting end-of-life drivers are re-inspected at appropriate intervals.
- Maintenance is undertaken as necessary to extend the life of the asset.
- Assets are replaced at the appropriate time. This will depend on the criticality of the asset, which is primarily determined by the consequences of an in-service failure; critical assets are replaced earlier to minimize the risk of the asset failing, whereas non-critical assets may be allowed to run to failure. Consequence is assessed in terms of both safety and the impact of an asset failure on the level of service we provide.

The defect management process is shown in Figure 6.1.

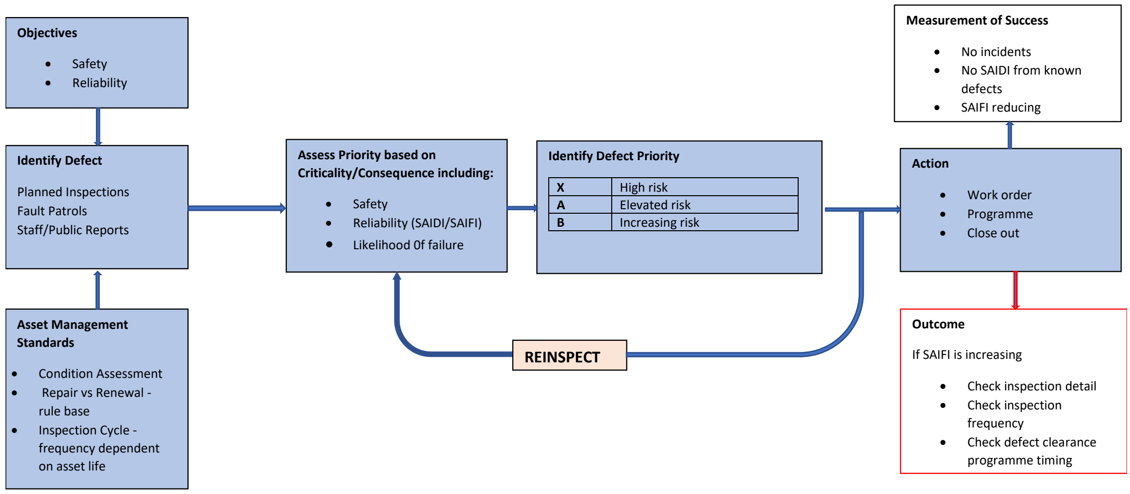


Figure 6.1: Defect Management Process

When an asset enters the defect management system, it is assigned a defect priority as follows:

- X defects are considered to present a high risk. Assets with an X defect are monitored monthly until the defect is remediated.
- A-Defects are considered to present an elevated risk. Assets are monitored six-monthly until remediation is completed.
- B-Defects are equipment considered to present an increasing risk. Assets are monitored two-yearly until remediation is completed.

These defect priorities are broadly equivalent to the risk categories R1-R3 in the EEA's Asset Criticality Guide. Risk categories in the criticality guide are two dimensional in that they take into account not only the condition of an asset but also the consequences should the asset fail in service.

This frequent monitoring of known defects enables risk to be regularly assessed. If a change in risk is identified, then the defect priority is updated, and the frequency of re-inspections is changed. This approach ensures defects are actively monitored and managed. Data on any backlog in the repair or re-inspection of defects is included in the General Manager Network's monthly Board report.

Additional measures are also taken to ensure that defect management is both effective and efficient. These include:

- Faults due to equipment failure are cross-referenced to the defect register to determine whether the fault was the consequence of a known defect. The SAIDI and SAIFI impacts of equipment failures are also reviewed annually. These processes are used to assess the effectiveness of our defect management.
- We coordinate the management of defects with our planned asset renewal capex programme, so we don't repair defects shortly before an asset is to be renewed. Situations may also arise where several small defects on a single asset result in earlier asset renewal.
- Asset components may be separated out and managed separately if we find, through fault analysis, that their failure rate is increasing. We have already identified an increasing trend in crossarm failures and have made a separate provision in our asset renewal capex forecast for a proactive crossarm replacement programme.

6.1.3 Replacement and Renewal Maintenance

Replacement and renewal maintenance is proactive condition-based maintenance triggered by the findings of the inspection, condition assessment and defect management programmes described in Section 6.1.2. The objective of the renewal maintenance programme is the prevention of unexpected, in-service failures with unacceptable safety or network performance consequence.

Whether defect-driven asset replacement and renewal activities are treated as opex, or capex is often an issue of scale. Should an inspection identify a problem requiring the replacement of part of an asset, such as an insulator or crossarm, defect remediation would be classed as a repair and treated as opex. Should a complete asset, such as a pole, need to be replaced the cost of the work would be capitalised (capex). We also capitalise planned maintenance projects targeted at the proactive replacement of crossarms and pole top hardware as these generally do not last as long as their associated concrete pole and are a primary cause of supply interruptions due to defective equipment. Capital replacements are discussed further in Section 6.1.4.

6.1.4 Capital Replacement

Once an asset has deteriorated to the point where it cannot economically be kept in service by applying renewal maintenance strategies, it is replaced. Our asset replacement strategies for each asset category are described in Sections 6.3-6.11.

Our capital forecast for the replacement of existing assets (as distinct from the creation of new assets) is described in Section 5.12.1. As described in that section, there are four components:

- Capex in response to service interruptions and emergencies (Section 6.1.1). This expenditure is reactive, and the forecast is based on historic costs.
- Reactive capex driven by our defect management system. Again, this forecast is based on historic costs.
- Proactive expenditure on refurbishment projects. Most of this expenditure is on subtransmission and distribution line refurbishments and is driven by the lower unit cost of replacing assets as part of a structured refurbishment project than that of replacing individual assets on a piecemeal basis. Some of this expenditure is allocated to the proactive replacement of critical substation assets known to be in poor condition.
- Expenditure on the proactive replacement of assets on a piecemeal basis. The need for this expenditure is determined by our top-down assessment of the health of our different asset

fleets and the need to keep the overall health of each asset fleet at an acceptable level. Our top-down analysis of the various asset fleet categories is presented in Sections 6.3-6.11.

6.2 Vegetation Management

6.2.1 Introduction

Vegetation is hazardous if it contacts live conductors. We manage the consequent public safety risk through our protection systems, which see vegetation contact as a fault and interrupt supply.

Vegetation contacting or falling on our electricity assets presents several public safety risks:

- Electrocution.
- Fire.
- Power surges.
- Network equipment failure (e.g., powerlines and poles breaking/falling).

Our preferred strategy is to permanently eliminate a vegetation hazard by:

- Establishing vegetation clear zones where no planting is permitted. However, we do not own the planting under our lines and have limited property rights over the land where our assets are located. This limits our ability to unilaterally require tree clearing; an agreement is generally required. Nevertheless, new plantings need to minimize foreseeable hazards that they may potentially create.
- Eliminating hazards by relocating lines to a safer location. This is again by agreement with the landowner and/or tree owner. For new plantings, such as commercial woodlots and shelterbelts, there are safety obligations under the Health and Safety at Work Act 2015 on Persons Controlling a Business or Undertaking (PCBU).
- Requiring active management on an ongoing basis, where a tree owner prefers trimming. We will seek an agreement with the tree owner on how they intend to meet their obligation to maintain vegetation at a safe clearance from our assets as defined in the Electricity (Hazards from Trees) Regulations 2003. This will include trees that, although they are outside regulatory clearances, still present a risk of falling onto our assets.

Secondary to safety is the issue of service interruption caused by vegetation. Contact with vegetation has a significant impact on our supply reliability. Our supply area has a high vegetation growth rate, which creates a high tree trimming workload. This requires an intense and focussed vegetation control programme to achieve an acceptable outcome within the limitations of the resourcing available within the region.

Faults that result from trees growing into lines (as distinct from those falling) are a failure of the tree owner and/or landowner to maintain compliance with the required regulatory clearance. Once such a fault occurs, the situation has progressed to a level of hazard that, for safety reasons, requires specialist competencies to remedy. We necessarily must be involved.

Our vegetation management strategy is discussed in greater detail in the following sections:

6.2.2 Risk Management

Tree owners' lack of awareness of safety issue and their responsibilities.	• Advertising and public safety campaigns. • Notices to tree owners in accordance with the Electricity (Hazards from Trees) Regulations 2003.
Vegetation burning in power lines (includes overhanging vegetation).	• This is a serious hazard requiring urgent intervention. We notify tree owners and, where necessary, use our powers under the Electricity (Hazards from Trees) Regulations

	2003 to remove the immediate threat and achieve a forced cut within three months.
Other vegetation risks include: • Ascendable trees growing close to power lines allowing potential access to live conductors. • Vegetation growing close to power lines presenting a future risk to power lines and public safety. • Trees at risk of falling that are within the fall distance of power lines. • Trees shedding bark or branches that fall or get blown onto power lines. • Vegetation covering ground mounted equipment or growing around poles and restricting access. • Vegetation entering ground mounted equipment near or on live components. • Persons attempting to remove vegetation encroaching live equipment without being aware of the risks or not taking the necessary precautions. • Vegetation growing into private lines or service lines that we do not own.	Our risk management strategies include: • Liaising with vegetation owners to remove vegetation or trim it to achieve the required regulatory clearances. • Not re-energising private lines after vegetation has caused a fault until vegetation has been removed or trimmed by the line owner. • Use of covered conductor in exceptional circumstances. • Provision of close approach and isolation services to tree owners managing their own vegetation. • Negotiation of formal agreements with tree owners on future management of the site and safety coordination. This applies particularly to commercial plantings.

6.2.2.1 Vegetation in Road Reserves

The New Zealand Transport Agency (NZTA) has advised us that it has “no interest” in vegetation growing within its road reserves and the FNDC has similarly advised that it has “no interest” in vegetation growing within its road reserves in rural areas. We manage this vegetation ourselves without a requirement for owner consent. Our management strategies include:

- Mechanical clearing at ground level.
- Hedge trimming where accessible from the roadside and neighbouring property.
- Spraying canopy or injecting the trunk.

We take a less aggressive approach to protected trees or, at our discretion, where we consider a tree has a high amenity value. Sections 6.2.3-6.2.4 provide additional information on our work practices.

Trees growing within urban road reserves are “owned” by the FNDC and are managed in accordance with our protocols for the management of privately-owned trees.

6.2.3 Preventive Maintenance

Inspections.	• Reactive post fault inspections as required. • Annual vegetation proximity and risk inspections of 110kV and 33kV lines. • Two-yearly vegetation proximity and risk inspections of other lines.
Administration.	• Public safety campaigns and information mail drops. • Notices to tree owners. • Negotiation of agreements with tree owners.

6.2.4 Summary of Tree Management Practices

General.	• All lines are surveyed regularly for vegetation interference in accordance with inspection frequencies in Section 6.2.3. • During these inspections, vegetation is assessed for compliance with Electricity (Hazards from Trees) Regulations 2003. • Where applicable, vegetation owners are then engaged and assisted in managing their vegetation in accordance with our vegetation management strategies.
Hedges.	• Hedges are recorded in a register. Owners are encouraged to trim their hedges with a regular trimming cycle. • Hedge owners are encouraged to remove high hedges or reduce height to allow hedges to be trimmed without violating the regulatory minimum approach distances to live lines. • Reminder notices are issued regularly to encourage hedge owners to trim hedges before they become a hazard to lines that would then require our intervention. • Bamboo hedges present a higher risk due to their growth rate and their potential for being pulled into lines at ground level. Owners are advised to remove the hedge as the only practical solution.
Privately owned trees and FNDC trees in urban zones.	• Tree owners are encouraged to remove trees that have the potential to threaten lines or that require ongoing trimming and expense beyond the value of the tree. • We will offer (once only) to remove or cut trees at our cost to a state manageable by the tree owner. In return, the tree owner will be required to sign an agreement that no tree will be planted on their property (knowingly or not) that could interfere with our network equipment. Any vegetation found interfering with network equipment thereafter will be removed at the owner's cost. • A tree owner who does not take up the option outlined above will be subject to the Electricity (Hazards from Trees) Regulations 2003. Trees will receive a first cut and trim and any vegetation management costs we incur thereafter will be charged to the tree owner.
Farm plantings and commercial wood lots.	• A formal agreement recording PCBU-to-PCBU safety coordination is required. This defines the responsibilities for the management of identified hazards, and provision of safe access at all times.
FNDC trees in non-urban zones.	• Trees in non-urban areas are of "no interest" to FNDC and are trimmed or removed at our discretion and cost.
NZTA trees.	• Trees within state highway road reserves are of "no interest" to NZTA and are trimmed or removed at our discretion and cost.
Trees on Department of Conservation (DOC) land.	• These are removed or trimmed at our cost and as agreed with DOC.

6.2.5 Vegetation Control

We currently operate three vegetation crews, two in our southern area depot at Puketona and one in our Kaitaia depot. Currently these crews work systematically across the network and vegetation control is applied to all parts of the network on a regular cycle, without regard to the SAIDI impact of vegetation faults on different parts of the network. All 110kV and 33kV lines are controlled annually and 11kV feeders are controlled on a two-yearly cycle.

From FYE2024, we plan to move to a more targeted, risk-based approach, where those parts of the network that have a high SAIDI impact are controlled more frequently and, where possible, more aggressively. This could mean, for example, that 33kV lines may be controlled less often where there is a parallel line that can seamlessly pick up the load in the event of a vegetation fault. On the other hand, parts of the 11kV South Road feeder that frequently experience vegetation faults could be controlled annually, rather than once every two years.

We also intend to mobilise an additional two-man vegetation control crew that will have a roving mandate. If a situation is reported where vegetation is growing into, or close to, a line before it is scheduled for its cyclic vegetation control, the smaller crew will be dispatched to address the situation in isolation. This is anticipated to have a twofold impact:

- It will increase the implementation efficiency of the planned vegetation management effort by reducing the number of times the planned work is disrupted by the need to attend to more urgent situations.
- Over and above this, the SAIDI impact of vegetation faults is expected to reduce due to both the additional vegetation control input and the ability to target higher risk situations more quickly and flexibly.

6.3 Poles

6.3.1 Failure Modes

Interference.	• Excavations. • Third party attachments (drilling into poles). • Accidental contact (vehicles).
Typical degradation.	• Spalling, rotting, rusting of poles. • Foundation movement due to ground subsidence.
Accelerated degradation.	• Material degradation in coastal and geothermal environments. • Vehicular impact. • Tree falling. • Ground subsidence. • Substandard manufacturing quality.
Known equipment issues.	• Wood poles are organic and are susceptible to rot and cellular breakdown. The breakdown rate is variable and dependent on the tree type, growing environment, pole processing, wood treatments and environmental conditions in which the pole is installed. These variables make the rate of deterioration of wood poles unpredictable. Larch poles pose a heightened risk as they can look good on the outside but be hollow and weak inside. • L-and T-shape concrete poles have a known construction flaw. Short pieces of reinforcing were welded together to make full length pieces when the correct length was unavailable. Affected units have failed and the whereabouts of these units is unknown. • Two recently installed 110kV poles are currently affected by ground subsidence and are being closely monitored. One structure is close to the Ngawha geothermal power station and is affected by movement of the geothermal field where it is located. The second is the replacement structure in the Maungataniwha Range that was installed in 2014 following a foundation failure caused by a severe storm. We have commissioned an external consultant to undertake geotechnical assessments before determining the remedial action required.

6.3.2 Risk Management

Climbing a pole identified as "unsafe to climb".	• Any pole assessed as unsafe to climb is tagged with a "DO NOT CLIMB" tag and must not be climbed without being mechanically supported.
Wood pole loses strength due to rot.	• All wood poles are treated as unsafe and given a below ground inspection to determine they are safe before they are climbed. • We have ultrasonically checked all wood poles on the network for residual strength and all high-risk poles identified by this process have now been replaced. The results of this assessment are now being used to prioritise poles for scheduled replacement.
L/T shape pole failure.	• L and T-shape poles are not climbed without being supported. These are not tagged, as field staff are made aware of this requirement during competency training.
Poles can be climbed unassisted.	• New structures are designed to be difficult to climb unassisted. Securing signage and other attachments to our poles is prohibited. The Far North District Council is aware of the risk and this restriction. • When a climbable pole is discovered, we undertake a risk assessment and prioritise remediation as appropriate to manage the risk. This may include removing the climbing aid, installing a climbing barrier, or replacing the pole.

6.3.3 Preventive Maintenance

Visual.	• Reactive patrols post-fault as required. • Pole condition assessment in accordance with our risk-based inspection strategy.
Test.	• Wood pole ultrasonic serviceability assessment programme.

6.3.4 Corrective and Reactive Maintenance

Minor unplanned and reactive remediation.	• Foundation repair and stay installations. • Hardware replacements.

6.3.5 Steel and Concrete Poles

Steel Towers

There are 12 steel tower structures on the 110kV Kaikohe-Kaitaia line. These were installed about 1966 as they were used to support the now dismantled 50kV line that originally supplied Kaitaia. They have been well maintained and are still in serviceable condition.

Steel Poles

There are 123 steel pole structures on our network. Most of these are on the 110kV system including the Kaikohe-Wiroa line (currently operating at 33kV) and on the recently constructed 110kV line constructed to deliver the electricity generated by the OEC4 unit at Ngawha to the 110kV bus at Kaikohe. A small number are replacement structures on the 110kV Kaikohe-Kaitaia line, installed as part of our ongoing structure maintenance programme on this asset.

Steel is now our preferred pole type for the 110kV network.

Concrete Poles

Almost 96.5% of the poles on our network are concrete, which remains our preferred pole type for all voltages, except 110kV.

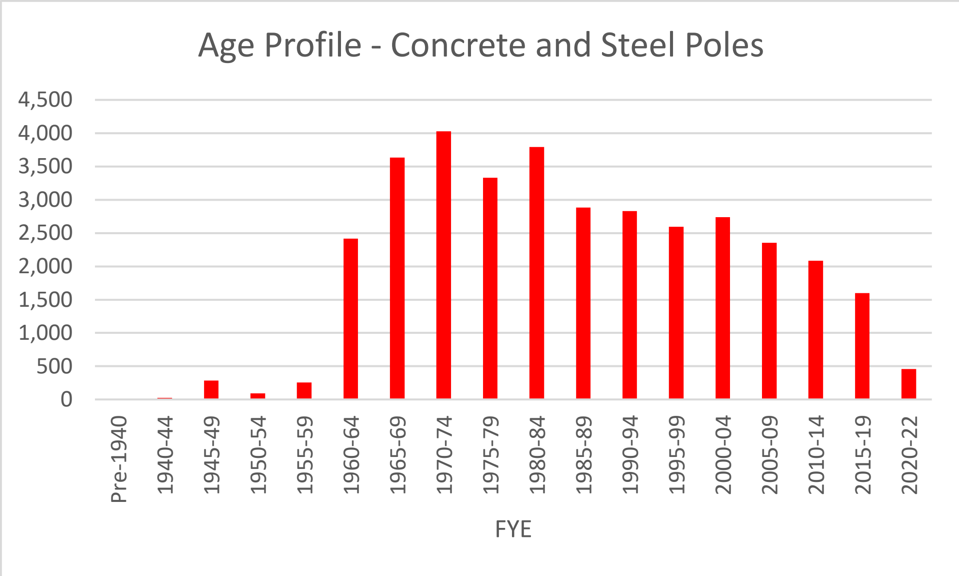


Figure 6.2: Age Profile – Concrete Poles

6.3.6 Wood Poles

There are 1,172 wood poles or pole structures on our network, almost 50% of which are hardwood. While some the original wood pole structures on the 110kV Kaikohe-Kaitaia line remain, more than half of our wood poles are on the low criticality SWER and low voltage lines. A small number of wood poles remain on the 33kV subtransmission network and the balance are dispersed across the 11kV two- and three-wire distribution network.

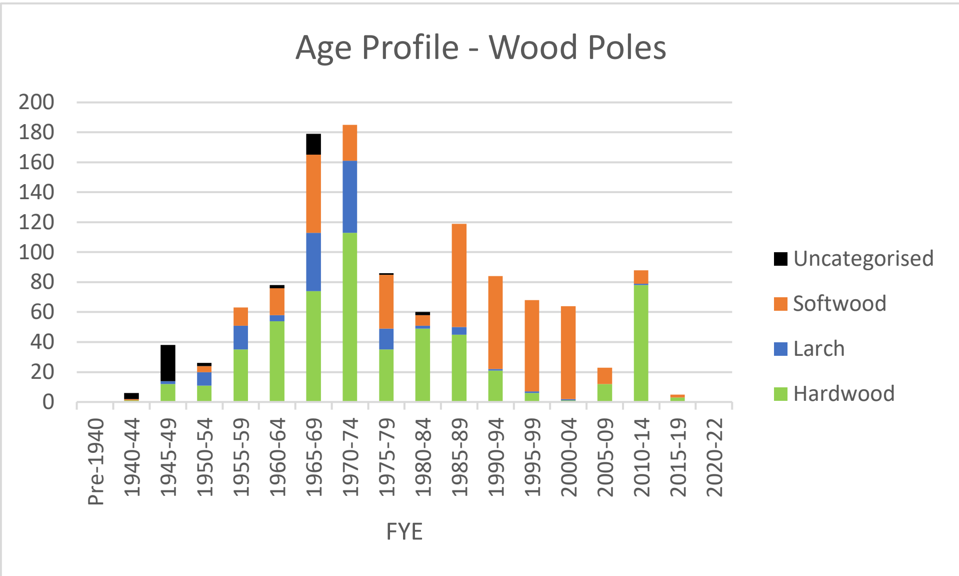


Figure 6:3: Age Profile – Wood Poles

6.3.7 Fiberglass Poles

There are 11 Fiberglass poles on our low voltage network. These have all been installed in the last ten years and are in new condition.

6.3.8 Pole Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Steel and concrete	1,381	7	903	3,006	28,383	1,724	35,403
Wood	15	2	150	798	175	33	1,172
Fiberglass	-	-	-	-	-	11	11

Table 6.2: Health Summary – Poles

6.3.9 Replacement Programme

110kV structures.	• These are critical assets and replacement of structures in poor condition is prioritized. We have allowed for the repainting and replacement of rusted members on one steel tower per year. When the conductor needs to be replaced, which will be sometime after the end of this AMP planning period, we will assess tower condition to determine whether replacement with steel poles is justified. • Our forecast also allows for the replacement of two 110kV pole structures per year, prioritized by structure condition.
Wood poles.	• We have an accelerated replacement programme in place for wood poles as a risk management measure, as pole deterioration is often internal and can be hard to detect. We are planning for the proactive replacement of approximately 85 poles per year, which will see most wood poles on the network replaced over the next 10 years. We are prioritizing replacements using the results of an ultrasonic wood pole testing programme, which covered all wood poles on the network.
Concrete poles.	• Concrete poles deteriorate slowly and usually remain serviceable for many years after end-of-life deterioration becomes apparent. We have allowed for the replacement of approximately 90 concrete poles per year. These are most likely to be L and T shaped poles, particularly where these are located in positions where access for a bucket truck or mobile crane is difficult. We expect our rate of concrete pole replacement to ramp up once most wood poles on our network have been replaced. • Most of our concrete poles were manufactured in Top Energy's own pole factory, which closed in 2007. While these poles have generally given good service, some are now showing signs of accelerated deterioration due to substandard quality control during manufacture. • In the current FYE2023 year we have targeted concrete pole replacements on sections of the Tokerau and Te Kao feeders where the poles are known to be in poor condition and where pole failures can have a high unplanned SAIDI impact due to the number of consumers connected downstream of the fault and the lack of an alternative supply. A total of 214 poles have been replaced on these feeders since FYE2016 with a further 94 to be replaced in the current FYE2023 year. This programme will continue in FYE2024 with the replacement of a further 77 poles on the Te Kao feeder. • A small number of pole replacements each year are reactive and result from events such as vehicle damage or ground subsidence.

6.4 Crossarm Assemblies

6.4.1 Failure Modes

Typical degradation.	• Rusting insulator stems. • Rusting crossarm straps. • Rotting wood.
Accelerated degradation.	• Glass/porcelain insulator breakage (e.g., wind, impact, poor load design or installation).
Known equipment Issues.	• Two-piece ceramic insulator (prone to the top shearing off).

6.4.2 Risk and Mitigation

2-piece insulator failure during in-service handling.	• Pre-work assessment of two-piece insulator condition for work method augmentation and risk mitigation.

6.4.3 Preventive maintenance

Visual Inspection.	• Pole-top condition inspection from ground using binoculars at same time as a pole is inspected. • Reactive post-fault patrols as required.

6.4.4 Corrective and Reactive Maintenance

Pole head hardware.	• Replace affected components (e.g., arms, insulators, binders, straps, bolts).

6.4.5 Replacement Programme

Typically, up to 50% of the SAIDI impact of interruptions due to defective equipment can be attributed to the failure of crossarm assemblies.

As crossarms and insulators are not treated as separate "assets" in our financial system, isolated component replacements are not capitalised. Operational expenditure constraints, and the fact that many crossarm and insulator defects are not seen during ground-based visual asset inspections, has resulted in an inadequate level of historical replacement.

We are introducing a new programme of crossarm and insulator replacements where these components will be proactively replaced over critical distribution network line sections. The line sections to be included in this programme will be selected based on analysis of the location of past high impact interruptions due to insulator and crossarm failure and are likely to be on feeder backbones close to zone substations. Proactive replacements over a defined line section will be treated as projects and capitalised.

6.5 Overhead Conductor

6.5.1 Failure Modes

Interference.	• Foreign object strikes line (e.g., windblown debris, drones). • Vegetation growing into lines (e.g., trees, vines). • Animal climbing or flying into lines (e.g., birds, possums). • Accidental contact (e.g., high load vehicles, fishing lines, people cutting trees).
Typical degradation.	• Connector (e.g., loosening or corroding).

	• Retention device (e.g., loosening, or corroding binder, dead-end, or armour rod). • Degradation from natural environmental exposure.
Accelerated degradation.	• Corrosion in coastal and geothermal environments. • Lightning strike. • Overloading (high demand, underrated conductors). • Vibration.
Known Equipment Issues.	• Steel conductor (rusting and weakening). • Copper conductor (aging and weakening). • Bimetal 'pencil' connector (grease leaching). • Hot tap connector (temporary connector used as a permanent connector). • Two-piece ceramic insulator (prone to the top shearing off).

6.5.2 Risk and Mitigation

Conductor failure during in-service handling.	• All live line work is currently suspended due to updated occupational safety and health requirements.
Close approach service.	• A close approach service is provided to enable contractors to better manage risk where conductors are present.

6.5.3 Preventive Maintenance

Visual Inspection.	• Post fault reactive patrols. • Two-yearly vegetation survey for conductors <33kV. • Annual vegetation survey for conductors ≥33kV.

6.5.4 Corrective and Reactive Maintenance

Conductor.	• Join broken conductors (no conductor replacement). • Cut out and replace damaged sections (partial span replacement). • Whole span replacement (one or more span replacement).

6.5.5 Subtransmission-110kV Conductor

There is a total circuit length of 56km coyote ACSR conductor on the Kaikohe-Kaitaia line. This shows no significant visual indicators of deterioration. The conductor condition was assessed in 2009 and minor galvanisation deterioration was detected in the core. We are also installing vibration dampers when any structures on the line are replaced. Nevertheless, the age of the conductor is such that it could need replacement sometime after the end of this AMP planning period.

We are planning a laser survey of the conductor on a section of the line during our planned FYE2024 maintenance shutdown. The result of this survey will be compared with the result of the 2009 assessment to provide a quantitative indicator of the rate of conductor deterioration. This will assist with the development of a long-term lifecycle asset management strategy that recognises the need to maintain a secure 110kV transmission connection to supply our northern area.

In FYE2021 we commissioned a new 4.7km double circuit line to connect the Ngawha OEC4 generator to our network. This line uses nitrogen AAAC conductor.

6.5.6 Subtransmission-33kV Conductor

Most of our 315km of overhead 33kV subtransmission conductor is AAC, although ACSR has been used over about 33km where extra strength is required. Approximately 36km of recently installed conductor is AAAC. An age profile of our 33kV subtransmission conductor is shown below. This conductor includes the Kaikohe-Wiroa transmission line, as it is currently energised at 33kV.

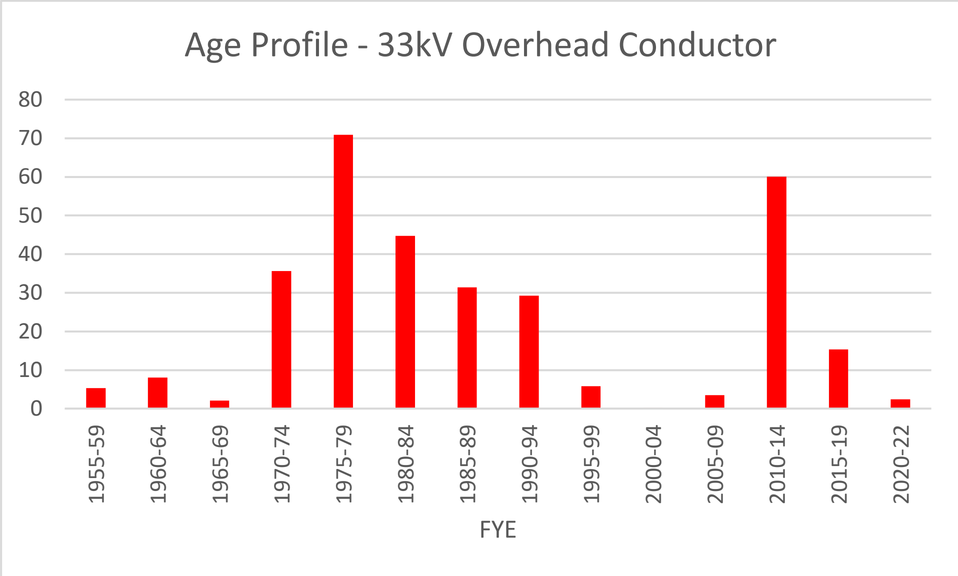


Figure 6.4: **Age Profile – 33kV Conductor**

6.5.7 Distribution Conductor – Two and Three Wire Line

Most of the 2,131km of conductor on our 11kV two- and three-wire network is aluminium or ACSR, although 85km of older copper conductor remains.

