2018 Asset Management Plan

www.topenergy.co.nz

TOP ENERGY®
TePuna Hihiko

"This 2018 AMP has been republished. The original version was approved and published on 27 March 2018. The amendments made were not material and relate only to statements that were unclear and could be misinterpreted. The underlying asset management strategy and corresponding schedules have not been altered."

Introduction

It gives me great pleasure to present Top Energy's FYE2019-28 Network Asset Management Plan (AMP).

This 2018 AMP follows on from the 2016 AMP and 2017 AMP Update, addressing in particular the key issues of reliability and security of supply. In this AMP, we detail our reliability improvement programme as well as our significant transmission and subtransmission investment plan over the next decade.

This AMP is the core asset management planning and operations document for Top Energy Networks and details planned inspection, maintenance, and capital replacement strategies for the next ten years, as well as the service level targets that we are aiming to deliver to our consumers.

In compiling this AMP, we have focused not only on ensuring compliance with the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012, but also on providing detailed information that accurately reflects what we need to invest in developing and maintaining the network and why this expenditure is necessary.

In 2015, our Board approved a Strategy Map for the Top Energy Group, which sets out the Group's mission, vision, and values and which underpins everything that we do. 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 but, importantly, maintains the Group's core values and high level corporate objectives.

This is an exciting time for the Top Energy Group. The future will have less dependence on centralised assets and services and will have an increased focus on the use of distributed local resources, regional independence and resilience, and a shift towards a customer centric view of our role in the industry. It is a "good news" story for the Far North, where we have the potential to decouple from the supply industry cost drivers associated with bigger population centres and deliver a more sustainable cost-efficient infrastructure, providing higher value services to our consumers.

We are the "string" tying the different sectors of the industry together, and the strategic environment in which we operate is altering quickly. This AMP adapts the strategies set out in our previous AMPs to optimise the new opportunities presented by the Ngawha geothermal generation expansion project and to adapt to the challenges and opportunities that new household-scale technologies present to our network.

Our Network mission remains: *to provide a safe, secure, reliable, and fairly priced supply of electricity to consumers in the Far North.* Our vision is to: *enable consumers to take greater control over their business and home energy supply needs by developing secure; two-way energy flow; and load information and management solutions.*

In developing this AMP for the period FYE2019-28 in accordance with our mission and vision, and mindful of our corporate values and objectives, we have addressed a number of strategic challenges. In particular:

- There is a strong community desire that we provide a higher level of supply security to the more than 10,000 consumers in the north of our supply area. These consumers are currently dependent on a single 110kV transmission circuit that is in average condition and that, as the asset ages, requires an increasing number of maintenance outages that last for a whole day. The strategic issue we are facing is how to affordably improve security and resilience to this community, which has modern expectations of service and an increasing economic dependence on a reliable supply of electricity. The planned second 110kV circuit has been delayed because of property acquisition delays, as a result we envisage a further 2-3 years before a line route can be finalised and a further 2-3 years for construction. Recent changes to health and safety legislation have also resulted in live line work no longer being possible. This means that a greater number of planned outages would be required on the line, increasing in frequency from 1 every 2 years to 6 each year. For these reasons, we have decided to defer completion of the line until FYE2028 and apply an alternative solution by installing local diesel generation for planned and emergency backup supplies. This solution, which can also be coordinated to deliver on a number of other network strategic initiatives, is sufficiently economic and beneficial to warrant its immediate deployment. It will reduce the risk until the second line can be completed and the existing line requires age replacement.
- With completion of the Kaeo substation in the FYE2018 financial year, we have broken the back of our TE2020 program to remedy the historic lack of investment in our sub-transmission network and can concentrate on meeting the needs of the future. Our focus will now shift to reconfiguring our 11kV distribution network to provide a further improvement in service. This will be a less capital-intensive

program and will include a significant component that focuses on improving our operational capability. We are introducing initiatives to improve the effectiveness of tree control and management of asset life cycle defect, safety, and compliance issues.

- The increasing connection of generation in the region, most significantly the 28MW Ngawha expansion and the 16MW alternative solution for Kaitaia's supply security, reduces our dependence on the national transmission grid. It is more efficient to generate electricity closer to the load. With the increased capacity planned for FYE2020, generation at Ngawha will become the centre of the region's energy supply and energy flow will be in the reverse direction to the extent that we become a net exporter of energy 90% of the time. This means that the transmission system, which is currently a cost to our region, has the potential to turn into an asset that adds value by allowing our region to export its energy production to southern markets. Consequently, we are evaluating options with the grid owner Transpower to readdress the cost proposition that transmission currently presents to consumers.
- Growth in terms of network connections from the housing affordability spill from Auckland, the connection of household scale generation, the forecast for battery and electrical vehicle uptake are keeping us busy in terms of creating flexible plans that will accommodate and integrate these new technologies. There are some new economic developments being signalled in the region and this plan is intended to communicate and provide investors with an assurance that we are prepared for whatever economic growth initiatives present themselves.
- Investment in our future capability is focused on computer system assets at group level and secondary system assets within the network business. This includes an Advanced Distribution Management System (ADMS) that uses the latest available technology. It will significantly increase the level of automation in our management of network outages and increase worker and public safety by reducing the risk of operator error. It will also be used to optimise the use of the additional generation we are adding to our network. Over time the system will be further developed to ensure that we are well positioned to embrace, for the benefit of all our stakeholders, the emerging technologies that are starting to change the face of our industry.

These challenges, and their impact on our asset management planning, are discussed in detail in this AMP. Overall, the plan presented in this document reflects our current view on how we might best contribute to Top Energy's corporate mission, given our forecast revenues and availability of debt funding under what we consider the most likely energy delivery scenario.

Implementation of the plans described in this AMP will see us invest approximately $170 million on network capital expenditure and $60 million in network maintenance expenditure over the ten-year period of this AMP. The Board and Management are confident that this expenditure will improve service outcomes to levels comparable to those experienced by consumers supplied by similar rural networks within New Zealand. Nevertheless, we continue to recognise the potential pricing impact of expenditure on this scale and will therefore focus on achieving a price-quality balance that is affordable and in the best interests of the communities that we serve.

In addition to the technical development of the network assets, we continue to develop the safety and asset management culture within Top Energy. We actively participate in industry safety initiatives. These require staff engagement at all levels and have the added benefit of sharing the experiences of other participants 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 this Asset Management Plan both informative and helpful. We welcome your feedback on the plan or 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

Table of Contents

TABLE OF CONTENTS

TABLE OF CONTENTS

Section 1 Executive Summary

1 Executive Summary

1.1 Overview

Top Energy Networks (TEN) is the electricity lines business that distributes electricity to more than 32,000 electricity consumers in the Far North District Council's territorial area, covering the mid and far north of the Northland region. We are a division of the Top Energy Group, which is wholly owned for the benefit of our consumers, by the Top Energy Consumer Trust (Trust). The Group, which employs around 150 people and is one of the biggest employers in our supply area, has three divisions:

- **Ngawha Generation Ltd**, which operates the Ngawha geothermal power plant, with a current capacity of 25MW and with an additional 28MW planned for installation by FYE2020;
- **Top Energy Networks**, which distributes electricity throughout the Far North District Council area; and
- **Top Energy Contracting Services (TECS)**, which provides contracting services to the electric power industry.

As a large electricity lines business, Top Energy is subject to regulation by the Commerce Commission in accordance with the requirements of Part 4A of the Commerce Act, 1986. In particular, we must publicly disclose information on the performance of our network assets in accordance with the Commission's Electricity Distribution Information Disclosure Determination 2012. 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 2015.

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 2018 to 31 March 2028. It sets out the ten-year capital and maintenance expenditures that we estimate will be needed to ensure that the network is managed in a sustainable way and describes in more detail our work plan for FYE2019, the first year of the planning period. 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 Requirements. It covers only our network assets and does not cover the assets of other divisions of the Top Energy Group. It also does not cover privately owned assets beyond the consumers' connection to our network.

1.2 Asset Management Policy

Our asset management policy has been developed in accordance with Top Energy's strategic objective of investing in business activities that:

- contribute to infrastructure and economic development in the Far North District;
- enhance the security of power supply in the area; and
- provide economic employment opportunities.

Within this overarching strategic framework, TEN's mission is to provide a safe, secure, reliable, and fairly priced supply of electricity to consumers in the Far North.

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 at all times 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. We will give consideration to the impact of all that we do on our employees, contractors, consumers, and the general 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 so that, over time, the reliability of supply that we provide to consumers improves to a level consistent with that generally provided in rural areas in other parts of New Zealand. We will achieve this using a range of strategies including targeted network development, more effective maintenance and improved response to supply interruptions that do 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

DESCRIPTION	QUANTITY
Area covered	6,822km^2
Consumer connection points	32,399(1)
Grid exit point	Kaikohe
Embedded geothermal generator injection point	Ngawha
Network Peak Demand (FYE2018)	70MW(2)
Electricity Delivered to Consumers (FYE2017)	322GWh
Number of Distribution Feeders	56
Distribution Transformer Capacity	265MVA(3, 4)
Transmission Lines (110 kV)	56km(3)
Subtransmission Cables (33kV)	20km(3)
Subtransmission Lines (33kV)	303km(3, 5)
HV Distribution Cables (22, 11 and 6.35kV)	198km(3)
HV Distribution Lines (22, 11 and 6.35kV including single wire earth return)	2,597km(3)

Note 1: Includes inactive connections, as at 31 March 2017.
Note 2: Estimated from SCADA data. May not correspond to FYE2018 information disclosure, which will be based on metered data.
Note 3: As at December 2017.
Note 4: Does not include 22/11 kV or SWER isolating transformers.
Note 5: Includes the Kaikohe-Wiroa line, which is constructed to 110kV, but currently operating at 33kV.

Table 1.1: Network parameters (FYE2017 unless otherwise shown)

Our electricity network stretches from Hukerenui, approximately 25km north of Whangarei, to Te Paki, 20 km 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 above lists the key network parameters.

1.4 Value of Network

The value of our fixed network assets, calculated in accordance with the Commerce Commission's Information Disclosure Requirements, was $237.8 million as at 31 March 2017; an increase of $13.3 million since 31 March 2016.

This increase in asset value was derived as shown in Table 1.2. The increase has largely been driven by the commissioning of new assets commissioned in accordance with our network development plan. The value shown in Table 1.2 is the regulatory asset value, which is different from the corresponding asset value shown in Top Energy's financial accounts, as the valuation methodologies are not fully consistent.

	$000
Asset Value at 31 March 2016	**224,551**
Add:	
New assets commissioned	16,730
Indexed inflation adjustment	4,864
Less:	
Depreciation	8,307
Asset disposals	7
Asset value at 31 March 2017	**237,830**

Table 1.2: Value of System Fixed Assets

1.5 Areas of Uneconomic Supply

Over 35% of our lines were originally built using subsidies provided by the Rural Electrical Reticulation Council (RERC). The subsidies supported post-war farming productivity growth in remote areas and helped provide electricity to consumers located in sparsely populated rural areas, which would otherwise have been uneconomic to serve. Many of these lines now require extensive rebuilding and refurbishment, notwithstanding the fact that continuing to supply many of the sparsely populated rural areas remains uneconomic. However, we are obligated by Section 105(2) of the Electricity Industry Act 2010 to continue to provide a supply to consumers already supplied from existing lines.

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, where 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), criteria based on an independent analysis of network costs undertaken by the Ministry of Economic Development.

Our own review of our distribution network in November 2013 using the above criteria found that 35% by length of our 11kV distribution network, serving just 9% of connected consumers, is potentially uneconomic. These lines are generally located in the more remote and rugged parts of the supply area, where maintenance costs per kilometre of line are higher, so it is likely that more than 50% of maintenance expenditure on the 11kV network is required to ensure that supply is maintained to just 10% of consumers. Funding this cross-subsidy is a significant burden on the remaining 90% of consumers and has created the current situation where underinvestment has left a network that is not capable of providing the level of supply reliability that is taken for granted in other parts of the country.

Figure 1.1 shows the potentially uneconomic parts of the 11kV distribution network.

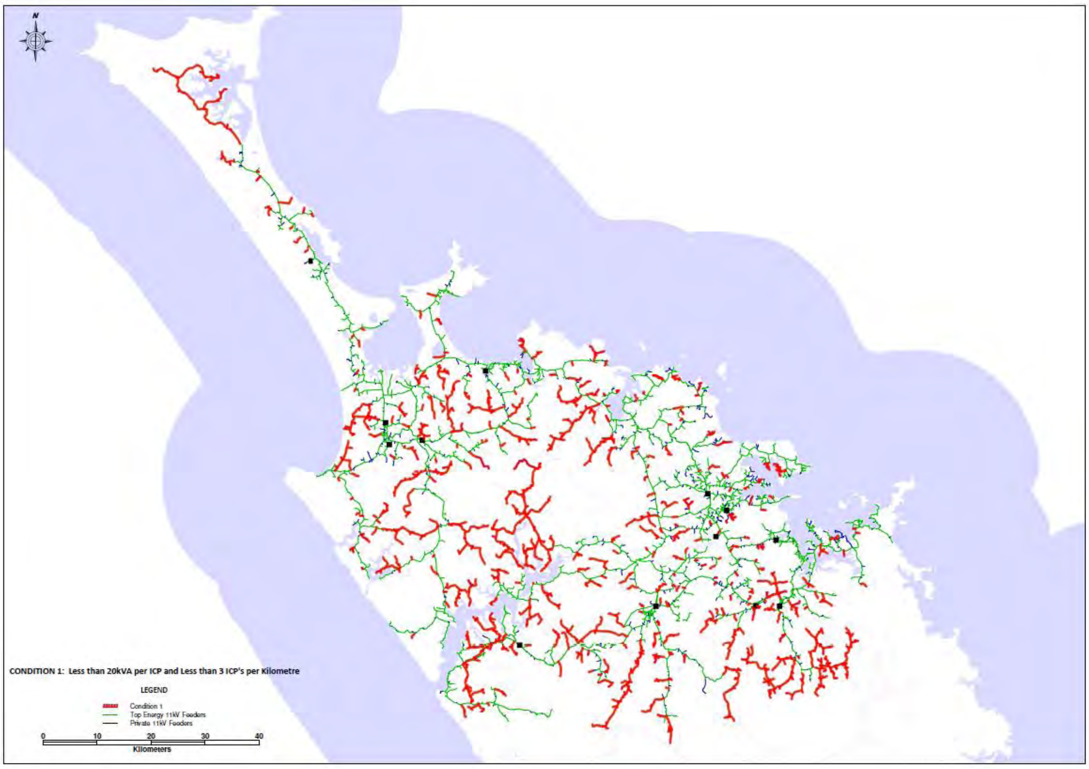


Figure 1.1: Uneconomic Segments of the 11kV Distribution Network

1.6 Asset Management Challenges

1.6.1 Supply Reliability

We remain one of the worst performing electricity distribution businesses in New Zealand for supply reliability.