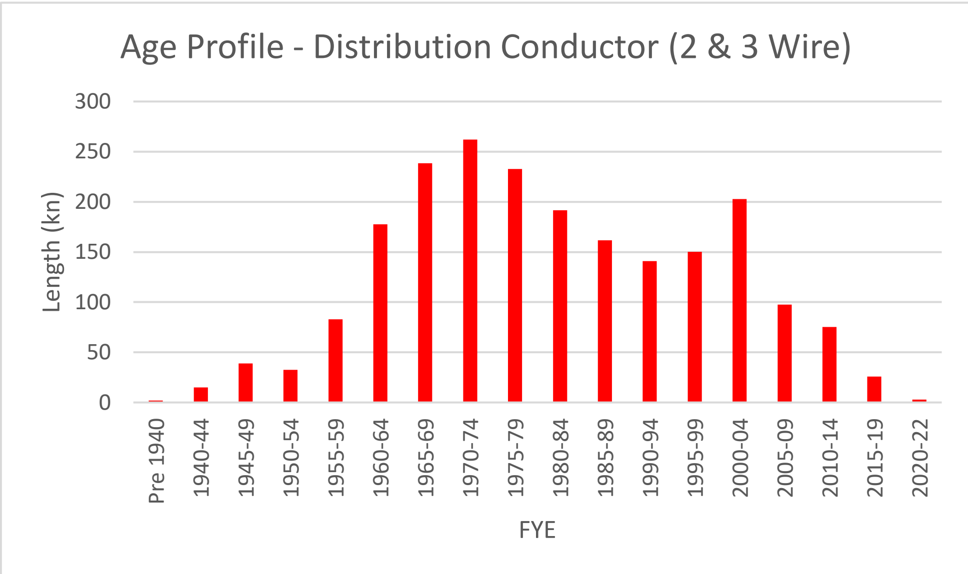


Figure 6.5: **Age Profile – Two and 3 Wire Distribution Conductor**

6.5.8 Distribution Conductor - Single Wire Earth Return Lines

We have 452km of SWER conductor on the network. Around 20km of galvanised steel and 55km of copper conductor remain on this part of the network. The balance is aluminium or ACSR.

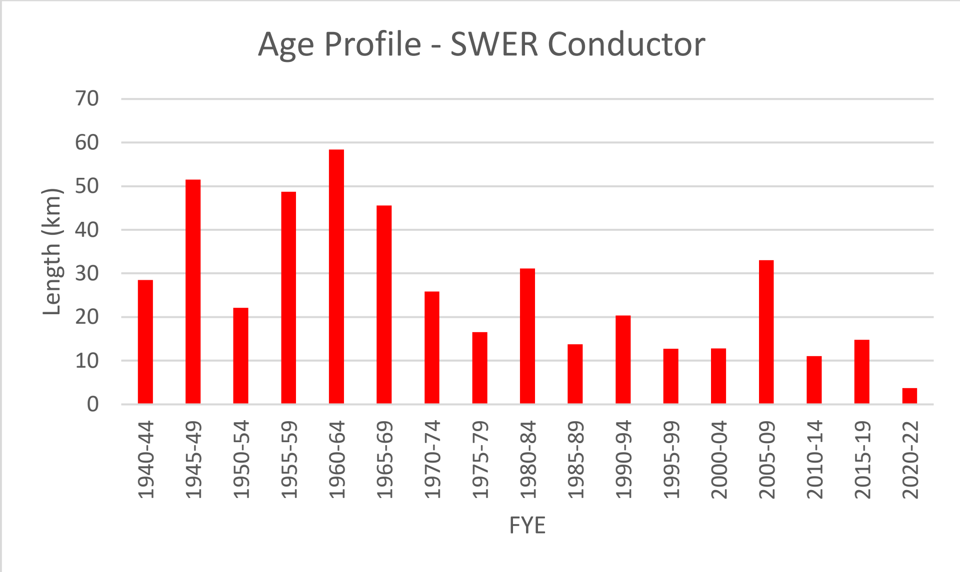


Figure 6.6: Age Profile – SWER Conductor

6.5.9 Low Voltage

We have 218km of low voltage overhead conductor on the network, of which about 120km of mostly older conductor is copper. The balance is aluminium, with a small amount of ACSR.

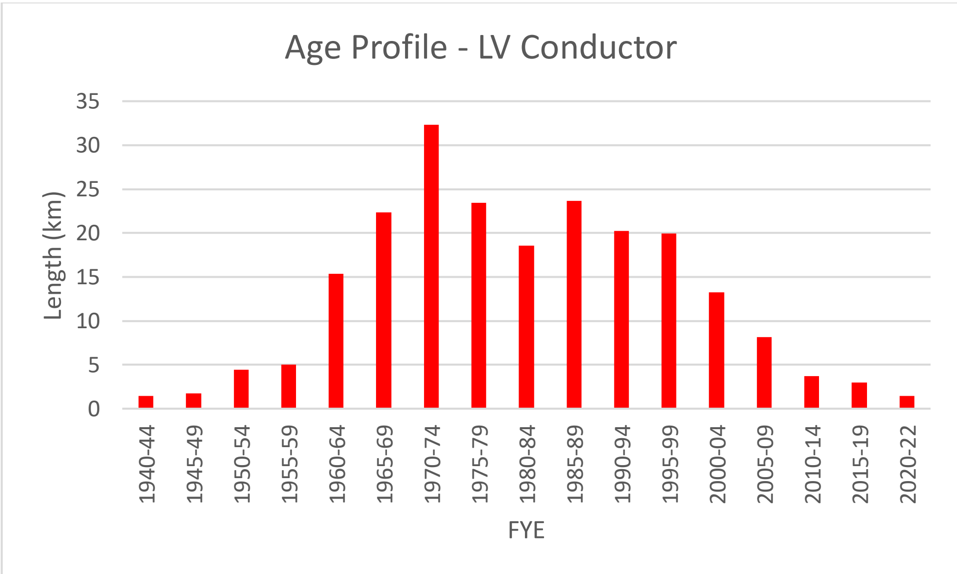


Figure 6.7: Age Profile – Low Voltage Overhead Conductor

6.5.10 Overhead Conductor Health Summary

Circuit-km	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
110kV					56	10	**66**
33kV	-	-	16	50	198	51	**315**
11kV 2 and 3 wire	-	67	259	577	788	441	**2,131**
11kV SWER	-	100	108	82	88	74	**451**
LV	-	5	18	67	93	34	**218**

Table 6.3: Overhead Conductor Health Summary

6.5.11 Replacement Programme

We are planning to replace up to 10 cct-km of conductor per year. This is prioritised as follows:

- Steel conductor: Steel is not a good conductor of electricity, but was used in remote areas, particularly on SWER lines, as it was strong, cheap, and enabled long spans. All our steel conductor has now deteriorated to the point where it has reached end-of life.
- Copper conductor: The copper conductor that remains in service is prone to failure due to its small size and deteriorating condition.
- Mink conductor: We have 85km of mink ACSR conductor on our network, much of which is now well over 60 years old. It is a small conductor that is prone to breakage and can be difficult to repair.

Once the steel conductor on our network has been replaced, we will start progressively replacing our copper and mink conductor, prioritising the conductor sections to be replaced by their condition.

6.6 Cables

6.6.1 Failure Modes

Interference.	• Third party excavation or drilling. • Anchor strike to submarine cables. • Storms moving moorings across submarine cables.
Accelerated degradation.	• Unsealed terminations in LV distribution allows water ingress. • Poor bedding or installation techniques can reduce sheath life.
Known Equipment Issues.	• Insulation used in early XLPE insulated cables is susceptible to water ingress and is known to have a reduced life. Cables installed pre-2000 may be affected.

6.6.2 Risk and Mitigation

Cable strike by third party excavation or drilling.	• A cable location service is provided to enable contractors to better manage risk when working where cables are present.
Damage to marine cable crossing from boat anchor or mooring.	• Signage is installed on shorelines and cable routes are marked on marine charts to minimise the risk of damage to submarine cables and harm to the public.

6.6.3 Preventive Maintenance

Visual.	• Associated equipment inspection. When equipment with a cable termination is checked, then the cable termination is also checked where practicable. • Annual submarine cable crossing signage assessment.

6.6.4 Corrective and Reactive Maintenance

Cable faults.	• Repair sheath damage. • Cut away damaged cable to a good section of the existing cable and join in a new piece. • Overlay larger, damaged sections.
Termination fault.	• Strip back old or damaged termination and repair. • Cut away damaged termination to good cable, join in a new piece, and terminate.

6.6.5 Subtransmission-33kV (XLPE)

We have a total of 23km of 33kV underground cable, all of which is in serviceable or as new condition.

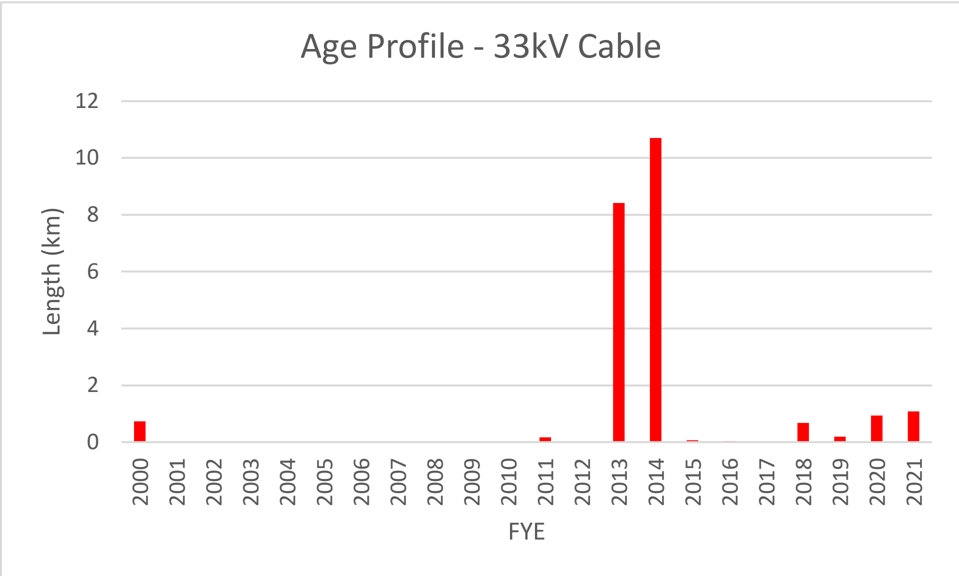


Figure 6.8:Age Profile – 33kV Underground Cable

6.6.6 Distribution

We have a total of 225km of 11kV underground cable on the network. Approximately 32km of mostly older cable is paper insulated, lead covered (PILC). Most of the rest is crosslinked polyethylene (XLPE), although there is a small amount of older PVC cable.

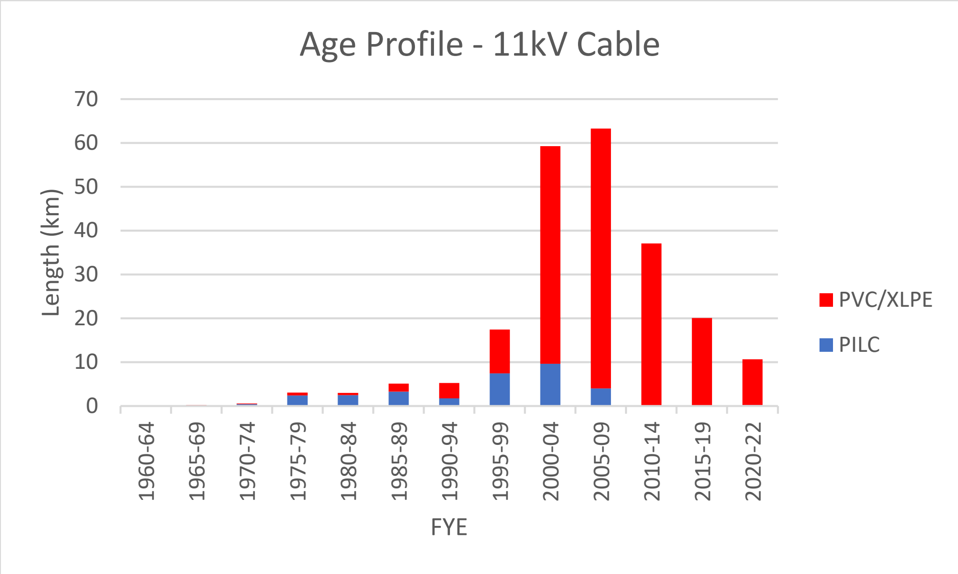
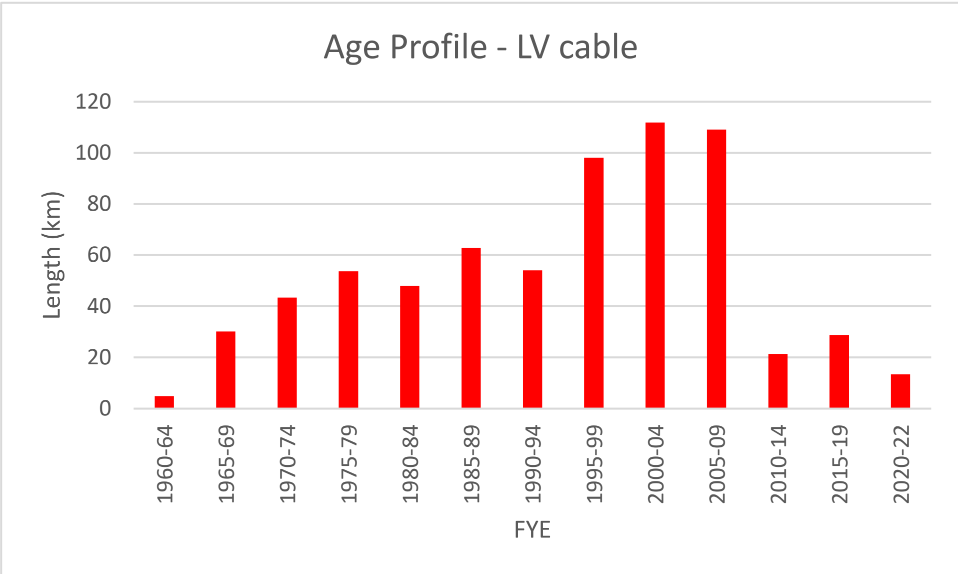


Figure 6.9: Age Profile – Underground Distribution Cable

6.6.7 Low Voltage

All our low voltage cable, including streetlight cable, is PVC insulated.



Note: Excludes streetlight cable

Figure 6.10: Age Profile – Underground Low Voltage Cable

6.6.8 Streetlight Cable

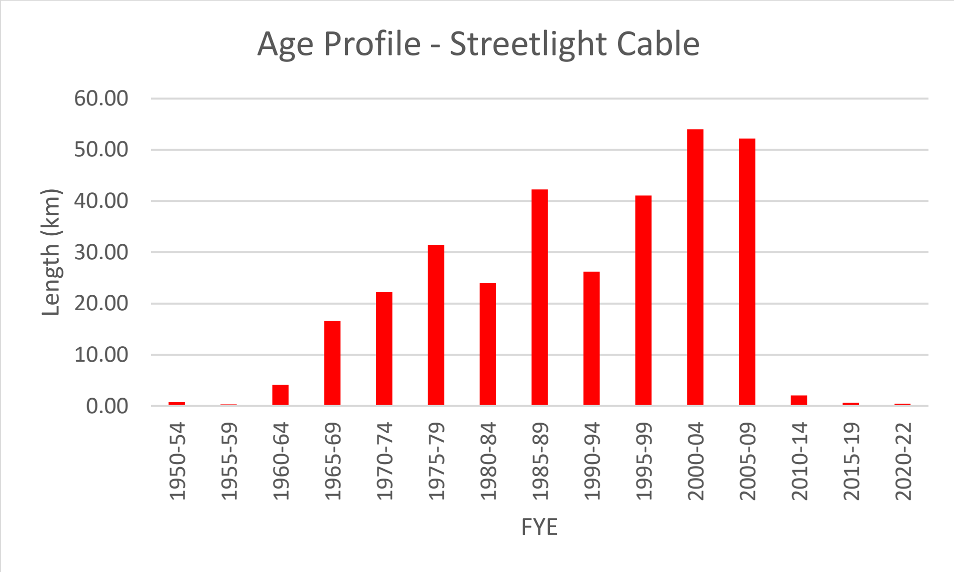


Figure 6.11: Age Profile – Streetlight Circuits

6.6.9 Cable Health Summary

Circuit-km	Unknown	H1 End of Life	**H2 Unreliable**	**H3 Fatigued**	**H4 Serviceable**	**H5 New**	**Total**
33kV	-	-	-	-	1	22	**23**
Distribution-PILC	-	-	1	4	21	6	**32**
Distribution-XLPE/PVC	-	-	1	11	46	146	**193**
LV	-	2	23	126	297	232	**680**
Streetlight	-	3	14	68	149	85	**318**

Table 6.4: Health Summary – Underground Cable

6.6.10 Replacement Strategy

The quantity of cable classified as unreliable, or end of life is primarily low voltage and not considered a critical asset. As unassisted cable failure does not generally create a safety issue, our strategy is to run to failure.

6.7 Distribution Transformers

6.7.1 Failure Modes

Typical degradation.	• Normal environmental exposure causing corrosion. • Seal degradation leading to oil leaks and water ingress. • Minor surface damage from incidental contact with ground mounted units.
Accelerated degradation.	• Corrosion in coastal and geothermal environments. • Overloading causes excessive heat, which breaks down components. • Vehicle impact.

6.7.2 Risk and Mitigation

Exposure to live internal parts.	• Ground mounted transformer enclosures are fitted with locks and bolts to prevent access. Warning notices are attached to equipment advising of the extreme risk within the enclosure. The emergency response number is also attached to enable people to call for help if any problem is identified.
Oil leaking into environment.	• Proximity to drains, waterways and other sensitive locations is considered when installing small distribution transformers. Any leaks identified are contained and repaired, and contaminated soil is disposed of appropriately.
Other issues which present a high risk.	• All distribution transformers are inspected in accordance with our time-based inspection strategy, and any identified safety issues are recorded and programmed for remediation. An emergency response number is also available to the public to report problems.

6.7.3 Age Profiles

6.7.3.1 Pole Mounted Distribution Transformers

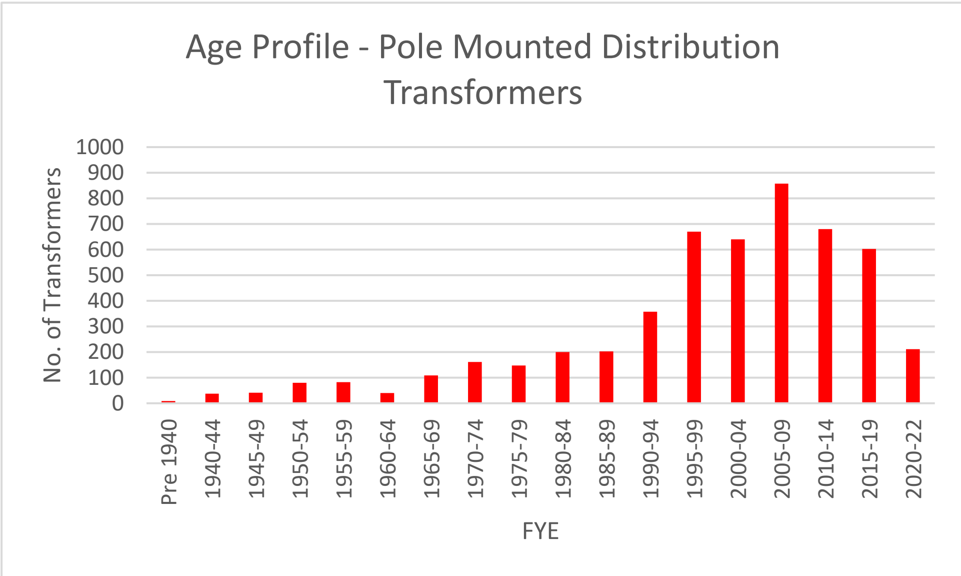


Figure 6.12: Age Profile – Pole Mounted Distribution Transformers

6.7.3.2 Ground Mounted Distribution Transformers

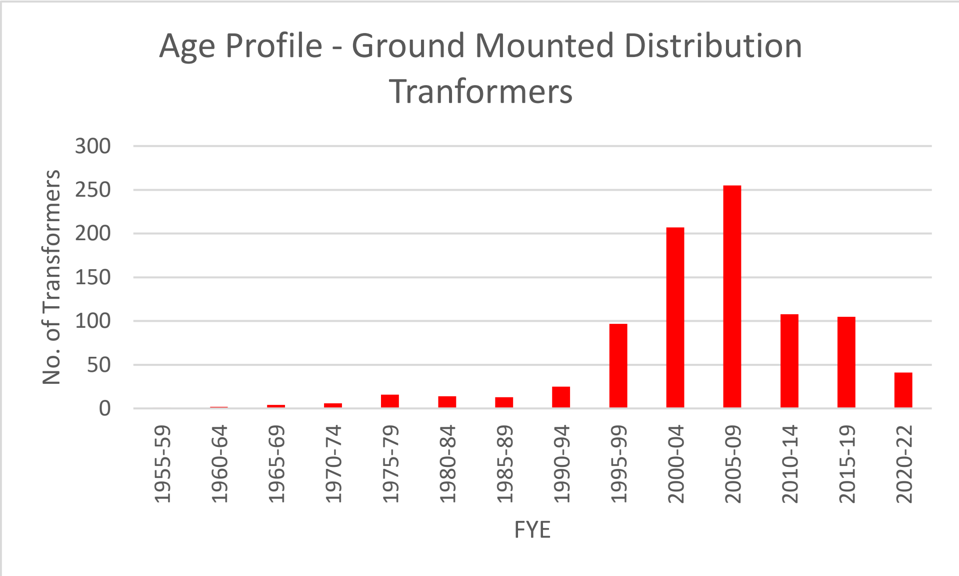


Figure 6.13: Age Profile – Ground Mounted Distribution Transformers

6.7.3.3 Ground Mounted Substation Housings

We have only five distribution substations situated in their own specially constructed buildings; the earliest of which was built in 1960 and the most recent in 2004. All buildings are fit for purpose, although the two oldest buildings are now fatigued.

6.7.4 Distribution Transformer Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Pole mounted	236	-	6	103	4,484	308	**5,137**
Ground mounted	23	1	3	106	703	58	**894**

Table 6.5: Health Summary – Distribution Transformers

6.7.5 Replacement Strategy

Our distribution transformer fleet is generally in good condition with only 10 (0.2%) considered unreliable or end of life. Units are replaced if actual or potential overloading is detected, or if oil leaks or excessive levels of rust are found during asset inspections. Many older transformers are not fitted with surge arresters and a small number of transformers fail each year after being struck by lightning. The condition of distribution transformers removed from service is assessed by an external repair workshop and, if economic, the transformer is refurbished prior to being returned to service.

6.7.6 Voltage Regulators

6.7.6.1 Introduction

Voltage regulators contain parts that are frequently moving, making them susceptible to wear. Oil testing is used to determine the amount of wear and contamination present. When oil testing indicates increased operational risk, then the unit is removed and sent for testing, and reconditioning if economical.

All new and replacement regulators are 32-step, 150-amp units.

6.7.6.2 Failure Modes

Interference.	• Foreign object strikes line (e.g., vegetation, windblown debris). • Vandalism (e.g., objects thrown into power lines). • Accidental contact (e.g., vehicle).
Typical degradation.	• Normal environmental exposure causing corrosion or seal degradation leading to oil leaks, water ingress, exposure of live parts or structural weakening.
Accelerated degradation.	• Corrosion in coastal and geothermal environments. • Overloading causes excessive heat which breaks down components. • Termination failure from poor installation. • Lightning strike.

6.7.6.3 Risk Management

Exposure to live or operable parts.	Equipment is designed to prevent access to live or operable parts by unauthorised persons and minimise the risk of harm by being: • Self-enclosed or contained within an enclosure or compound and secured by a lock or bolts or both. • Mounted on a pole and out of easy reach. Any damage that exposes live parts is treated with urgency and is corrected as soon as practicable.
Oil leaking into environment.	The risk of the proximity to drains, waterways and other sensitive locations is considered when installing equipment containing contaminants. Any leaks identified are contained and repaired. Contaminated material is disposed of appropriately. Larger equipment is bunded and complies with all resource consent requirements. Spill kits and spill response plans are stored at zone substations to manage larger spill events.
Electric shock.	Equipment is fully bonded to an earth system, creating an equipotential zone to minimise the risk of electric shock. Earthing and protection is designed to minimise the risk of exposure to faults.
Public awareness of risks and reporting problems.	Warning notices are attached to enclosures advising of the risks contained within the enclosure. Contact numbers are attached to enclosures, which enable people to call for help if any problem is identified.

6.7.6.4 Preventive Maintenance

Inspection.	• Post fault reactive inspections. • Condition and earth inspections in accordance with our risk-based inspection programme.
Test.	• Oil tests – undertaken as part of inspection programme. • Operational tests undertaken six-yearly. • Ten-yearly earth tests.
Service.	• If oil test results are low, the regulator is removed from service and its condition is assessed. If economical, it is reconditioned.

6.7.6.5 Corrective and Reactive Maintenance

Security malfunction.	• Replace missing or damaged locks.

	• Repair, recondition or scrap equipment with damage that allows access to live or operable parts as appropriate.
Earth system malfunction.	• Repair damaged earth conductors. • Extend or replace earth bank to improve earth bank resistance and functionality.
Mounting and foundation malfunction.	• Replace damaged platform or components. • Re-secure equipment to platform. • Repair subsided foundations and ensure affected equipment is level. • Repair, recondition or scrap equipment with damaged mountings as appropriate.
Equipment leaks.	• Repair, recondition or scrap equipment with oil leak as appropriate.
Environmental contamination.	• Contain any leaks, clean up contamination and dispose of contaminated material responsibly.
Damage affecting equipment safety or operability.	• Repair, recondition or scrap equipment where damage affects the safety and operability of the equipment as appropriate.

6.7.6.6 Age Profile

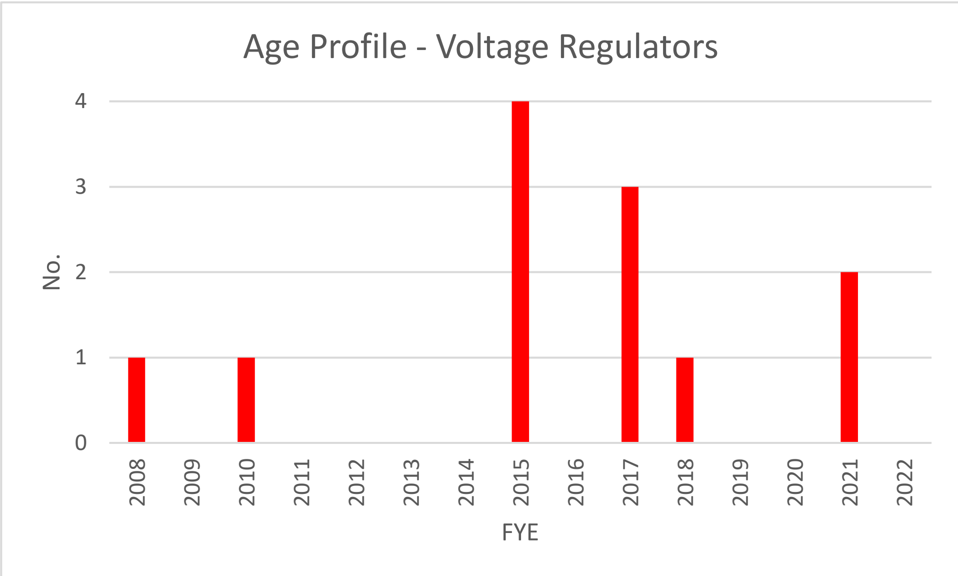


Figure 6.14: Age Profile – Voltage Regulators

6.7.6.7 Voltage Regulator Health Summary

Unknown	H1 End of Life	**H2 Unreliable**	**H3 Fatigued**	**H4 Serviceable**	**H5 New**	**Total**
-	-	-	1	7	4	**12**

Table 6.6: Health Summary – Voltage Regulators

6.7.6.8 Replacement Strategy

Regular maintenance is required due to the frequency of regulator operation while in service, and we maintain a spares inventory so that units can be rotated in and out of service to allow this. We do not envisage a need to replace any of our existing fleet over the planning period. However, some of the structures on which our regulators are mounted have deteriorated to the point where refurbishment is required, and our capital replacement forecast provides for this.

6.8 Zone Substations

6.8.1 Buildings and Grounds

6.8.1.1 Introduction

Substation buildings are constructed with a variety of materials and styles. Construction is to Building Code requirements and the buildings are expected to remain serviceable for many decades. Our oldest building was constructed in 1939 and remains in a serviceable condition.

Asbestos is present at some substations. This asbestos is non-friable and low risk. It will be removed when any building is refurbished.

A shipping container has been utilised to house control equipment at Mt Pokaka substation and containers are also used as housings for our generator sets.

6.8.1.2 Failure Modes

Interference.	• Vandalism (e.g., damage to buildings, enclosures, break-ins, theft of equipment). • Pests (e.g., animals, insects, nesting).
Typical degradation.	• Spalling, rotting, rusting of structural elements. • Cladding degradation due to normal environmental exposure. • Foundation movement.
Accelerated degradation.	• Material degradation in coastal and geothermal environments. • Leaks or flooding accelerating degradation to structural elements. • Vehicle impact.

6.8.1.3 Risk Management

Access to energised or operable equipment by unauthorised persons.	Switchyards are enclosed with security fencing. Buildings and enclosures are locked with high security locks. Security keys are carefully managed to minimise the risk of coming into the possession of unauthorised persons. Security cameras, electronic key access and remote monitoring is installed at zone substations. Substations are checked monthly to confirm security measures remain intact and functioning as intended.
Water or pest ingress affecting equipment operation.	Substations are inspected monthly. If leaks or pests are detected, then ingress points are sealed, and any leaks or pests are cleaned up or removed. Any affected equipment is checked for damage and remediated as necessary.
Asbestos exposure.	Signage is present at all substations warning of the potential risk. Cutting or moving of building materials is prohibited. If cutting or moving of building material is necessary, then the problem is escalated, and a specialist will be engaged to provide support.
Hazardous material spills.	Signage is present at all substations warning of the presence of hazardous substances. Spill kits and emergency plans are also available at each substation.
General hazard management.	Signage is present at all substations stating minimum personnel protective equipment (PPE) requirements. Workers entering a site are required to assess and manage hazards. A hazard board is also installed to enable workers to notify others of hazards. A defect reporting process enables issues to be registered, prioritised, and scheduled for remediation.

6.8.1.4 Preventive Maintenance

Inspection.	• Monthly inspection of security (e.g., doors, windows, locks, security fence), services (e.g., lights, power points, water, wastewater), pests, leaks (e.g., building, water pipes, wastewater system) and air-conditioning. • Quarterly Inspection of transformers, switchgear, bus, panels, AC/DC systems, earth connections, communications equipment.
Test	• Quarterly assessment of all primary electrical equipment with a thermal camera and partial discharge detector.
Service	• Sweep/vacuum in non-hazardous areas, replace consumables (e.g., soap, toilet paper) during monthly inspections. • Wash building exterior as required. • Mow lawns, maintain gardens, check boundary fence monthly.

6.8.1.5 Corrective and Reactive Maintenance

Security malfunction.	• Replace missing or damaged locks. • Repair or replace doors, windows, and gates, as necessary. • Engage service provider to repair malfunctioning monitored electronic security system.
Equipment in distress.	• Take safety precautions, escalate the issue, and initiate remedial action as appropriate to the level of risk.
Building leaks.	• Minimise the risk of damage to sensitive equipment. • Engage service provider to remediate the leak and replace any damaged structural elements or cladding. • Inspect, test, and repair any equipment damaged by the leak as appropriate.
Ground subsidence	• Engage service provider to assess the extent of the subsidence. • Undertake action to mitigate any risks associated with the subsidence. • Reinstate the subsidence to original state if practicable. • Undertake any repairs to building or equipment affected by the subsidence if possible. Significant subsidence, like that incurred through an earthquake, sinkhole, landslide, or tsunami, may result in irreparable damage to the site.

6.8.1.6 Substation Buildings

We have three 110kV substation buildings, one constructed in 1939 and a second in 1945. Both remain in a serviceable condition. The third building is the control room for the recently commissioned Ngawha 110kV switchyard. Other substation buildings include zone substation control and switchgear rooms and a small number of small buildings housing distribution substations. The fatigued buildings in the age profile below are the Pukenui control building, two distribution substation housings and the old control rooms at Moerewa and Kaikohe zone substations, which are now used for storage. All remain fit for purpose, based on their current use.

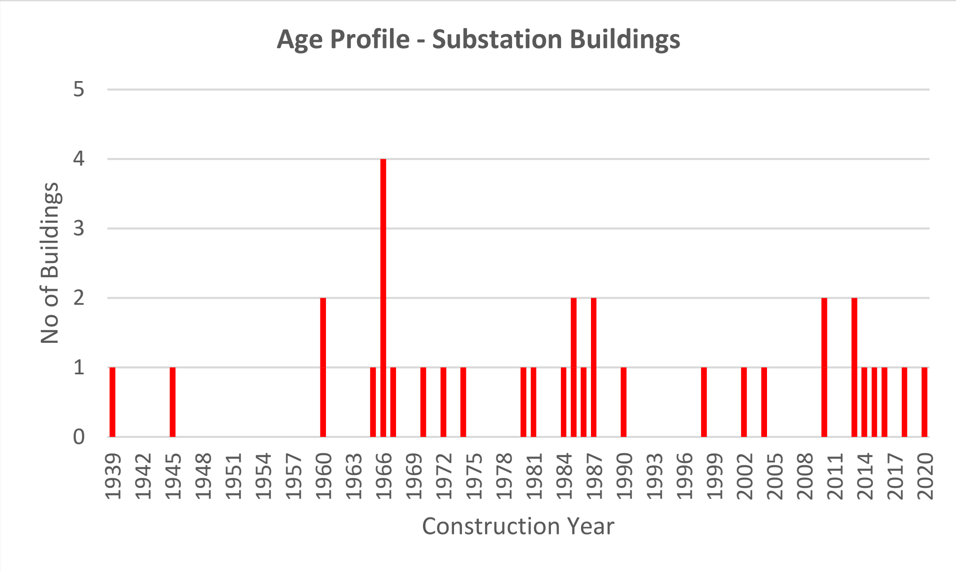


Figure 6.15: Age Profile – Substation Buildings

6.8.1.7 Substation Building Health Summary

Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
-	-	-	5	18	11	34

Table 6.7: Health Summary – Substation Buildings

6.8.1.8 Replacement Strategy

Building maintenance on all substation buildings will be undertaken as required to ensure all remain fit for purpose.

6.8.2 Power Transformers

6.8.2.1 Maintenance Strategy

Our zone substation power transformers are visually inspected every three months as part of our technical substation inspection programme. There is also a monthly non-technical walk through as part of the grounds and buildings inspection strategy, where any obvious issues may be identified and reported.

The transformers are also subject to a four-yearly servicing strategy. This an overall condition assessment, clean and protection scheme testing and service.

We undertake oil sampling and testing of our power transformers every year. The results of these tests are analysed for any immediate potential issues and feed into longer term life cycle strategies.

6.8.2.2 Age Profile

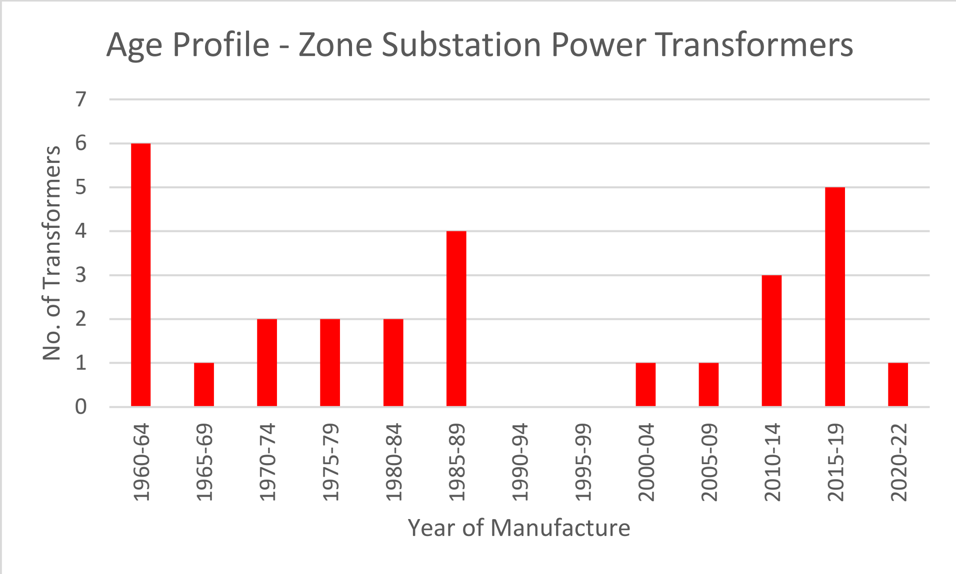


Figure 6.16: Age Profile – Power Transformers

6.8.2.3 Power Transformer Health Summary

In February 2023 we received an initial report from an external consultant on the condition of our power transformer fleet. The report indicated five transformers in unreliable condition, Pukenui, Taipa, Kawakawa T1 and Kaikohe T11 and T12. A further 11 transformers were considered fatigued. The report found that many of our order transformers were in worse condition than indicated by our regular oil testing regime. This is thought to be because oil purification treatment was applied to some of our older transformers some forty years ago and this has not been considered when interpreting the results of our oil tests as the old paper records are no longer available. It is therefore possible that the condition of the transformer oil is not an accurate indication of the condition of the paper insulation.

		Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
Total		-	-	5	11	7	5	28

Table 6.8: Health Summary – Power Transformers

6.8.2.4 Power Transformer Replacement Strategy

The results of the report are yet to be peer reviewed, however of the five transformers categorised as unreliable, only Pukenui and Taipa are at single transformer substations. Pukenui has back up generation at the substation while the mobile substation is stationed at Taipa on a permanent basis, unless required for an emergency elsewhere on the network. Should the Pukenui transformer fail, we would replace it with one of the Moerewa transformers and if the Taipa transformer failed we would replace it with one from Kaeo. Both replacement transformers are located at two-transformer substations and are in new condition. The other three transformers are in two-transformer substations and, should one fail, the second transformer would pick up the load. We note that the Kaikohe transformers are not fully loaded and more than 20% of the load on the Kawakawa substation should be transferred to Haruru before the FYE2024 winter.

Therefore, we are well placed to deal with the unexpected failure of one of these five transformers. Nevertheless, the consultant's report has highlighted the need for us to develop a power transformer fleet management strategy that identifies the replacement or refurbishment requirements of individual transformers and includes a time-based programme for undertaking this work. The costs of this programme will be included in the expenditure forecasts in our 2024 AMP Update.

6.8.3 Circuit Breakers

6.8.3.1 Maintenance Strategy

Oil filled substation circuit breakers are serviced every four years. This includes an operational check and may include an oil change and contact replacement, depending on the condition and the number of operations.

6.8.3.2 Outdoor 110kV Circuit Breakers

We have 10 outdoor 110kV circuit breakers, five at Kaikohe, three at Kaitaia and two at Ngawha. The two unreliable units are older oil filled units at Kaitaia. One of these is programmed for replacement in FYE2025 and the second is not in service but is an identical circuit breaker that is kept as a spare. All other 110kV breakers are SF_6 insulated.

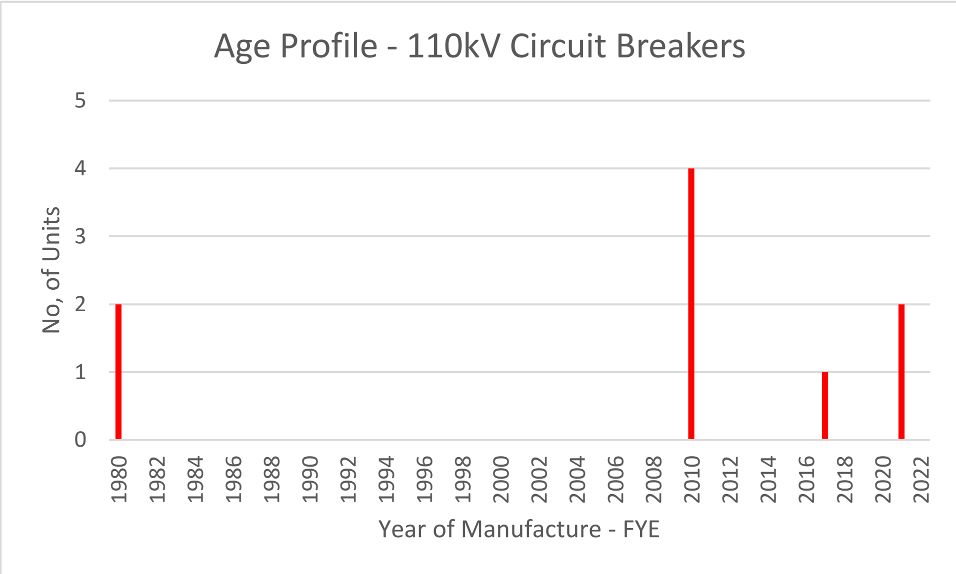


Figure 6.17: Age Profile – 110kV Circuit Breakers

6.8.3.3 Indoor 33kV Circuit Breakers

We have 44 indoor 33kV circuit breakers on the network at Kaikohe, Wiroa, Moerewa, Kerikeri and Kaeo substations. They were installed between FYE2014 and FYE2018 and all are in as new or serviceable condition.

6.8.3.4 Outdoor 33kV Circuit Breakers

The outdoor 33kV circuit breakers at Kaitaia and a limited number of other outdoor units scattered across the network are oil filled. The remainder are either vacuum or SF_6 units.

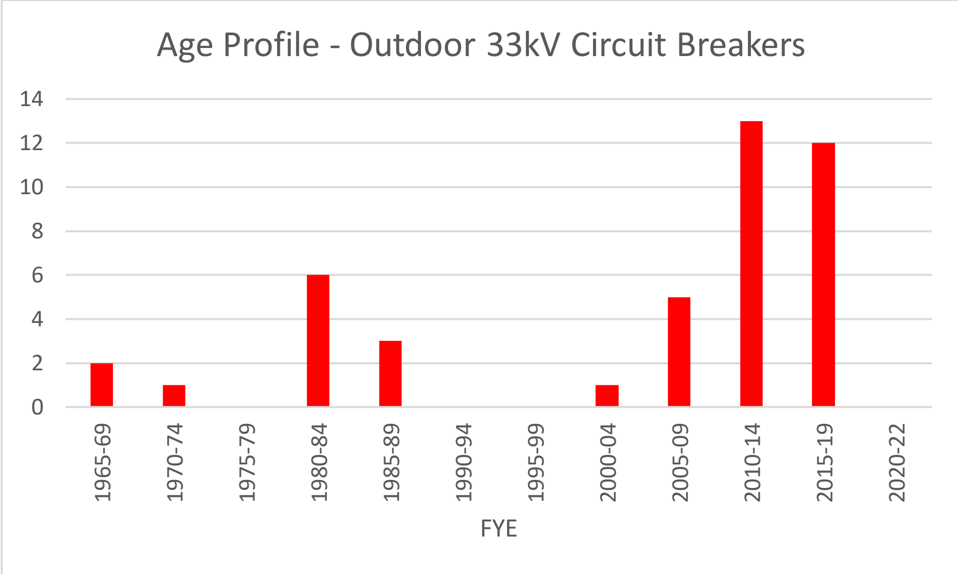


Figure 6.18: Age Profile – 33kV Outdoor Circuit Breakers

6.8.3.5 11kV Circuit Breakers

We have 115 11kV circuit breakers in our zone substations, all of which are ground mounted, except for three units at Pukenui. While most ground mounted units are part of an indoor switchboard, a number are enclosed, individual ground mounted outdoor units. The indoor circuit breakers at Kaikohe, Okahu Rd and Taipa substations are oil filled but all other 11kV circuit breakers are either vacuum or SF_6.

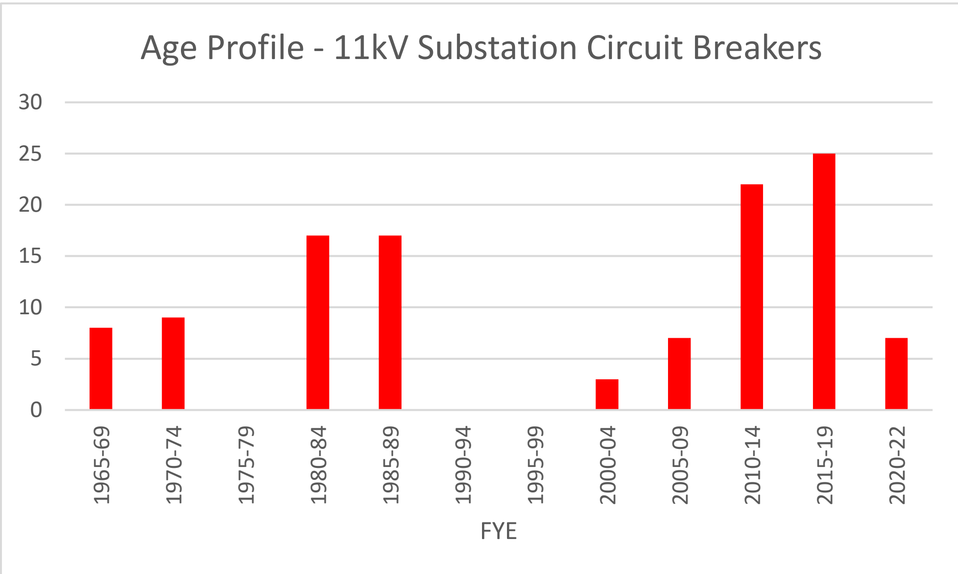


Figure 6.19: Age Profile – 11kV Circuit Breakers

6.8.3.6 Circuit Breaker Health Summary

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
110kV Outdoor		-	2	-	4	3	**10**
33kV Indoor	-	-	-	-	3	41	**44**
33kV Outdoor	1	-	-	4	26	12	**39**
11kV	1	-	6		87	21	**115**

Table 6.9: Health Summary – Circuit Breakers

6.8.3.7 Circuit Breaker Replacement Strategy

As noted in Section 6.9.3.1, we plan to replace the in-service, unreliable 110kV circuit breaker at Kaitaia by FYE2025.

6.9 Switchgear

6.9.1 Introduction

6.9.1.1 General

A variety of switchgear types has historically been utilised. Switchgear manufacturers have used several medium for insulation and arc quenching, some of which (e.g., oil) have now been superseded, while other equipment no longer meets safety or operational requirements, such as arc flash management and remote-control operation).

Design requirements for new switchgear include, as appropriate:
- Remote control and SCADA visibility.
- Elevated switch handles.
- Non-withdrawable gear.
- Arc flash containment.
- Plug in cable connections.
- Stainless steel for coastal installations.

6.9.1.2 Air-Break Switchgear

We no longer buy new air-break switches. Existing air-break switchgear is replaced at end-of-life with switchgear fitted with vacuum or SF_6 interrupters, and with air, resin or SF_6 insulation as appropriate for the application. Pole mounted switches are replaced with stick operated units or are retrofitted with a rocker arm for stick operation. This minimises the risks associated with having a handle within reach of the ground and the need for an associated earth system. Remote operation may also be provided when a unit is replaced.

6.9.1.3 Oil Filled Switchgear

Oil filled switchgear is being phased out due to its:
- High maintenance requirement.
- Flammability in certain failure conditions.
- Environmental impact as a contaminant.

We no longer purchase oil filled switchgear and new plant is fitted with vacuum or SF_6 interrupters and air, resin or SF_6 insulation as appropriate for the application. Remote operation may also be provided for when a unit is replaced.

6.9.2 Failure Modes

Interference.	• Foreign object (e.g., vegetation, pests).

	• Vandalism. • Accidental contact (e.g., vehicle).
Typical degradation.	• Normal environmental exposure causing corrosion or seal degradation, leading to oil leaks, water ingress, exposure of live parts or structural weakening.
Accelerated degradation.	• Corrosion in coastal and geothermal environs. • Termination failure from poor installation. • Lightning strike.

6.9.3 Risk Management

Exposure to live or operable parts.	Equipment is designed to prevent access to live or operable parts by unauthorised persons and minimise the risk of harm by being: • Self-enclosed or contained within an enclosure or compound and secured by a lock or bolts or both. • Mounted on a pole and out of easy reach. Any damage that exposes live parts is treated with urgency and is corrected as soon as practicable.
Oil leaking into environment.	The risk of the proximity to drains, waterways and other sensitive locations is considered when installing equipment containing contaminants. Any leaks identified are contained and repaired. Contaminated material is disposed of appropriately. Larger equipment is bunded and complies with all resource consent requirements. Spill kits and spill response plans are stored at substations to manage larger spill events.
Electric shock.	Equipment is fully bonded to an earth system creating an equipotential zone to minimise the risk of electric shock. Earthing and protection is designed to minimise the risk of exposure to faults.
Molten metal from ABS operation igniting scrub.	• Operational conditions are checked prior to operation to minimise the associated risks. • Replacement switches are selected to minimise this risk.
Switch fails and vents in public place.	To date, this has never happened on our network. New switchgear is selected the minimise the risk of arc flash and explosive failures. This risk is progressively being reduced as equipment condition or operational requirements drive replacement.
Public awareness of risks and reporting problems.	Warning notices are attached to enclosures advising of the risks contained within. Contact numbers are attached to enclosures, which enable people to call for help if any problem is identified.

6.9.4 Preventive Maintenance

Inspection.	• Switchgear is reactively inspected following a fault that may have resulted in equipment damage. • Field-mounted switchgear is routinely inspected in accordance with our risk-based asset inspection programme. • Substation switchgear is included in our quarterly zone substation inspections.
Service.	• Batteries on remote controlled switchgear are replaced every six years.
Test *(field).*	• Six-yearly remote management system test. • Four-yearly oil test for oil-filled switchgear. • Ten-yearly earth test.

Test *(substation).*	• Two-yearly earth bond test. • Two-yearly remote management system test.

6.9.5 Corrective and Reactive Maintenance

Security malfunction.	• Replace missing or damaged locks. • Repair, recondition or scrap equipment with damage that allows access to live or operable parts as appropriate.
Earth system malfunction.	• Repair damaged earth conductors. • Extend or replace earth bank to improve earth bank resistance and functionality.
Protection system malfunction.	• Check and test that protection system meets design standard. • Correct, repair, or replace protection to meet design standard.
Mounting and foundation malfunction.	• Repair or replace hanger arm, platform, pad, or components. • Re-secure equipment to hanger arm, platform, or pad. • Repair subsided foundations and ensure affected equipment is level. • Repair, recondition or scrap equipment with damaged mountings as appropriate.
Equipment leaks.	• Repair, recondition or scrap equipment with oil leak, as appropriate.
Environmental contamination.	• Contain any leaks, clean-up contamination and dispose of contaminated material responsibly.
Damage affecting equipment safety or operability.	• Repair, recondition or scrap equipment where damage affects the safety and operability of the equipment, as appropriate.

6.9.6 Ground Mount 33kV Switches

We have 48 Ground mount 33kV switches on the network. All were installed in FYE2018 or later and all are in as new condition.

6.9.7 Pole Mount 33kV Switches

6.9.7.1 Age Profile

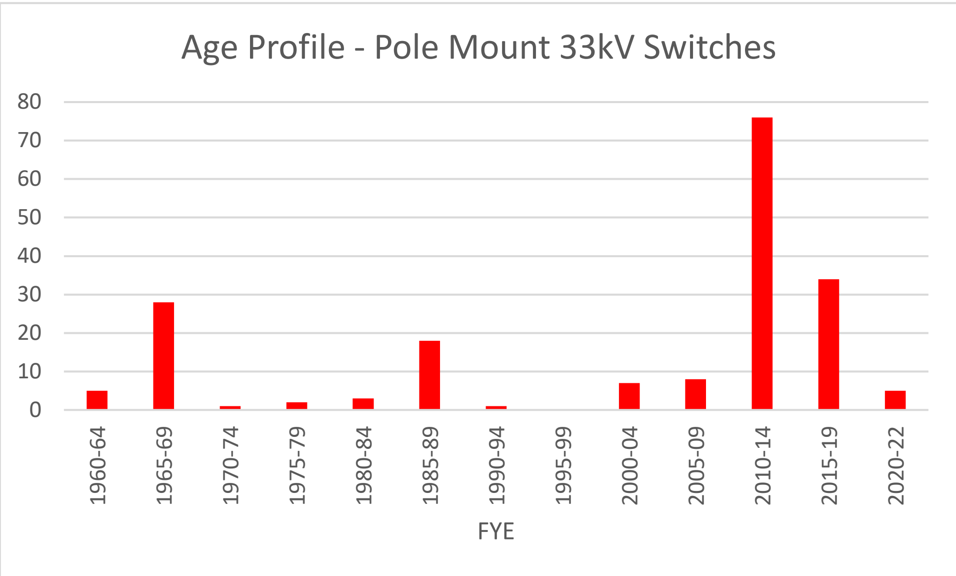


Figure 6.20: Age Profile – 33kV Switches

6.9.8 Overhead Distribution Switches and Links

6.9.8.1 Age Profile

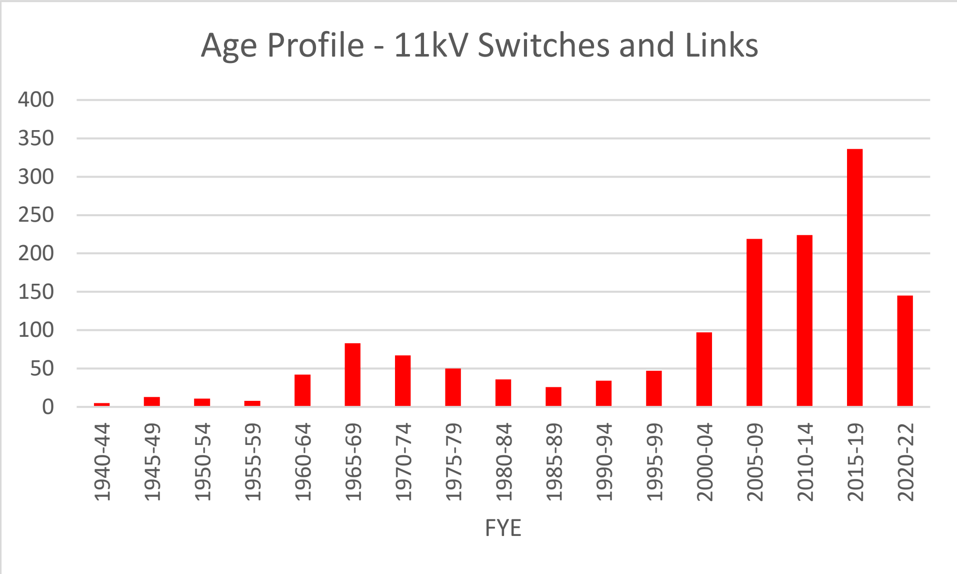


Figure 6.21: Age Profile – Overhead Distribution Switches

6.9.9 Sectionalisers and Reclosers

6.9.9.1 Age Profile

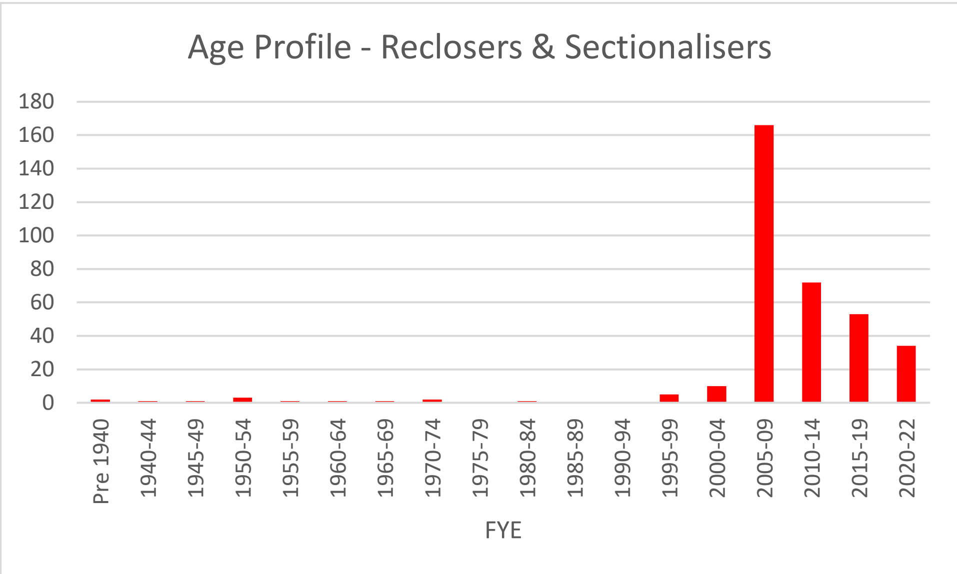


Figure 6.22: Age Profile - Sectionalisers

6.9.10 Ring Main Units

6.9.11 Age Profile

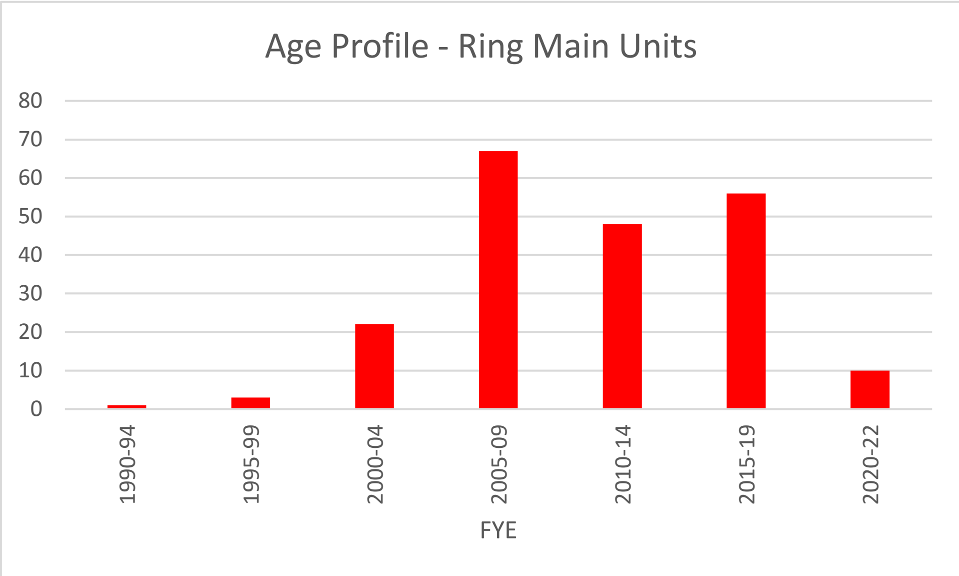


Figure 6.23: Age Profile – Ring Main Units

6.9.12 Health Summary - Switchgear

	Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
33kV Switch - ground mount						48	**48**
33kV Switches - Pole Mount	4	1	-	1	102	75	**188**
11kV Switches/ Links	19	108	163	198	310	645	**1443**
Reclosers / Sectionalisers	5	1	-	15	276	56	**353**
Ring Main Units	9	-	1	5	20	173	**207**

Table 6.10: Health Summary – Distribution Fuses

6.9.13 Switchgear Replacement Strategy

Our capital expenditure forecast provides for the proactive replacement of seven ring main units, five 11kV and two 33kV air-break switches annually.

Our health assessment of 11kV fuse links indicates a substantial number that have reached end-of-life. These are generally run to failure, as a failure in service generally does not have a significant SAIDI or safety impact.

6.9.14 Underground Service Fuse Pillars

6.9.14.1 Failure Modes

Interference.	• Vandalism. • Accidental contact (e.g., vehicle, mower).
Accelerated degradation.	• Flooding. • Foundation subsidence. • Poor design or installation.