This performance is a consequence of:

- a lack of supporting transmission infrastructure due to our fringe network location. We are supplied from a single incoming double circuit 110kV line supplied from Maungatapere, and population drift has also meant that our main transmission substation at Kaikohe is now poorly located;
- a legacy subtransmission and distribution network that was built at a time when cost was the overriding consideration. This network was never designed to deliver the supply reliability taken for granted in the modern world.
- The large proportion of the network that is uneconomic to service, and the level of cross-subsidisation that is required to maintain supply to uneconomic areas. This has left a legacy of under-investment, as funding the cross-subsidy the limited the availability of funds to invest in the development of the network to the extent needed to keep abreast of changing consumer expectations.

With the support of our community, we have embarked on an investment strategy to turn this situation around and provide a reliability of supply comparable to that provided by similar New Zealand distribution businesses supplying rural areas. This is consistent with the Trust's objective of supporting the economic development of its supply area, since economic development in the modern world requires a reliable electricity supply. This AMP identifies the strategies that are being implemented to make this happen.

Our investment strategy will capitalise on the expansion of Ngawha, which will become the primary source of our region's energy supply, and apply innovative solutions, combined with consumer uptake of new technology, to develop the existing network into an efficient and effective distributed energy system. Our region will become less dependent on the national grid, which will reduce the disadvantages of our remote location. The grid will change from being cost to the region to a value adding proposition, as we export energy to southern markets.

1.6.2 Demographics

The challenges we face in improving our network performance are due not only to our fringe network location but also demographic shifts within our supply area. As a result, the location of the legacy 110kV infrastructure relative to the major population centres is no longer appropriate. These assets were constructed at a time when the inland urban centres of Kaikohe and Kaitaia were the hubs of both economic and population growth in the region.

Over the last twenty years, there has been a steady decline in the growth of Kaikohe and other inland towns, which have lost population and become economically depressed. At the same time there has been significant growth and economic development in Kerikeri, the Bay of Islands and the eastern coastal peninsulas. This demographic change has increased the number of consumers connected to our 11kV feeders supplying these areas, resulting in larger numbers of consumers losing supply when an 11kV feeder fault occurs. Furthermore, our load centre has shifted from Kaikohe to Wiroa and we are adjusting the asset optimisation and network configuration accordingly.

1.7 Network Development

To address these issues and improve the reliability and security of supply, we will invest approximately $170 million over the planning period of this AMP in the development and renewal of our network. This is in addition to the development we have undertaken to date.

Since commencing our network development programme in 2012 we have commissioned a new double circuit 110kV line between Kaikohe and Wiroa (currently operating at 33kV), a new 33kV switching station at Wiroa and a new 33/11 kV substation at Kerikeri. We have also commissioned a new 110/33kV transformer at our Kaitaia transmission substation, an indoor 33kV switchboard to replace the outdoor 33kV switchyard at Kaikohe, rebuilt the Moerewa substation and replaced the protection on much of our 33kV network so that in the event of a fault, load will be seamlessly transferred to another circuit without any interruption to supply. We have also installed diesel generation at our Taipa zone substation and are progressively refurbishing the single circuit 33kV subtransmission lines that supply our smaller zone substations.

We have also acquired 110kV transmission assets from Transpower, including the Kaikohe and Kaitaia transmission substations and the 110kV circuit between the two substations. This acquisition is benefitting our consumers by allowing us to capture the synergies available from integrating the development and maintenance of the transmission and distribution networks.

Over the ten-year planning period of this AMP we plan to address the following network weaknesses.

1.7.1 Supply to Kaitaia and our Northern Network

Our northern network supplies over 10,000 consumers and has a peak demand of approximately 25MW. Currently it is served by a single 110kV incoming circuit constructed along a route that crosses the Maungataniwha Range. Consumers supplied from this network are at risk of an extended unplanned supply interruption should an inaccessible fault occur on this circuit and are also subjected to planned maintenance interruptions that can last for nine hours or more. An industry safety moratorium suspending the use of live-line maintenance work practices is increasing the number of outages required to maintain this line. It will also require conductor renewal from 2030, which will create unacceptable outage durations lasting weeks without an alternative supply option.

We were planning to address this situation by constructing a second 110kV incoming circuit over an eastern coastal route, that would also be used to supply loads at Kerikeri, Kaeo and Taipa. The southern section of this line between Kaikohe and Wiroa has been completed. It is currently energised at 33kV and is being used to supply the Kerikeri and Waipapa zone substations. Work continues on securing a route for the northern section of this line between Wiroa and Kaitaia. While agreements have already been reached with most affected landowners, there are some that are unwilling to negotiate, and three landowners are challenging our plans in the Environment Court.

Given these delays, and the time and cost of constructing a new line, we are now planning to install an additional 15 smaller diesel generators to bring the total generation capacity in the northern area to 15MW. Most of these generators will be installed in two diesel power stations, which will be located at our Kaitaia 110kV and NPL zone substations, but some generators with appropriate noise reduction will be dispersed across the network to provide feeder support. The two machines currently at Taipa will be relocated to NPL.

We anticipate that these generators will be in place by the end of FYE2020. At that time there will be sufficient generation capacity available to maintain an uninterrupted supply to consumers in our northern area during planned maintenance shutdowns of the existing 110kV incoming circuit (apart from NPL where we have negotiated a special arrangement). In the event of an unplanned fault on this line, the generators will be used to restore supply without having to wait for the fault to be found and repaired. The new generators will be containerised and readily relocatable, so will provide additional flexibility in operating the network. They will be disbursed across the network to establish a distributed generation operating model and will be deployed in a number of applications to deliver benefits to all our consumers.

1.7.2 Supply to Kaeo and the Eastern Coastal Peninsulas

Kaeo and the eastern coastal peninsulas and beaches north of Kerikeri are supplied from three long 11kV feeders energised from the Waipapa zone substation. The area served is large and, as there are only three feeders, a fault on the 11kV network affects a large number of consumers. The construction of a new zone substation in Omanu Rd, Kaeo is due for completion by the end of March 2018. This will increase the number of feeders supplying this area from three to seven. As each feeder will be shorter and supply fewer consumers, the impact of a feeder fault will be less and the reliability of supply in this area should improve.

The new substation will be supplied from an existing 33kV circuit, that has been energised at 11kV. A second incoming 33kV circuit will utilise the new 110kV line structures over much of its length, but we will be unable to complete this circuit until the new 110kV line route is available and construction of the southern section of this new line is complete. We expect this line section to be completed by the end of the AMP planning period.

1.7.3 Supply to Russell Peninsula

We have two submarine cables that supply the Russell peninsula. One of these is laid across the Waikare Inlet and the second is run between Lemons Bay, near Opua, and Okiato point. We have already improved the supply to Russell, by offloading the line between Kawakawa and the Waikare submarine cable to create a Russell express feeder, and also by replacing old, under-sized copper conductor on the 11kV distribution lines serving the Russell township.

A remaining weakness is that both cables terminate on the same spur line serving Okiato point. To address this, we are planning to run a new underground 11kV cable between the Waikare cable termination and the main 11kV line serving the peninsula to enable one submarine cable to supply Russell town and the second to supply Rawhiti and the surrounding area. To enable this, we have already reinforced the network to relieve constraints on the Opua side of the Okiato point submarine cable. This work is currently planned for completion in FYE2022. We will also have some resilience and peak load support capacity available from the diesel generation we have invested in.

1.7.4 Omanaia Substation Transformer

The Omanaia substation transformer bank is almost 65 years old and is in poor condition. This bank is currently being replaced with a new three-phase unit. As a temporary measure, we are also planning to install generators at Omanaia to allow the incoming single circuit subtransmission line to be refurbished. When this refurbishment is complete the generators will likely be relocated to Kaitaia.

1.7.5 Renewal of Transmission Assets

Some of the transmission assets acquired from Transpower are in poor condition. We have undertaken a formal condition assessment of these assets and have prioritised their renewal and replacement requirements. We have already replaced one of the 110/33kV power transformers at Kaitaia and the second transformer is programmed for replacement in FYE2020. The outdoor switchyard at Kaikohe has also been replaced with an indoor switchboard, and we have included an annual provision of more than $500,000 in the capex forecast for ongoing structure replacements on the 110kV line.

1.8 New Technology Challenges

Whereas five years ago the only generation embedded in our network was the Ngawha geothermal plant, we now have 2MW of solar generation injecting power into of network from 600 injection points. As this trend accelerates, our network will 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 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 users 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. To this end, our capital expenditure forecast includes provision of for the implementation of projects that pilot the application of these new technologies. The research will have the following objectives:

- Development of a range of solutions that apply new technologies to address issues of poor service, high cost of supply, and the renewal of uneconomic networks;
- A focus on opportunities that are centred on the distribution and the wider community, in preference to individual service lines or consumers;
- A focus on projects where a community or business partnership might be developed; and
- Post-implementation analysis to determine appropriate demarcation between Top Energy and private sector or consumer investment, optimal design, build, and operation arrangements and associated commercial terms.

1.9 Advanced Distribution Management System

Over the two-year period FYE2019-20 we will be upgrading our network control operation through the installation of an Advanced Distribution Management System (ADMS). The initial deployment in FYE2019 will include a new SCADA master station and an automated Outage Management System (OMS). The OMS will combine 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 SAIDI impact of supply interruptions, leading to more timely and accurate management reporting.

In FYE2020, a Distribution Management System (DMS) module will be added. This will overlay the above systems with a real time model of the network, using inputs from SCADA, the GIS and our SAP Asset Management System (AMS). It will provide a decision support system for the operation of the network by making real time information on network status and asset condition available to operators through a single user-friendly graphical interface, automatically producing switching schedules, confirming that all required isolation procedures are undertaken before operators issue field staff a permit to work, and providing many other benefits. This will reduce operator error, support the enhanced safety procedures we are introducing and optimise the operation and management of the network.

The installation of the ADMS is timely in that our network will become significantly more complex and difficult to operate with the installation of new diesel generation in FYE2019-20. The ADMS can potentially be configured to optimise the use of this plant by automatically starting relevant generators following an interruption or when needed to alleviate localised network constraints.

The installation of the ADMS will be a key tool in the management of 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 we plan to install has been future-proofed and modules to support distributed energy resource management (DERM) and demand response management (DRM) have already been developed by ADMS vendors and will be added as required.

1.10 Life Cycle Asset Management

We have benchmarked our FYE2017 network operations and maintenance expenditure (Note: excludes the capital expenditure in each of the same categories) against that disclosed by other New Zealand EDBs with largely rural supply areas. This has shown that:

- our total maintenance expenditure per km is approximately 24% higher than the average of our peers, which equates to additional expenditure of around $1 million. This is not yet fully reflected in a lower incidence of faults as we are still improving condition assessment processes, more accurate targeting, and higher levels of more formally planned maintenance;
- our expenditure on vegetation management is, on average, 116% higher than our peers for the same level of performance indicating it is time to refresh strategy and policy as the very high historical level of tree related outage has been bought down to industry norms;
- we are spending on average 12% more than our peers on routine maintenance. Most of this is on inspection and condition assessment. Now that we have implemented the bulk of our investment program it is necessary to establish maintenance programs for these new assets to manage them through their life cycle;
- our operational expenditure on asset renewal is 34% below the average. Our asset renewal programs are largely delivered through capital investment programs. This maintenance expenditure is targeted at components of assets that need replacement for the asset to maintain serviceability to the end of its service life – an example being crossarms which have a shorter life expectancy to pole structure they are part of; and
- our reactive (fault and emergency) maintenance is higher than our peers by 21% on average. This is not all directly related to fault repair as our efficiency in this area is limited by the tools currently available to our control room and operational staff. The ADMS should drive more efficiency in this area, as will other projects targeting SAIDI improvement.

The key messages from this analysis are that our total network operations and maintenance expenditure is high but as we realise the benefits of the high investment we have made over the past decade this will now be able to be reduced over time.

We are therefore reprioritising our expenditure on network maintenance and asset renewal to focus on reducing the impact of unplanned interruptions on the reliability of supply to our consumers at minimum cost. These strategies involve:

- reducing the cost of routine asset inspections by no longer undertaking maintenance inspections on assets where experience has shown that the probability of an asset failure is low;
- reducing expenditure on vegetation management by focusing on trees that are causing a safety hazard and where, for this reason, landowner consent to address the problem is not required. Tree management is an area where the community has a role, and a responsibility to own outage outcomes. We will look to establish a better partnership with our community, to support and encourage a higher level of self-management;
- focusing our maintenance effort on monitoring and maintaining older assets, so that they remain in service for longer without materially increasing the risk of asset failure. We will adopt industry Asset Health assessment guidelines to maintain confidence in our asset condition compliance; and
- increasing staff awareness of the importance of maintaining safe work practices and implementing enhanced safety management strategies to ensure that maintenance of worker and public safety is not dependent on asset condition.

Our revised maintenance strategy will substantially reduce expenditure on the inspection of assets that are likely to still be fit for service, and this will be balanced with earlier asset renewal when the cost-benefit ratio becomes marginal. Instead the focus will be on applying more intensive monitoring and a higher level of maintenance on the subset of the asset base that is reaching the end of its expected life, to ensure that these assets remain fit for service. In parallel with this, we are enhancing our safety procedures to mitigate any additional safety risk arising from the less intensive monitoring of the bulk of our asset base.

1.11 Reliability

We measure the reliability of our network for internal management purposes using the normalised measures of SAIDI and SAIFI that the Commerce Commission uses to monitor the reliability of the network under its price-quality control regime. However, our internal targets are more challenging than the thresholds set by the Commission because we use them to measure the effectiveness of our investment programme.

The normalisation of the raw performance measure, as applied by the Commission, 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, by limiting the extent to which events outside our control and response capacity impact the measured performance.

The impact of this normalisation process is to:

- exclude interruptions originating from events outside our network;
- limit the impact of unplanned interruptions occurring on “major event days” 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 historic performance of our network.
- include only 50% of the actual SAIDI and SAIFI impact of planned interruptions in the normalized measure. This recognizes that our consumers receive advance notice of planned interruptions, which should therefore make them less disruptive.

The normalisation process can have a significant impact on the reported reliability in years where reliability is poor due to an abnormally high number of severe storms. In FYE2015, a year of extremely bad weather, our actual SAIDI of 1,837 minutes was reduced by more than 67% to 600 minutes after normalisation.