6.9.14.2 Risk Management

Exposure to live or operable parts.	• Equipment is designed to prevent access to live or operable parts by unauthorised persons, and to minimise the risk of harm by being self-enclosed and secured by bolts. • Any damage that exposes live parts is treated with urgency and is corrected as soon as practicable. • Earlier boxes were constructed with bare lugged connections. These are replaced with sealed systems upon replacement of the box, which makes them less likely to expose live parts if the security is compromised.
Poor connections overheat and damage box.	• Connections that come loose over time, or through poor installation practice, will overheat. This often burns-out the fuse base and mountings. Occasionally, the location of the fuse and the intensity of the heat is enough to melt the enclosure. New fuse bases utilise shear-off bolted connections ensuring the connection is properly tightened.
Box is regularly damaged.	• Any pillar that suffers repeated breakdown due to exposure to an event (i.e., location makes it prone to vehicular impact, vandalism, flooding, erosion, vegetation) will be considered for relocation or redesign to manage any associated risk.

6.9.14.3 Preventive Maintenance

Inspect.	• Post fault reactive inspection • Routine inspections in accordance with our risk-based asset inspection strategy

6.9.14.4 Corrective and Reactive Maintenance

Security malfunction.	• Replace missing screws or, if this is not possible, use self-tapping screws to secure enclosure. • Replace box if enclosure cannot be secured.
Box is not secured to ground.	• Reinstate any ground subsidence. • Correct improper installation work.
Box cannot be accessed.	• Remove any obstructions. • Redesign and relocate to a more accessible location.

6.9.14.5 Age Profile

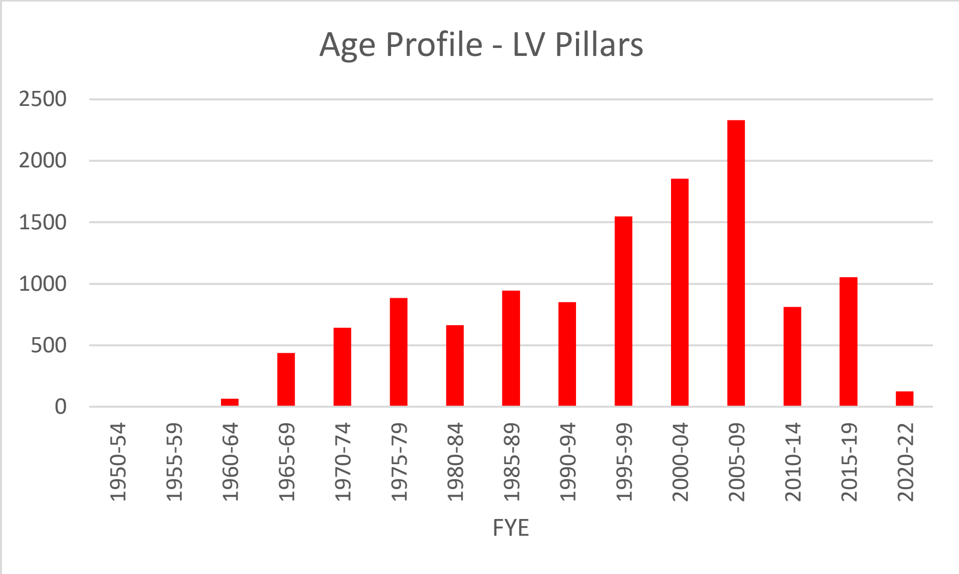


Figure 6.24: Age Profile – Underground Service Pillars

6.9.14.6 Underground Service Fuse Pillar Health Summary

Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
871	-	67	2,093	7,915	1,278	**12,224**

Table 6.11: Health Summary – Underground Service Pillars

6.9.14.7 Replacement Strategy

Fiberglass boxes can become brittle while metal boxes require earth systems for safety, so we now use plastic boxes to avoid these issues. There are very few Fiberglass or metal boxes remaining on the network and they are targeted for replacement when identified. Assets identified as being a safety hazard, either on inspection or following reports from the public, are also replaced. We anticipate replacing around 15 boxes per year.

6.10 Other

6.10.1 Protection Equipment

6.10.1.1 Failure Modes

Interference.	• Foreign object tangled in protection device (e.g., vegetation, windblown debris). • Vandalism (e.g., objects thrown into protection device, component theft).
Typical degradation.	• Normal environmental exposure causing corrosion or seizing of components. • Battery or power supply failure. • Repeated fault exposure.
Accelerated degradation.	• Corrosion in coastal and geothermal environments. • Condensation. • Pests (e.g., animals, insects, nesting). • Poor design or installation.

- Lightning strike.

6.10.1.2 Risk Management

Exposure to live or operable parts	Equipment is designed to prevent access to live or operable parts by unauthorised persons and minimises the risk of harm by being: • Self-enclosed or contained within an enclosure or compound and secured by a lock, or bolts, or both. • Mounted on a pole and out of easy reach. Any damage that exposes live parts is treated with urgency and is corrected as soon as practicable.
Protection system power supply or communications failure	Systems requiring power supplies or communication systems are routinely checked and tested. Equipment with these systems is often self-monitoring and provides warnings prior to failure if conditions indicate a problem.

6.10.1.3 Preventive Maintenance

Inspect *[Distribution].*	• Post-fault reactive inspections. • Ten-yearly earth and condition inspection. • Hardware, including protection devices, that are attached to poles are visually checked during programmed pole inspections.
Test *[Distribution].*	• Six-yearly protection relay test. • Ten-yearly earth test.
Inspect *[Substation].*	• Protection devices are visually checked during substation inspections.
Test *[Substation].*	• Annual earth grid and bond test. • Four-yearly protection relay test.

6.10.1.4 Corrective and Reactive Maintenance

Equipment malfunction.	• Diagnose malfunction and repair or replace faulty component.
Fuse arrester, or protection operation.	• Investigate cause of protection operation. • Remediate fault cause. • Reset or replace protection device as appropriate.
Earth system damage.	• Repair earth system.

6.10.1.5 Protection Relay Age Profiles

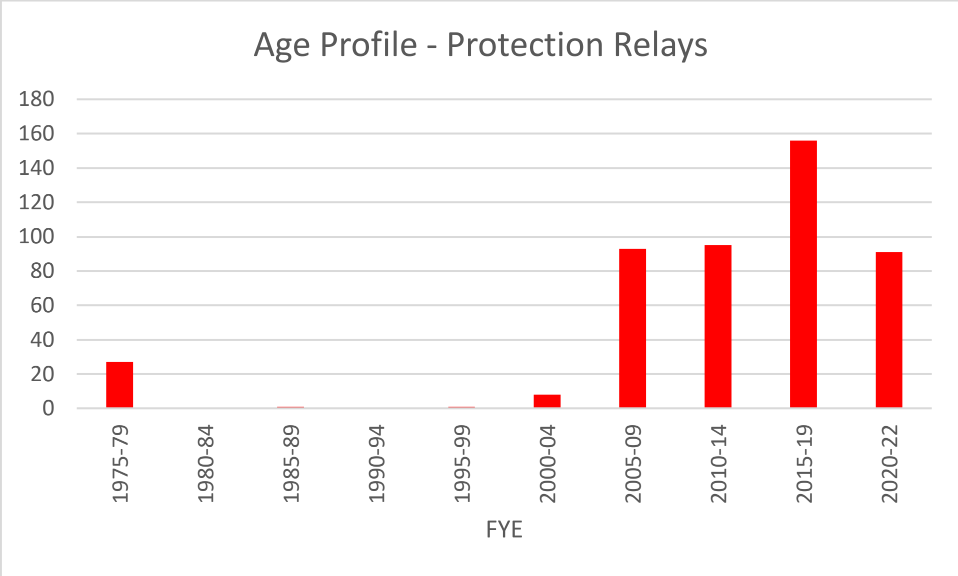


Figure 6.25: Age Profile – Substation Protection Relays

6.10.1.6 Protection Relay Health Summary

Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
-	35	-	7	137	291	**471**

Table 6.12: Health Summary – Substation Protection Relays

6.10.1.7 Replacement Strategy

Obsolete mechanical relays remain at both Kaikohe 110kV substation and on the 11kV switchboard at the Kaikohe zone substation. These relays are still serviceable and will be replaced if testing shows them to be unreliable.

6.10.2 SCADA and Communications

While we have replaced our SCADA master station with an ADMS, the hardware outside our control room is being retained and incorporated into the new system.

6.10.2.1 Failure Modes

Interference.	• Foreign object blocks signal (e.g., vegetation, structure, aerial damage). • Vandalism (e.g., damage, theft of components).
Typical degradation.	• Normal environmental exposure causing corrosion. • Power supply failure (e.g., battery, charger). • Water or pest ingress (e.g., condensation, ants).
Accelerated degradation.	• Corrosion in coastal and geothermal environs. • Lightning strike.

6.10.2.2 Risk Management

Exposure to live or operable parts.	Equipment is designed to prevent access to live or operable parts by unauthorised persons and minimise the risk of harm by being:

	• Self-enclosed or contained within an enclosure or compound and secured by a lock, or bolts, or both. • Mounted on a pole and out of easy reach. Any damage that exposes internal parts is treated with urgency and is corrected as soon as practicable.
Loss of equipment operational control or telemetry Server failure	• Communication systems are routinely checked and tested. These systems are often self-monitoring and provide warnings if conditions indicate a problem. • A disaster recovery site exists at Ngawha, which can be used in the event of a server failure.
Tele-communications failure	Multiple communication pathways exist in case of a telecommunications failure. Service level agreements are in place with service providers to minimise any downtime. If there are multiple pathway failures, then remote control equipment can be manually operated and locally monitored.

6.10.2.3 Preventive Maintenance

Inspection *[Distribution].*	Post-fault reactive inspection.
Inspection *[Substation].*	Quarterly battery and charger inspection.
Test.	Six-yearly remote-controlled communications and SCADA functional test.
Service.	Six-yearly remote-controlled communications and SCADA battery replacement.

6.10.2.4 Corrective and Reactive Maintenance

Equipment malfunction.	Diagnose malfunction and repair or replace faulty component.

6.10.2.5 RTU Replacement

Remote terminal units (RTU) are installed in our zone substations and in the field. While we have not prepared an RTU age profile or a fleet condition assessment, about ten substation RTUs and 30 field units are obsolete, in that they are no longer supported by the manufacturer. We respond to failures of these units using spare parts from our inventory and from units that have been removed from service for various reasons while still operational. We anticipate being able to keep these obsolete units serviceable using this approach for a further ten years in the case of substations, and five years for units located in the field. After this, any obsolete RTUs that fail in service will need to be replaced with new units.

6.10.3 Capacitor Banks

6.10.3.1 Introduction

Capacitors are used to improve the power factor[14] across the network to maintain compliant voltage and reduce losses. Our capacitors are pole mounted on the 11kV distribution network and protected with a small vacuum circuit breaker.

6.10.3.2 Failure Modes

Interference.	• Foreign object strikes (e.g., vegetation, windblown debris). • Vandalism (e.g., objects thrown into power lines).

---

[14] Power factor is a technical parameter that is essentially a measure of the efficiency with which energy is delivered. An improved power factor will increase the amount of useful energy delivered at a given current level, which will result in reduced losses and improved voltage regulation.

	• Accidental contact (e.g., vehicle).
Typical degradation.	• Normal environmental exposure causing corrosion or seal degradation leading to oil leaks, water ingress, exposure of live part or structural weakening. • Dielectric breakdown.
Accelerated degradation.	• Corrosion in coastal and geothermal environments. • Termination failure from poor installation. • Lightning strike.

6.10.3.3 Preventive Maintenance

Inspection.	• Post fault reactive inspection. • Earth and condition inspection in accordance with our risk-based asset inspection programme.
Test.	• Ten-yearly earth test.

6.10.3.4 Corrective and Reactive Maintenance

Earth system malfunction.	• Repair damaged earth conductors. • Extend or replace earth bank to improve earth bank resistance and functionality.
Protection system malfunction.	• Check and test that protection system meets design standard. • Correct, repair, or replace protection to meet design standard.
Mounting and foundation malfunction.	• Repair or replace hanger arm, platform, pad, or components. • Re-secure equipment to hanger arm, platform, or pad. • Repair, recondition or scrap equipment with damaged mountings as appropriate.
Equipment leaks.	• Repair, recondition or scrap equipment with oil leak as appropriate.
Damage affecting equipment safety or operability.	• Repair, recondition or scrap equipment where damage affects the safety and operability of the equipment as appropriate.

6.10.3.5 Age Profile

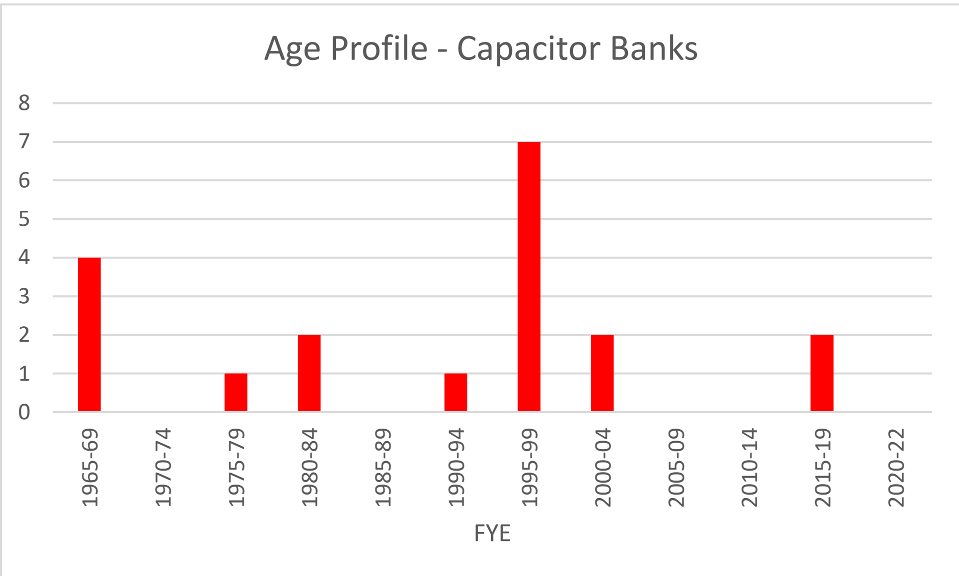


Figure 6.26: Age Profile – Capacitor Banks

6.10.3.6 Health Summary

H0 Unknown	H1 End of Life	H2 Unreliable	H3 Fatigued	H4 Serviceable	H5 New	Total
-	2	-	11	4	2	**19**

Table 6.13: Health Summary - Capacitors

6.10.3.7 Replacement Strategy

Capacitors were installed to manage power factor and have not been considered operationally critical or requiring proactive renewal or replacement. As a result, some units have now reached end-of-life. We are planning to replace one unit per year.

6.10.4 Load Control Equipment

6.10.4.1 Failure Modes

Typical degradation.	• Normal environmental exposure causing corrosion. • Control unit component failure.
Accelerated degradation.	• Water or pest ingress (e.g., condensation, ants, dust, cobwebs).

6.10.4.2 Risk Management

Exposure to live or operable parts.	Equipment is designed to prevent access to live or operable parts by unauthorised persons and minimise the risk of harm by being contained within a secure control building. Any damage that exposes live parts is treated with urgency and is corrected as soon as practicable.
Loss of equipment operational control or telemetry.	Remote control and associated communication systems are routinely checked and tested. These systems are often self-monitoring and provide warnings if conditions indicate a problem.
Ripple plant failure.	A service agreement is in place with the manufacturer for the provision of spare parts, service technician, 24hr support and an emergency backup plant.
Server failure.	A disaster recovery site exists at Ngawha that can be used in the event of a server failure. A software support agreement is in place with the software provider.

6.10.4.3 Preventive Maintenance

Inspection.	• Post-fault reactive inspection. • Quarterly visual plant inspection.
Test.	Annual transmitter test, covered by service agreement with manufacturer.
Service.	Annual ripple plant room, tuning circuit, and injection transformer clean and service.

6.10.4.4 Corrective and Reactive Maintenance

Equipment malfunction	• Activate service agreement with service provider. • Diagnose malfunction and repair or replace faulty component.
Damaged or faulted equipment	• Activate service agreement with service provider. • Clean up any debris and contamination in plant room. • Replace damaged equipment

6.11 Breakdown of Network Maintenance Forecasts

The tables below disaggregate the network maintenance forecasts further than shown in the regulatory schedule s11b (see Appendix A). The disaggregation of the service interruption and emergencies forecast is based on a breakdown of our current reactive repair costs and the disaggregation of our asset replacement and renewal forecasts is based on an analysis of our defects schedule. We use these breakdowns to signal our likely resource and skill requirements to our contractors.

The forecasts below show opex only. Therefore, they do not capture our full maintenance costs, as the replacement of complete assets, as well as targeted line refurbishments packaged as separate projects, are all capitalised. A breakdown of the defect and fault-driven maintenance capex forecast is shown in Table 6.23.

6.11.1 Service Interruptions and Emergencies

($000 in constant FYE2024 prices)	FYE									
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Lines and poles	706	709	712	716	720	723	727	731	734	738
Cables and pillars	199	200	201	202	203	204	205	206	207	208
Transformers	142	143	143	144	145	145	146	147	148	148
Buildings and grounds	2	2	2	2	2	2	2	2	2	2
Switchgear and protection	124	125	125	126	127	127	128	129	129	130
Secondary systems	208	209	210	211	212	213	215	216	217	218
Total	**1,381**	**1,387**	**1,394**	**1,401**	**1,408**	**1,415**	**1,423**	**1,430**	**1,437**	**1,444**

Note 1: Totals may not add due to rounding

Table 6.14: Service Interruptions and Emergency Maintenance Opex by Asset Category

6.11.2 Routine and Corrective Maintenance

($000 in constant FYE2024 prices)	FYE									
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Routine maintenance & inspection	**2,197**	**2,208**	**2,219**	**2,230**	**2,241**	**2,253**	**2,264**	**2,275**	**2,287**	**2,298**
Vegetation	**2,238**	**2,290**	**2,301**	**2,313**	**2,324**	**2,336**	**2,347**	**2,359**	**2,371**	**2,383**
Asset replacement & renewal										
Lines and poles	736	740	743	747	751	755	759	762	766	770
Cables and pillars	94	94	95	95	96	96	96	97	97	98
Transformers	354	355	357	359	361	362	364	366	368	370
Buildings and grounds	139	140	140	141	142	142	143	144	145	145
Switchgear and protection	170	170	171	172	173	174	175	176	176	177
Secondary systems	155	156	157	157	158	159	160	160	161	162
Subtotal – replacement & renewal	**1,647**	**1,655**	**1,663**	**1,671**	**1,680**	**1,688**	**1,697**	**1,705**	**1,714**	**1,722**
TOTAL	**6,122**	**6,153**	**6,183**	**6,214**	**6,245**	**6,277**	**6,308**	**6,339**	**6,372**	**6,403**

Note 1: Totals may not add due to rounding.

Table 6.15: Breakdown of Routine and Corrective Maintenance

6.11.3 Summary of Maintenance Opex Forecast

($000, constant FYE2024 prices)	FYE									
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Service interruptions and emergencies	1,381	1,387	1,394	1,401	1,408	1,415	1,423	1,430	1,437	1,444
Vegetation	2,238	2,290	2,301	2,313	2,324	2,336	2,347	2,359	2,371	2,383
Routine maintenance and inspection	2,197	2,208	2,219	2,230	2,241	2,253	2,264	2,275	2,287	2,298
Replacement and renewal	1,647	1,655	1,663	1,671	1,680	1,688	1,697	1,705	1,714	1,722
Total	**7,463**	**7,540**	**7,577**	**7,615**	**7,653**	**7,692**	**7,731**	**7,769**	**7,809**	**7,847**

Note: Totals may not add due to rounding

Table 6.16: Breakdown of Maintenance Opex Forecast

6.11.4 Breakdown of Asset Replacement Capex Forecast

($000, constant FYE2024 prices)	FYE									
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Transmission and subtransmission lines	199	199	199	199	199	199	199	199	199	199
Transmission and zone substations	71	71	71	71	71	71	71	71	71	71
Distribution lines	1,418	1,418	1,418	1,418	1,418	1,418	1,418	1,418	1,418	1,418
Distribution cables	126	126	126	126	126	126	126	126	126	126
Distribution substations and transformers	309	309	309	309	309	309	309	309	309	309
Distribution switchgear	379	379	379	379	379	379	379	379	379	379
Other network assets	28	28	28	28	28	28	28	28	28	28
Total	**2,530**	**2,530**	**2,530**	**2,530**	**2,530**	**2,530**	**2,530**	**2,530**	**2,530**	**2,530**

Note: Excludes accelerated asset replacements with safety and supply reliability drivers
Numbers might not add due to rounding.

Table 6.17: Breakdown of Reactive Maintenance (Faults and Defects) Capex Forecast

6.12 Non-network Capital Expenditure

The non-network assets covered by this AMP are limited to computer hardware and software, motor vehicles assigned to TEN staff, office equipment and miscellaneous equipment, such as survey equipment and the new ADMS. This situation is not expected to change over the planning period and expenditure is generally limited to the purchase of additional assets to accommodate increases in TEN staff levels and replacement of assets as required. The capex forecast in Appendix A, Schedule 11a, includes the purchase of non-network assets.

6.13 Non-network Operations Expenditure

This AMP discusses in some detail:

- The existing and planned service levels provided by our network assets.
- The development and maintenance strategies we will use to achieve these service levels and accommodate the forecast increase in demand for electricity.
- The direct costs of implementing these strategies.

It does not consider in detail the indirect cost of achieving these asset management objectives. These costs include:

- The cost of operating the network in real time, including the cost of managing and staffing the network control centre in Kerikeri.
- The cost of planning and implementing the asset management strategies described in this AMP. This includes the cost of staffing the TEN asset management team, as shown in Figure 2.5.
- The cost of the business support functions required for our TEN team to function effectively. These include governance, commercial, human resource, regulatory, finance and other support services, which are provided by Top Energy's corporate services staff and are shared with Top Energy's other operating divisions. The costs of providing these services are allocated to TEN in a way that is consistent with the Commission's regulatory requirements.

Table 6.27 shows the forecast costs of providing these services in constant prices. These forecasts are based on the current costs of providing these support services and are also shown in the corresponding expenditure categories in Schedule 11b of Appendix A.

($000, constant FYE2024 prices)	FYE									
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
System operations and network support	7,691	7,525	7,552	7,504	7,562	7,620	7,680	7,742	7,803	7,867
Business support	7,800	7,726	7,725	7,725	7,726	7,726	7,726	7,726	7,725	7,726
Total	15,491	15,250	15,278	15,229	15,288	15,346	15,406	15,467	15,529	15,593

Table 6.18: Non-network Opex Forecast

7 Risk ManagementRisk Management Policy

The Top Energy Group's risk management policy recognises risk as a core business responsibility and commits the Group to providing all necessary resources to assist those accountable and responsible for managing risk. The policy requires the following activities to ensure that its policy is implemented:

- Integrating risk management into all business processes.
- Establishing and operating systematic risk management processes consistent with the requirements of AS/NZS ISO 31000: 2009.
- Requiring risk assessments carried out in accordance with the standard to be a part of all business cases.
- Making all staff members responsible for responding to risks they become aware of, by initiating and utilising the risk management processes in line with their delegated risk authority.
- Maintaining a balance of risks, benefits, and costs to ensure that risks with the potential to impact negatively on the business are kept as low as practicable.
- Prioritising risk treatment and ensuring the risk management process is reviewed and monitored, so that mitigation remains effective as the nature of some risks change.
- Maintaining a "risk aware" culture, where risk is recognised as an everyday part of business.
- Creating awareness through training and regular communication of our risk values.
- Reviewing and auditing regularly to test that mitigation processes are effective.

7.2 Risk Management Process

Governance of the Top Energy Group is the responsibility of the Board of Directors. The CEO and his executive management team are responsible and accountable to the Board of Directors for the representation, direction, and business success of the Group. This delegation of responsibility requires a formal management process, which includes the flow of information to and from the CEO and the Board. All aspects of the Group's activities are included in this process, including exposure to risk, a critical aspect in the effective discharge of the executive management team's management responsibilities.

To ensure that risk management is recognised and treated as a core management function, the Group has established a corporate risk management committee, and implemented a cost-effective and coordinated framework for the management of risk. This framework ensures that a formal and consistent process of risk identification, assessment, acceptance, and treatment is carried out company wide. Emphasis is placed on exposure to business and safety risks that may exist in the short to medium-term.

In managing the areas of significant risk, the Group's risk management framework provides for:

- The identification of major risk areas incorporating all relevant programmes, processes, projects, activities, and assets.
- A standard framework and risk register for the identification, assessment, acceptance and/or mitigation of risks across all major risk areas.
- Regular reporting of the risk register, including reporting of the status of risk profiles, to alert management to any critical changes to the Group's overall risk profile.

- Annual reappraisal of the risk register and associated processes by the executive management team, with findings reported to the Audit & Risk Committee (ARC) of the Board.
- Bi-annual reporting to the ARC on the identified risks and the associated management of those risks.

Our network risk management process focuses on the assessment of credible network risks, which include asset failure due to the normal asset ageing processes, overloading, material deterioration, human error, poor workmanship, lightning, fire, earthquake, and flood. All EDBs experience these risks.

7.2.1 Corporate Risk Management Committee

The corporate risk management committee manages an ongoing, cyclical process of identifying risks and ensuring appropriate mitigation strategies are in place for each identified risk. The committee comprises the CEO and the General Managers from each division of the business, the Health, Safety and Risk Manager, and various specialists who may be co-opted onto the committee from time-to-time.

7.2.2 Network Risk Management Committee

TEN has its own specialised network risk committee consisting of:

- General Manager Network.
- Network Planning Manager.
- Network Maintenance Manager.
- Network Operations Manager.
- Distribution System Operations Manager.
- Network Project Delivery Manager.
- Technical Safety Advisor.

Our Technical Safety Advisor manages the committee, organises four-monthly meetings, seconds other internal expertise as required and is responsible for updating the risk register.

The network risk committee reviews and maintains the network risk register. The review includes checks to ensure that:

- All existing risks remain valid.
- New risks are identified.
- All risks are appropriately treated/mitigated.
- Existing risk mitigation plans are actioned.
- The company's risk management policy is being followed.

Our network risk register is presented to the corporate risk committee on an annual basis. The following table outlines the cyclical review and reporting activities associated with our network risk management process.

ACTIVITY	RESPONSIBILITY	FREQUENCY
Update risk register.	All staff.	As required.
Review risks contained within network risk register.	Network risk committee.	Four-monthly.
Risk register/mitigation plan to corporate risk committee.	General Manager Network.	Annually.
Approve risk register and mitigation plans.	Corporate risk committee.	Annually.

Table 7.1: Network Risk Management Review and Reporting Cycle.

7.2.3 Risk Management Framework

We employ a quantitative approach to risk management that evaluates both risk likelihood and risk consequence. Where event outcomes can be quantified with a probability, this is used in the risk analysis.

This approach accommodates risk events of high consequence that are characterised by uncertainty or surprise rather than historical occurrence. History is not necessarily a useful guide to future events; consequently, a systematic and rigorous process has been adopted to identify high risk possibilities.

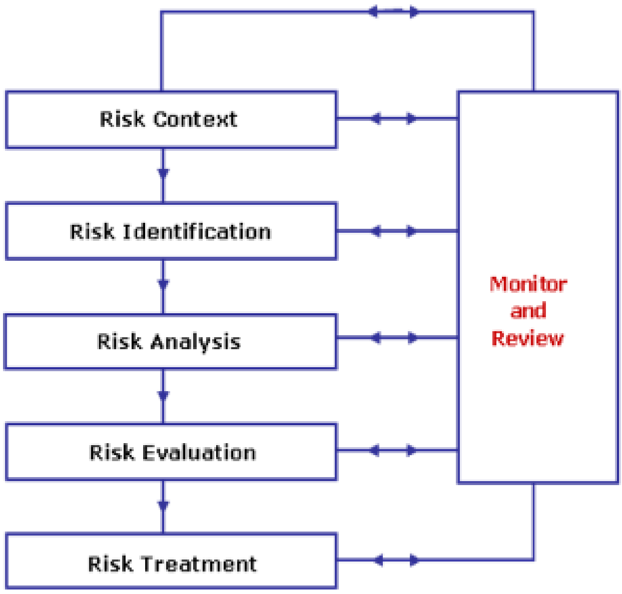


Figure 7.1: Network risk management process

Our network risk process is consistent with AS/NZS ISO 31000: 2009 and incorporates the steps shown in Figure 7.1. The process includes the following main elements:

- *Risk context:* Defining the strategic, organisational, and physical environment under which the risk management is carried out. Establishing the context involves identifying, planning and mapping-out the framework of the whole risk management process. Network risks are classified in the following areas (domains) and typical sub-areas:

RISK DOMAINS	CONSEQUENCE ARISING FROM POOR MANAGEMENT PRACTICES
Public/Employees.	Harm to public. Harm to staff.
Environmental.	Damage to the environment. Sustainability.
Regulatory Compliance.	Regulatory compliance – general. Health & safety. Industry specific. Environmental.
Asset Management.	Loss, damage, destruction. Denial of access. Inability to meet consumer requirements. Inability to meet growth requirements.
Business Model/Change Management.	Market competitive forces. Changed stakeholder expectations. Poorly managed change processes.

RISK DOMAINS	CONSEQUENCE ARISING FROM POOR MANAGEMENT PRACTICES
Financial.	Revenue loss or constraints. Increased expense flows.
Products/Services.	Liability arising from product or service delivery.
Technology.	High reliance on specific technologies. Impact relating to the failure of technology. Impact of significant technological changes.

Table 7.2: Risk process main elements

- *Risk identification:* Identifying all elements relevant to the risk context. After establishing this, the next step is to identify potential risks. A culture of risk awareness at all levels is encouraged within Top Energy to recognise, assess, and manage a risk before possible adverse impact on public, personnel, or company. There are also formal processes based around focus groups that actively identify new and review known risks.

  Identified risks are considered by the network risk committee and the person responsible for the risk domain. Once approved, it forms part of the risk register and is then remedied or mitigated. Risks considered are not limited to current risks, but also include those that may arise over the predicted life of the asset. This long-term view strongly influences capital and maintenance planning for the network.

- *Risk analysis and evaluation:* Estimating the likelihood of the identified risks occurring, the extent and cost implications of loss and comparing the levels of risks against pre-established criteria. This process facilitates effective decision-making.