The reliability targets we set in previous AMPs and in our earlier Statements of Corporate Intent have proved unrealistic. The only year in which we came close to meeting our targets was FYE2013, a year in which very benign weather conditions were experienced over most of the country. We have therefore reset our reliability targets to levels we consider to be more realistic, in that they better reflect the current state of our network and the average weather conditions experienced in our supply area.

The new targets are shown in Table 1.3 and assume that:

- there will be one planned transmission related interruption each year in FYE2019 and FYE2020;
- the new 110 kV Wiroa-Kaitaia circuit will be not be commissioned before the end of the AMP planning period, but supply to the northern area will be secured through the installation of diesel generation by the end of FYE2020;
- that weather conditions will be average for the area;
- there are no unplanned outages of the 110kV Kaikohe-Kaitaia transmission line; and
- in the short term we will not use mobile generation to mitigate the SAIDI impact of planned interruptions, although the generation at Taipa will continue to be used to mitigate the impact of transmission outages and outages of the incoming 33kV circuit. Once we have our new generation in place and have gained some experience in the application of generation to manage both planned and unplanned outages, the forecasts may be improved.

FYE	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
SAIDI										
Distribution Related	330	315	310	305	300	295	290	285	285	285
Transmission Related	60	60	-	-	-	-	-	-	-	-

Target	390	375	310	305	300	295	2900	285	285	285
SAIFI										
Distribution Related	4.3	4.2	4.1	4.0	3.9	3.8	3.7	3.6	3.6	3.6
Transmission Related	0.4	0.4	-	-	-	-	-	-	-	-
Target	**4.7**	**4.6**	**4.1**	**4.0**	**3.9**	**3.8**	**3.7**	**3.6**	**3.6**	**3.6**

Table 1.3: Reliability Targets

The change in these targets over the planning period is shown graphically in Figures 1.2 and 1.3 below, which also compare the targets with the historical reliability of our network. The graphs are indicative only as the historical performance is not directly comparable to the performance targets going forward. Firstly, performance prior to FYE2008 was estimated rather than directly measured. Secondly the reported actual performance prior to FYE2010 has not been normalised in accordance with the Commerce Commission's measurement methodology and finally the normalisation methodology changed from FYE2016 onwards was changed.

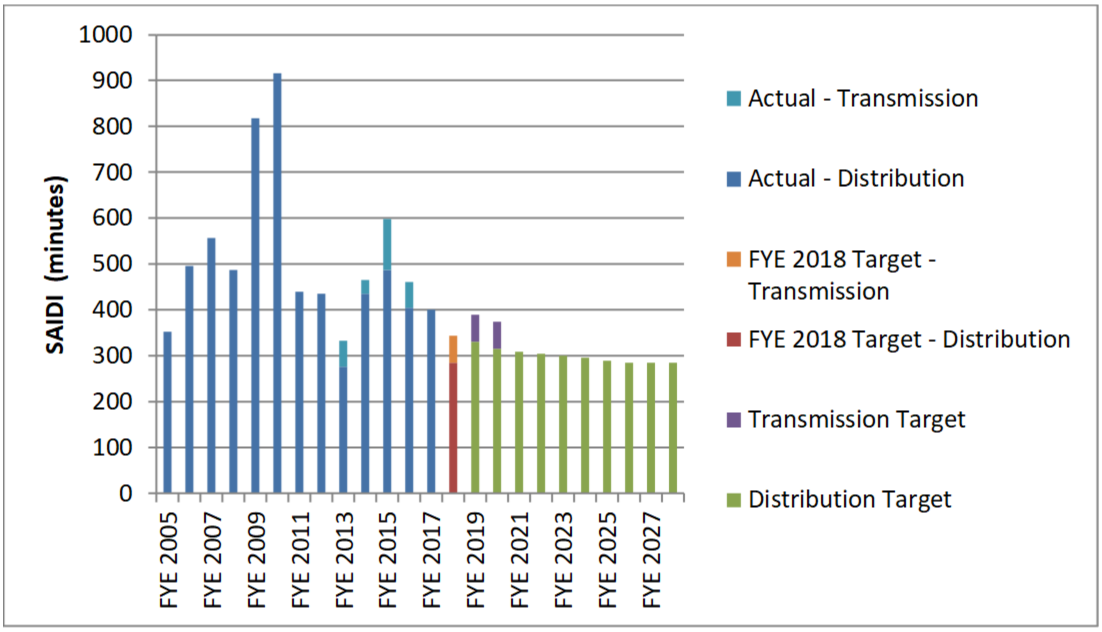


Figure 1.2: Historical and Target SAIDI

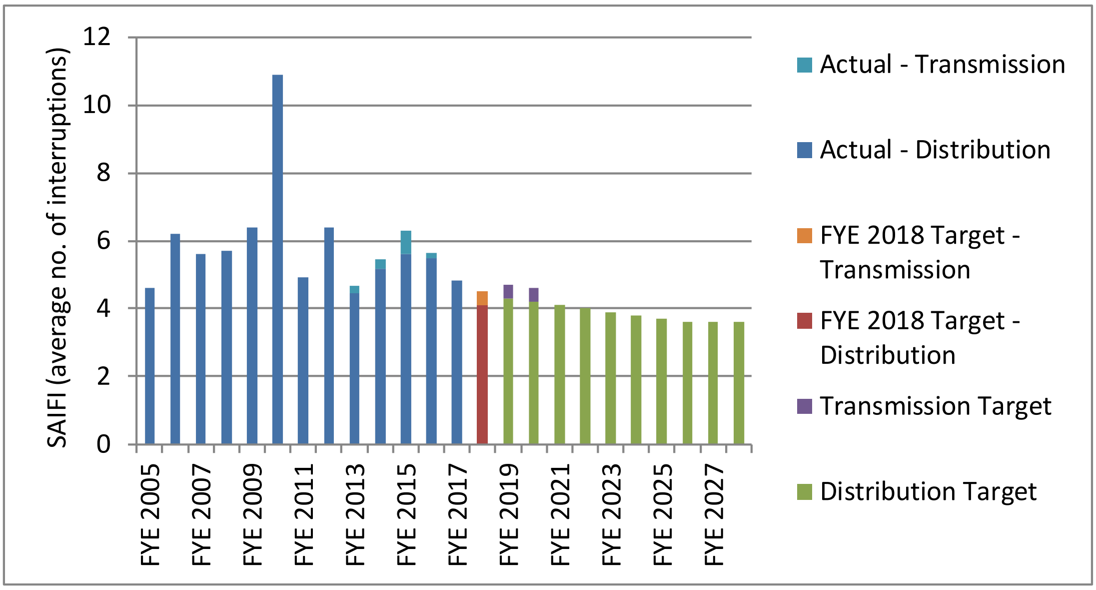


Figure 1.3: Historical and Target SAIFI

1.12 Capital Expenditure Forecast

Table 1.4 shows the total network capital expenditure (capex) forecast for the period FYE2019-23, highlighting the major projects.

$ million (real)	FYE				
	2019	2020	2021	2022	2023
System Growth					
Consumer connections (incl. capital contributions)	1.28	1.27	1.50	1.50	1.50
New 110kV transformer T2 at Kaitaia			0.52	3.58	
11kV feeder reconstruction			0.45	2.07	1.20
Kaeo-Manganui voltage regulator	0.21				
Wiroa ripple injection plant					0.69
Ngawha power station interconnection	1.96	7.03	6.06		
Total (including capital contributions)	**3.46**	**8.30**	**8.56**	**7.14**	**3.38**
Capital contributions (including Ngawha)	1.06	1.06	1.06	1.06	1.06
Total system growth (net of capital contributions)	**2.40**	**7.24**	**7.50**	**6.08**	**2.32**
Reliability, Safety and Environment					
110kV line route property rights	1.38	0.76	0.22	0.25	0.05
Mangamuka 110kV substation		0.16			2.72
Asset management data updates	0.22	0.67	0.08	0.03	0.03
Research and development	0.17				1.04
Kaitaia bus tie circuit breaker			0.67		
11kV feeder interconnections		1.66	0.73	0.75	1.22
Distribution network architecture	0.30	0.37	0.55	0.90	0.51
Diesel generation – northern area	5.06	5.07			
Diesel generation - Omanaia	2.63				
Mobile generator implementation				0.49	
Russell reinforcement			0.61	0.67	
Protection, Communication and SCADA	0.56	0.20	0.13	0.06	0.06
Other	0.38	0.39	0.51	0.52	0.53
Total reliability, safety and environment	**10.70**	**9.28**	**3.50**	**3.67**	**6.06**
Asset Replacement and Renewal					
Air break switch replacements			0.29	0.29	0.29
11kV line replacements	0,24		0.35		0.32
110kV line tower painting	0.11	0.12	0.12	0.12	0.12
Transmission protection replacements	0.21	0.12			
Omanaia 33kV line refurbishment	0.24	0.43	0.41	0.41	
Low voltage pillar replacements					0.26
Distribution transformers earth remediation	0.19	0.19	0.19	0.19	0.19
Wood pole replacements	0.57	0.91	0.91	0.91	0.91
Ring main unit replacement	0.11	0.27			

$ million (real)	FYE				
	2019	2020	2021	2022	2023
Moerewa-Haruru line steel tower replacements	0.33	0.48			
110kV line structure replacements	0.53	0.53	0.54	0.54	0.54
Waipapa Substation reconstruction			4.36		
SWER replacement					0.33
Taipa 33kV line upgrade	0.23	0.23			
Other	0.50	0.16	-	-	0.26
Subtotal	**3.02**	**3.44**	**7.16**	**2.45**	**3.22**
Maintenance and Faults	3.33	2.81	2.28	2.27	2.29
Total asset replacement and renewal	**6.35**	**6.25**	**9.44**	**4.72**	**5.51**
TOTAL NETWORK CAPEX (net of capital contributions)	**19.45**	**22.77**	**20.44**	**14.47**	**13.89**

Table 1.4: Network Capex FYE2019-23.

1.13 Maintenance Expenditure Forecast

Table 1.5 shows the forecast maintenance expenditure (excluding capitalised asset replacements) over the first five years of the ten-year planning period. Expenditure over the second five years is expected to be similar (in constant price terms).

$000 (real)	FYE				
	2019	2020	2021	2022	2023
Service interruptions and emergencies	1,200	1,258	1,252	1,220	1,136
Routine maintenance and inspection	1,867	1,891	1,939	1,925	1,924
Vegetation	1,750	1,750	1,750	1,750	1,750
Replacement and renewal	1,120	1,120	1,120	1,120	1,120
Total	**5,937**	**6,019**	**6,061**	**6,015**	**5,930**

Table 1.5: Forecast Maintenance Expenditure (FYE2019-23)

Section 2 Background and Objectives

2 Background and Objectives

2.1 Overview

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

- **Ngawha Generation**, which operates the 25MW Ngawha geothermal power plant;
- **Top Energy Networks (TEN)**, which distributes electricity throughout the Far North; and
- **Top Energy Contracting Services (TECS)**, which provides construction and maintenance services to Top Energy Networks.

The Top Energy Group 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 160 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 32,000 electricity consumers within our supply area. The network was originally constructed to supply these consumers from electricity sourced from the national transmission grid and, more recently, the Ngawha geothermal power station. However, recent development in small scale photovoltaic generation technologies, has resulted in approximately 2MW of localised generation dispersed across approximately 600 injection points now being connected to our network.

This Asset Management Plan (AMP) covers the management of TEN's assets, which had a regulatory asset value of almost $238 million as at 31 March 2017. This figure does not include assets owned by Top Energy's other operating divisions, which are not covered by this AMP.

TEN's role has traditionally been to manage, on behalf of retailers, the one-way flow of electricity from the national grid and the Ngawha geothermal plant to our consumer stakeholders. However, with the installation of localised generation expected to accelerate, electricity flows within our network are becoming increasingly bidirectional. Furthermore, the emergence of new technologies is rapidly changing the use and management of electricity by our consumers and consequently the demand for the services that we can provide. If we are to meet these challenges and remain relevant in a changing world, we must transition from a traditional electricity distributor to a network service provider, with the innovation and flexibility to meet the evolving needs of an increasing diverse consumer base. This AMP sets out our strategy for managing this transition.

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	32,399[(1)]
Grid Exit Point	Kaikohe
Embedded geothermal generator injection point	Ngawha
Network Peak Demand (FYE2018)	70MW[(2)]
Electricity Delivered to Consumers (FYE2017)	322GWh
Number of Distribution Feeders	56
Distribution Transformer Capacity	265MVA[(3,4)]
Transmission Lines (110 kV)	56km[(3)]
Subtransmission Cables (33kV)	20km[(3)]
Subtransmission Lines (33kV)[5]	303km[(3)]
HV Distribution Cables (22, 11 and 6.35kV)	198km[(3)]
HV Distribution Lines (22, 11 and 6.35kV including single wire earth return)	2,597km[(3)]

Note 1: Includes inactive connections, as at 31 March 2017.
Note 2: Estimated from SCADA data. May not correspond to FYE2018 information disclosure, which will be based on metered data.
Note 3: As at December 2017.
Note 4: Does not include 22/11 kV or SWER isolating transformers.
Note 5: Includes the Kaikohe-Wiroa line, which is constructed to 110kV, but currently operating at 33kV.

Table 2.1: Network parameters (FYE2017 unless otherwise shown)

TYPE OF GENERATION	NO OF INJECTION POINTS	CAPACITY (MW)
Geothermal	1	25
Diesel	1	4
Photovoltaic	600	2

Table 2.2: Embedded Generation (as at 31 December 2017)

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 which 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 but, importantly, maintains the Group's core values and high level corporate objectives.