  Risks are analysed and evaluated in terms of consequence and probability, which in turn deliver an associated risk ranking level of high, medium, or low. It is Group policy to regularly monitor high and medium-level risks. Where possible, additional analysis is undertaken to establish sensible consequence and probability levels. For example, in the case of network outages, consumer's costs of non-supply calculations often involve the analysis of historical asset failure rates.

  The Group's risk analysis and evaluation framework (Appendix C) is used to assess risks that are recorded within the network risk register.

- *Risk treatment:* Defining the actions to remove, mitigate or prepare for the risk. This involves developing contingency plans where appropriate.

7.3 Network Risk Management

7.3.1 Health and Safety

The safety of our employees, contractors and the public is of utmost importance in the operation, maintenance, and expansion of the network. The Group employs a Health, Safety and Risk Manager who is responsible for promoting Health and Safety across all divisions of the organisation and actively investigating all health and safety incidents. In addition, there is a Technical Safety Advisor within TEN reporting directly to the General Manager Networks.

We operate under the EEA Safety Rules that meet the requirements of the Acts, Regulations, Codes of Practice and Guidelines that govern the electricity industry.

We are committed to a reduction in both the frequency and severity of injuries to staff, contractors, and the public. The long-run results of initiatives implemented under this system demonstrate the commitment by staff to effectively manage health and safety. A philosophy of continuous improvement prevails within our health and safety system, with focus maintained on the following core activities:

- Employer commitment.

- Planning, review, and evaluation.
- Hazard identification, assessment, and management.
- Information, training, and supervision.
- Incident and injury reporting, recording and investigation.
- Employee participation.
- Emergency planning and readiness.
- Management of contractors and subcontractors.

Further, a high standard is maintained in the timeframes and process for the reporting and investigation of incidents. Similarly, employee commitment is being maintained through the continuing development of “safe teams”, which involve employees at all levels in the management of health and safety by including employees in regular meetings to discuss and improve health and safety in their individual work areas.

We have gained accreditation as an Electrical Workers’ Registration Board (EWRB) safety refresher provider and continue to make a significant investment in the training and development of our employees, as they undergo both regulatory and NZQA Unit Standard based training towards appropriate National Certificates for their various roles.

We offer training to upskill existing employees in the following work practices:

- Close-proximity vegetation work.
- Utility arborist.
- Vegetation management (including regulatory and legal compliance).
- Control room operator.

We maintain, and are continually improving, our authorisation holder’s certificate (AHC) system, which requires formal assessments of current competency before staff are permitted to work on and around the network. This assessment process ensures the safety of employees as they only work within their proven competency.

The current AHC system has been updated to integrate the EWRB’s competency-based refresher classes and we are working toward incorporating the National Common Competency Framework along with the majority of the EDB’s. We maintain a proactive role in staff competency, monitoring industry safety issues, and implementing training and guidance where required.

Our recently commissioned ADMS is used to reduce the likelihood of a health and safety incident arising through operator error. The ADMS, which includes a network model and is used to produce switching schedules for all network outages, will generate an alarm if a planned switching schedule will result in a network condition where it is unsafe for a clearance to be issued.

7.3.1.1 Transmission Risks

Our transmission system comprises a single 110kV circuit between Kaikohe and Kaitaia and the recently completed 110KV transmission line that transports electricity generated by the Ngawha OEC4 generating unit to Kaikohe. It also includes the 110kV transformers and switchgear at the Kaikohe and Kaitaia substations and the Ngawha 110kV switchyard. These are critical assets, not least because of failure of the Kaikohe-Kaitaia circuit means that the 10,000 consumers in our northern area are no longer connected to the grid. While we acquired most of our transmission assets from Transpower in April 2012, the experience of TECS staff in the maintenance of 110kV transmission assets is limited. To minimise and mitigate our transmission risk:

- We have undertaken a comprehensive condition assessment of our transmission assets and developed a replacement plan that will ensure that the assets are replaced before they reach the end of their expected economic life. Provision for these asset replacements is included in the capital expenditure forecasts in this AMP.
- We have contracted the maintenance of all our 110kV line and substation assets to an experienced external service provider. The contract requires that these assets be inspected and

maintained to a level at least equivalent to that of similar Transpower assets. We also prioritise the repair of defects identified in transmission asset inspections.

- We facilitate regular site inspections and, in the process, engage with owners of property over which our 110kV assets are situated.

We have recently completed the installation of diesel generation in the Kaitaia area to avoid the need for maintenance shutdowns and to provide resilience in the event of an unplanned line outage. This is discussed further in Section 7.3.2.

7.3.1.2 Network Spares

We maintain an inventory of critical spares where there could be long delivery times in the event of network equipment failure. In most cases, the equipment we use is standardised and of modular design and can relatively easily be replaced using our inventory of equipment held to maintain and expand the network. Nevertheless, we regularly review our inventory of specialised spares and have joined a cooperative group of other EDBs to provide mutual support and risk mitigation when needed.

For the 110kV transmission assets, critical spares have been procured for standard hardware, cross arms, insulators, and poles. An arrangement has also been made with Transpower to obtain a 110/33kV transformer bank at short notice if required. Our mobile substation is also a network critical spare.

7.3.1.3 Defect Management

Defects identified during our asset inspection programme are included in our defect management programme where they are risk assessed and categorised. This programme requires assets identified as defective to be inspected more frequently with the objective of allowing them to remain in service until they reach the end of their economic life, but at the same time ensuring that critical assets are replaced before they fail in service.

We monitor the implementation of our defect management programme using indicators related to outstanding defects and the SAIDI impact of defective equipment faults. We also report data on any backlog in the repair or remediation of defects monthly to the Board.

Our defect management program is described in detail in Section 6.1.2.3.

7.3.1.4 Vegetation Management

Our ongoing vegetation management programme is described in Section 6.2. While the primary focus of this programme is the management of supply reliability, trees growing into our lines are a public safety and property hazard and addressing this problem is prioritised when the fire risk is high.

We are also working with commercial plantation owners to develop vegetation management agreements and are actively campaigning to remove bamboo growing in the vicinity of our lines.

7.3.1.5 Asset Management

We have developed lifecycle asset management plans, including a risk management plan, for all our main asset groups. These are summarised in Sections 6.3 – 6.11.

7.3.2 Network Resilience

Network resilience relates to the ability of the network to withstand high impact, low probability events. The network development plan that we have implemented over the last ten years has focused on building a transmission and subtransmission network that is resilient to high impact events, and we have now got to the point where we can restore supply with a target restoration time of 1 hour following a single element failure anywhere on our subtransmission network. This is explained in Table 5.1.

Our mobile substation is also available to support the subtransmission network as required. Now that we have increased the resilience of the transmission and subtransmission networks through our investment in diesel generation, the mobile substation is most likely to be used to save on the cost of running diesel generation for an extended period following the loss of a transformer or switchgear asset at one of our smaller zone substations.

Notwithstanding this significant improvement in network resilience, the 110kV Kaikohe-Kaitaia line remains vulnerable to a severe storm causing a landslide that results in the failure of one of the transmission tower foundations in the Maungataniwha Range. This happened in FYE2015 when a tropical storm remained stationary over our supply area for three days. Fortunately, on that occasion there was no supply interruption as the tower was supported by its conductors and did not fall over.

Nevertheless, there is evidence that the line route across the range is becoming more geotechnically unstable, presumably due to climate change, and the risk of a structure failure is therefore increasing. In the event of such a failure we will utilise a temporary structure provided by Transpower. We have discussed this increasing risk with Transpower and the Department of Conservation, which manages the land, and are working with them to develop a detailed response plan, should there be a structure failure. This will increase our preparedness for such an event. We have also identified the most vulnerable structures on the line and have engaged a consultant to develop preliminary designs and identify possible locations for permanent replacement structures, should they be needed.

The diesel generation at Kaitaia has mitigated the consequences of such an event. This generation is not designed to run continuously for extended periods and supplying our northern area using diesel generation for the time required to erect a temporary replacement structure would place a substantial financial burden on Top Energy.

The planned connection of 67MVA of utility scale solar generation will create a vulnerability at the Kaitaia substation. The substation has two 110/33kV transformers, but the smaller transformer does not have the capacity to accommodate all the connected generation. The larger transformer is relatively new and in good condition, so a failure is unlikely.

Vulnerabilities remain on the distribution network primarily due to the number of long rural radial feeders serving the sparsely populated rural parts of the network remote from the major population centres. The length of these feeders means they have a high fault exposure. Their remoteness extends the time required to repair a fault and this, together with the high number of connected consumers on each feeder, means that the SAIDI impact of faults can be high, particularly during adverse weather events when there can be several faults spread across different parts of the network. This is one reason why the reliability of the supply we provide consumers is volatile and sensitive to weather conditions. The 11kV improvements described in Section 5 are designed to reduce these distribution network vulnerabilities.

7.3.3 Emergency Preparedness and Response Plan

Events can arise that are outside our network design envelope or exceed the response capacity of our field resources. The most likely scenario is a major storm event but other events, such as the loss of both transformers at a large substation, are possible.

We have an Emergency Preparedness and Response Plan to deal with such situations. This is designed to ensure that our network capabilities are sustained as far as practicable during emergency circumstances and events through the adoption of effective network management and associated practices. They ensure that we have the capability and resources to meet our community obligations, including fulfilment of civil defence emergency management requirements, while at the same time enhancing stakeholder and public confidence.

The plan addresses how we respond to major emergencies electricity supply by focusing on the four 'R's:

- *Reduction* (mitigation) of potential and actual threats or impacts arising from a diversity of natural and man-made hazards or risks that surround Top Energy and its assets. This does not extend to the management of network asset-related risks separately addressed during network planning, which are included in the risk register.
- *Readiness* (preparedness) to anticipate and prepare for potential and actual risks or threats beyond those alleviated by other means.
- *Response* to a potential and actual emergency, to stabilise the situation and prevent further danger and unnecessary outage.
- *Recovery* following response, to restore full normal services and functions.

The objectives of the plan are:

- To provide general guidelines that can be combined with sound judgment, initiative, and common sense to address any emergency, irrespective of whether that set of circumstances has been previously considered and planned for. These guidelines define the roles, duties and obligations of Top Energy and other personnel in preparing for and managing an emergency, prioritised on:
    - Protection of life (staff and public).
    - Safety and health of staff, service providers, consumers, and the public.
    - Protection of property and network assets.
    - Protection of the environment.
    - Ongoing integrity of the electricity network.
    - Establishment and maintenance of relationships and communication channels within Top Energy and with third parties.
- To provide a business continuity programme for the electricity network that will:
    - Raise and sustain appropriate individuals' preparedness, competence, and confidence to appropriate levels.
    - Provide Top Energy with the necessary facilities, information and other resources for response and recovery management.
    - Develop adequate relationships and approaches to ensure sustained plan implementation and evolution.
- To provide guidance to Top Energy staff for responding to, and recovering from, electricity network emergencies.
- To assist Top Energy to comply with statutory requirements and accepted industry standards with respect to management and operation of the electricity network during an emergency.

The plan covers emergency event classification, emergency response team roles and responsibilities, communications and reporting processes, emergency response prioritisation, detailed emergency response actions and business continuity programme maintenance procedures.

Our Emergency Preparedness Plan was activated during the July 2014 storm discussed in Section 7.3.2. It was also activated when insulators on both circuits of Transpower's Maungatapere-Kaikohe 110kV grid connection were damaged by bullets in 2016 causing an extended outage to our whole supply area; and during a subtropical storm in January 2018, which had a raw SAIDI impact of almost 100 minutes over a two-day period. Most recently it was activated during Cyclone Gabrielle in February 2023. It is reviewed after each activation to capture the lessons learnt from our management of that event.

We have updated our formal emergency response plan and splitting it into two separate documents, one covering preparedness and one covering response. The revised plan will formalise the regular testing of our preparedness and response capability and specify the frequency with which infrequently used systems, such as communications systems, that are in place to facilitate our response to high impact low probability (HILP) events, are reviewed and tested.

7.3.4 Lifelines Group

The Civil Defence Emergency Management Act 2002 requires organisations managing lifelines to work together with the civil defence emergency management group in their region. Lifelines are the essential infrastructure and services that support our community (e.g. utility services such as water, wastewater and storm water, electricity, gas, telecommunications, and transportation networks including road, rail, airports, and ports). Top Energy is an active member of the Northland Lifelines Group co-ordinated by the Northland Regional Council, which coordinates efforts to reduce the vulnerability of Northland's lifelines to hazard events, ensuring they can recover as quickly as possible after a disaster.

The role of the group is to:

- Encourage and support the work of all authorities and organisations (including local authorities and network operators) in identifying hazards and mitigating the effects of hazards on lifelines.

- Facilitate communication between the authorities and organisations involved in mitigating the effects of hazards on lifelines, to increase awareness and understanding of interdependencies between organisations.
- Create and maintain awareness of the importance of lifelines and of reducing the vulnerability of lifelines to the various communities within the region.
- Promote ongoing research and technology transfer aimed at protecting and preserving the lifelines of the region.

As part of the lifelines group coordination activities, we have committed to work with the Northland Civil Defence Emergency Management Group to provide use of our ripple control network for the activation of audible alarm sirens or tones. A procedure has been adopted to ensure that we meet this commitment to operate our injection equipment and deliver support to the Northland Lifelines Group Community Tsunami warning system. This procedure sets out the requirements for:

- The acknowledgement of activation requests.
- The activation of alarms.
- The process for notifications, and the logging of events and activations.
- The protocols for testing and reporting of system failures.

We also participate in formal civil defence exercises organised by the Northland Lifelines Group.

7.3.5 Load Shedding

We maintain a load shedding system to meet our regulatory requirement to ensure that an automatic under-frequency load shedding system is installed for each grid exit point to which a local network is connected (in our case, Kaikohe). The system enables the automatic disconnection of two blocks of demand as explained in Section 5.9.

We also maintain an up-to-date process for the manual disconnection of demand for points of connection, in accordance with our regulatory requirements.

A feeder shedding schedule is maintained, which specifies the shedding priority (manual and automatic) by under-frequency zone and substation for the 11kV network and the Transpower point of supply. This information is provided on an annual basis to Transpower and the Electricity Authority in accordance with their automatic under-frequency load shedding requirements.

7.3.6 Contingency Plans

We have standardized operating procedures and switching instructions that are managed and updated on a regular basis by our central control room staff. These switching instructions outline the methods for rearranging the electrical network to supply consumers during network contingencies (equipment outages).

We have also commissioned a separate and completely independent emergency control centre at the Ngawha Power Station, and our training programmes provide for regular operator familiarisation and testing activities.

7.3.7 Mobile Substation

Many of our risk scenarios involve consumer non-supply through equipment failure in zone substations, particularly in substations where there is only one transformer. In FYE2003, we mitigated this risk by purchasing a mobile substation and modifying single-transformer substations to allow the unit to be installed quickly following formalised procedures.

7.4 Safety Management

As noted in Section 2.6, we are required by our Asset Management Policy to develop an AMP that gives safety our highest priority. Safety management covers a broad range of issues including how we design, build, and operate our network, ensure that we meet all legal compliance requirements, and interface with our contractors and other external organisations, the general public and our network users.

Section 63A of the Electricity Act 1992 requires us to have a Public Safety Management System (PSMS). Our PSMS is certified as compliant with NZS 7901 and is regularly audited externally to maintain this certification. These audits cover both the alignment of our documented PSMS with NZS 7901 and the extent that our staff comply with the requirements of the system. We have integrated our PSMS into our asset management safety practices and use it to manage the safety risks in operating our network. Ensuring that our compliance with our PSMS is externally audited provides a level of governance that ensures that our safety practices take due account of the requirements of the Health and Safety at Work Act 2015 and other relevant legal requirements.

The coverage of our PSMS extends beyond our own network assets into consumer-owned assets. This is because, while we do not own consumer assets and therefore are not responsible for their compliance, we do operate them, and we must ensure the safety of our staff. We also have responsibilities with respect to the equipment we allow to connect to our network and be energised.

7.5 Network Risks

7.5.1 Corporate Risk Register

Table 7.3 schedules the risks in Top Energy's Corporate Risk Register that have been assigned to TEN and the controls we have in place to mitigate these risks.

No.	Risk	Probability	Consequence	Mitigation
Risks from the Top Energy Group Risk Register that are Assigned to TEN				
15.	Third party loss or damage.	Medium, mitigated to medium.	Exposure to compensation or fines.	• Compliance with Electricity (Safety) Regulations and associated Codes of Practice. • Public Safety Management System certified to NZS 7901 in place.
2.	Serious harm to members of the public relating to interaction with the Group's facilities	High, mitigated to medium	Exposure to compensation or fines. Regulatory investigation.	• Compliance with Electricity (Safety) Regulations and associated Codes of Practice. • Public Safety Management System certified to NZS 7901 in place.
5.	Failure of network equipment or systems, owing to inadequate design specification, installation, operation, or maintenance.	Medium, mitigated to medium.	Regulatory investigation.	• Adoption of ISO 55000/PAS 55 as a best practice asset management standard. • Assessment of asset management capability and maturity, and continuous improvement as per the standard. • The use of external consultancy when inhouse capability insufficient.

No.	Risk	Probability	Consequence	Mitigation
16.	Cost overruns and delays in implementing network projects.	Medium, mitigated to medium.	Impact on pricing control – loss of incentives and/or penalty	• Dedicated in-house project delivery manager to support competent planning team.
20.	Unplanned network outage affecting more than 10,000 customers for longer than 12 hours.	Medium, mitigated to medium.	Breach of regulatory quality targets.	• Provision of network resilience with diesel generation. • Contingency plans, including disaster recovery and emergency preparedness.
19.	Loss of incoming grid supply for more than 24 hours.	Medium, mitigated to medium.	Loss of grid supply to all consumers.	The network currently has 17.2MW of diesel generation it can deploy to critical load locations in the event of sustained loss of grid supply. Supply would need to be rationed in the event of an extended interruption. Our Emergency Response Plan includes the contact details of hire generator suppliers who would be used to augment the generation capacity in the southern area.
21.	Environmental damage.	High, mitigated to low.	Exposure to compensation or fines	• Compliance with resource consents. • Response plans (e.g., oil containment and spill kits). Current focus areas include identification of environmental vulnerabilities and then updating mitigation provisions.

Table 7.3: Corporate Risk Register

7.5.2 Network Safety Management System Hazard Register

In implementing its Public Safety Management System, TEN maintains a formal Hazard Register. This is actively managed by the Technical Safety Advisor and reviewed four-monthly by the Network Risk Management Committee as discussed in Section 7.2.2. For each risk the register identifies risk mitigation strategies including relevant external safety regulations and guidelines as well as internal processes that are in place to manage the risk. Each risk is assigned a residual risk score that is based on:

- Consequence – the likely worst outcome from exposure to the risk.
- Frequency – how often exposure to the hazard is likely to occur.
- Likelihood – how likely the consequences would be incurred on each exposure.

Residual risk scores greater than 800 are considered extreme – there are no such risks on the current register. Risk scores between 200 and 800 are considered high and those between 40 and 200 are rated mediums. Scores below 40 are considered acceptable. Table 7.4 shows the risks on the register that are currently rated high or medium.

Risk	Residual Risk Score
Vegetation at risk of being in contact with live network assets	800
Person interacting with vegetation planted for non-commercial purposes under, or too close to, power lines	600
Cross polarity or other issue occurs during the installation of smart meters	480
A member of the public decides to cut trees around live power lines and receives an electric shock	400
Contact between overhead power lines of dissimilar voltages resulting in over-voltages to installations	400
Privately owned lines not being maintained to industry and regulatory standards posing a risk to persons and property	240
Vehicle striking live overhead line with over-dimensional load	200
Non-compliant ground clearances of lines	200
Contamination from leaking oil filled equipment	200
Low fault current leading to slow protection operation	200
Public movement through inactive or unended worksites resulting in harm to persons or property	160
Aircraft striking aerial conductors in its flight path	80
Unauthorised third-party assets mounted on or near pole or other equipment	80
Low structure enabling unassisted climbing and access to live exposed parts	80
Security of ground mounted transformers is breached allowing access to live internals	80
Lightning striking equipment, resulting in potential rise in connected installations or earth potential rise around the affected equipment	48
Current leakage to earth causing unacceptable step and touch potential	48

Table 7.4: High and Medium Risks on Safety Hazard Register

7.6 Climate Change

We anticipate that climate change will primarily impact the management of our network in two ways:

- Decarbonisation of the economy will impact both the demand for electricity and the expectations of network users in relation to the services we provide. This is discussed in Section 2.4.3.
- Changes in weather patterns will affect the reliability of supply to consumers which, all else being equal, is strongly correlated with the weather; and

7.6.1 Changing Weather Patterns

The Ministry for the Environment predicts the following changes to the weather patterns in our supply area:

- Compared to 1995, average temperatures are likely to increase by 0.7°C to 1.1°C by 2040, and to increase further beyond that, at a rate that will depend on how successful the world is in reducing carbon emissions. This could lead to more frequent droughts, which in turn could lead to water shortages, increased demand for irrigation and increased risk of wildfires. Our area currently experiences very few frosts and in future frosts are likely to become extremely rare. This suggests that growth in our winter peak demand will ameliorate but electricity consumption over the summer will increase with an increased demand for air conditioning and water pumping. Eventually we could have a summer peaking load, as is currently the case throughout mainland Australia.

- While there will be some variability in seasonal rainfall, changes in annual rainfall are expected to be small and our area is not expected to experience a significant change in the frequency of extremely rainy days due to climate change. In fact, it is likely to experience a decrease in daily extreme rainfall by 2090 under the highest emissions scenario. While there is expected to be little change in the frequency of storms and cyclones, the intensity of ex-tropical cyclones is likely to increase, and these could cause more damage as a result of heavy rain and strong winds.

- While there may be an increase in westerly wind flow during winter and north-easterly wind over summer, the frequency of extremely windy days is not expected to increase.

- New Zealand tide records show an average rise in mean sea level of 1.7mm per year over the 20th century. Globally the rate of rise has increased, and further rise is expected in the future. This will lead to an increase in flooding in low-lying coastal areas. The Taipa substation is in such an area as discussed further in Section 7.6.2.

  The Far North District Council and the Northland Regional Council are both monitoring sea level rise and have published a map, such as Figure 7.2, showing areas of coastal inundation for varying degrees of change. Similar maps have also been produced to show the impact of earthquake induced tsunami on the coastline.

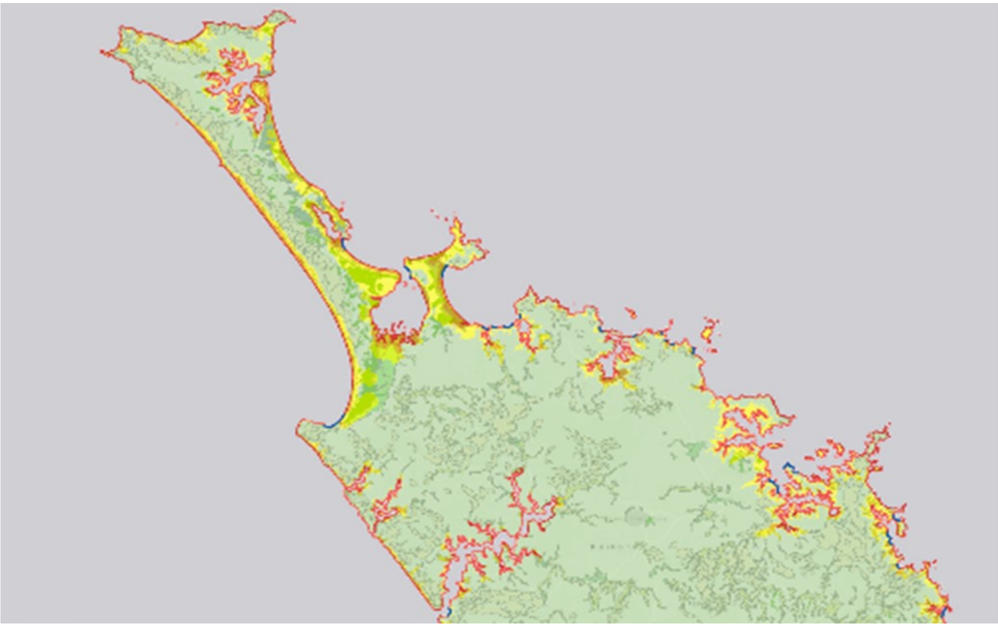


Figure 7.2: Northland Regional Council Tsunami and Flood Hazard Zones

These predictions are consistent with our own observations over the last ten years. Historically, the provision we have made for weather in in setting the targets in our AMPs and Statements of Corporate Intent has been insufficient – we only hit our SAIDI targets in FYE2013 and FYE2019, both years of benign weather. As shown in section 4, we now set reliability targets that mirror the Commerce Commission's objective of ensuring no material deterioration in reliability over time. As our new targets reflect the average reliability of the network over a ten-year historic reference period, they take account of the weather conditions we experience.

The meteorological forecasts reflect an increased intensity of major storms and an increase in average wind speeds across our supply area. Over time the impact of the weather on the reliability of our network is therefore likely to increase. We must therefore develop a network that is increasingly resilient to climate impacts. This will entail not only improved vegetation management but, over time, introducing a network architecture that reduces the number of consumers affected by a single fault. The RSE component of our 11kV reliability improvement plan is designed to do this.

We already mitigate the impacts of changing weather patterns through our vegetation management plans, asset replacement programmes, and the implementation of safety by design for new assets. The measure of success will depend on how well capital investment keeps pace with natural degradation of the network plus the incremental cost of matching the advancing impact of intensifying weather patterns. The situation will need to be monitored on an ongoing basis and adjusted or managed accordingly.

7.6.2 Vulnerability of Substation Assets

Taipa Substation is the most critical asset likely to be impacted by tsunami or sea level rise. It is situated 250 metres from the Oruru River estuary and approximately 1.8m above mean high water level. The arrow in Figure 7.3 shows where past high tides have encroached upon the site. The substation has now reached its full capacity and as discussed in Section 5, will be replaced by two new substations, one at Tokerau Bay and the second at either Mangonui or Coopers Beach.

Figure 7.3: Taipa Substation Tidal Flood Encroachment

Other substation assets which are low-lying are Kaeo and Omanaia substations. The risk to these sites is not as great as for Taipa, and is dependent on significant sea level rise, high tide and flooding all occurring simultaneously. To mitigate these risks flood remediation has been undertaken at Omanaia, and Kaeo substation has been elevated above any anticipated flood condition.

8 Evaluation of Performance

This Section evaluates our asset management performance in respect of:

- The extent to which we have met the service level performance targets for FYE2022, the most recent year for which complete data is available. The targets were set in our 2021 AMP.
- Our expenditure on network development and maintenance in FYE2022.
- The quality of our asset management systems and procedures.

8.1 Achievement of Service Level Targets

Our performance against the service level targets for FYE 2022 are shown in Table 8.1.

Service Level Indicator	Internal Target	Threshold	Outcome
Normalised Unplanned SAIDI	245	380	342.7
Normalised Unplanned SAIFI	2.98	4.5	3.95
Planned SAIDI[1]	125	1,905.4[2]	113.5
Planned SAIFI	0.5	7.75[2]	0.97
Loss Ratio	9.0%	-	10.4%
Ratio of Total Opex to Total Regulatory Income	33%	-	40.6%

Note 1: After de-weighting notified interruptions in accordance with the provisions of the Electricity Distribution Services Default Price-Quality Path Determination 2020.
Note 2: Aggregate value for all five years of RCP3.

Table 8.1: Achievement of FYE2020 service Level Targets

The table shows that in FYE2022 we failed to meet any of our AMP internal targets, apart from planned SAIDI. Our performance against these targets is discussed in the following sections.

8.1.1 Unplanned SAIDI and SAIFI

The AMP unplanned SAIDI and SAIFI targets shown in Table 8.3 are internal targets and reflect a significantly higher network reliability than the quality thresholds imposed by the Commission under its price-quality path regime. In the current FYE2023 year we will breach the unplanned SAIDI price-path threshold and, at the time of writing, are at risk of breaching the unplanned SAIFI threshold.

It has become clear that the internal targets in the 2021 AMP and 2022 AMP Update do not adequately take into account the weather conditions we typically experience in our supply area. It can be seen from Figure 4.1 that in the last in the last 15 years the only times we would have met our current unplanned SAIDI target of 245 were FYE2013 and FYE2019, both years in which the weather in our area was unusually benign. We would have only met our current SAIFI target of 2.95 in FYE2019. In view of the amounts by which we missed our internal targets in FYE2022 and the current FYE2023 year, our Board has now decided to set internal unplanned SAIDI, and SAIFI targets based on the Commission's regulatory objective of no material deterioration in reliability over time. Our internal unplanned SAIDI and SAIFI targets for each year of the FYE2024-33 planning period have therefore been reset on this basis, as explained in Section 4.4.1.1.

We also acknowledge that the normalised reliability of our network has deteriorated since FYE2020, culminating in our FYE2023 price-quality path threshold breach. While we think this is in part due to climate change, we need to do more to increase the resilience of our network to the challenges of the external environment. To this end we have reviewed the performance of our network over the five-year FYE2018-22 period. The analysis focused on SAIDI, since our SAIFI performance is less of a concern and initiatives designed to improve SAIDI should also improve SAIFI, although possibly not to the same extent. We found that:

- Over the review period the average unplanned network SAIDI was 296. However, in four of the five years of the period the SAIDI outcome was higher than that. If the unusually low SAIDI of FYE2019 is excluded, the average increases to 316.

- There were three unplanned interruptions of the 110kV network, two of which occurred in the same year. These three interruptions had a total normalised SAIDI impact of 22 minutes.
    - In FYE2018 there was a tripping of the 110kV network that Transpower's protection indicated was a 110kV busbar fault at Kaikohe substation. Due to the potential implications of such a fault, we undertook an extensive investigation to find a possible cause before the system was re-energised, with no fault being found. This incident had a raw SAIDI impact of 87 minutes. To prevent a reoccurrence this situation, we have since split the Kaikohe 110kV bus, installed a bus coupler circuit breaker and also bus zone protection. Under the current normalization methodology, the SAIDI impact of this fault was normalised back to 0.6 minutes.
    - A short circuit in the protection wiring, which incorrectly sent a trip signal when the load on the line exceeded 24MW, caused a single fault with a SAIDI impact of 18 minutes.
    - The third fault had a SAIDI impact of 3.6 minutes, was due to a technician's error when testing the secondary circuits. This outage lasted just over ten minutes.