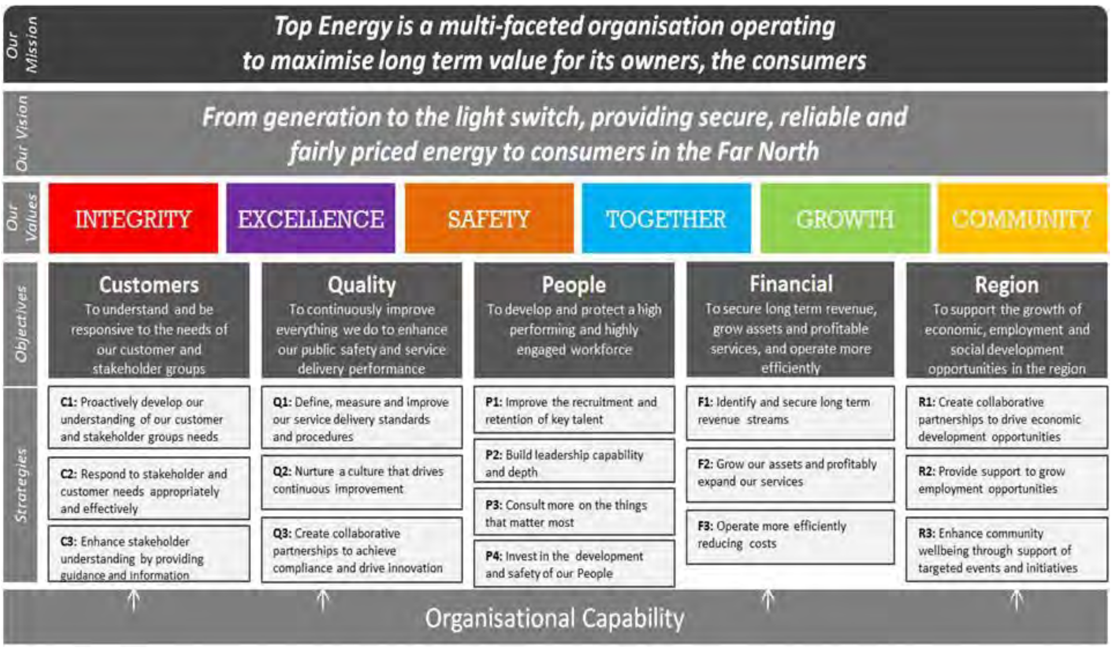


Figure 2.1 Group Strategy Map

2.2.2 Top Energy Networks

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

2.2.2.1 Mission

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

2.2.2.2 Vision

Our vision is to:

- *enable consumers to take greater control over their business and home energy supply needs by developing secure, two-way energy flow, and load information and management solutions.*

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 and the rapid development of battery storage technologies are making self-generation by small consumers increasingly viable, both technically and economically. Disconnection from the grid is becoming a realistic possibility for domestic consumers. Alternatively, the advent of electronic time of use metering, coupled with ongoing developments in communications and power control technologies, is making it possible for 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. We think that while some consumers may disconnect from the grid, most will remain connected, but many of these will want to use the grid very differently from the way they have in the past.

It follows that the emergence of these disruptive technologies is challenging the relevance of the monopolistic business and regulatory models that underpin our industry. While the future is unclear, it is already apparent that we will not meet the continuing needs of our consumers and other stakeholders if we continue to operate as we have in the past. If Top Energy is to achieve its vision of ensuring that Far North consumers have continuing access to a safe, reliable, and secure energy supply, we must develop and operate a network that embraces the application of new technologies and makes it easy our consumers to take advantage of the many benefits that they can provide.

2.2.2.3 Asset Management Challenges

In developing our AMP for the planning period FYE2019-28 in accordance with our mission and vision, and mindful of our corporate values and objectives, we have addressed a number of asset management challenges. In particular:

- There is a strong community desire that we provide a higher level of supply security for the approximately 10,000 consumers in the north of our supply area, who remain dependent on a single 110kV transmission circuit that requires an annual maintenance outage lasting a whole day. The strategic issue we are facing is what to do about this situation, which the Trust considers unacceptable in a developed economy – during these maintenance outages EFTPOS machines won't work and fuel cannot be purchased so, aside from the inconvenience, there is a real cost to business.

  The existing line is now in good condition and the immediate concern is to provide an alternative supply during relatively infrequent unplanned faults and planned maintenance interruptions. However, by around 2030, the conductor will have deteriorated to extent that replacement will be necessary, which will require the line to be taken out of service for extended periods. Furthermore, new regulatory constraints on the use of live line work practices mean that reliance on the existing single circuit to meet the supply requirements of the northern region is no longer a practical medium-term option, as the line now needs to be deenergised for all maintenance work. This means an increased number of planned interruptions unless a second line or an alternative generation source in the Kaitaia area is available. The 2014 slip in the Maungataniwha Ranges that caused a tower in this line to move 10 metres and some tower members to break has reinforced the vulnerability of the existing supply to our northern area to extreme weather conditions. We were fortunate that this incident did not cause an interruption to supply, and acknowledge that an extended supply interruption could easily have occurred. We must recognise that an extended unplanned outage of this line remains a possibility and need to plan for such a contingency.

  Until recently we have focused on the installation of a second 110kV line, routed closer to the eastern seaboard, to supply Kaitaia. This would fully meet all future requirements using proven technology. However, it is a long-life, high-cost solution that could be made redundant by emerging technologies. In addition, while good progress has been made, we have still to fully secure the route for this line. Some landowners have now appealed our plans to the Environment Court, so we still do not have certainty as to whether the route currently planned is feasible.

  The alternative of installing diesel generation, which is discussed further in Section 5.15, may not be a sustainable long-term solution, not least because it uses a sunset technology with high operating costs and high greenhouse gas emissions. However, as it has a relatively low capital cost and can be installed relatively quickly, it is now seen as the only option that will provide a secure supply to the northern area within a timeframe acceptable to our consumers. At this stage it is seen as an interim solution that will remain in place until the impact of emerging technologies on the electricity sector is clarified to the point where an optimal long-term solution can be determined with more certainty.

- While there has been improvement in our reliability of supply in recent years, it remains well below our consumers' expectations. This is due to our fringe location on the transmission grid, the lack of a dominant urban centre, the architecture of our distribution network and the very high proportion of uneconomic medium voltage lines. Historically, funds that could have been invested in subtransmission development have been needed to fund the essential maintenance of these uneconomic lines. This has left a legacy of underinvestment.

Our reliability improvement plan has focused on improving the condition of our transmission and subtransmission assets. Protection upgrades have now improved the reliability of our subtransmission system to the extent that the load on most of these circuits is now seamlessly transferred to an alternative circuit in the event of a fault. Completion of the Kaeo substation should further improve reliability by reducing the number of people affected by an 11kV fault in the Whangaroa area.

We are now focusing on improving the reliability of our 11kV network by transitioning to a network architecture that reduces the number of customers interrupted following the failure of a network element and allows supply to be restored more quickly to consumers not directly affected by the fault. This will involve the installation of new protective devices with improved discrimination in the core network, the installation of additional interconnections between neighbouring feeders and in some cases the installation of standby generation at the end of a feeder.

- Recent changes in the Health and Safety in Employment legislation have adversely impacted the rate at which we are able to improve our reliability of supply. WorkSafe New Zealand now requires lines companies to avoid the use of live line maintenance except under exceptional circumstances. Due to a lack of clarity as to what might constitute exceptional circumstances we, along with other New Zealand lines companies including Vector, now only allow our staff and contractors to work on deenergised lines. This has increased the number of planned supply interruptions, although we continue to develop and implement strategies to minimise these impacts where practical and cost effective.

  As indicated above, consumers in our northern area are likely to be most affected by this new approach to safety, as much of the maintenance work on the single transmission circuit supplying Kaitaia has been done live in the past. Fortunately, as a result of our intensive maintenance since acquiring the line, it is now in reasonable condition. It is inspected regularly and all known defects requiring prioritised remediation have been attended to. Nevertheless, until an alternative supply is available, routine maintenance interruptions may need to be longer or more frequent, and the likelihood of planned interruptions having to be organised at short notice to address an unforeseen maintenance requirement has increased.

  The increase in the number of planned interruptions could mean that we breach the reliability thresholds under the Commerce Commission's price-quality regulatory regime, given that our measured reliability is very sensitive to the performance of the 110kV line. However, the Commission has some discretion in its response to a breach and we are confident that we will not be unduly penalised, given that the outcome is a result of new legislation and the policies of the government entity responsible for enforcing the change. The reliability thresholds will be reset in FYE2020 and we expect the revised thresholds to take due account of the impact of these new operating constraints.

- Electricity volumes supplied to consumers peaked in FYE2012 following a period of relatively strong growth and have since declined from a peak of 333GWh to a current level of 322GWh in FYE2017. This decline is attributed to flat consumption by our large industrial consumers, an increasing number of consumers installing photovoltaic generation behind the meter, and energy efficiency initiatives implemented by our consumers. The flat industrial consumption is a function of the stagnant economic climate in our supply area, while energy efficiencies and the installation of photovoltaic generation are in part driven by a response to the price increases that we introduced to fund our network development programme and in part by the increased community awareness of the environmental impacts of excessive electricity consumption.

- The rate at which we can improve the security and reliability of our network is limited by the need to restrict our capital to adopt a prudent debt management strategy and keep within the price path determined by the Commerce Commission.

- We need to develop our network to accommodate the expansion of the Ngawha Power Station. The Board, with the agreement of the Trust, considers this investment to be fully aligned with Top Energy's mission and vision, largely because it will increase energy self-sufficiency within our supply area and limit our consumers' exposure to transmission price increases being proposed by the Electricity Authority.

These challenges, and their impact on our asset management planning, are discussed in more detail elsewhere in this AMP. Overall, the plan presented in this document reflects our current view on how we might best contribute to Top Energy's corporate mission given our forecast revenues and the expected availability of debt funding under what we consider the most likely energy delivery scenario.

2.3 Purpose of this Plan

Top Energy's Statement of Corporate Intent (SCI) describes this AMP as the defining document for TEN, which sets out 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 transmission and distribution 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:

- document 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 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; and
- comply with clause 2.6.1 of the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012.

2.4 Asset Management Policy

This asset management plan is guided by our asset management policy, which has been approved by Top Energy's Board. In summary, this policy requires us to develop an asset management plan that:

- gives safety our highest priority. We must act at all times in accordance with industry standard safe working practices and, in consultation with our employees and contractors, develop and adopt systems and procedures that minimize the risk of harm to people and property;
- 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;
- provides, over time, a reliability of supply consistent with that generally provided in rural areas of other parts of New Zealand. To do this we use a range of strategies including targeted network development, more effective maintenance, the application of new and innovative technologies and improved response to supply interruptions that do occur;
- improves our network's security and reliability at a rate that is both financially sustainable to the business and affordable to our consumers. We must also strive to continually improve the efficiency and cost effectiveness of our asset stewardship to increase the value we provide to our stakeholders

- monitors the technological changes affecting our industry and is ready to modify our asset management strategies where necessary in 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 we use to implement this policy. Our current AMMAT assessment is shown in Schedule 13 in Appendix A. Our aim is to improve our processes to achieve a minimum score of 3 for all indicators by the end of FYE2021.

2.5 Asset Management Objectives

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

2.5.1 Consumers and other Stakeholders

Our corporate objective is to:

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

We will 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; and
- enhancing stakeholder understanding by providing guidance and information. We are increasing the amount and timeliness of information uploaded on to Top Energy's website to better communicate with our external stakeholders. The interactive outage map that is now on our website is an example of this.

Sections 2.8.2 and 2.8.3 identify our different stakeholders, the interests of each stakeholder, and explain in more detail the actions we take to accommodate these interests and what we do to resolve stakeholder conflict.

2.5.2 Quality

Our corporate objective is to:

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

We will 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. Initiatives to implement safety by design across all our projects and to implement an integrated safety, process and performance auditing and inspection programme are well in hand. Over time, we are planning to develop and implement 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; and
- creating collaborative partnerships to achieve compliance and drive innovation. We are actively involved with industry groups such and 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 to work collaboratively towards the achievement of shared objectives. We will broaden this collaboration to include other lines companies and digital technology providers where this helps us better serve our consumers.

2.5.3 People

Our corporate objective is to:

develop and protect a high performing and highly engaged workforce.

We will do this by:

- improving our processes for the recruitment and retention of key talent;
- building leadership capability and depth by incorporating leadership competencies into all management personnel development plans and providing annual leadership development opportunities;
- 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; and
- 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.

2.5.4 Financial

Our corporate objective is to:

Secure long-term revenue, grow our assets and operate more efficiently.

We will do this by:

- securing our long-term revenue stream by implementing a pricing strategy designed to increase the certainty of our revenue levels; and
- growing our assets and profitably expanding our services by 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; and
- operating more efficiently to reduce costs through the development and implementation of a standardized project management delivery framework, reviewing behaviours to identify procurement and cost saving opportunities and providing operations and financial management training to managers to enhance financial decision making.

2.5.5 Region

Our corporate objective is to:

Support the growth of economic, employment and social development opportunities.

We will do this by:

- providing network and non-network solutions that will underpin the economic development in one of the most deprived areas of the country by assisting investors, developers and industry fulfil their growth ambitions;
- providing holiday work experience to tertiary students in accordance with our recruitment strategy;
- participating in community events; and
- encouraging and supporting employees to volunteer for community emergency services.

2.6 Strategic Issues

2.6.1 Connection of Embedded Generation

The Stage 1 expansion of the Ngawha Geothermal Power Station from 25MW to 53MW by FYE2021 will shift the centre of electricity supply to our consumers from remote grid connected generation located south of Auckland to local generation embedded in our network. Ngawha currently generates approximately 70% of the electricity requirements of consumers connected to our network and, at current levels of demand, we estimate that once this first stage expansion is complete this will increase to over 98%.

The power station will inject power into our network at Kaikohe, where it will supply the local demand within our supply area and export surplus generation over Transpower's spur line to Maungatapere, which connects our network to the national transmission grid. Once the Stage 1 expansion is complete, we expect that up to 45% of the power generated at Ngawha will be exported and that the Maungatapere line will be used for export 85% of the time, compared to around 10% of the time at present[I]. Only about 2% of the electricity consumed within our supply area will need to be imported.

On completion of the Stage 1 expansion, our consumers will be less reliant on the grid as a source of energy and the primary function of the connection to Maungatapere will be to export electricity generated at Ngawha south for use by consumers outside our area.

There are sufficient local renewable generation resources available for our supply area to be fully self-sufficient in its energy supply and the potential to further develop the local economy by exporting more energy to the grid. Overall the New Zealand power system will benefit from increased generation located north of Auckland. The network provides an essential service to investors wanting the utilise this generation resource - it connects generators with their market, both local and national. To deliver these services we will need to transition from a distributor of electricity sourced from a remote bulk supply to a manager of electricity flows within a system of distributed energy resources.

2.6.2 Economic Development from an Improved Energy Supply

An energy park at Ngawha with a number of sizeable new ventures/loads is well into its planning phase and some resource consents have already been granted. This is located close to the network injection point at Kaikohe and within the Kaikohe-Ngawha-Wiroa network backbone. A medium size industrial development near or Wiroa point of injection has also received resource consent. These developments will be located between Top Energy's centre of supply at Ngawha and its load centres at Wiroa and Kaikohe, better utilising the network assets that interconnect generation and load. The strategic locations of these developments will improve asset utilisation and the efficiency of our network investments.

2.6.3 Disruptive Business Models

The development of new business models, such as the rapid rise of the AirBnB market within our consumers' households, is creating expectations of a higher level of supply reliability. The tourism sector is booming in our supply area, with the Bay of Islands recently hosting three cruise liners in one day. The catering, accommodation, and tourism ventures associated with the tourism market have a very high Value of Lost Load (VOLL) and the tourism industry's economic development is sensitive to loss of supply even for relatively short durations.

2.6.4 Increased Demand for Resilience

We are located at the most remote end of the core transmission grid, well away from most connected generation. Furthermore, our network is remotely connected to the core grid via a single long transmission spur. Hence our security of our connection to the transmission grid is much lower it would

---

[I] See load duration curve - Figure 5.2.

be if our supply area was in the middle of the power system, and this limits the benefits we derive from our grid connection. Our connection to the grid has been unexpectedly interrupted four times in the last four calendar years. Given the increased national focus on resilience to climate change and natural disasters, and the higher reliance by many consumers on security of supply, the transmission grid arguably no longer meets our needs. While Transpower has recently invested heavily in improving the security of supply into Auckland, we have derived little benefit from this investment.

2.6.5 Unsustainability of Transmission

Transmission has been on a strong upwards price trend and the Electricity Authority's proposed new transmission pricing methodology will result in an unsustainable value proposition for our consumers. Importing bulk electricity from the grid is no longer the most economically efficient means of satisfying our consumers' energy requirements. Grid electricity will be used less and less to meet new demand, and this will create a spiral of change towards local and self-generation with our transmission and subtransmission networks increasingly interconnecting generation and load.

2.6.6 Connection Growth

We are experiencing high growth in new connections with the number of connections increasing by more than 1% per year. Our supply area is attracting retirees escaping the increasingly less sustainable cost of living in Auckland on fixed incomes, and they are building new houses where the capital cost of using emerging technologies is only a marginal cost. They exploit energy efficiency technology, and new technologies provide them with an opportunity to minimise the impact of the upwards price path of grid supplied electricity. This trend explains the static growth in residential electricity consumption, notwithstanding the increased number of domestic consumers.

2.6.7 Grid Parity

The cost of new technologies is approaching a point where they present consumers with a similar cost option to purchasing electricity from the grid. Our fringe grid location means high transmission charges and a high consumer tariff compared to other parts of the country, which may account for the fact that we have the second highest penetration of roof-top photovoltaic generation arrays in NZ. Almost 2% of consumers now have their own photovoltaic generation, and the total connected capacity is approaching 2MW. Photovoltaics will continue to displace grid generation and shift network investment away from capacity upgrade. Furthermore, storage technology is reaching the price point where a unit of energy can be stored and used at a similar cost to a unit from the grid, and the cost of storage is expected to reduce by 50% over the next 5 years.

2.6.8 Economics of Remote Supply

Approximately 35% by length of our distribution network is uneconomic. Energy efficient technology that reduces electricity consumption will only worsen this situation. However, new technology also presents an opportunity to address issues such as resilience. An example is the development of new tourism ventures in remote locations where the cost of connecting and achieving satisfactory security of supply through a traditional network augmentation is prohibitive. A distributed energy solution incorporating a local energy source could address this problem. We need to be responsive in developing solutions that meet our consumers' electricity requirements at a reasonable cost to encourage such investments, which in turn promote the economic wellbeing of the wider community.

2.6.9 Electric Vehicles

The Government is strongly promoting the introduction of electric vehicles because of the high proportion of electricity generation from renewable resources. Global trends are that electric vehicles have a high uptake in retired populations. NZ will follow this trend we can expect the penetration of electric vehicles in our supply area to increase faster than the national average. We will benefit from the development of load management features that allow vehicle batteries to be used for energy storage when integrated into energy supply systems. We expect a trend to emerge well within the ten-year planning horizon of this AMP where consumers connected to our network will start using vehicle batteries in this way. With proper load management, electric vehicles will increase the storage capacity on our network and allow operation of our distributed energy system to be enhanced and further optimised. A key challenge will be matching the addition of new distributed energy supplies to the growth in new loads such as electric vehicles.

2.6.10 Developing a Platform for New Services and Markets

We have an organisational challenge to build the operational knowledge and technical capability to transition from a distribution network operator to a distributed energy system operator. Our operations and the services we provide will become increasingly automated and software driven and less reliant on the use of physical assets.

2.7 Rationale for Asset Ownership

Our rationale for asset ownership is derived from our mission statement, which as noted in Section .2.2.2.1, 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.

Historically, when the economies of scale in electricity generation were substantial, technologies for storing large quantities of electricity were not available and the demand for electricity was growing exponentially, this has been achieved using a network of conductors and transformers designed to deliver electricity sourced from a centralised transmission grid to individual consumer premises. This industry paradigm is now changing to the extent the installation of traditional network assets may not always be the most cost-effective solution. A key risk is asset stranding. Traditional network assets are expensive to install and have lives in excess of forty years. It is only cost effective to use such assets to meet today's distribution requirements if we can be confident 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.

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 can be reduced through the installation of lower cost alternatives with a relatively short life, on the basis that by the end of their life the future of the industry should be clearer, and we can then replace these assets with solutions the better meet our stakeholders' long-term requirements.

Moving forward, we will be open to the use of non-network solutions to meet the needs of our consumers. This will involve the installation of diesel generation to provide supply security in the absence of a second circuit. We have already installed diesel generation for this purpose at Taipa and plans are in place to install additional generation in our northern area for the same reason.

We are obliged by Section 105(2) of the Electricity Industry Act 2010 to continue to provide a supply to consumers already supplied from our existing lines. Many lines currently serving consumers in remote areas are in poor condition to the extent that providing supply through a local generation or microgrid solution could be more cost effective than extending the life of these lines.

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.

2.8 Asset Management Planning

The key internal planning documents that directly connect with the 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 outcomes 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 generally 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 given year. Annual Plans are approved by our executive management but do not require formal 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 the 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:

- 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, detailing 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, detailing 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; and the
- 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, which is set out in the Commission's Electricity Distribution Services Default Price-Quality Path Determination 2015. The development of the asset management strategies and action plans described in the AMP is also constrained 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.

Preparation of the AMP

This AMP is both a strategic and an operational document. It is strategic in that it sets out our current plans for the management of its network assets over a ten-year planning period. It is operational in that the more detailed plans and budgets within the AMP for the first year of the period form the basis for the current Annual Plans, which control asset management expenditure for FYE2019. Hence, for the first year of the planning period the AMP content is purely operational. In subsequent years the content becomes progressively more strategic to the extent that in the later years of the planning period the AMP content is entirely strategic.

The SCI provides the context for the AMP, which in turn provides the context for the Annual Plans. All documents are interdependent, and they are therefore 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 constrained by 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 limited by the available funding. They are also influenced by a number of factors that impact our operation, including:

- the capacity of the existing network assets to accommodate localised growth in the demand for electricity;
- the needs of consumers and other network stakeholders;
- the cost of meeting legal and regulatory requirements; and
- 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 capital, operations and maintenance expenditure 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 is consistent with one another, aligns with our mission, and accommodates 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.

2.8.1 Planning Periods Adopted

This AMP is dated 1 April 2018 and relates to the period from 1 April 2018 to 31 March 2028. It was approved by the Board on 27 March 2018 and replaces all previously published AMPs and AMP Updates.

2.8.2 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 (large capital projects such as the construction of the new 110kV line);
- meetings with suppliers;
- performance review and management for internal and external contractors;

- papers and submissions; and
- local media.

Table 2.2 below indicates how the AMP incorporates the expectations of stakeholders. Each year, the published AMP is made available to all stakeholders for their information, and 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;
- a balance is sought between the cost of non-supply and the investment needed to provide the desired level of reliability; and
- alignment with the Trust objectives as published in the SCI.

If a conflict between different stakeholders continues, we will adopt an appropriate resolution process to address all concerns and arrive at a final solution. Conflict most often arises because stakeholders do not have a complete understanding of the issues and can usually be resolved by working closely with the parties concerned. 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

2.8.3 Stakeholder Interests

Table 2.3 below identifies our key stakeholders, 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 the price threshold 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 development plan is progressively implemented. 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 practical and cost effective.
	Reliability	• We continually measure and review reliability against the SAIDI and SAIFI targets detailed in the AMP. We target higher reliability than the benchmarks set by the Commerce Commission in applying its price-quality framework to reflect the planned outcomes of our network development and maintenance initiatives; • We are developing a distribution network planning standard reduce the impact of distribution network faults on the reliability of supply and will progressively upgrade the distribution network to comply with this standard. This work will be prioritised to focus on areas with a high level of non-compliance.
	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 network and are implementing augmentations to address non-compliances; • We have a documented Emergency Preparedness Plan that sets out the procedures we will follow when 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	• Phone Plus has been contracted to ensure consumers are directed to the appropriate point of contact for quick and efficient service;

STAKEHOLDER	EXPECTATIONS	ACTIONS
		• 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.
	Embedded generation	• We welcome the connection of embedded generation 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; • We provide incentives for the connection of new generation in situations where a connection will benefit our consumers by reducing transmission costs or avoiding costly network augmentation
RETAILERS	Communications	• We share information on network outages and other relevant issues with retailers in accordance with standard industry protocols.
	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 received recognition of excellence from the industry and has been further 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 actively 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 continually strive to improve our operating efficiency in the expectation that over time network users and the Trust will benefit through lower prices for the services we provide; We report financial outcomes monthly to the Board. This report includes a comparison against the budgets in this AMP.

STAKEHOLDER	EXPECTATIONS	ACTIONS
	Economic development	• Consistent with the objective of supporting economic development within our supply area, we will negotiate with potential new industrial and commercial consumer 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 Statement of Corporate Intent (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.
COMMERCE COMMISSION	Price	• We set our prices in accordance with the price path set by the Commission under its price-quality regulatory regime and confirm compliance annually through our audited regulatory compliance statement.
	Quality	• We set internal reliability targets and monitor our performance against these targets monthly through our Board reports. • We confirm that our quality of supply is better than the quality 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 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 and are currently preparing a formalized plan to guide this transition

STAKEHOLDER	EXPECTATIONS	ACTIONS
	Legal compliance	• We manage our business in accordance with the Electricity Industry Participation Code and provide the 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 MBIE with the statistical 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 transmission substations; • We regularly provide Transpower with updated information on our forecast peak demand and our connection point requirements; • We use Transpower standards as the benchmark for determining the maintenance requirements of our 110kV assets.
WORKSAFE NEW ZEALAND	SAFETY	• We manage all work in 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 WorkSafe New Zealand requirements and is regularly reviewed.
	Job security and satisfaction	• We need motivated staff with high levels of job satisfaction to meet stakeholder expectations. To this end, we regularly survey staff to monitor satisfaction with their work and working environment • 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; • 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 control programme in accordance with the Electricity (Hazards from Trees) Regulations 2003. • We target expenditure on vegetation control on the basis of the expected 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 general 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

2.8.4 Accountabilities and Responsibilities for Asset Management

The Trust is the sole shareholder of Top Energy Ltd. The shares are held on behalf of electricity consumers connected to the Top Energy network and 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 the Top Energy strategy, approval of this AMP and of individual project business cases, which must be prepared 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 2.2.

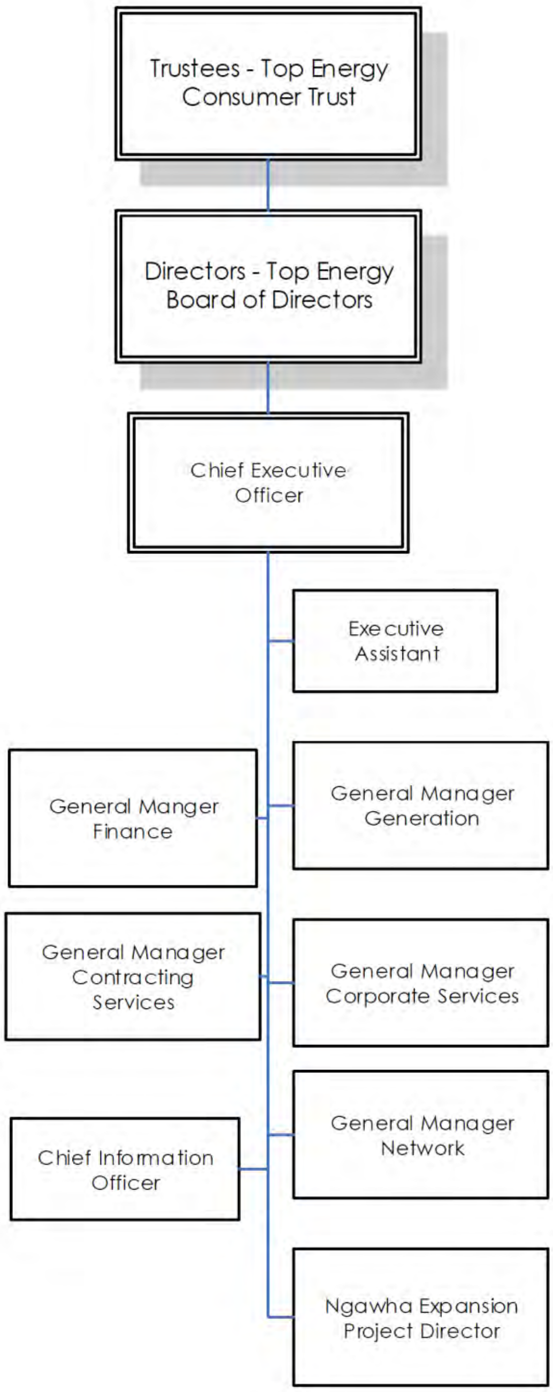


Figure 2.2: Top Energy Structure

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, which is responsible for managing the network assets covered by this AMP, 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; and
- the ongoing management of the network assets within approved renewal, maintenance, capital and operational expenditure budgets.

In particular, 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.

Maintenance work on the transmission network, including the 110kV transmission line and the 110kV substation assets, as well as 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. Apart from specialist activities and major 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 Networks as if TECS was an external contractor operating under an arms-length relationship. The nature of the formal relationship between Networks and TECS is discussed further in Section 2.15.4 and is regularly reviewed. The cost of field work is comparatively benchmarked against current industry costs to ensure 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 fully 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.

TEN has overall responsibility for the safety of all personnel working on the network. Consistent with the requirements in "Safety Manual – Electricity Industry (SM-EI)", we implement an Authorisation Holders Certificate (AHC) assessment process to ensure the competence level of field staff (both internal and external) is compliant with company and industry standards. Employees and contractors' staff are required to be assessed 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 without supervision to the level permitted by their AHC. The assessment and approval for issuing an AHC to an individual is by recommendation of the Network Operations Manager and with the consent of the General Manager Network.

TEN currently has a staffing establishment of 46 full time equivalents and its structure is outlined in Figure 2.3 below.