  Unplanned interruptions of the 110kV network are infrequent, but when they do occur a single fault can have a significant SAIDI impact because of the number of consumers affected. Nevertheless, the overall impact of 110kV faults on our overall network reliability is small – over the review period only 1.5% of the total normalised network SAIDI impact could be attributed to 110kV line interruptions.

- The average normalised SAIDI impact of 33kV faults over the review period was 29. This is less than 10% of the normalized network SAIDI impact and is a positive outcome of the TE2020 investment over the last decade. In particular, the provision of differential protection on all subtransmission circuits has enabled two circuits to be run in parallel, so there is now no interruption for most subtransmission faults. Furthermore, we have installed diesel generation for network support at most substations where there is only one incoming subtransmission circuit.
- It follows that almost 90% of our normalised network SAIDI is due to faults on the 11kV network, and the reliability of this part of the network needs to be addressed if our overall network SAIDI is to be stabilised at the new target. To this end, in April 2022 the Board decided to defer construction of the 110/33kV Wiroa substation and reallocate the funding to projects and programmes designed to improve the reliability of the 11kV network. The subsequent decision to defer the build of the 110kV Wiroa-Kaitaia line has released further funds, some of which will be allocated to 11kV reliability improvement.
- Over the review period, 34% of normalised 11kV network SAIDI was caused by defective equipment faults and 25% by vegetation. This equates to 90 minutes and 65 minutes respectively. Third party interference, primarily car vs pole impacts caused 23% of faults and the cause of 11% of faults was unknown.
- Vegetation events can be further categorised as tree fall or tree contact events. Over the review period the average annual SAIDI impact of 11kV tree fall events was 36 minutes while the impact of tree contact events was 29 minutes. There is little we can do to stop tree fall events from occurring since most trees that fall onto our lines are growing outside the clearance zones specified in the Electricity (Hazards from Trees) Regulations 2003. The normalised SAIDI impact of tree contact events is increasing and was over 54 minutes in FYE2022.

Our 11kV reliability improvement programme has three components.

- We are increasing the rate at which we proactively replace 11kV assets that have reached the end of their economic life. This includes planned distribution line refurbishments, the programmed replacement of assets such as conductors where asset condition cannot be readily assessed, and the replacement of assets where there is an elevated risk of a failure in service with a significant safety or SAIDI impact.
- As discussed in Section 6.2.5, we are transitioning from a strictly time-based vegetation management strategy to a strategy where those parts of the network that have a high tree contact SAIDI impact are managed more frequently. This has similarities to the transition from a time-

based maintenance programme to a condition-based programme, where assets at higher risk of failure are maintained more frequently. We are also introducing a new small two-man maintenance crew which will be able to respond to reports of high vegetation risk without waiting for the next programmed treatment. Using this approach will prioritise the vegetation management of those feeders with a high tree contact SAIDI impact – over the review period almost 33% of our total normalised 11kV tree contact SAIDI could be attributed to just five feeders.

- While the above two components of the programme are focused on preventing faults occurring, the final component is designed to reduce the SAIDI/SAIFI impact of faults that occur. The two main subcomponents of this effort are:
  - Optimisation of feeder protection. This includes the installation of new reclosers and sectionalisers on less reliable feeders to reduce the number of consumers affected by a fault.
  - The installation of normally open interconnections between feeders to enable supply to be restored downstream of a faulted switching section before a fault is repaired.

  Other subcomponents include the installation of a new injection point using the 11kV tertiary winding of the Kaitaia 40/60MVA, 110/33kV transformer, the installation of fault passage indicators, the replacement of manually operated air-break switches with remote controlled vacuum units and the installation of Autolink sectionalisers.

Over the next 3 years (FYE2024-26) period our forecast capital expenditure on initiatives that impact the reliability of the 11kV network is $13.55 million. This is 24% higher than the corresponding forecast in the FYE2022 AMP Update. Furthermore, our vegetation management opex provision has increased by approximately 20% over the same period.

8.1.2 Planned SAIDI and SAIFI

The planned SAIDI and SAIFI targets in our 2021 AMP and 2022 AMP Update were equal to the average annual planned SAIDI and SAIFI impacts over the FYE2010-19 reference period that the Commission used when setting the RCP3 quality thresholds. Over this time the Commission used a hybrid measure combining both planned and unplanned interruptions as a basis for assessing the reliability of our network. We therefore had an incentive to minimise the impact of planned interruptions.

For a RCP3 the Commission is separately measuring planned and unplanned interruptions, and while it has set planned SAIDI and SAIFI thresholds, this incentive is much reduced. Another factor is that we undertook significant live line work in the early years of the historic reference period, whereas we no longer work on live conductors. Therefore, we are now doing more maintenance work requiring planned interruptions on the 11kV network than we were doing in RCP1 and RCP2 and we have therefore increased our AMP planned SAIFI target from 0.5 to 1.0 to allow for this. This is discussed further in Section 4.4.1.2.

8.1.3 Loss Ratio

We did not meet our 9% loss ratio target in FYE2022, although our actual loss ratio of 10.4% was an improvement on the 11.1% we achieved in FYE2021. We note that in three of the four years prior to FYE2021 we bettered our 9% loss ratio target.

As can be seen from Figure 4.3, our FYE2021 and FYE2022 network loss ratios were significantly higher than in previous years. This is likely due to the higher peak demand – the disclosed peak demands in FYE2021 and FYE2022 were 75MW and 77MW respectively, almost 10% higher than the peak demand over the period FYE2013-20 when the disclosed peak demand did not exceed the 71MW disclosed in both FYE2013 and FYE2020. The reason for this sudden jump is not clear, but we suspect it is related to changes in the patterns of electricity consumption due to Covid. As instantaneous losses are proportional to the square of demand, all else being equal network losses over a year will increase at a substantially higher rate than the proportional increase in peak demand.

Going forward, the impact of the 67MW of solar generation in our northern area on our network loss factor is not clear and, as yet, we have not tried to analyse this. Most of this load will be exported south through our 110kV line, which will often be fully loaded, and it is possible that our loss factor will increase as a result.

We think it would be premature to change our loss factor targets until we better understand the impact of this new generation.

8.1.4 Cost Performance

The ratio of total operational expenditure to total regulatory income in FYE2022 was 40.6% compared to a target of 33%. In FYE2021 the ratio was 39.0%. Between FYE2013 and FYE2020 the ratio has been at or below the target level.

The main reason for the step increase in the ratio has been the reduction in regulatory income due to the RCP3 price-path determination. The average regulatory income in RCP2 was $50.39 million but this has reduced to an average $47.5 million over the first two years of RCP3. At the same time operational expenditure on the network has not reduced as these costs are largely fixed, and they have also been impacted by the current high inflation rates.

We think there is justification for increasing the AMP target. However, we think it premature to determine the appropriate amount so have left the target unchanged in the meantime.

8.2 Financial and Physical Performance

A comparison of our actual expenditure in FYE2022 for both network capex and network maintenance opex with the budgeted expenditures, as presented in the 2021 AMP, is provided in Table 8.2.

EXPENDITURE CATEGORY	BUDGET FYE2022	ACTUAL FYE2022	VARIANCE	
Network capital expenditure ($000)				
Consumer connection	4,113	4,629	516	13%
System growth	1,263	1,303	40	3%
Asset replacement and renewal	6,888	4,909	(1,979)	(29%)
Reliability, safety, and environment	2,116	1,475	(641)	(30%)
Asset relocations	-	-		-
Subtotal – network capital expenditure	**14,380**	**12,316**	**(2,064)**	**(14%)**
Maintenance expenditure ($000)				
Service Interruptions and emergencies	1,313	2,082	769	59%
Vegetation management	1,850	1,865	15	1%
Routine and corrective maintenance and inspection	2,120	2,261	141	7%
Asset replacement and renewal	1,019	966	(53)	(5%)
Subtotal – maintenance expenditure	**6,302**	**7,174**	**872**	**14%**
TOTAL DIRECT NETWORK EXPENDITURE	**20,682**	**19,490**	**(1,192)**	**(6%)**

Table 8.2: Comparison of actual and budget network capex and network maintenance opex in FYE2022

8.2.1.1 Network Capital Expenditure

As shown in Table 8.4 actual capital expenditure in FYE2022 was 14% lower than forecast with material variations from budgeted levels in all expenditure categories, except system growth.

Consumer Connections

- We have little control over this expenditure and there was more consumer-driven activity than expected. The additional expenditure was largely offset by increased consumer contributions.

Asset Replacement and Renewal

- The ongoing wood pole replacement programme was deferred in FYE2022. All the wood poles on our network have been tested ultrasonically and none were considered to need urgent replacement. Replacement of some other assets that are not critical to network performance was also deferred. We have recommenced this programme in the current FYE2023 year.

Reliability, Safety and Environment

- Installation of the interconnection between the Matauri Bay and Whangaroa feeders was deferred because the combined unplanned SAIDI impact of the two feeders was low in FYE2021. However, this was an aberration and the SAIDI impact of the Whangaroa feeder in FYE2022 and FYE2023 has been high. This project has now been reinstated under our 11kV reliability improvement programme. The other major RSE project, the removal of the overhead 11kV bus and structure at Waipapa substation, was completed – this was considered a safety issue.

8.2.1.2 Network Maintenance Expenditure

As shown in Table 8.4, operational expenditure on network maintenance in FYE2022 was 14% above budget, due to the 59% overrun in the cost of responding to service interruptions and emergencies. Our control over expenditure in this category is limited.

8.3 Asset Management Improvement Programme

Our organisational philosophy is one of continuous improvement across all Top Energy's business units and our certification to ISO 9001 is testimony to this. This was the culmination of a major business improvement initiative that took several years and affected all business units within the Group.

We are implementing a range of initiatives to improve our asset management effectiveness and better utilise our electronic asset management tools. These include:

- *LV network data capture.* In FYE2023, we initiated a three-year LV data capture project, which will capture accurate data on our LV assets and their connectivity across the network. As the data comes in, it is being input into the GIS and will in time be used to extend the functionality of the ADMS to include real time management of the LV system. A former employee was engaged on contract in FYE2023 to initiate this project and a second former employee has now been engaged. Eventually it is envisaged that a team of three will be out in the field gathering data. The project includes opening all service pillars to confirm LV connectivity and has been useful in identifying issues that require remediation, but which would otherwise have gone unnoticed.

- *Access to smart meter data.* Approximately 70% of the consumers on our network have smart meters. We are negotiating with retailers and metering service providers for access to this data. If these negotiations are successful, we plan to trial the Gridsight LV visibility and hosting capacity platform. The package will integrate the LV connectivity model in the GIS, developed using data from the data capture project, with smart meter data it to identify potential power quality issues on the LV network. It also uses artificial intelligence to identify ICPs with behind-the-meter photovoltaic installations and EV chargers. Gridsight is a cloud-based platform that would not integrate directly with ADMS, but which operate as a standalone system that would be used for both operational and planning purposes.

- *Enhancing ADMS functionality.* We have procured the distribution power flow (DPF) module of our ADMS software platform to extend the functionality of our ADMS system. The module provides a power flow model of the network in real time to identify situations where the network is running, or could potentially run, outside its design envelope. For example, it would identify if a potential reconfiguration of the network to minimize the impact of a fault would cause a safety issue or create an overload or low voltage situation. However, if this functionality is to be fully utilized, it requires accurate data on the network and this data input process is ongoing.

- *Asset Risk Management Model.* We are working with an external consultant to develop a quantified asset risk management model (ARMM) for our overhead lines. The model creates a risk score for each individual asset, which is the product of the asset's probability of failure and the consequence of failure. The risk scores for each asset are then aggregated to create a risk profile for each asset class. Based on the rate of deterioration generally observed for each asset type, the model can track the change in risk profile of each asset class over time. We will use the model as a tool that will enable us to evaluate how different rates of asset replacement will impact the risk profile, and this will allow us to quantify the optimal rate of asset replacement to maintain the asset fleet in a condition that is fit for purpose.

  A separate model is prepared for each asset class and in FYE2024 we will work with the consultant to create risk management models of our overhead line assets, including conductors, poles and crossarms. Our expectation is that we will then generate similar models for other assets in the following years.

- *Integration of Existing Asset Management Systems.* As noted in Section 2.11.3, we will continue the process of integrating our new GIS with our asset maintenance and finance system (SAP) and our power system analysis software (DigSilent Power Factory).

9 Appendices

9.1 Appendix A – Asset Management Plan Schedules:

Schedule 11a	CAPEX Forecast
Schedule 11b	OPEX Forecast
Schedule 12a	Asset Condition
Schedule 12b	Capacity Forecast
Schedule 12c	Demand Forecast
Schedule 12d	Reliability Forecast
Schedule 13	Asset Management Maturity Assessment
Schedule 14a	Mandatory Explanatory Notes on Forecast Information
Schedule 15	Voluntary Explanatory Notes

Company Name	Top Energy Ltd
AMP Planning Period	1 April 2023 – 31 March 2033

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
8		for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10	Consumer connection		4,250	4,223	3,751	3,462	2,762	2,713	2,767	2,822	2,879	2,936	2,995
11	System growth		828	462	-	-	-	5,548	9,693	5,313	5,942	7,950	4,411
12	Asset replacement and renewal		6,654	10,520	10,467	11,611	12,027	8,418	7,180	7,754	8,098	7,474	8,658
13	Asset relocations												
14	Reliability, safety and environment:												
15	Quality of supply		1,353	5,315	4,738	3,504	3,764	1,676	2,379	2,151	1,721	1,834	3,701
16	Legislative and regulatory												
17	Other reliability, safety and environment		122										
18	**Total reliability, safety and environment**		1,475	5,315	4,738	3,504	3,764	1,676	2,379	2,151	1,721	1,834	3,701
19	**Expenditure on network assets**		13,207	20,520	18,956	18,577	18,553	18,354	22,019	18,040	18,640	20,195	19,766
20	Expenditure on non-network assets		420	1,199	2,724	1,025	1,144	1,121	1,127	1,499	1,267	1,201	1,309
21	**Expenditure on assets**		13,627	21,719	21,680	19,601	19,697	19,475	23,146	19,540	19,906	21,396	21,075
22													
23	*plus* Cost of financing		85	100	100	100	100	100	100	100	100	100	100
24	*less* Value of capital contributions		3,900	3,500	3,121	2,813	2,099	2,141	2,184	2,227	2,272	2,317	2,364
25	*plus* Value of vested assets		5	5	5	5	5	5	5	5	5	5	5
26													
27	**Capital expenditure forecast**		9,817	18,324	18,664	16,893	17,703	17,439	21,067	17,418	17,739	19,184	18,816
28													
29	Assets commissioned		8,827	16,869	16,676	15,869	16,063	15,890	10,481	25,219	15,547	15,271	22,227

			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 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
32			**$000 (in constant prices)**										
33	Consumer connection		4,250	4,223	3,607	3,232	2,528	2,434	2,434	2,434	2,434	2,434	2,434
34	System growth		828	462	-	-	-	4,978	8,527	4,582	5,024	6,590	3,585
35	Asset replacement and renewal		6,654	10,520	10,064	10,839	11,007	7,553	6,316	6,687	6,847	6,196	7,037
36	Asset relocations		-	-	-	-	-	-					
37	Reliability, safety and environment:												
38	Quality of supply		1,353	5,315	4,556	3,271	3,445	1,504	2,093	1,856	1,455	1,521	3,008
39	Legislative and regulatory		-	-	-	-	-	-					
40	Other reliability, safety and environment		122	-	-	-	-	-					
41	**Total reliability, safety and environment**		1,475	5,315	4,556	3,271	3,445	1,504	2,093	1,856	1,455	1,521	3,008
42	**Expenditure on network assets**		13,207	20,520	18,227	17,342	16,980	16,469	19,370	15,559	15,760	16,740	16,064
43	Expenditure on non-network assets		420	1,199	2,619	956	1,047	1,005	991	1,293	1,071	996	1,064
44	**Expenditure on assets**		13,627	21,719	20,846	18,298	18,027	17,474	20,361	16,852	16,831	17,736	17,128
45													
46	**Subcomponents of expenditure on assets (where known)**												
	**EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*												
47	Energy efficiency and demand side management, reduction of energy losses												
48	Overhead to underground conversion												
49	Research and development												
50	Cybersecurity (Commission only)												
51													

Company Name	Top Energy Ltd
AMP Planning Period	1 April 2023 – 31 March 2033

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*
for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
Difference between nominal and constant price forecasts	**$000**										
Consumer connection	-	-	144	230	234	279	333	388	445	502	561
System growth	-	-	-	-	-	570	1,166	731	918	1,360	826
Asset replacement and renewal	-	-	403	772	1,020	865	864	1,067	1,251	1,278	1,622
Asset relocations	-	-	-	-	-	-	-	-	-	-	-
Reliability, safety and environment:											
Quality of supply	-	-	182	233	319	172	286	296	266	314	693
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
Total reliability, safety and environment	-	-	182	233	319	172	286	296	266	314	693
Expenditure on network assets	-	-	729	1,235	1,573	1,885	2,649	2,482	2,879	3,454	3,702
Expenditure on non-network assets	-	-	105	68	97	115	136	206	196	205	245
Expenditure on assets	-	-	834	1,303	1,670	2,000	2,785	2,688	3,075	3,660	3,947

Commentary on options and considerations made in the assessment of forecast expenditure

EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**

11a(ii): Consumer Connection

*Consumer types defined by EDB**	**$000 (in constant prices)**					
All types	4,250	4,223	3,607	3,232	2,528	2,434
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
**include additional rows if needed*						
Consumer connection expenditure	4,250	4,223	3,607	3,232	2,528	2,434
less Capital contributions funding consumer connection	3,900	3,500	3,001	2,626	1,921	1,921
Consumer connection less capital contributions	350	723	606	606	607	513

11a(iii): System Growth

Subtransmission						
Zone substations						4,978
Distribution and LV lines	828	462				
Distribution and LV cables						
Distribution substations and transformers						
Distribution switchgear						
Other network assets						
System growth expenditure	828	462	-	-	-	4,978
less Capital contributions funding system growth						
System growth less capital contributions	828	462	-	-	-	4,978

	Company Name	Top Energy Ltd
	AMP Planning Period	1 April 2023 – 31 March 2033

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
96			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
97		for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
98	**11a(iv): Asset Replacement and Renewal**		**$000 (in constant prices)**					
99		Subtransmission	2,963	2,517	1,895	1,495	1,522	1,473
100		Zone substations	76	71	71	71	71	71
101		Distribution and LV lines	2,167	5,433	5,201	6,886	7,897	4,509
102		Distribution and LV cables	135	389	126	546	126	126
103		Distribution substations and transformers	428	1121	1491	938	488	488
104		Distribution switchgear	802	779	744	744	744	744
105		Other network assets	83	210	536	159	159	142
106		**Asset replacement and renewal expenditure**	6,654	10,520	10,064	10,839	11,007	7,553
107	*less*	Capital contributions funding asset replacement and renewal						
108		**Asset replacement and renewal less capital contributions**	6,654	10,520	10,064	10,839	11,007	7,553
109								

110			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
111		for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
112	**11a(v): Asset Relocations**							
113		*Project or programme**	**$000 (in constant prices)**					
114		[Description of material project or programme]						
115		[Description of material project or programme]						
116		[Description of material project or programme]						
117		[Description of material project or programme]						
118		[Description of material project or programme]						
119		**include additional rows if needed*						
120		All other project or programmes - asset relocations						
121		**Asset relocations expenditure**	-	-	-	-	-	-
122	*less*	Capital contributions funding asset relocations						
123		**Asset relocations less capital contributions**	-	-	-	-	-	-
124								

125			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
126		for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
127	**11a(vi): Quality of Supply**							
128		*Project or programme**	**$000 (in constant prices)**					
129		Kaitaia 11kV injection Point		736	631			
130		New 11kV sectionalisers and reclosers		1,194	632	1,148	1,195	
131		New 11kV feeder interconnections		1,934	1,556	705	889	465
132								
133								
134		**include additional rows if needed*						
135		All other projects or programmes - quality of supply	1,353	1,451	1,737	1,418	1,361	1,039
136		**Quality of supply expenditure**	1,353	5,315	4,556	3,271	3,445	1,504
137	*less*	Capital contributions funding quality of supply						
138		**Quality of supply less capital contributions**	1,353	5,315	4,556	3,271	3,445	1,504
139								

Company Name	Top Energy Ltd
AMP Planning Period	1 April 2023 – 31 March 2033

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

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

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

This information is not part of audited disclosure information.

sch ref

11a(vii): Legislative and Regulatory

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
*Project or programme**	**$000 (in constant prices)**					
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other projects or programmes - legislative and regulatory						
Legislative and regulatory expenditure	-	-	-	-	-	-
less Capital contributions funding legislative and regulatory						
Legislative and regulatory less capital contributions	-	-	-	-	-	-

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

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
*Project or programme**	**$000 (in constant prices)**					
Waipapa substation safety remediation	122					
**include additional rows if needed*						
All other projects or programmes - other reliability, safety and environment						
Other reliability, safety and environment expenditure	122	-	-	-	-	-
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	122	-	-	-	-	-

11a(ix): Non-Network Assets

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
Routine expenditure						
*Project or programme**	**$000 (in constant prices)**					
General	380	686	545	668	681	692
Software	40	514	8	288	366	313
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other projects or programmes - routine expenditure						
Routine expenditure	420	1,199	552	956	1,047	1,005
Atypical expenditure						
*Project or programme**						
Software - SAP Upgrade			1,442			
General - Hardware Data Centre			625			
[Description of material project or programme]						
[Description of material project or programme]						
[Description of material project or programme]						
**include additional rows if needed*						
All other projects or programmes - atypical expenditure						
Atypical expenditure	-	-	2,067	-	-	-
Expenditure on non-network assets	420	1,199	2,619	956	1,047	1,005

Company Name	Top Energy Ltd
AMP Planning Period	1 April 2023 – 31 March 2033

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*
7												
8	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	2,595	1,381	1,456	1,508	1,545	1,584	1,624	1,666	1,708	1,750	1,794
11	Vegetation management	1,655	2,238	2,405	2,489	2,552	2,615	2,681	2,748	2,817	2,888	2,960
12	Routine and corrective maintenance and inspection	2,325	2,197	2,318	2,400	2,460	2,522	2,586	2,650	2,716	2,785	2,855
13	Asset replacement and renewal	1,611	1,647	1,738	1,799	1,843	1,890	1,937	1,987	2,036	2,088	2,139
14	**Network Opex**	8,186	7,463	7,917	8,195	8,400	8,611	8,828	9,050	9,277	9,511	9,748
15	System operations and network support	6,351	7,691	7,901	8,168	8,278	8,509	8,746	8,991	9,244	9,504	9,773
16	Business support	6,925	7,800	8,112	8,355	8,522	8,693	8,867	9,044	9,225	9,409	9,598
17	**Non-network opex**	13,276	15,491	16,013	16,523	16,800	17,202	17,613	18,035	18,469	18,913	19,371
18	**Operational expenditure**	21,462	22,954	23,930	24,718	25,200	25,813	26,441	27,085	27,746	28,424	29,119

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 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	2,595	1,381	1,387	1,394	1,401	1,408	1,415	1,423	1,430	1,437	1,444
23	Vegetation management	1,655	2,238	2,290	2,301	2,313	2,324	2,336	2,347	2,359	2,371	2,383
24	Routine and corrective maintenance and inspection	2,325	2,197	2,208	2,219	2,230	2,241	2,253	2,264	2,275	2,287	2,298
###	Asset replacement and renewal	1,611	1,647	1,655	1,663	1,671	1,680	1,688	1,697	1,705	1,714	1,722
26	**Network Opex**	8,186	7,463	7,540	7,577	7,615	7,653	7,692	7,731	7,769	7,809	7,847
27	System operations and network support	6,351	7,691	7,525	7,552	7,504	7,562	7,620	7,680	7,742	7,803	7,867
28	Business support	6,925	7,800	7,726	7,725	7,725	7,726	7,726	7,726	7,726	7,725	7,726
29	**Non-network opex**	13,276	15,491	15,250	15,278	15,229	15,288	15,346	15,406	15,467	15,529	15,593
30	**Operational expenditure**	21,462	22,954	22,790	22,855	22,844	22,941	23,038	23,137	23,236	23,338	23,440

31 **Subcomponents of operational expenditure (where known)**

**EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*

32–33	Energy efficiency and demand side management, reduction of energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance	760	764	840	899	944	991	1,041	1,093	1,148	1,205	1,265
37	Cybersecurity (Commission only)											

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

39

40		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
41	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**	**31 Mar 33**
42	**Difference between nominal and real forecasts**	**$000**										
43	Service interruptions and emergencies	-	-	69	114	144	176	209	243	278	313	350
44	Vegetation management	-	-	115	188	239	291	345	401	458	517	577
45	Routine and corrective maintenance and inspection	-	-	110	181	230	281	333	386	441	498	557
46	Asset replacement and renewal	-	-	83	136	172	210	249	290	331	374	417
47	**Network Opex**	-	-	377	618	785	958	1,136	1,319	1,508	1,702	1,901
48	System operations and network support	-	-	376	616	774	947	1,126	1,311	1,502	1,701	1,906
49	Business support	-	-	386	630	797	967	1,141	1,318	1,499	1,684	1,872
50	**Non-network opex**	-	-	763	1,245	1,571	1,914	2,267	2,629	3,002	3,384	3,778
51	**Operational expenditure**	-	-	1,140	1,863	2,356	2,872	3,403	3,948	4,509	5,086	5,680

52

53 **Commentary on options and considerations made in the assessment of forecast expenditure**

54 *EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operational expenditure for the current disclosure year and a 10 year planning period in Schedule 15.*

55

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2023 – 31 March 2033**

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref													
7					Asset condition at start of planning period (percentage of units by grade)								
8													
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
10	All	Overhead Line	Concrete poles / steel structure	No.	0.02%	2.65%	8.83%	83.43%	5.07%	3.90%	4	1.00%
11	All	Overhead Line	Wood poles	No.	0.20%	12.97%	68.97%	2.83%	15.03%	1.29%	4	39.20%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	100.00%	-	4	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	5.22%	15.77%	62.87%	16.14%	-	2	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	83.58%	16.42%	-	2	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	-	100.00%	-	2	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	9.09%	63.64%	27.27%	-	4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	100.00%	-	-	4	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	6.67%	93.33%	-	4	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	10.52%	61.41%	28.07%	1.72%	4	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	0.60%	54.49%	44.91%	1.76%	4	-
30	HV	Zone substation switchgear	33kV RMU	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	28.57%	-	-	71.43%	-	4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	-	70.83%	29.17%	-	4	-
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	13.88%	-	50.00%	36.12%	2.70%	4	-
35												

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2023 – 31 March 2033**

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												
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.	-	2.08%	20.83%	58.34%	18.75%	-	4	-
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3.13%	12.17%	27.06%	36.97%	20.67%	-	2	1.09%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
42	HV	Distribution Line	SWER conductor	km	22.04%	23.85%	18.16%	19.55%	16.40%	-	2	9.34%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	0.29%	0.62%	23.67%	75.42%	-	2	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	1.76%	12.43%	65.75%	20.06%	-	2	-
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	100.00%	-	-	-	2	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	0.27%	-	4.18%	79.40%	16.15%	1.37%	4	0.27%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	7.60%	11.45%	13.90%	21.78%	45.27%	1.29%	2	7.60%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	0.11%	2.34%	30.93%	66.62%	4.26%	4	7.25%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	0.13%	2.10%	91.48%	6.29%	4.59%	4	0.75%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.08%	0.32%	12.17%	80.86%	6.57%	2.62%	4	0.20%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	10.53%	54.39%	35.08%	-	4	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	25.00%	75.00%	-	-	4	-
55	LV	LV Line	LV OH Conductor	km	2.39%	8.48%	30.93%	42.64%	15.56%	-	2	2.39%
56	LV	LV Cable	LV UG Cable	km	0.29%	3.38%	18.50%	43.76%	34.07%	-	2	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.80%	4.28%	21.34%	46.86%	26.72%	-	2	-
58	LV	Connections	OH/UG consumer service connections	No.	0.02%	0.51%	15.83%	74.48%	9.16%	5.02%	4	0.25%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	7.50%	-	1.50%	29.25%	61.75%	-	4	7.50%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	100.00%	-	-	4	N/A
61	All	Capacitor Banks	Capacitors including controls	No.	9.30%	2.33%	58.14%	20.93%	9.30%	-	4	26.32%
62	All	Load Control	Centralised plant	Lot	-	-	-	100.00%	-	-	4	-
63	All	Load Control	Relays	No.	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
64	All	Civils	Cable Tunnels	km	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2023 – 31 March 2033**

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	Kaikohe	10	17	N-1	1	58%	17	60%	No constraint within +5 years	
10	Kawakawa	7	6	N-1	3	109%	6	74%	No constraint within +5 years	1.5MW to be transferred to Haruru by winter FYE2024, after completion of Russell reinforcement project.
11	Moerewa	3	5	N-1	3	68%	5	68%	No constraint within +5 years	
12	Waipapa	11	23	N-1	8	46%	23	56%	No constraint within +5 years	
13	Omanaia	3	-	N-0	2	-	-	-	Transformer	Transfer capacity includes 2MVA of onsite generation. Mobile transformer is available if needed.
14	Haruru	6	23	N-1	2	25%	23	31%	No constraint within +5 years	1.5MW to be transferred from Kawakawa by winter FYE2024, after completion of Russell reinforcement project.
15	Mt Pokaka	3	-	N-0	2	-	-	-	Transformer	Mobile transformer available if needed. Sufficient transfer capacity available to supply all small use consumers.
16	Kerikeri	8	23	N-1	6	36%	23	42%	No constraint within +5 years	
17	Kaeo	4	-	N-0	4	-	-	-	Subtransmission circuit	
18	Okahu Rd	10	12	N-1	4	83%	12	60%	No constraint within +5 years	1.5MVA to be transferred to Kaitaia transmission substation by winter FYE2025
19	Taipa	6	-	N-0	3	-	-	-	Subtransmission circuit	The transfer of the mobile substation to Taipa on a permanent basis has mitigated the transformer constraint. However the substation still has only one incoming transfmission circuit.
20	NPL	10	23	N-1	4	43%	23	43%	No constraint within +5 years	
21	Pukenui	2	-	N-0	2	-	-	-	Transformer	Transfer capacity includes onsite diesel generation. Mobile transformer available.
22	Kaikohe 110kV	48	39	N-1	25	123%	39	149%	No constraint within +5 years	The 25MVA of transfer capacity is from OEC1-3 at Ngawha power station, which bypass the transformers and inject power into the 33kV busbar. Approximately 27 MVA of the Kaikohe 110kV peak demand will be transferred to Wiroa when the 110/33kV Wiroa substation is commissioned. This is now expected by FYE2029.
23	Kaitaia 110kV	26	-	N-0	16	-	-	-	Subtransmission circuit	Transfer capacity is diesel generation in northern area. The installation of utility scale solar generation will fully utilise the 40/60MVA transformer should the smaller transformer fail. Approximately 1.5MVA of 11kV load will be supplied from this substation by FYE2025.
24	[Zone Substation_16]					-			[Select one]	
25	[Zone Substation_17]					-			[Select one]	
26	[Zone Substation_18]					-			[Select one]	
27	[Zone Substation_19]					-			[Select one]	
28	[Zone Substation_20]					-			[Select one]	