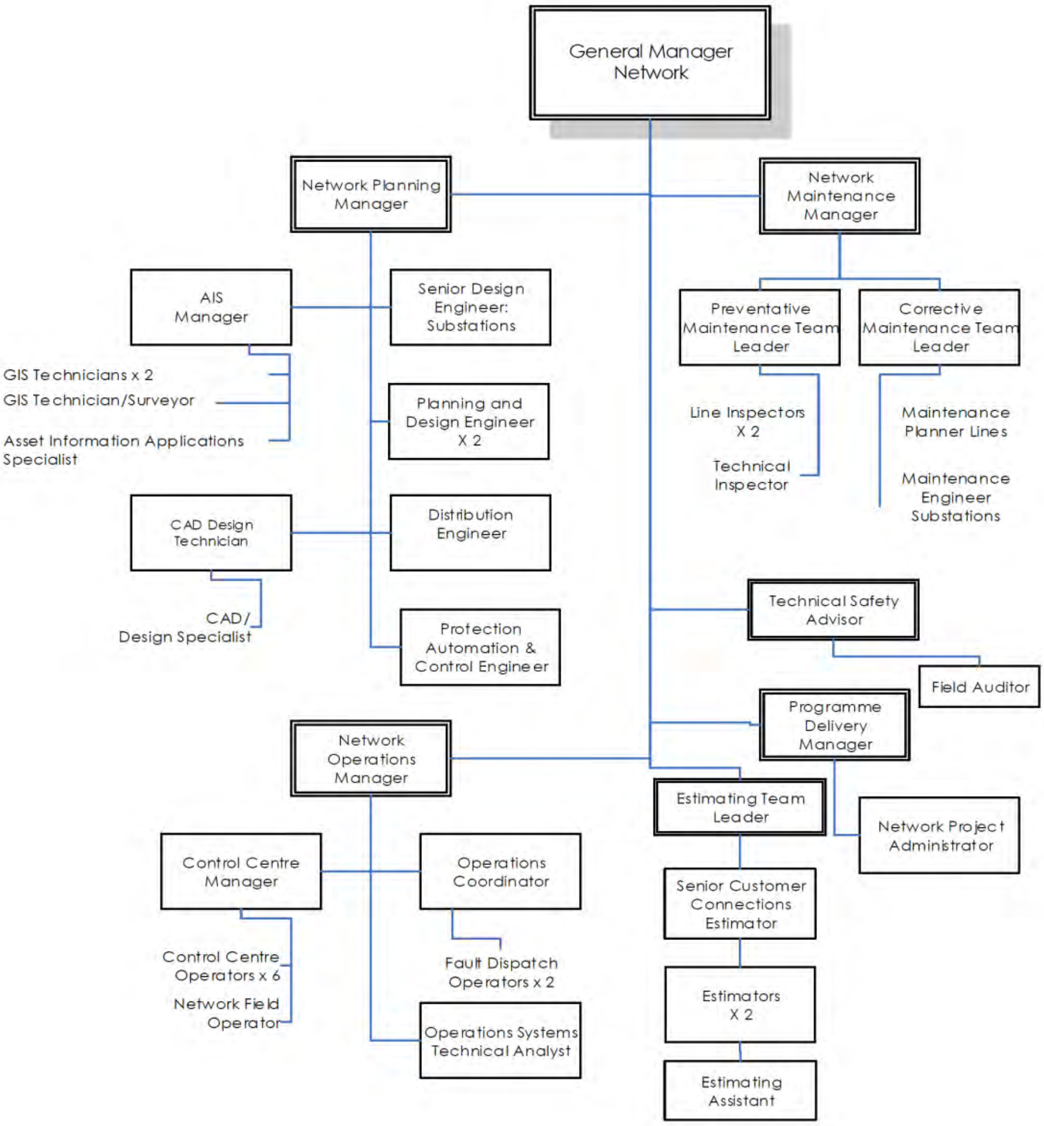


Figure 2.3: **Top Energy Networks - Structure**

The key responsibilities of our senior Networks management are:

Position	Accountability
General Manager Network	To control the overall, annually-approved network budget.
Maintenance Manager	To control the annually-approved maintenance and renewal budget.
Planning Manager	To control the annually approved capital budget.
Programme Delivery Manager	To manage the delivery of the capital investment programme. Budgets assigned as per individual projects.
Manager Asset Information Systems	To manage the GIS department budget to ensure the asset data integrity is maintained.
Operations Manager	To manage the control centre and fault budget and monitor network performance.
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	$30,000

Table 2.5: Top Energy order approval levels

2.9 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.

2.9.1 System Control and Data Acquisition

We use the iPower SCADA system for operational, real-time load data-gathering requirements, load control and logging and reporting state changes from controllable devices. The system provides for circuit breakers at the two transmission substations and all zone substations to be remotely operated from our central control room at Kerikeri. In addition, it is possible to remotely operate switches and reclosers situated at strategic locations throughout the subtransmission and distribution networks.

The SCADA system also records system and feeder half-hour demand information, which is available via the company's intranet for further analysis and processing in separate systems.

We are planning to upgrade our SCADA master station to an advanced distribution management system (ADMS), which will provide a significantly higher level of functionality and are looking to reduce that cost by sharing a common platform with another North Island EDB. This upgrade, which has now been approved by the Board, is discussed further in Section 5.19.

2.9.2 Accounting/Financial Systems

The Group uses SAP for the management of expenditure, capital accounts, estimating capital jobs, inventory, orders, and accounts payable and receivable. It 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; and
- capital and maintenance expenditure.

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

2.9.3 GIS System

The Intergraph Geographic Information System (GIS) is an engineering asset register and provides a spatial representation of assets, their connectivity and relationship with one another, consumers, and vegetation. This information is merged with the Terralink database and overlaid with raster images from aerial photography.

Our GIS data includes several integrated critical business applications that are used to manage and report on assets. These are:

ICP Application

This application is integrated into the national registry to manage and report on consumers' Installation Control Points (ICPs). Supplementary information is included to facilitate our management of consumer connections, including safety and pre-connection status.

Permission Application

We use this for storing details and agreements relating to easements and general property access rights.

Incidents/Faults Management System

Where the location of a fault is noted against an asset that has failed, the application provides electrical traces to be run to ascertain the areas, roads and numbers of consumers affected under different switching configurations. We currently use this to manually generate our SAIDI and SAIFI reliability reports, although this information will be generated automatically once our new ADMS is commissioned.

2.9.4 Network Analysis System

We use the DigSilent power systems analysis package for load flow, voltage profile and protection design. It also has provision for harmonic and stability analysis, although these functions are not generally required to support our operations.

2.9.5 Consumer Management System

We contract Phone Plus to handle consumer calls. Phone Plus uses its Consumer Management System (CMS) to provide details about consumer calls and call statistics.

2.9.6 Drawing Management System

We now use Autodesk AutoCAD 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; and
- control, circuit and wiring diagrams.

2.9.7 Asset 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 inspection is undertaken internally by TEN and 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.

We anticipate that a full asset inspection cycle covering all assets will be completed by the end of FYE2019. We will then transition to a revised inspection regime that focuses on assets approaching the end their expected economic life and newer assets that are unlikely to be unfit for service will not have regular maintenance inspections. This is discussed in Section 6.1.2.2.

2.10 Asset Data Accuracy

We maintain a dedicated GIS team that is responsible for ensuring that asset data is accurately recorded and maintained.

GIS data is considered highly accurate in the following areas:

- 11kV Lines and associated equipment;
- transformers (overhead and ground mount);
- line switchgear and equipment;
- low voltage service boxes and link pillars;
- 33kV zone substations;
- 33kV lines;
- 33kV switchgear;
- transmission assets, transferred from Transpower;
- other technical equipment including SCADA;
- 11kV cable and related equipment including switchgear; and
- 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.

Some data gaps and errors exist with respect to:

- low voltage systems; and
- 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. The missing data is now being collected in conjunction with the asset inspection programme. Asset inspectors are given information from the GIS database and required to manually mark as-built modifications as necessary and return the mark ups to the Manager, Asset Information Systems for GIS data entry. The process is working well with corrected data being returned and input as required. It is expected that this process will be finalised by the completion of the full asset inspection cycle in FYE2019.

2.11 Asset Management Systems

2.11.1 Asset Inspections and Maintenance Management

As described in Section 2.9.7, our time-based asset inspection programme is uploaded into and managed through SAP. 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. Time based inspection is 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 different maintenance policies for specific asset types is provided in Chapter 6 of this AMP. Asset condition information is loaded directly into SAP by our asset inspectors using remote, hand-held input devices.

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

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 promptly attend to defects that pose an immediate threat to public safety.

2.11.2 Network Development Planning and Implementation

Our network development plan, is strategic in nature and requires an ambitious level of expenditure relative to our expected annual income. It is reviewed annually at both a strategic and detailed planning level.

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. Given the current low rate of growth in incremental demand our strategic focus is on improving the security and reliability of supply.

At a more detailed planning level the plan is reviewed to ensure that localised demand growth can be accommodated and takes due account of expected resource availability.

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 Chapter 5 of this AMP.

2.11.3 Network Performance Measurement

We currently use a real-time fault management system that we have developed internally. Once a call is received by the control room staff, a fault job is raised. This details information such as time raised, location, dispatcher notified, team details, on-site arrival, site departure and work carried out. This provides a detailed fault analysis tool for tracking, managing and post-fault analysis of all network fault events. The fault management system also provides a list of faults with active or incomplete status, so that we can follow-up to ensure service attendance was achieved.

For each fault that has an impact on SAIDI and SAIFI, there is an individual switching record created. The record is then entered into a database that contains the necessary data to generate an outage report to provide statistical data for use in producing accurate performance reports. This information is also used for statistical failure mode data analysis, which can be used for maintenance and future fault prevention planning.

Operational fault and switching times are logged for each fault event by Control Centre staff. This information is used to run a GIS query for each fault to determine the numbers of consumers affected at each switching stage of the fault and, subsequently, calculate the SAIDI and SAIFI impact for each high voltage fault event.

Monthly and annual audits are carried out on all fault calculations. In the event of an error, a wider sample (or the entire population) is audited. Annual audits are also carried out by an external auditor.

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

As discussed in Section 5.19, we are planning to automate our measurement of network reliability. Further to this, in addition to the broad SAIDI and SAIFI measures used by the Commerce Commission, we are planning to develop reliability measures that better reflect the level of reliability individual consumers can expect by categorising categorise feeders into urban, rural, and remote, and separately report the average reliability across each category. Urban consumers can expect a more reliable supply than rural consumers because urban feeders are generally shorter and therefore less exposed to risk. Similarly, consumers of rural feeders would receive a more reliable supply that those on feeders categorised as remote. Reliability measures would reflect this.

2.12 Assumptions and Uncertainties

The network development plan and other asset management strategies described in this AMP are ambitious 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 a number of 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. If forecasts of delivery volumes are not met, then the funding available for new capital works will reduce.	We have developed a funding plan based on a combination of increased bank borrowings and revenues from electricity volumes delivered. 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. Increases in transmission and subtransmission capacity tend to be lumpy rather than incremental and the development plan will therefore increase network capacity in excess of the immediate requirement. Hence, even if electricity delivery volumes grow, over time the level of network investment will reduce, and this should assist in stabilising future pricing.	Our ongoing network development plan is not primarily capacity driven but is being implemented because much of our network currently does not meet accepted industry standards for reliability and security of supply. While there are no known potential projects in the pipeline, our failure to improve supply reliability could impede the economic development of the region, if large industrial or commercial initiatives that rely on a secure supply of electricity, decide not to proceed. Current indications are that the current decline in electricity sales will continue in the short term, but this trend could be reversed if economic activity increases following a settlement of the Ngapuhi Waitangi Tribunal claim or if there is an increased penetration of electric vehicles.
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 line charge increases needed to finance the plan are provided for by the Commerce Commission. The Commission's 2015-20 price path determination issued in December 2014 was supportive of our network development plans, so our regulatory risk in the medium term is now considered low.
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 by 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.	Our network development plan has prioritised improvements to the transmission and subtransmission network. However, without the ability to effectively control peak load, we may need to reinforce the distribution network more than is currently planned and this would utilise funds currently intended to be used elsewhere. This is a significant long-term risk from the penetration of electric vehicles. There will need to be incentives in place to discourage the charging of vehicles during times of peak demand, if investment in the distribution network to accommodate new electric vehicle load is to be minimised.

ISSUE	ASSUMPTION	BASIS FOR THE ASSUMPTION	POTENTIAL IMPACT OF UNCERTAINTY
RELIABILITY AND QUALITY	Consumers want an improvement in the reliability and quality of electricity supply.	Our current supply reliability is poor in comparison to our peers. The Trust and Board both consider that improving the reliability of supply is consistent with our SCI objective of investing in activities that contribute to economic development within its supply area. The poor supply reliability is a result of limitations in the design of the existing network and a meaningful improvement is not achievable without significant investment in enhancing the network. We have consulted widely with the local community and received strong support for our proposals, notwithstanding the significant increase in line charges that will be necessary to fund the investment.	There is a risk that the current support for reliability driven network development initiatives will decline as consumers feel the impact of increased line charges. Notwithstanding the funding requirements of our network development plan, we are conscious that we supply one of the most economically deprived areas of the country and that we have a responsibility to show some restraint in the prices we charge. A reduction in electricity consumption or widespread resistance to the price increases required to fund network development could force us to reduce our expenditure to the extent that planned improvements to supply security and reliability are delayed or not achieved.
ASSET CONDITION	The asset replacement and renewal expenditure forecasts beyond the first five years of the planning window that have been included in the AMP have been assumed but have a high level of uncertainty.	The forecasts are largely based on existing 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. The introduction of a formalised asset condition assessment in the Commerce Commission's Electricity Distribution Services Information Disclosure Determination 2012 provides an indication of the change in the overall condition of the asset base over time. This tool 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 be in poor condition.	Defective equipment currently causes approximately one third of our unplanned supply interruptions and 20% of our unplanned SAIDI. However, it is a fault cause that is difficult to target through a reliability improvement programme, since equipment failures can occur anywhere on the network in a largely random fashion. The programme to increase the number of remote controlled switches on the distribution network will not reduce the number of defective equipment faults that occur but is designed reduce the SAIDI impact by allowing supply to be restored sooner; particularly to consumers upstream of a fault location. The installation of diesel generators at Taipa, upgrades to the protection systems on the 33kV subtransmission system and the completion of the new Kerikeri zone substation have also resulted in SAIDI improvements. The network development plan also provides further SAIDI improvements, because most transmission and subtransmission faults no longer cause a supply interruption and because increasing the number of zone substations reduces the length of distribution feeders.

ISSUE	ASSUMPTION	BASIS FOR THE ASSUMPTION	POTENTIAL IMPACT OF UNCERTAINTY
			Hence, the number of consumers affected by a specific distribution network fault will be reduced. However, these programmes are designed to reduce the impact rather than the cause of faults; the majority of which occur on the distribution network. The overall condition of the distribution network assets limits the reliability improvements that can be achieved through network development. Improvements beyond this will only be achieved if the overall condition of these assets is improved.
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.	Variability of weather conditions inevitability 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. Network reliability that was consistently worse than the target over a period of 3-5 years will indicate that further management intervention may be needed.
NGAWHA POWER STATION	Bore drilling outcomes are positive and Stage 1 of the Ngawha power station expansion is commissioned in FYE2021.	Analysis and tests to date of geothermal field capacity.	There is a risk that poor outcomes from bore drilling early in the project will result in a decision to halt further development. This will not affect the planned network development presented in Section 5. Its main impact will be reduced opportunity to reduce use of the grid connection and therefore grid connections cost until other distributed generation opportunities are taken up elsewhere on the network. It is expected that the Ngawha Energy Park will proceed even if the power station is not expanded.
ELECTRIC VEHICLE CHARGING STATIONS	There is sufficient capacity in the existing network to accommodate installation of electric vehicle charging stations over the AMP planning period.	The network has spare capacity available and the uptake of electric vehicles over the AMP planning period is unclear.	We are not planning investment in charging stations. However, if uptake in electric vehicles is higher than anticipated then some localised network augmentation may be needed to accommodate the additional load.
INFLATION	Except where otherwise shown, cost estimates in the AMP are presented in real New Zealand dollars as at 31 March 2018. Where these cost estimates are expressed in nominal New Zealand dollars, an	This is the mid-point of the Reserve Bank's long-term target consumer price index (CPI) inflation rate of 1-3%.	

ISSUE	ASSUMPTION	BASIS FOR THE ASSUMPTION	POTENTIAL IMPACT OF UNCERTAINTY
	annual inflation rate of 2% is assumed for the whole of the planning period.	Network cost increases are driven by increases in the cost of the labour skills required (which are generally in short supply) as well as changes in the cost of copper and aluminium. Historically changes in network costs have not mirrored CPI and can be significantly higher, due to the highly skilled workforce required. 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 plan.	

Table 2.6: AMP Assumptions and Uncertainties

2.13 Asset Management Strategy and Delivery

2.13.1 Asset Management Strategy

A gap analysis undertaken by Asset Management Consulting Proprietary Limited (AMCL) in benchmarked the quality and structure of our asset management system against the requirements of PAS 55. It confirmed that this AMP meets the requirement of clause 4.3.1 of PAS 55, now known as ISO 55001, to have a documented asset management strategy.

The key objective of this strategy is to improve the reliability of supply provided to our consumers, as measured by SAIDI and SAIFI, to levels comparable to that typically received by consumers in other rural provincial parts of New Zealand. This is being done by:

- securing a route for a second 110kV transmission circuit between Kaikohe and Kaitaia to increase the security of supply to consumers in the northern part of our supply area. While it is now apparent that the lead time for completion of this line is too long to meet consumer expectations, completion of a second circuit is still the only identified option using currently available technology that will meet consumer aspirations over the longer term;
- installing diesel generation in our northern area to provide security of supply in the short term at a relatively low cost;
- development and implementation over time of a standard network architecture to reduce the SAIDI and SAIFI impact of a fault on the 11kV and low voltage networks;
- replacement of assets that are in poor condition and nearing the end of their economic life;
- targeting vegetation management at trees that are a safety hazard and at those parts of the network where supply reliability is poor; and
- improving the efficiency of the maintenance effort by focusing on assets that are nearing the end of their economic lives and are therefore most likely to fail in service.

The detailed network development and lifecycle asset management plans in Sections 5 and 6 of this AMP describe the means though which we are implementing this strategy and the progress we have made to date.

The strategy is consistent with the overarching corporate mission statement described in Section 2.2.1 and, in the opinion of both our Trust and the Board, will underpin the longer-term development of the economically-depressed Far North region. While the bulk of the asset management expenditure is on network development, the strategy does not ignore other periods of the asset life cycle, since improvement in the performance of the existing asset base is essential if the targeted improvements in SAIDI and SAIFI are to be realised. Our maintenance management system is described in Section 2.9.7 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.

2.13.2 Contingency Planning

We have a documented Emergency Preparedness Plan setting out processes for the response and management of serious incidents and events. This was activated for the July 2014 storm which lasted three days and caused significant damage to our assets that resulted in extended supply interruptions for many of our consumers. We have subsequently reviewed our response to this event and revised out Emergency Preparedness Plan to incorporate the lessons learnt. We also try to proactively anticipate and plan for foreseeable emergencies and this planning has resulted, for example, in the construction of a mobile substation, the installation of diesel generators at Taipa, and the planned installation of additional generation in the Kaitaia area in FYE2019 and FYE2020.

2.13.3 Risk Management Process

The AMCL analysis found that the approach to risk management did not appear to be fully consistent across the organisation. It also found no evidence the formal processes existed for the bottom-up identification, reporting, mitigation, and closure of asset management risks that occur at an operational level. Since this analysis we have formalised and certified our Public Safety Management Plan and introduced processes to identify and manage design and operations risks. Nevertheless, these systems are still managed independently of one another and we still need to develop a more integrated approach to risk management across the business.

2.13.4 Implementation of Asset Management Plans

AMCL found that we have processes, but not necessarily documented procedures, for the implementation of our asset management plans. These processes were relatively strong for the asset creation phase of the life cycle, but weaker for asset utilisation and maintenance. With the introduction of SAP and an ISO 9001 certified quality system, these procedures have now been documented and our processes are a lot stronger than at the time of the AMCL review.

These processes were further strengthened by corporate restructures that have shifted responsibility for maintenance planning from TECS to TEN.

2.13.5 Corrective and Preventive Action

AMCL found that a strong process was in place for determining preventive and corrective actions when an asset management problem was identified. This required the process owner to undertake a root cause analysis, determine appropriate corrective actions and track these through to close-out. However, it found little evidence that the process was being implemented as intended. It suspected that very often, corrective actions were being informally implemented, but were rarely formally tracked and closed-out as required by the process.

We think the process is now working well when a major incident arises. However, our response tends to be reactive and we have yet to develop a culture that encourages our staff to proactively identify issues and implement incremental process improvements.

2.14 Information and Data Management

At the time of the AMCL assessment, asset data was primarily stored in the GIS database. However, AMCL considered that this is a repository rather than a tool. While this is true from an asset maintenance perspective, the GIS is primarily an operational tool that is used in real-time to manage fault response, operational switching and to accurately calculate SAIDI and SAIFI reliability data. Hence, it records the existence and key properties of an asset but not condition data.

At the time we were relying on in-house spreadsheets to manage the maintenance effort, and data on the condition of individual assets was sparse. AMCL also found issues with defects management, which it considered was not fully under control. It found that, when defects were addressed in the field, they were not necessarily being closed out in the defects database. There were therefore issues with both the accessibility and accuracy of the maintenance data that was recorded.

This maintenance management issue was addressed with the introduction of SAP.

A mature process is in place for the management of GIS data, described in some detail in Section 2.10. Processes for the management of maintenance data in SAP are still maturing and we have specified measurement points and asset condition criteria for the different asset types. Hand held electronic input devices are used by asset inspectors to upload asset condition data into SAP directly from the field. Nevertheless, it will take one full five-year inspection cycle before this asset condition data entry process is complete. The quality of the data set is improving over time as assets are progressively inspected.

2.15 Asset Management Documentation, Controls and Review

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

2.15.1 Asset Management Policy

Our asset management policy, which is discussed in Section 2.4, underpins all asset management effort.

2.15.2 Asset Management Plan

This AMP is the document central to the implementation of our asset management system. The AMCL review found that the AMP as it currently exists generally meets the requirements of clause 4.3.3 of PAS 55 for the organisation to have documented asset management plans. This reflects the structure of the AMP where Chapter 2 covers strategic issues in some detail and Chapters 5 and 6 provide more detailed action plans for the development and maintenance of the asset base. However, AMCL also found there was no clear set of quantifiable and measurable objectives linking the asset management plans to the overall asset strategy and noted that:

> *...individual objectives require a "clear line of sight" from the Asset Management Policy though the Asset Management Strategy to the Asset Management Plan. This is almost achieved within the Asset Management Plan, but this document would benefit from a clearly set out group of Asset Management Objectives.*

AMCL further stated:

> *…The Asset Management Plan should include a section on Asset Management Objectives, which contains Top Energy's high-level objectives relating to the management of the Assets and also the development of Top Energy's Asset Management System.*

We have qualitative objectives derived from the corporate mission statement and discussed in detail in Section 2.5, but we still need to develop a formal process for evaluating how well we are achieving these. This is likely to mean developing quantifiable measures that we can use to track the progress we are making towards those objectives described in Section 2.5 that we consider most critical to achieving our corporate mission.

The quantifiable objectives set out in Chapter 4 of this AMP do this to some extent. However, these objectives relate only to those areas of our operation that are regulated by the Commission under Part 4A of the Commerce Act. Full compliance with PAS 55 would require this set of objectives to be expanded to cover performance in areas such as health and safety and environmental compliance that are outside the Commission's jurisdiction. It should also include leading indicators of our asset management performance – these could include indicators relating to the completion of planned asset inspections and the level of defect backlogs. We already have internal measures and targets relating to health and safety, but leading indicators of our asset performance have still to be developed and formalised in some areas.

2.15.3 Annual Plans

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

2.15.4 Interface Agreement and Sourcing Strategy

These two documents define the formal relationship between TEN and TECS and so are critical to the implementation of the action plans within this AMP. The Interface Agreement defines the pseudo-contractual relationship between the two business units based on an asset owner–service delivery model.

AMCL assessed our outsourcing strategy to be borderline and almost compliant with clause 4.4.2 of PAS 55. The main issue was the management of the interface between TEN and TECS, which at the time was still transitioning to an arm's length pseudo-contractual relationship. AMCL considered that, while this relationship was nominally formalised, it was often not so in actuality. This suggested that the accountabilities and responsibilities of the staff involved were not always clearly acknowledged.

Following internal reorganisations, functions such as asset inspection and maintenance planning are now undertaken directly by TEN staff rather than by TECS. While good progress in addressing the problems identified by AMCL has been made, issues at the interface between TEN and TECS remain.

2.15.5 Documentation of the Asset Management System

We have implemented a public safety management system in accordance with the requirements of NZS 7901. AMCL noted that many of the public safety management system procedures and work instructions documented what was already occurring within TEN and TECS and that many of these procedures and work instructions were relevant to our asset management system.

Since the AMCL audit we have refined our quality management system to the point where it was certified as compliant with ISO9001 early in FYE2016. This system documents many processes and procedures relevant to asset management and, in particular, the implementation of this AMP.

Our long-term goal of creating and implementing formalised, fully documented, ISO 55001-certified asset management system remains. However, there is no timeframe for this and no formal project to achieve this objective has been established.

2.15.6 Legal Compliance Database

Ensuring that we comply with all legal obligations is the responsibility of the General Manager Corporate Services and is explicitly identified in the ISO 9001 process maps that are owned by this position. For this purpose, Corporate Services maintains a database, which can automatically email staff responsible for legal compliance. AMCL considered that the management of this database was borderline for compliance with PAS 55 requirements, with the main concern being the lack of a formalised procedure to ensure that legislative and regulatory changes are proactively reflected in the database. We also doubt that this system will capture changes to technically focused regulations such as safety rules, although we are confident that we would become fully aware of such changes though our membership of and engagement with relevant industry bodies.

2.15.7 Network Development Procedures and Controls

AMCL noted that the process of converting the annual budget into a work programme was defined in a number of procedures that, although new, appeared reasonably well embedded. It also noted that individual project managers look after the work, monitoring delivery as required. However, it considered that TEN lacked a clear "line of sight" into TECS implying that TEN, as the asset owner, had limited meaningful involvement in the implementation of new project works once a decision is made to proceed to construction.

2.15.8 Network Maintenance Procedures and Controls

At the time of the AMCL review, routine asset maintenance was an area of concern as maintenance planning and review processes were spreadsheet-based and difficult to manage. AMCL found that implementation of work instructions for condition assessment and management of the defects backlog was well intentioned, but ineffective. The lack of a clear "line of sight" into TECS suggested that accountability for implementation of the maintenance plan was unclear or not well understood.

These issues have now been largely addressed by the introduction of SAP and also by the company reorganisation that has transferred responsibility for maintenance planning from TECS to TEN.

2.15.9 Performance and Condition Monitoring

We have routine asset inspection processes in place and proactive condition monitoring processes for critical assets such as power transformers. However, AMCL found these processes to be reactive and driven primarily by a need to manage SAIDI and SAIFI over the short-term. It noted that, while reactive measures should be monitored, PAS 55 compliance requires a much broader range of measures, including leading indicators; which are currently not routinely monitored.

The introduction of SAP as a maintenance management tool, and the new information disclosure requirement to measure and report on changes to the overall health of the asset base in a consistent manner, has helped us address these deficiencies. Our maintenance backlog, measured as the number of defects that have not been cleared within the specified maintenance timeframe, is a leading indicator that is now included in TEN's monthly Board report.

2.15.10 Audit

The AMCL report noted that no formal internal audit procedures exist, although there was informal auditing of asset management activities; particularly field activities undertaken within TECS or by its subcontractors. Since the AMCL review, a formal public safety management system and an ISO 9001 certified quality system have been put in place, both of which require formal external audits.

2.15.11 Continual Improvement

The AMCL review found evidence of a focus on continual improvement relating to specific elements of the broader asset management effort. The report cited, as an example, the TOP Programme that uses process improvement teams to provide structure and control over the improvement process. The report noted that this programme demonstrates a good commitment and structure to encourage continuous improvement and many elements of best practice. The effectiveness of these continual improvement programmes has been recognised in the industry awards won by Top Energy, including the 2012 Deloitte Lines Company of the Year Award. Top Energy was also joint winner with Transpower of the 2012 Electricity Engineers' Association Engineering Excellence Award. The successful introduction of our public safety management system and the ISO certified quality management system, which we were not required by regulation to introduce, is testimony to the ongoing improvement culture that exists within our organisation.

However, the report also noted that continual improvement of the core asset management system documentation such as the asset management system, policy and plans was not formalised. Notwithstanding this, we believe that there is a culture of continual improvement within the Top Energy Group, driven by our Board and executive management team. This culture is particularly strong within TEN. The preparation and ongoing improvement of this AMP is accorded a high priority to the extent that over the last few years to the extent the Board now includes an asset management subcommittee, which guides the strategic direction of this AMP at an early stage of its development. We have also engaged an external consultant with a good knowledge of our network to assist with the preparation of this document.