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Company Name: **Top Energy Ltd**

AMP Planning Period: **1 April 2023 – 31 March 2033**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

12c(i): Consumer Connections

Number of ICPs connected in year by consumer type

	Number of connections					
	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
*Consumer types defined by EDB**						
Residential	412	348	360	370	380	390
Commercial	37	67	75	80	85	90
[EDB consumer type]						
[EDB consumer type]						
[EDB consumer type]						
Connections total	449	415	435	450	465	480

**include additional rows if needed*

Distributed generation

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
Number of connections made in year	300	305	310	315	320	325
Capacity of distributed generation installed in year (MVA)	2	25	22	26	2	2

12c(ii) System Demand

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	Maximum coincident system demand (MW) for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
	GXP demand	21	20	21	23	24	26
plus	Distributed generation output at HV and above	57	57	57	57	57	57
	Maximum coincident system demand	78	77	78	80	81	83
less	Net transfers to (from) other EDBs at HV and above						
	Demand on system for supply to consumers' connection points	78	77	78	80	81	83
	Electricity volumes carried (GWh)						
	Electricity supplied from GXPs	10	10	10	15	23	24
less	Electricity exports to GXPs	100	124	157	211	216	246
plus	Electricity supplied from distributed generation	459	483	516	570	575	605
less	Net electricity supplied to (from) other EDBs						
	Electricity entering system for supply to ICPs	369	369	369	374	382	383
less	Total energy delivered to ICPs	332	331	332	335	339	342
	Losses	37	38	37	39	43	41
	Load factor	54%	55%	54%	53%	54%	53%
	Loss ratio	10.0%	10.3%	10.0%	10.3%	11.3%	10.7%

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2023 – 31 March 2033**
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*
8							
9	for year ended	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	140.0	150.0	150.0	150.0	150.0	150.0
12	Class C (unplanned interruptions on the network)	1,800.0	350.0	350.0	350.0	350.0	350.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.75	1.00	1.00	1.00	1.00	1.00
15	Class C (unplanned interruptions on the network)	6.20	4.01	4.01	4.01	4.01	4.01

		Company Name	Top Energy Ltd
		AMP Planning Period	1 April 2024– 31 March 2033
		Asset Management Standard Applied	PAS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
27	Asset management plan(s)	How has the organisation communicated its plan(s) to all relevant parties to a level of detail appropriate to the receiver's role in their delivery?	3	Planning of maintenance work is done within the Networks Division and the required work is communicated to service providers via the annual works plan and individual projects are issued via work orders. Our quality system is certified as ISO 9001 compliant and contains procedures that set out the various roles and responsibilities for service delivery and the linkages between the personnel involved. Compliance with these procedures is externally audited on a regular basis to ensure we remain compliant.		Plans will be ineffective unless they are communicated to all those, including contracted suppliers and those who undertake enabling function(s). The plan(s) need to be communicated in a way that is relevant to those who need to use them.	The management team with overall responsibility for the asset management system. Delivery functions and suppliers.	Distribution lists for plan(s). Documents derived from plan(s) which detail the receivers role in plan delivery. Evidence of communication.
29	Asset management plan(s)	How are designated responsibilities for delivery of asset plan actions documented?	3	The responsibilities of staff and service providers responsible for maintenance are clearly set out in their job descriptions and our annual plans identify the personnel responsible for the implementation of individual projects. Our quality system is certified as ISO 9001 compliant and contains procedures that set out the various roles and responsibilities for service delivery and the linkages between the personnel involved. Compliance with these procedures is externally audited on a regular basis and we remain compliant.		The implementation of asset management plan(s) relies on (1) actions being clearly identified, (2) an owner allocated and (3) that owner having sufficient delegated responsibility and authority to carry out the work required. It also requires alignment of actions across the organisation. This question explores how well the plan(s) set out responsibility for delivery of asset plan actions.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers. If appropriate, the performance management team.	The organisation's asset management plan(s). Documentation defining roles and responsibilities of individuals and organisational departments.
31	Asset management plan(s)	What has the organisation done to ensure that appropriate arrangements are made available for the efficient and cost effective implementation of the plan(s)? (Note this is about resources and enabling support)	3	We are continually refining our standard designs, as well as our outsourcing and procurement processes, to maintain consistency, avoid unnecessary duplication and ensure that all resources needed to deliver the work programme are available as and when required through competitive tendering. Our quality system is certified as ISO 9001 compliant and contains procedures that set out the various roles and responsibilities for service delivery and the linkages between the personnel involved. Compliance with these procedures is externally audited on a regular basis and we remain compliant.		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	As described in Sections 7.3.3 and 7.3.4 of the AMP, we have documented Emergency Preparedness, Emergency Response and Business Continuity plans in place that define roles, responsibilities and procedures to be followed when a situation arises that exceeds our capacity to manage in the normal course of business. We are actively involved in the Northland Lifelines Project and maintain strong links with other organisations responsible for the management of civil emergencies.		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	Top Energy Ltd
AMP Planning Period	1 April 2024– 31 March 2033
Asset Management Standard Applied	PAS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Responsibility for delivering the requirements of the asset management strategy, objectives and plans rests with the General Manager Network. Top Energy has a documented organisational structure that fully covers the development and delivery of the asset management plan. The responsibilities and accountabilities of each position in the structure are well defined in the relevant position description. The level of delegated authority for each position is appropriate.		In order to ensure that the organisation's assets and asset systems deliver the requirements of the asset management policy, strategy and objectives responsibilities need to be allocated to appropriate people who have the necessary authority to fulfil their responsibilities. (This question, relates to the organisation's assets eg, para b), s 4.4.1 of PAS 55, making it therefore distinct from the requirement contained in para a), s 4.4.1 of PAS 55).	Top management. People with management responsibility for the delivery of asset management policy, strategy, objectives and plan(s). People working on asset-related activities.	Evidence that managers with responsibility for the delivery of asset management policy, strategy, objectives and plan(s) have been appointed and have assumed their responsibilities. Evidence may include the organisation's documents relating to its asset management system, organisational charts, job descriptions of post-holders, annual targets/objectives and personal development plan(s) of post-holders as appropriate.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	3	Prior to each budget year, we prepare a detailed programme of works, as well as a resource forecast and resourcing strategy to deliver the programme. We are actively engaging with contractor groups to assist with the delivery of the works plan.		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	Performance against the works programme and the quality targets set out in our AMP is reported to the Board monthly. Following each Board meeting the CEO briefs the full management team, who in turn are required to update their staff.		Widely used AM practice standards require an organisation to communicate the importance of meeting its asset management requirements such that personnel fully understand, take ownership of, and are fully engaged in the delivery of the asset management requirements (eg, PAS 55 s 4.4.1 g).	Top management. The management team that has overall responsibility for asset management. People involved in the delivery of the asset management requirements.	Evidence of such activities as road shows, written bulletins, workshops, team talks and management walk-abouts would assist an organisation to demonstrate it is meeting this requirement of PAS 55.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	3	Processes for the engagement and management of external service providers are outlined in our documented procedures and agreements to meet a minimum criteria for approval to work on our assets. Procedures are being reviewed to refine the approval process. Controls include direct supervision, or general supervision with competency accreditation, induction of company procedures site supervision, quality audits, health and safety audits, regular reporting.		Where an organisation chooses to outsource some of its asset management activities, the organisation must ensure that these outsourced process(es) are under appropriate control to ensure that all the requirements of widely used AM standards (eg, PAS 55) are in place, and the asset management policy, strategy objectives and plan(s) are delivered. This includes ensuring capabilities and resources across a time span aligned to life cycle management. The organisation must put arrangements in place to control the outsourced activities, whether it be to external providers or to other in-house departments. This question explores what the organisation does in this regard.	Top management. The management team that has overall responsibility for asset management. The manager(s) responsible for the monitoring and management of the outsourced activities. People involved with the procurement of outsourced activities. The people within the organisations that are performing the outsourced activities. The people impacted by the outsourced activity.	The organisation's arrangements that detail the compliance required of the outsourced activities. For example, this this could form part of a contract or service level agreement between the organisation and the suppliers of its outsourced activities. Evidence that the organisation has demonstrated to itself that it has assurance of compliance of outsourced activities.

Company Name	Top Energy Ltd	
AMP Planning Period	1 April 2024– 31 March 2033	
Asset Management Standard Applied	PAS 55	

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	3	A recent review of resource requirements and appropriate skills (gap analysis) was undertaken by an external consultancy. Yearly personal development plans (PDP) (with 6 month reviews) are used to identify skills development opportunities for staff. We identify skills and resources needed and engage with internal and external service providers to align resourcing to match the delivery of the asset management plan. General Managers provide the Board with an annual update of team member skills and competencies.		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?	3	Job descriptions define minimum competencies for each specific role. A competency/skills matrix defines competency requirements framework for interacting with assets. The competency database records current competencies held or required. Training records are held in the document centre/HR files. Staff training requirements are discussed, agreed, and signed off annually during PDP consultation reviewed six monthly. Training hours are routinely monitored and reported.		Widely used AM standards require that organisations to undertake a systematic identification of the asset management awareness and competencies required at each level and function within the organisation. Once identified the training required to provide the necessary competencies should be planned for delivery in a timely and systematic way. Any training provided must be recorded and maintained in a suitable format. Where an organisation has contracted service providers in place then it should have a means to demonstrate that this requirement is being met for their employees. (eg, PAS 55 refers to frameworks suitable for identifying competency requirements).	Senior management responsible for agreement of plan(s). Managers responsible for developing asset management strategy and plan(s). Managers with responsibility for development and recruitment of staff (including HR functions). Staff responsible for training. Procurement officers. Contracted service providers.	Evidence of an established and applied competency requirements assessment process and plan(s) in place to deliver the required training. Evidence that the training programme is part of a wider, co-ordinated asset management activities training and competency programme. Evidence that training activities are recorded and that records are readily available (for both direct and contracted service provider staff) e.g. via organisation wide information system or local records database.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	3	Job descriptions define minimum competencies for each specific role.The recruitment process ensures alignment with the Job Description. We have a formal staff assessment system in place where a personal development plan (PDP) is prepared in consultation with each staff member. This contains both performance targets linked to our mission and values, and a personal training plan. Performance against the PDP is reviewed with the staff member at the middle and end of each year. Work is outsourced where competent in-house resources are not avaialable.		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	**Top Energy Ltd**
AMP Planning Period	**1 April 2024– 31 March 2033**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	Communication is provided through structured meetings including CEO management briefings (available on the intranet to all staff). Other forms of asset information is provided via more specific channels such as TEN TECS meetings, stakeholder coordination meetings (internal and external), Safe Team Meetings, and tool box meetings. Appropriate processes and procedures are documented in our ISO 9001 certified quality management system. Compliance with these procedures is externally audited on a regular basis and we remain compliant. Relevent information is uploaded onto the in-house intranet and available to all staff that need to access it.		Widely used AM practice standards require that pertinent asset management information is effectively communicated to and from employees and other stakeholders including contracted service providers. Pertinent information refers to information required in order to effectively and efficiently comply with and deliver asset management strategy, plan(s) and objectives. This will include for example the communication of the asset management policy, asset performance information, and planning information as appropriate to contractors.	Top management and senior management representative(s), employee's representative(s), employee's trade union representative(s); contracted service provider management and employee representative(s); representative(s) from the organisation's Health, Safety and Environmental team. Key stakeholder representative(s).	Asset management policy statement prominently displayed on notice boards, intranet and internet; use of organisation's website for displaying asset performance data; evidence of formal briefings to employees, stakeholders and contracted service providers; evidence of inclusion of asset management issues in team meetings and contracted service provider contract meetings; newsletters, etc.
59	Asset Management System documentation	What documentation has the organisation established to describe the main elements of its asset management system and interactions between them?	3	Documntation includes The Asset Management Policy The Asset Management Plan, the Maintenance Code and specific procedures and processes (the interaction of these is defined in the Promapp system). The information is documented in our ISO 9001 certified quality management system. Compliance with these procedures is externally audited on a regular basis and we remain compliant.		Widely used AM practice standards require an organisation maintain up to date documentation that ensures that its asset management systems (ie, the systems the organisation has in place to meet the standards) can be understood, communicated and operated. (eg, s 4.5 of PAS 55 requires the maintenance of up to date documentation of the asset management system requirements specified throughout s 4 of PAS 55).	The management team that has overall responsibility for asset management. Managers engaged in asset management activities.	The documented information describing the main elements of the asset management system (process(es)) and their interaction.
62	Information management	What has the organisation done to determine what its asset management information system(s) should contain in order to support its asset management system?	3	Our GIS identifies the location and connectivity of all system assets for operational purposes. GIS information is complete and reliable for the HV assets. There is currently a programme validating and labelling LV assets as part of the process of bringing them under operational control of our Control Centre. When a new asset type is introduced the required information is determined (and where it will be stored). Information on the condition of individual assets is held in SAP and we have documented inspection standards that specify what information is to be recorded and how asset condition is to be assessed for the different asset types.		Effective asset management requires appropriate information to be available. Widely used AM standards therefore require the organisation to identify the asset management information it requires in order to support its asset management system. Some of the information required may be held by suppliers. The maintenance and development of asset management information systems is a poorly understood specialist activity that is akin to IT management but different from IT management. This group of questions provides some indications as to whether the capability is available and applied. Note: To be effective, an asset information management system requires the mobilisation of technology, people and process(es) that create, secure, make available and destroy the information required to support the asset management system.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Operations, maintenance and engineering managers	Details of the process the organisation has employed to determine what its asset information system should contain in order to support its asset management system. Evidence that this has been effectively implemented.

63	Information management	How does the organisation maintain its asset management information system(s) and ensure that the data held within it (them) is of the requisite quality and accuracy and is consistent?	2	Information is electronically entered into SAP from the field by asset inspectors using electronic PDIs. Asset alterations to the network carried out by field staff is recorded on asset change forms and/or as built plans. GIS information is updated manually by a dedicated data management team. The asset data team has begun an asset information maturity discussion with the view of developing policy and standards to benchmark against information captured through SAP.		The response to the questions is progressive. A higher scale cannot be awarded without achieving the requirements of the lower scale. This question explores how the organisation ensures that information management meets widely used AM practice requirements (eg, s 4.4.6 (a), (c) and (d) of PAS 55).	The management team that has overall responsibility for asset management. Users of the organisational information systems.	The asset management information system, together with the policies, procedure(s), improvement initiatives and audits regarding information controls.

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2024– 31 March 2033**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	2	The asset data team has begun an asset information maturity discussion with the view of developing policy and standards to benchmark against information captured through SAP. This has included discussions with the network teams regarding their data requirements. Systems for recording asset information are in place. The Advanced Distribution Management System provides effective real time visibility and operation of the assets.		Widely used AM standards need not be prescriptive about the form of the asset management information system, but simply require that the asset management information system is appropriate to the organisations needs, can be effectively used and can supply information which is consistent and of the requisite quality and accuracy.	The organisation's strategic planning team. The management team that has overall responsibility for asset management. Information management team. Users of the organisational information systems.	The documented process the organisation employs to ensure its asset management information system aligns with its asset management requirements. Minutes of information systems review meetings involving users.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	2	Asset and network risk are documented in the Asset Management Plan. The Maintenance Code and associated instructions and guides outline the asset management and remediation processes. We have a Public Safety Management system that includes hazard assessment and control processes which is externally audited to certify against NZS 7901. We incorporate "Safety in Design' principles to our network designs. We are currently integrating our asset management and corporate business risk processes.		Risk management is an important foundation for proactive asset management. Its overall purpose is to understand the cause, effect and likelihood of adverse events occurring, to optimally manage such risks to an acceptable level, and to provide an audit trail for the management of risks. Widely used standards require the organisation to have process(es) and/or procedure(s) in place that set out how the organisation identifies and assesses asset and asset management related risks. The risks have to be considered across the four phases of the asset lifecycle (eg, para 4.3.3 of PAS 55).	The top management team in conjunction with the organisation's senior risk management representatives. There may also be input from the organisation's Safety, Health and Environment team. Staff who carry out risk identification and assessment.	The organisation's risk management framework and/or evidence of specific process(es) and/ or procedure(s) that deal with risk control mechanisms. Evidence that the process(es) and/or procedure(s) are implemented across the business and maintained. Evidence of agendas and minutes from risk management meetings. Evidence of feedback in to process(es) and/or procedure(s) as a result of incident investigation(s). Risk registers and assessments.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	2	Where a serious risk is identified it is communicated throughout the organisation including appropriate controls to manage the risk. We proactively identify potential asset risks and put in place response plans for the management of these risks.		Widely used AM standards require that the output from risk assessments are considered and that adequate resource (including staff) and training is identified to match the requirements. It is a further requirement that the effects of the control measures are considered, as there may be implications in resources and training required to achieve other objectives.	Staff responsible for risk assessment and those responsible for developing and approving resource and training plan(s). There may also be input from the organisation's Safety, Health and Environment team.	The organisations risk management framework. The organisation's resourcing plan(s) and training and competency plan(s). The organisation should be able to demonstrate appropriate linkages between the content of resource plan(s) and training and competency plan(s) to the risk assessments and risk control measures that have been developed.

82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	2	Our General Manager Finance is responsible for identifying our legal obligations. However he is unlikely to capture all changes to our technical obligations. Our active involvement with industry organisations such as the Electricity Networks Association and Electricity Engineers Association means that it is unlikely changes to our technical obligations would be missed. Nevertheless processes to ensure that such changes are identified and complied with have still to be formalised.		In order for an organisation to comply with its legal, regulatory, statutory and other asset management requirements, the organisation first needs to ensure that it knows what they are (eg, PAS 55 specifies this in s 4.4.8). It is necessary to have systematic and auditable mechanisms in place to identify new and changing requirements. Widely used AM standards also require that requirements are incorporated into the asset management system (e.g. procedure(s) and process(es))	Top management. The organisations regulatory team. The organisation's legal team or advisors. The management team with overall responsibility for the asset management system. The organisation's health and safety team or advisors. The organisation's policy making team.	The organisational processes and procedures for ensuring information of this type is identified, made accessible to those requiring the information and is incorporated into asset management strategy and objectives

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2024– 31 March 2033**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	There is a documented process which includes the use of a dedicated team responsible to review and recommend the adoption of new asset types onto the system. This includes confirming specifications, management of spares, inspections and maintenance schedules. Processes are in place to manage the end to end delivery of assets specified in work packs. This includes design, procurement, construction and commissioning.		Life cycle activities are about the implementation of asset management plan(s) i.e. they are the "doing" phase. They need to be done effectively and well in order for asset management to have any practical meaning. As a consequence, widely used standards (eg, PAS 55 s 4.5.1) require organisations to have in place appropriate process(es) and procedure(s) for the implementation of asset management plan(s) and control of lifecycle activities. This question explores those aspects relevant to asset creation.	Asset managers, design staff, construction staff and project managers from other impacted areas of the business, e.g. Procurement	Documented process(es) and procedure(s) which are relevant to demonstrating the effective management and control of life cycle activities during asset creation, acquisition, enhancement including design, modification, procurement, construction and commissioning.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	3	The Maintenance Code outlines requirements to inspect and maintain assets. Inspection procedures are based on industry best practise, such as EEA Asset Health Indicator Guide. Field inspectors and auditors carry out implementation. Regular reviews are undertaken to ensure consistency of application.		Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	3	As previously described, we have a formal asset inspection programme in place and defined standards for measuring and recording asset condition in accordance with the maintenance code. This information is used to track the performance of assets and justify their replacement. Through condition assessments for asset classes, we develop annual work plans. We plan to develop leading indicators during asset inspections and the rates at which defects are identified.		Widely used AM standards require that organisations establish implement and maintain procedure(s) to monitor and measure the performance and/or condition of assets and asset systems. They further set out requirements in some detail for reactive and proactive monitoring, and leading/lagging performance indicators together with the monitoring or results to provide input to corrective actions and continual improvement. There is an expectation that performance and condition monitoring will provide input to improving asset management strategy, objectives and plan(s).	A broad cross-section of the people involved in the organisation's asset-related activities from data input to decision-makers, i.e. an end-to end assessment. This should include contactors and other relevant third parties as appropriate.	Functional policy and/or strategy documents for performance or condition monitoring and measurement. The organisation's performance monitoring frameworks, balanced scorecards etc. Evidence of the reviews of any appropriate performance indicators and the action lists resulting from these reviews. Reports and trend analysis using performance and condition information. Evidence of the use of performance and condition information shaping improvements and supporting asset management strategy, objectives and plan(s).

99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	3	We have an Accident and Incident Investigation Policy and Process, based on the ICAM methodology, which is applied to all events that are considered significant or had the potential to be significant. Incidents and findings are entered into Assura, with actions assigned to individuals. Outcomes are shared to all relevant parties. All unplanned outages over two SAIDI minutes are investigated.		Widely used AM standards require that the organisation establishes implements and maintains process(es) for the handling and investigation of failures incidents and non-conformities for assets and sets down a number of expectations. Specifically this question examines the requirement to define clearly responsibilities and authorities for these activities, and communicate these unambiguously to relevant people including external stakeholders if appropriate.	The organisation's safety and environment management team. The team with overall responsibility for the management of the assets. People who have appointed roles within the asset-related investigation procedure, from those who carry out the investigations to senior management who review the recommendations. Operational controllers responsible for managing the asset base under fault conditions and maintaining services to consumers. Contractors and other third parties as appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2024– 31 March 2033**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	3	Our ISO 9001 quality system and our NZS 7901 Public Safety Management System are audited in accordance with their certification requirements. Internal audits are undertaken in accordance with ISO 9001 requirements. Our measurement of supply reliability is also externally audited in accordance with the Commission's requirements. There is a formal process in place to audit the field activities undertaken on the network.		This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	3	We have a formal corrective action process for addressing issues identified in our external and internal quality system audits. We also have a Business Improvement Team that investigates business improvements including improvement suggestions made by staff. As noted in Q99, we have a formal incident investigation process based on the ICAM methodology. Monthly reporting captures measurables including financial performance, asset performance, health and safety, customer experience, works programme delivery, relaibility. These provide visibility for opportunity to improve.		Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews

113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	3	As part of our continual improvement journey we have introduced a condition based asset replacement programme focussed on risk and consequence for many of the assets employed. Completed projects are reviewed to identify opportunities for improvement. Engagement with stakeholders to ascertain ways of improvement. Engaging with industry including forums and workshops to ensure we are staying abreast of advances in technology. We are engaging a Future Technology Engineer to identify and impliment opportunities. We are engaging an Analyst to compile and conduct statistical analysis on network performance to identify areas for improvement.		Widely used AM standards have requirements to establish, implement and maintain process(es)/procedure(s) for identifying, assessing, prioritising and implementing actions to achieve continual improvement. Specifically there is a requirement to demonstrate continual improvement in optimisation of cost risk and performance/condition of assets across the life cycle. This question explores an organisation's capabilities in this area—looking for systematic improvement mechanisms rather that reviews and audit (which are separately examined).	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. Managers responsible for policy development and implementation.	Records showing systematic exploration of improvement. Evidence of new techniques being explored and implemented. Changes in procedure(s) and process(es) reflecting improved use of optimisation tools/techniques and available information. Evidence of working parties and research.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	3	We engage with the wider asset management community, particularly as it relates to electricity distribution through industry events. Our staff have regular contact with vendors offering new and improved technologies and explore new technologies becoming available to the industry.		One important aspect of continual improvement is where an organisation looks beyond its existing boundaries and knowledge base to look at what 'new things are on the market'. These new things can include equipment, process(es), tools, etc. An organisation which does this (eg, by the PAS 55 s 4.6 standards) will be able to demonstrate that it continually seeks to expand its knowledge of all things affecting its asset management approach and capabilities. The organisation will be able to demonstrate that it identifies any such opportunities to improve, evaluates them for suitability to its own organisation and implements them as appropriate. This question explores an organisation's approach to this activity.	The top management of the organisation. The manager/team responsible for managing the organisation's asset management system, including its continual improvement. People who monitor the various items that require monitoring for 'change'. People that implement changes to the organisation's policy, strategy, etc. People within an organisation with responsibility for investigating, evaluating, recommending and implementing new tools and techniques, etc.	Research and development projects and records, benchmarking and participation knowledge exchange professional forums. Evidence of correspondence relating to knowledge acquisition. Examples of change implementation and evaluation of new tools, and techniques linked to asset management strategy and objectives.

Company Name	Top Energy
For Period Ended	31 March 2033

Schedule 14a Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018.)

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause2.7.2. 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 current disclosure year and 10-year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

Constant prices are for FYE2024. Going forward, we have assumed an inflation rate of 4% per annum in FYE2025, 3% per annum in FYE2026 and 2% per annum thereafter. This reflects the high rates of inflation we are currently experiencing, but in the longer term we assume inflation will settle at about the mid-point of the Reserve Bank's 1-3% inflation target. We do not consider an inflation rate assumption based on an analysis of industry-specific cost drivers is warranted given the high levels of uncertainty in the forecast.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

Constant prices are for FYE2024. Going forward, we have assumed an inflation rate of 5% per annum in FYE2025, 3% per annum in FYE2026 and 2% per annum thereafter. This reflects the high rates of inflation we are currently experiencing, but in the longer term we assume inflation will settle at about the mid-point of the Reserve Bank's 1-3% inflation target. We do not consider an inflation rate assumption based on an analysis of industry-specific cost drivers is warranted given the high levels of uncertainty in the forecast.

In the short term we expect operational expenditure inflation to be higher than capital expenditure inflation as the proportion of labour costs is greater, but we do not expect this differential to be sustained.

Company Name: Top Energy

For Planning Period Ended: 31 March 2033

Schedule 15 Voluntary Explanatory Notes

1. This schedule enables an EDB to provide, should it wish to-

   1.1 additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, 2.5.2 and 2.6.6;

   1.2 information on any substantial changes to information disclosed in relation to a prior disclosure year, as a result of final wash-ups.

2. Information in this schedule is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

Our capital expenditure forecast has been prepared on the basis that:

- Construction of the 110kV Wiroa-Kaitaia line will be deferred until after the end of the planning period (Section 5.12.3.1).
- Construction of the 110/33kV Wiroa substation has been deferred and will now commence in FYE2028 (Section 5.12.2.2).
- Our capital expenditure will focus on improving the reliability and resilience of the 11kV distribution network, particularly in the early part of the planning period (Section 5.12.13.2).
- There will be a need to extend the coverage of the 33kV subtransmission network towards the end of the planning period to accommodate decarbonisation load growth.

Our operational expenditure forecast provides for an additional two-person vegetation management crew to be mobilised in FYE2024.

9.2 Appendix B – Nomenclature

GENERAL	
kV kilovolt	1,000 volts of voltage; typically used in the description of the nominal rating of transmission (110kV), subtransmission (33kV) and distribution (11kV, 22kV and 6.35kV) circuits.
kA kilo-ampere	1,000 amperes of current. Fault current is typically measured in kA or its MVA equivalent, according to MVA=sqrt3 x kV x kA.
kW kilowatt	1,000 watts of real power (e.g. a 2kW oil-filled heater is real power the consumer actually uses, represented on the x axis) as opposed to reactive power, which is the quadrature component.
MVA	One million volt-amperes (1,000 kilo volt-amperes) of apparent power. Apparent power is the vector equivalent of reactive or quadrature component power and real power. Apparent power is typically larger than either real or quadrature power and is the quantity that the system actually needs to provide, in order to get real power to the consumer. Generators and lines are all rated in terms of MVA, but the consumer typically only uses real power; a lesser quantity. The quadrature difference is used in the equipment and circuits along the way and is necessary for them to work.
MW	One million watts (1,000 kilo watts) of real power.
MVAr	The quadrature vector component, that when added to real power, gives apparent power.
kA rms	One of the ratings of equipment is 'square root of the mean of the squares'.
3-phase	3-phase or three phase means 3-phase power. In this case there are three conductors; in this country red, yellow, and blue. All three phases are out of phase with each other by 120 degrees.
INFORMATION TECHNOLOGY RELATED	
GIS	Geographic Information System. A computerised system that spatially represents the assets.
GPS	Global Positioning System. Handheld GPS devices receive and average locational signals from multiple satellites to give a location. The device includes software called a data dictionary, whereby attributes of the asset being captured are also entered. The data captured with GPS devices is entered onto the GIS system.
CMMS	Computerised Maintenance Management System involving a register of asset type, its condition, interlinked to the GIS and to the financial system. A CMMS is used to implement maintenance strategies in a consistent manner for large volumes of assets. This involves interaction with mobile hand-held information technology devices, scheduling, prioritizing and interaction with the financial system both at estimating/works order stage, for invoicing, general ledger, and work in progress reporting.
SCADA	Supervisory Control and Data Acquisition. A system involving communication equipment to monitor and control remote equipment from a central point. It includes remote terminal units (RTUs) to marshal signals at the remote location and communication either via radio, microwave, or the telephone system. The central control point receives and sends signals to the remote equipment. Data is logged here, and control functions may occur either according to the control room operator's command or automatically.
CIRCUIT RELATED	
OH	Overhead.
UG	Underground.
GXP	Grid Exit point. The point at which an EDB network is connected to the Transpower grid. For the Top Energy network, the GXP is the incoming circuit breakers at the Kaikohe substation. Transpower has retained ownership of these circuit breakers.
Subtransmission	Circuits carrying electricity at 33kV (in our case) from the transmission substations at Kaikohe and Kaitaia to our zone substations.

Zone substation	A facility that steps the electricity down from 33kV to 11kV (or 22kV) for distribution out to the locations near to consumers.
Distribution	Both OH and UG circuits at 11kV, 22kV, or 6.35kV that distribute power from zone substations to distribution substations or distribution transformers.
Distribution substation/ Distribution Transformer	A facility involving either a pole mounted transformer or a ground-mounted transformer, whereby electricity is stepped down from distribution voltage (11kV, 22kV or 6.35kV) to low voltage.
LV	Low voltage circuits either OH or UG at either 415V 3 phase or 480V/240V single phase that reticulate electricity from distribution substations to consumers' premises.
SWER	A low-cost distribution system called single wire earth return (SWER) used to reticulate electricity to remote areas involving low load densities. The start of the SWER system is a pole mounted isolating transformer where electricity is converted from conventional two or three -wire 11kV distribution to either 11kV SWER or 6.35kV SWER, which are the two SWER voltages we use. The SWER system involves a single overhead conductor to supply conventional distribution substations or distribution transformers near to the consumers. The return conducting path to the isolating transformer is through the earth. This avoids cost of more than one overhead distribution conductors. Once the electricity reaches the distribution substation, LV reticulation to homes occurs in the conventional manner.
Transfer capacity (≥ 3h)	The substation load that can be switched away to adjacent substations within three hours. It is considered that one feeder could be switched within this time. Accordingly, it is the largest of the feeder loads that can be picked up by adjacent substations in an emergency condition.
Firm capacity (N-1)	For a two-transformer substation, is the capacity of the smaller of the two transformers plus the transfer capacity (3hr). The transfer capacity is considered a contribution to firmness because this load can still be supplied within three hours from elsewhere. Firm capacity cannot occur at a substation with only one transformer (e.g. Taipa, Pukenui, Mt Pokaka and Omanaia).
Switched capacity	The sum of capacities that can be supplied to the zone substation location, including transfer capacity (≥ 3hr), from elsewhere if that zone substation is out of service.
Note	We size our transformers for local load forecast and future envisaged transfer capacity for feeders between a zone substation and its neighbour that a zone substation would have to supply if the neighbouring zone sub failed. Our approach is to cover one major equipment outage event, not two. So, if a zone substation fails, the feeders between it and an adjacent zone substation are picked up by the adjacent zone substation, with all of the transformers at the adjacent zone substation operating concurrently. If we were to cover the event of both a zone substation failing and one of the transformers at an adjacent zone substation also failing concurrently, then that would require much larger transformers and an approach that we consider inappropriate for a substantially rural lines business.
CONDUCTOR RELATED	
ACSR	Aluminium Conductor Steel Reinforced conductor used for OH lines
HD AAC	Hard Drawn All Aluminium Conductor
AAAC	All Aluminium Alloy Conductor
ABC	Aerial Bundled Conductor involving an overhead, insulated multi-core cable.
PVC	Polyvinyl Chloride. An insulation used for low voltage conductors.
XLPE	Cross linked Polyethylene. An insulation type prevalently used for conductors at distribution and subtransmission voltages.
PILC	Paper Insulated Lead Sheathed Conductor.
PILCSWA	Copper conductor with insulation of PILC and Steel Wire Armour. An outer light PVC serving is typically used outside of the armour.
OTHER EQUIPMENT RELATED	

ABS	Air Break Switch. These are manually operated or motorised remote-control switches. These switches are used to create an open point between two feeders, to achieve more operational flexibility on the lines.
Pillar Box or Pillar	A ground mounted LV fuse enclosure, where electricity from LV circuits is connected to the final LV service mains to consumers' premises.
RMU	Ring Main Unit. A ground-mounted unit with set of three switches, one with fuse arrangement. The fused switch is configured to supply and protect a distribution transformer.
Recloser	Normally a pole-mounted protection device acting as a small circuit breaker on either a subtransmission or distribution circuit. An automatic circuit recloser is a self-contained device with the necessary circuit intelligence to sense over current, to time and interrupt the over currents and to reclose automatically to re-energize the line. If the fault should be permanent, the recloser will 'lock open' after a pre-set number of operations and isolate the faulted section from the main part of the system.
Sectionaliser	A Sectionaliser is a pole mount protective device that automatically isolates faulted sections of line from a distribution system. Normally applied in conjunction with a backup recloser or breaker, a sectionaliser opens and allows the backup device to reclose onto the remaining unfaulted sections of the line.
Circuit Breaker (CB)	A circuit breaker is usually employed at the substation level in distribution system over current protection applications. It is a mechanical switching device capable of making, carrying, and breaking currents under normal operation and also capable of making, carrying, and breaking currents under specified abnormal condition for a specified time.
TRANSFORMER RELATED – COOLING NOMENCLATURE	
ONAN	Oil Natural, Air Natural (no fans or pumps)
ONAF	Oil Natural, Air Forced (fans but no pumps)
OFAF	Oil Forced, Air Forced (fans and pumps)
ODAF	Oil Directed Flow, Air Forced (fans and typically pumps plus internal vanes that direct oil flow through the core-coil winding assembly)
TRANSFORMER CONDITION NOMENCLATURE	
DP	Degree of Polymerization. This is a measure of the condition of cellulose-based paper insulation in oil. A new transformer will have a DP value of around 1,000. Through a combination of pyrolysis and hydrolysis, the paper-in-oil insulation gradually degrades to an end life of around DP 150 to DP 200. The most accurate way of ascertaining DP is through an actual paper sample cut opportunistically from the core-coil assembly during a major refurbishment; or from a small sample piece of paper insulation, if the manufacturer has provided one in an easy to get at location (typically at the top, inside the transformer tank). Not all manufacturers provide this unless asked. Outside of major refurbishment occasions, a less invasive method is to indirectly determine DP through analysing Furan derivatives from an oil sample. Furans are a by-product of the cellulose degradation process. An indication of whether a Furan analysis or further investigation would be required is obtained from Dissolved Gas Analysis (DGA) whereby dissolved gas by-products from pyrolysis and hydrolysis action in an oil sample are analysed using gas spectrometer and other means. Other electrical tests may also be used as required to give an indication to the engineer of what is happening inside the transformer; one of the most revealing being partial discharge analysis.
PD	A partial discharge is essentially a minor conduction across an insulation medium; not exactly a full discharge, which would be a spark that would involve full insulation failure. A partial discharge by contrast gives an early indication of insulation degradation. Full failure is typically some time away; this could be anywhere from imminent, to months or even years away. The PD techniques enable this to be analysed, failure times predicted and more importantly, the location of degrading insulation to be pin pointed. In the case of a transformer, before the expensive process of de-tanking.
Buchholz Relay	A protection device on a transformer situated below the header tank or 'conservator'. Gases generated inside the transformer will gravitate up to this point. If the magnitude of them is sufficient, the relay will operate and trip the transformer; hopefully before a failure involving serious damage can occur.

BUSINESS RELATED	
ODV	Optimised Deprival Valuation. An industry-wide standard method of valuing monopoly lines businesses set and administered by the New Zealand Commerce Commission to enable line business performance to be compared consistently and as the basis for regulatory control of maximum return on assets.
OUTAGE RATES – FIGURES OF MERIT	
SAIDI:	System Average Interruption Duration Index calculated by: $SAIDI = \frac{\sum \text{Number of customers affected} \times \text{Duration of interruption}}{\text{Total number of customers}}$ I.e. the average number of minutes a consumer will be without power in a year
SAIFI:	System Average Interruption Frequency Index calculated by: $SAIFI = \frac{\sum \text{Number of customers affected by interruptions}}{\text{Total number of customers}}$ I.e. the average number of outages per year for any consumer
CAIDI:	Consumer Average Interruption Duration Index calculated by: $CAIDI = \frac{SAIDI}{SAIFI} = \frac{\sum \text{Number of customers affected} \times \text{Duration of interruption}}{\sum \text{Number of customers affected by interruptions}}$ I.e. the average duration of an outage

9.3 Appendix C – Risk Management Framework

9.3.1 Risk Management Process

The adopted risk management framework is consistent with AS/NZS 4360 (now superseded by AS/NZS ISO 31000:2009), which defines risk assessment and management.

9.3.2 Risk Management Context

The key risk criteria adopted for assessing the consequences of identified risks are:

- health and safety;
- financial impact;
- environmental impact;
- public image/reputation;
- business interruption; and
- regulatory compliance.

9.3.3 Risk Analysis

The basis for assessing risk is risk probability and risk consequence, which are used to determine risk severity ratings are defined in Tables C.1 and C.2 respectively. Table C.3 provides the basis for the assessment of risk severity and Table C.4 shows the level of management normally accountable for risks of differing levels of severity.

RARE	UNLIKELY	POSSIBLE	LIKELY	ALMOST CERTAIN
Event may occur, but only in exceptional circumstances	The event could occur at some time	The event is not uncommon.	Likely to occur despite best efforts.	Likely to occur several times.
Occur less than once in 20 years	Occur once every 10 years	Occur once every 5 years	Occur once a year	Occur more than once per year

Table C.1: Assessment of risk probability

CONSEQUENCE	HEALTH & SAFETY	FINANCIAL IMPACT	ENVIRONMENTAL IMPACT	PUBLIC IMAGE REPUTATION	BUSINESS INTERRUPTION	REGULATORY
Catastrophic	Multiple fatalities Serious long-term health impact on public	Financial costs or exposure exceeds $75M (DCF basis) Shareholder flight	An incident that causes significant, extensive, or long-term (5 years or more) ecological harm .	Continuing long-term damage to company reputation. International or government Investigation. Long-term impact on public memory.	Total service cessation for a week or more	Jail term of any length or fine exceeding $100,000.
Major	Single fatality and or multiple serious injuries	Financial cost or exposure exceeds $10M (DCF basis). Share value stagnation, shareholder dissatisfaction.	An incident which causes significant, but confined, ecological harm over 1-5 years.	Local TV news headlines and/or regulator investigation. Medium-term impact on public memory.	Cessation of service to Northern or Southern areas for a number of days	Prosecution of Director or employee
Moderate	Individual serious injury or multiple/recurring minor injuries	Loss or increased costs from $1M to $10M (DCF basis).	Significant release of pollutants with mid-term recovery	Local press attention and or low-profile regulator investigation	Cessation of service for over 10% of consumer base for more than a week	Prosecution of business or prohibition notice.
Minor	First aid injuries only	Loss or increased costs from $50k to $1M (DCF basis)	Transient environmental harm	Limited local press attention	Cessation of service for more than a week	Improvement notice.
Insignificant	No requirement for treatment	Loss or increased costs less than $50,000 (DCF basis).	An incident which causes minor ecological impacts that can be repaired quickly through natural processes.	No impact on public memory	Cessation of service for more than a 24hrs	Regulator expresses verbal or written concern.

Table C2: Assessment of risk consequence

	INSIGNIFICANT 1	MINOR 2	MODERATE 3	MAJOR 4	CATASTROPHIC 5
Almost certain 1	High	High	Extreme	Extreme	Extreme
Likely 2	Moderate	High	High	Extreme	Extreme
Possible 3	Low	Moderate	High	Extreme	Extreme
Unlikely 4	Low	Low	Moderate	High	Extreme
Rare 5	Low	Low	Moderate	High	High

Table C.3: Assessment of risk severity

Extreme	Extreme Risk - Should be brought to the attention of Directors and continuously monitored
High	High Risk – Requires the attention of the CEO and General Managers
Moderate	Moderate Risk – appropriately monitored by middle management
Low	Low Risk – Monitored at a supervisory level

Table C.4: Risk management accountability

9.4 Appendix D – Cross References to Information Disclosure Requirements

The table below cross references the requirements of Attachment A of the Commerce Commission's Electricity Distribution Information Disclosure (Targeted Review Tranche 1) Amendment Determination 2022 with the contents of this AMP.

Handbook Reference	Requirement	AMP Ref	Comment
Summary			
3.1	The AMP must include a summary that provides a brief overview of the AMP contents and highlights information that the EDB considers significant.	1.	
Background and Objectives			
3.2	The AMP must include details of the background and objectives of the EDB's asset management and planning processes	2.1, 2.7	
Purpose Statement			
3.3	The AMP must include a purpose statement that		
3.3.1	Makes the status of the AMP clear.	2.5	
3.3.2	States the corporate mission or vision as it relates to asset management	2.2	
3.3.3	Identifies the documented plans produced as outputs of the annual business planning process	2.10	
3.3.4	States how the different documented plans relate to one another with specific reference to any plans specifically dealing with asset management	2.10.1	
3.3.5	Includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes and plans;	2.7	
Planning Period			
3.4	The AMP must state that the period covered by the plan is 10 years or more from the commencement of the financial year.	2.10.2	
3.5	The AMP must state the date on which the AMP was approved by the Board of Directors.	2.10.2	
Stakeholder Interests			
3.6	The AMP must identify the EDB's important stakeholders and indicate	2.10.4	
3.6.1	- how the interests of stakeholders are identified;	2.10.3	
iii	- what these interests are;	2.10.4	

Handbook Reference	Requirement	AMP Ref	Comment
iv	- how these interests are accommodated in the EDB's asset management practices: and	2.10.4	
v	- how conflicting interests are managed.	2.10.3	
Accountabilities and Responsibilities for Asset Management			
3.7.1	The AMP must describe the extent of Board approval required for key asset management decisions and the extent to which asset management outcomes are regularly reported to the Board.	2.10.5	
3.7.2	At the executive level, the AMP must provide an indication of how the in-house asset management and planning organisation is structured.	2.10.5	
3.7.3	At the field operations level, the AMP must comment on how field operations are managed, the extent to which field work is undertaken in-house and the areas where outsourced contractors are used.	2.10.5	
Significant Assumptions and Uncertainties			
3.8	The AMP must identify significant assumptions, which must: :	2.14	
3.8.1	Be quantified where possible.	2.14	
3.8.2	Be clearly identified in a manner that makes their significance understandable to interested persons including:	2.14	
3.8.3	Include a description of the changes proposed where the information is not based on the EDB's existing business.	N/A	
3.8.4	Identify the sources of uncertainty and the potential effect of the uncertainty on the prospective information.	2.14	
3.8.5	Include the price inflator assumptions used to prepare the information in Schedules 11a and 11b.	2.14 (final row)	
3.9	Include a description of the uncertainties that may lead to changes in future disclosures.	2.14	
Asset Management Strategy and Delivery			
3.10	To support the AMMAT disclosure, the AMP must include an overview of asset management strategy and delivery.	2.15 2.19	

Handbook Reference	Requirement	AMP Ref	Comment
Asset Management Data			
3.11	To support the AMMAT disclosure, the AMP must include an overview of the processes for managing asset management data; and	2.12, 2.13.1 2.13.2 2.16 8.3	As described in Section 8.3 our asset management improvement programme focuses on the development of improved tools for the management and use of asset data.
3.12	A statement covering any limitations on the availability and completeness of asset management data and disclosure of initiatives intended to improve the quality of this data.	2.12, 2.16	
Asset Management Processes			
3.13	The AMP must include a description of the processes used for:		
3.13.1	- Managing routine asset inspections and network maintenance;	2.13.1	
3.13.2	- Planning and implementing network development projects; and	2.13.2	
3.13.3	- Measuring network performance.	2.13.3	
Asset Management Documentation, Controls and Review Processes			
3.14	To support the AMMAT disclosure, the AMP must include an overview of asset management documentation, controls, and review processes.	2.17	
Communication and Participation Processes			
3.15	To support the AMMAT disclosure, the AMP must include an overview of communication and participation processes.	2.18	
Assets Covered			
4.1	High Level Description of the Distribution Area		
4.1.1	The high-level description of the distribution Area must include: - the regions covered;	3.1.1	
4.1.2	- identification of large consumers that have a significant impact on network operations or asset management priorities;	3.1.12	
4.1.3	- description of the load characteristics for different parts of the network; and	3.1.12	

Handbook Reference	Requirement	AMP Ref	Comment
4.1.4	- the peak demand and total electricity delivered in the previous year, broken down by geographically non-contiguous network, if any.	2.1 Table 2.1	
4.2	Description of the Network Configuration		
4.2.1	The AMP must include a description of the network configuration which includes: - identification of the bulk electricity supply points and any embedded generation with a capacity greater than 1 MW;	3.1.2, 3.1.3	
4.2.1	- the existing firm supply capacity and current peak load at each bulk supply point;	3.1.4 Table 2.1	
4.2.2	- a description of the [transmission and] subtransmission system fed from the bulk supply points, including identification and capacity of zone substations and the voltage of the subtransmission network;	3.1.4, 3.1.5, Table 3.1	
4.2.2	- the extent to which individual zone substations have N-x subtransmission security;	Table 5.1	
4.2.3	- a description of the distribution system including the extent to which it is underground;	3.1.7	
4.2.4	- a brief description of the network's distribution substation arrangements;	3.1.7	
4.2.5	- a description of the low voltage network, including the extent to which it is underground; and	3.1.8	
4.2.6	- an overview of secondary assets such as ripple injection systems, SCADA, and telecommunications systems.	3.1.9 3.1.10 3.1.11	

Handbook Reference	Requirement	AMP Ref	Comment
4.4	Description of the Network Assets		
	The AMP must include a description of the assets that make up the distribution system that includes, for each asset category: voltage levels, description and quantity of assets, age profiles, and a discussion of the condition of the assets, further broken down as appropriate and including, if necessary, a discussion of systemic issues leading to premature asset replacement.	3.2 6	Section 3.2 provides a general description of each asset fleet while age profiles and asset health profiles and other maintenance issues are discussed in Section 6.
4.5	The asset categories discussed must at least include:		
	[Transmission]	6.3-6.5	
4.5.1	Subtransmission	6.3.-6.5	
4.5.2	Zone substations	6.8	
4.5.3	Distribution and LV lines	6.3-6.5	
4.5.4	Distribution and LV cables	6.6	
4.5.5	Distribution substations and transformers	6.7	
4.5.6	Distribution switchgear	6.9	
4.5.7	Other system fixed assets	6.10	
4.5.8	Other assets	6.12	
4.5.9	Assets installed at bulk supply points owned by others	3.1.3	The incoming 110kV circuit breakers at Kaikohe fall into this category.
4.5.10	Mobile substations and generators whose function is to increase supply reliability or reduce peak demand	3.1.5 3.1.6	
4.5.11	Other generation plant.	N/A	
Service Levels			
6.	Performance indicators for which targets are defined must include SAIDI and SAIFI values for the next 5 disclosure years.	4.2	SAIDI and SAIFI targets are provided for each year of the planning period.
7.	Performance indicators for which targets are defined should also include		
7.1	- Consumer orientated service targets that preferably differentiate between different consumer types	4.2	Currently SAIDI and SAIFI are the only performance indicators used. These measures are not differentiated by consumer type although we measure these indicators by feeder to assist us mange network reliability.

Handbook Reference	Requirement	AMP Ref	Comment
7.2	- Indicators of asset performance, asset efficiency and effectiveness, and service efficiency, such as technical and financial performance indicators related to the efficiency of asset utilisation and operation.	4.3.1 4.3.2	Loss ratio Operational expenditure ratio
8.	The AMP must describe the basis on which the target level for each performance indicator was determined. Justification for target levels of service includes consumer expectations or demands, legislative, regulatory, and other stakeholder's requirements or considerations. The AMP should demonstrate how stakeholder needs were ascertained and translated into service level targets.	4.4	
Network Development Planning			
11.1	The AMP must include a description of the planning criteria and assumptions for network developments.	5.1	
11.3	The AMP must include a description of any strategies and processes that promote cost efficiency including through the use of standardised assets or designs.	5.1.4	
11.5	The AMP must include a description of the strategies or processes (if any) that promote the energy efficient operation of the network.	5.2	
11.6	The AMP must include a description of the criteria used to determine the capacity of equipment for different types of assets on different parts of the network.	5.1.4 5.1.5	
11.7	The AMP must describe the process and criteria for prioritising network developments and how these processes and criteria align with the overall corporate goal and vision.	5.4	
11.8	Demand Forecasts		
11.8.1	The AMP must describe the demand forecasting methodology, including all the factors used in preparing the estimates.	5.5	
11.8.2	The AMP must provide separate demand forecasts to at least the zone substation level and cover at least a minimum five-year forecast period.	5.6.1	

Handbook Reference	Requirement	AMP Ref	Comment
11.8.2	The AMP must discuss how uncertain but substantial individual projects or developments. The extent to which these uncertain load developments that affect load are taken into account in the forecasts, making clear the extent to which these uncertain increases in demand are reflected in the forecasts.	5.6.2	
11.8.3	The AMP must identify any network or equipment constraints that may arise due to the anticipated growth in demand during the AMP planning period	5.11	
11.8.4	The AMP must discuss the impact on the load of any anticipated levels of distributed generation in the network and the projected impact of any demand management initiatives.	5.9 5.11	
	Network Development Plan		
11.9	The AMP should include an analysis of the network level development options available, and details of the decisions made to satisfy and meet target levels of service, including:		
11.9.1	- the reasons for choosing a selected option for projects where decisions have been made;	5.12	These are addressed as appropriate for all the projects discussed in this section.
11.9.2	- the alternative options considered for projects that are planned to start in the next five years and the potential for non-network solutions described;		
11.9.3	- considerations of planned innovations that improve efficiencies within the network, such as improved utilisation, extended asset lives, and deferred investment	5.12	
11.10.1	The AMP must include: - a detailed description of the material projects and a summary description on the non-material projects currently underway or planned to start in the next twelve months;	5.12	
11.10.2	- a summary description of the programmes and projects planned for the next four years (where known); and		
11.10.3	- an overview of the material projects being considered for the remainder of the AMP planning period.		

Handbook Reference	Requirement	AMP Ref	Comment
11.11	The AMP must include a description of the EDB's policies on distributed generation, including the policies for connecting distributed generation. The impact of such generation on network development plans must also be stated.	5.8	
11.12	The AMP must include a description of the EDB's policies on non-network solutions including:	5.7 5.9	
11.12.1	- economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation;		
11.12.2	- the potential for non-network solutions to address network problems or constraints.		
Lifecycle Asset Management Planning (Maintenance and Renewal)			
12	The AMP must provide a detailed description of the lifecycle asset management processes, including:		
12.1	The key drivers for maintenance planning and assumptions.	6.1	
12.2	Identification of routine and corrective maintenance and inspection policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include:		
12.2.1	- the approach to inspecting and maintaining each category of assets, including a description of the types of inspections, tests and condition monitoring and the intervals at which this is done;	6.1 6.3-6.10	An overview of the way in which maintenance is managed is given in Section 6.1 and the remaining sections deal with individual asset categories.
12.2.2	- any systemic problems identified with ant systemic asset types and the proposed actions to address these problems;		
12.2.3	- budgets for maintenance activities broken down by asset category for the AMP planning period	6.11	
12.3	Identification of the asset replacement and renewal policies and programmes and actions to be taken for each asset category, including associated expenditure projections. This must include:		

Handbook Reference	Requirement	AMP Ref	Comment
12.3.1	- the processes used to decide when and whether an asset is replaced and refurbished, including a description of the factors on which decisions are based, and consideration of future demands on the network and the optimum use of existing network assets.	6.1	
12.3.2	- a description of the innovations made that have deferred asset replacement;		
12.3.3	- a description of the projects currently underway and planned for the next twelve months;	5.12.1	All capital expenditure forecasts including both proactive and reactive asset replacements are discussed in Section 5.12.1. A year-by-year breakdown of our asset replacement capex forecast, disaggregated by asset category is provided in Table 6.26.
12.3.4	- a summary of the projects planned for the next four years; and		
12.3.5	- an overview of the other work being considered for the remainder of the planning period.		
12.5	Approach used for developing capital expenditure projections for lifecycle asset management	5.12.1.3 6.3-6.10	Section 5.12.1.3 provides a high-level overview and Sections 6.3-6.10 summarises the asset health and includes a replacement strategy for each asset category.
12.6	Approach to vegetation related maintenance	6.2	
12.7	Consideration of non-network solutions to inform capital and operational expenditure projections for lifecycle asset management.	-	This is a new requirement. We will include this information in our 2024 AMP Update, as provided for in the Commissions 2022 Tranche 1 Information Disclosure decision.
Non-network Development, Maintenance and Renewal			
13	The AMP must provide a summary description of material non-network development, maintenance and renewal plans including:		
13.1	a description of non-network assets;	6.12 6.13	We do not consider our expenditure on non-network assets to be material.
13.2	development, maintenance, and renewal policies that cover them;		
13.3	a description of material capital expenditure projects (where known planned for the next five years); and		
13.4	a description of material maintenance and renewal projects (where known) planned for the next five years.		
Risk Management			
14.	The AMP must provide details of risk policies and assessment and mitigation including:		

Handbook Reference	Requirement	AMP Ref	Comment
14.1	- methods, details, and conclusions of risk analysis;	7.1 7.2	
14.2	- strategies used to identify areas of the network that are vulnerable to high impact, low probability events and a description of the resilience of the network and asset management systems to such events;		
14.3	- a description of the policies to mitigate or manage the risks of events identified in subclause 14.2 above; and		
14.4	- details of emergency response and contingency plans.	7.3.3-7.3.7	
Evaluation of Performance			
15.	AMPs must provide details of performance measurement, evaluation and improvement including:		
15.1	- a review of progress against plan, both financial and physical;	8.2	
15.2	- an evaluation and comparison of actual service level performance against targeted performance;	8.1	
15.3	- an evaluation and comparison of the results of the asset management maturity assessment disclosed in the Report on Asset Management Maturity set out in Schedule 13 (see Appendix A) against relevant objectives of the EDB's asset management and planning processes; and	2.13-2.18 8.3	
15.4	- an analysis of gaps identified in subclauses 15.2 and 15.3 above. Where significant gaps exist (not caused by one-off factors) the AMP must describe any planned initiatives to address the situation.	5.12.3.2	The deterioration in the reliability of the 11kV network is our most significant asset management issue.
Capability to Deliver			
16	The AMP must describe the processes used by the EDB to ensure that:		
16.1	- the AMP is realistic, and the objectives set out in the plan can be achieved;	2.19	
16.2	- the organisation structure and the processes for organisation and business capabilities will support the implementation of the AMP plans.	2.19	

Handbook Reference	Requirement	AMP Ref	Comment
Qualitative Information in Narrative Form			
17.1	Communication with consumers regarding planned and unplanned interruptions.	-	As provided for by the Commission in its 2022 Tranche 1 Information Disclosure decision, these disclosures will be published as a separate document on our website by 30 June 2023.
17.2	Voltage quality.		
17.3	Customer service practices.		
17.4	Connection of new consumers.		
17.5	Impact that new demand, generation and storage capacity will have on the network.		
17.6	Innovation practices.		

9.5 Appendix E – Certification for Year Beginning Disclosures

TOP ENERGY® Te Puna Hihiko

Certification for Year-beginning Disclosures

Pursuant to Schedule 17

Clause 2.9.1 of section 2.9

Electricity Distribution Information Disclosure Determination 2012

We, David Alexander Sullivan, and Jon Edmond Nichols, being directors of Top Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge –

a) The following attached information of Top Energy 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.

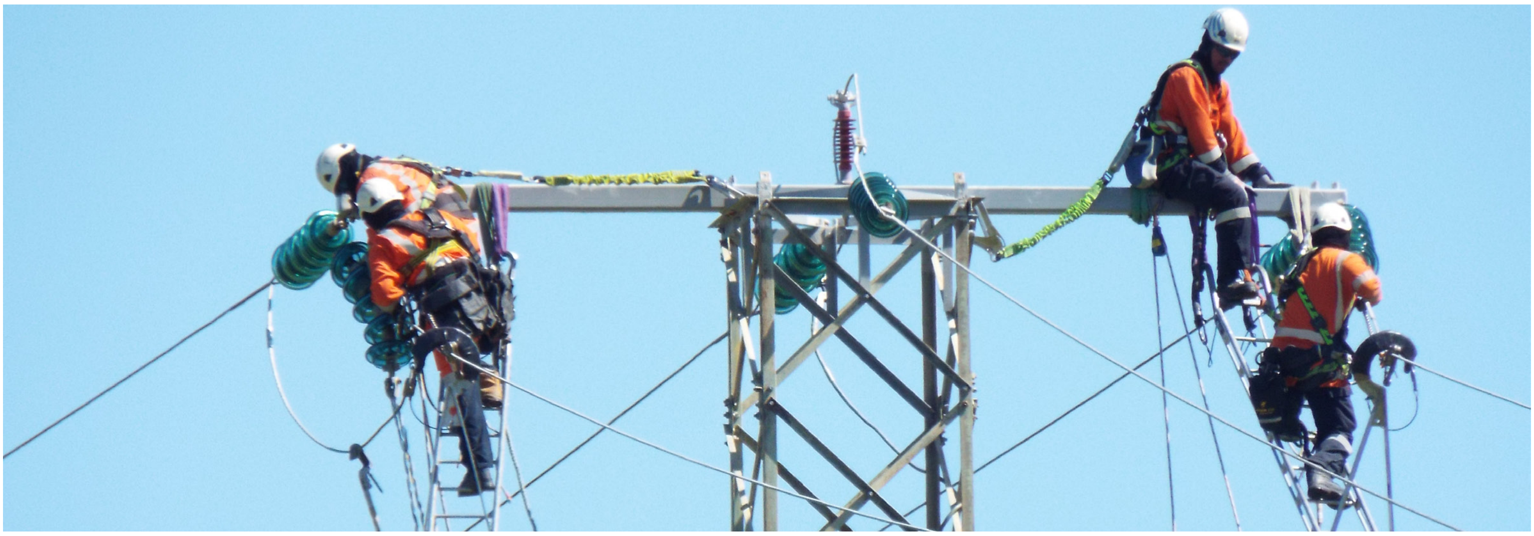
c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Top Energy Ltd's corporate vision and strategy and are documented in retained records.

D A Sullivan

J E Nichols

27 March 2023

Top Energy Limited
Level 2, John Butler Centre
60 Kerikeri Road
Kerikeri
PO Box 43 Kerikeri 0245
New Zealand



www.topenergy.co.nz