2.16 Communication and Participation Processes

2.16.1 Communication of the AMP to Stakeholders

Our SCI identifies this AMP as the defining document for the management of our network. All senior managers within TEN are involved in its preparation and it is distributed widely within the organisation. We also actively encourage external stakeholders to review and comment on the content of the AMP. A copy is provided for stakeholder perusal in the reception foyer of our Head Office in Kerikeri and the AMP is also available on our web site.

2.16.2 Management Communication and Support

Our executive management has undertaken a planned engagement process consulting both internal and external stakeholders and has gained broad acceptance of the network development plan described in this AMP. This consultation occurred to understand the expectations that stakeholders have for the performance of their electricity supply, to seek feedback on the network development plan and to communicate the need for increased line charges to fund network improvements.

Management communication and support for the other life cycle elements of this plan, particularly asset maintenance, has been less visible, except for areas such as vegetation management that are expected to result in an immediate and material improvement in reliability, as measured by SAIDI and SAIFI. This situation is changing as the Board and senior management have seen the need to adjust the balance between development and maintenance to better meet the need of our consumers.

2.16.3 Communication, Participation and Consultation

The AMCL gap analysis found that communication with external stakeholders on asset management issues was effective and that the leadership provided at CEO and General Manager level was also clear and effective. However, there were deficiencies in the communication and involvement of lower level staff in the asset management process to the extent that overall the level of compliance with PAS 55 requirements was found to be relatively low. This concern applied particularly to TECS and also to the interface between TEN and TECS.

Internal restructures have now clarified the lines of communication, accountability, and responsibility for delivering the asset management plan.

2.17 Capability to Deliver

The investment programme described in this AMP continues to be ambitious. We developed this programme in full consultation with our local community, and with the full support of the Trust, the Board of Directors, and the Executive Management Team. While the challenges of this investment programme are unique, Top Energy and its shareholder have already demonstrated an ability to successfully undertake challenging projects for the benefit of its stakeholders. The successful construction, commissioning, and operation of Stage 1 of the Ngawha Geothermal Power Station, with the involvement of local iwi, is testimony to this. In addition, much has already been achieved in the delivery of our network development programme.

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

- financing;
- the ability to secure line routes;
- engineering; and
- construction.

These are each discussed in the following sections.

2.17.1 Financing

With the help of external consultants, Top Energy has put together a carefully designed financing plan for this investment programme. As indicated in Section 2.10 this includes:

- revenues from line charges; and
- increased bank borrowings. We have secured the bank funding needed to fund the investment.

Nevertheless, finance is the limiting constraint on the rate at which we can deliver our network development plan. This is due to lower than expected revenues resulting from a gradual decline in energy delivered since FYE2012, and a consequent need to limit our bank borrowings to sustainable levels and is also a consequence of the Board’s decision to proceed with the expansion of the Ngawha Geothermal Power Station.

2.17.2 Engineering

The design of the network development works set out in this AMP requires engineering skills and resources beyond our in-house capabilities. We are outsourcing the skills and engineering resources that we cannot provide in-house and have allowed for this in estimating the project costs.

2.17.3 Construction

Construction of the works described in this AMP is generally undertaken by TECS, to the extent that it has the skills and resources in-house. Construction works are outsourced when internal resources are not available. In general, line construction and cable laying are undertaken internally, while the construction of new substations is outsourced.

2.18 Public Safety Management Issues

The passage of the Health and Safety at Work Act 2015 has raised awareness of the potential risk that the operation of an electricity network can create for the general public and in particular the potential 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.

2.18.1 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 supply system in our area. Consequently, SWER lines were used extensively in the original reticulation of our area and many such lines remain. However, the load is now getting far too high for 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 could rise to hazardous levels creating a risk of shock and possibly death to persons and stock coming into contact with our primary 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 are now undertaking a full 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 have also decided that any new consumer wanting to connect to our SWER network must 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.

2.18.2 Private Lines

Many of the private lines in our area are in poor condition and pose a significant safety risk. However, these lines are not regularly inspected and there are no systems in place for ensuring they are maintained in a safe condition.

We have suggested to the Commerce Commission that we include these lines in our inspection programme and advise the owners if repairs are required. However, the Commission's view is that this is not our role and that regulated revenues should not be used for this purpose.

There is a risk that, following a public safety event involving a private line somewhere in the country, legislation will be enacted that requires the local distribution company to assume ownership of these lines. We will then become responsible for their safety and maintenance. Even if ownership is assumed at no cost, this will impose a substantial financial liability that we have not provided for.

Section 3 Assets Covered

3 Asset Description

3.1 Overview

3.1.1 Distribution area

Top Energy manages the northern-most 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 (shown in Figure 3.1).

Figure 3.1: Top Energy Transmission and Subtransmission Networks

Most of our supply area is rural. There is no single dominant urban area, with urban development spread amongst several small towns with populations between 1,000-6,000 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.

There were 32,399 consumer connection points on the network, including inactive connections, as at 31 March 2017.

Compared to New Zealand as a whole, the district is notable for a high proportion of people who are either on low incomes or unemployed; and who have lower rates of educational achievement. Consequently, in FYE2017, the average quantity of electricity supplied to each active connection point was again the second lowest in the country, notwithstanding the impact of the large Juken Nissho triboard mill load.

3.1.2 Load characteristics and large users

For FYE2017, the maximum demand on our network was 68.7MW and the total energy delivered to consumers was 322 GWh. Most of our electrical load is residential, small commercial and agricultural. We have only five large consumers:

- Juken Nissho Mill near Kaitaia (≈ 10MVA);

- AFFCo Meat Works near Moerewa (≈ 2MVA);
- Mt Pokaka Timber Products Ltd, south of Kerikeri (≈ 1MVA);
- Immery's Tableware near Matauri Bay (≈ 1MVA); and
- Northern Regional Corrections Facility (NRCF) at Ngawha (≈ 0.6MVA).

Juken Nissho, AFFCo, Mt Pokaka all have dedicated supply feeders from a zone substation 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.

We discuss and negotiate maintenance, renewal and replacement strategies for assets that affect the operations of our major consumers with each individual company. As a result, we usually schedule maintenance work affecting these consumers during their off-peak or non-operational periods. We also work closely with our major consumers to ensure that the service we provide aligns with their requirements, to the extent feasible on a shared network.

Almost 20% of the energy delivered through our network supplies these five largest consumers. Other consumers throughout the area are predominantly residential or rural, with milking sheds making up a significant proportion of the rural load. There is no predominant urban centre and light commercial and industrial loads are generally concentrated within a number of small towns and settlements dispersed throughout our supply area.

3.1.3 Network Characteristics

Energy from the national grid is delivered to our Kaikohe transmission substation through a double circuit 110kV Transpower-owned transmission line from Maungatapere and the points of injection into our network are the 110kV incoming circuit breakers at this substation. Power from our 25MW Ngawha geothermal power station situated about 7km Southeast of Kaikohe is also delivered to Kaikohe though two 33kV subtransmission lines.

Our supply area is separated into two distinct geographic areas. The northern area including Kaitaia, Taipa; and the Cape Reinga peninsula is supplied from our 110kV transmission substation located at Pamapuria, approximately 10km east of Kaitaia. The larger and more populous southern area (including Rawene, Kaikohe Kawakawa, Moerewa and the coastal towns of Kaeo, Kerikeri, Paihia and Russell) is supplied from the Kaikohe substation. A single circuit 110kV transmission line, which crosses the Maungataniwha Range, connects the two substations; there is no interconnection at subtransmission voltage.

A 33kV subtransmission network supplies twelve zone substations; four in the northern area and nine in the southern. The zone substations in turn supply 61 distribution feeders, which operate at 11kV. In rural areas, many spur lines fed from distribution feeder backbones are two wire single phase or single wire earth return. Approximately 20km of the Rangiahua feeder in the southern area has been uprated from 11kV to 22kV operation. Low voltage (LV) distribution is at 415V three-phase, 480/240V two-phase and 240V single phase.

3.1.4 Grid Exit Point

With the acquisition of the transmission assets from Transpower in 2012, our only GXP is the termination of the Transpower 110kV Maungatapere-Kaikohe circuits. Transpower retains ownership of the two 110kV circuit breakers at Kaikohe that terminate these circuits, each of which has a winter rating of 77MVA. However, generation from Ngawha reduces the circuit loading and, with the likely increase in the capacity of the Ngawha power station, the existing lines will meet all foreseeable requirements.

3.1.5 Transmission 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 Ngawha generation would be required should the larger of these transformer banks be out of service at times of peak demand.

The single circuit 110kV transmission line between Kaikohe and Kaitaia has a winter rating of 68MVA, which is sufficient to supply the foreseeable Kaitaia load. Therefore, the existing constraint between Kaikohe and Kaitaia is one of security rather than capacity.

There are two 110/33kV transformer banks at Kaitaia, a newly installed unit rated at 40/60 MVA and an older unit rated at 22MVA. As the capacity of the smaller unit is insufficient to provide N-1 security at times of peak demand, in the event of failure of the new transformer supply might need to be rationed until a replacement unit (provided by Transpower) is transported to site and installed. However, such an event is unlikely given that the transformer is new and relatively lightly loaded. Condition assessment indicates that the older bank has limited remaining life and it is scheduled for replacement in FYE2022.

The outdoor 33kV switchyard at Kaikohe was replaced in FYE2015 with a new indoor switchboard. Outdoor 33kV switchyards are no longer considered good industry practice and it is planned to install a similar indoor switchboard at Kaitaia in FYE2027.

3.1.6 Subtransmission system

A geographic diagram of our 33kV subtransmission network is shown in Figure 3.1 above.

Table 3.1 below shows our existing zone substation transformers. We generally purchase transformers that can be upgraded by the addition of cooling systems to suit increasing load growth.

Historically, we have standardised on an 11.5/23MVA transformer rating for our larger load substations, to allow the relocation of transformers in case of an emergency if a single unit should fail. However, consistent with our policy of increasing the number of injection points into the distribution network, some of our new substations have smaller units. Also, to provide backup to locations where only a single 33/11kV transformer is installed, we have a 7.5MVA mobile transformer unit.

SUBSTATION	UNIT	NOMINAL ONAN/ ONAF OR OFAF MVA RATINGS WITH EXISTING COOLING	PRESENT MAXIMUM MVA RATING
Southern GXP			
Kaikohe	T1	11.5/23MVA ONAN/OFAF (Has pumps but no fans)	17
	T2	11.5/23MVA ONAN/OFAF (Has pumps but no fans)	17
Kawakawa	T1	5/6.25MVA ONAN/ONAF (Has fans but no pumps)	6.25
	T2	5/6.25MVA ONAN/ONAF (Has fans but no pumps)	6.25
Moerewa	T1	3/5MVA ONAN/ONAF (Has no pumps but has fans)	5
	T2	3/5MVA ONAN/ONAF (Has no pumps but has fans)	5
Waipapa	T1	11.5/23MVA ONAN/OFAF (Has both pumps and fans)	23
	T2	11.5/23MVA ONAN/OFAF (Has both pumps and fans)	23
Omanaia	T1	3/5MVA ONAN/ONAF (Has no pumps but has fans)	5
Haruru	T1	11.5/23MVA ONAN/OFAF (Has pumps and one fan)	23
	T2	11.5/23MVA ONAN/OFAF (Has pumps and one fan)	23
Mt Pokaka	T1	3/5 MVA ONAN/ONAF (Has no pumps but has fans)	5
Kerikeri	T1	11.5/23MVA ONAN/OFAF (Has pumps and fans)	23
	T2	11.5/23MVA ONAN/OFAF (Has pumps and fans)	23
Kaeo	T1	5/10MVA ONAN/OFAF (Has pumps and fans)	10
	T2	5/10MVA ONAN/OFAF (Has pumps and fans)	10
Northern GXP			
Okahu Rd	T1	11.5MVA ONAN (Has no pumps or fans)	11.5
	T2	11.5MVA ONAN (Has no pumps or fans)	11.5
Taipa	T1	5/6.25 MVA ONAN/ONAF (Has fans but no pumps)	6.25
Pukenui	T1	5MVA ONAN (Has no pumps or fans)	5
NPL	T1	11.5/23 MVA ONAN/OFAF (Has both pumps and fans)	23
	T2	11.5/23 MVA ONAN/OFAF (Has both pumps and fans)	23

Table 3.1: Present Zone Substation Transformers

Table 3.2 below shows the transformer capacities together with the firm (N-1) capacities and the present transfer capacities (within 3 hours).

The transfer capacity is the load that can be transferred to other substations in the event of a fault by reconfiguring the 11kV distribution network. It is important to note that the security rating refers to the subtransmission network only; there is not full N-1 supply security in the northern area, as there is only one incoming 110kV circuit.

As can be seen from the table, the Taipa substation does not provide full N-1 security even though its peak demand exceeds 5MVA. The Omanaia, Mt Pokaka and Pukenui substations also do not provide N-1 security, but the peak demand at these substations is much smaller.

SUBSTATION	UNIT	PRESENT RATING (MVA)	SUBSTATION PRESENT CAPACITY (MVA)		
Southern Area			Firm (N-1)	11kV feeder Switched Transfer Capacity	Year Substation N-1 Exceeded
Kaikohe	T1	17	17	1.	>FYE2028
	T2	17			
Kawakawa	T1	6.25	5	2.5	>FYE2028[1]
	T2	6.25			
Moerewa	T1	5	5	2.1	>FYE2028
	T2	5			
Waipapa	T1	23	23	6	>FYE2028
	T2	23			
Omanaia	T1	2.75	-	0.3	Current
Haruru	T1	23	23	0.5	>FYE2028
	T2	23			
Mt Pokaka	T1	5	-	1.5	Current[2]
Kerikeri	T1	23	23	6	>FYE2028
	T2	23			
Northern Area			Firm (N-1)	11kV feeder Switched Capacity	Year Substation N-1 Exceeded
Okahu	T1	11.50	11.50	3.70	>FYE2028
	T2	11.50			
Taipa	T1	6.25	-	4[3]	Current
Pukenui	T1	5.00	-	0.25	Current
NPL	T1	23.00	23	1	>FYE2028
	T2	23.00			

Table 3.2: Present Zone Substation Transfer/Switching Capabilities

Note 1: Approximately 1.5MVA of demand will be transferred to Haruru on completion of the Russell reinforcement project in FYE2022.

Note 2: There is sufficient 11kV switched transfer capacity to supply all small use customers beyond FYE2028. Arrangements have been made for the Mt Pokaka mill load to be interrupted in the event of a transformer failure until supply cam be restored using the mobile transformer.

Note 2: Diesel generation

3.1.7 Distribution system

Our distribution system consists of 56 predominantly overhead rural feeders[2], which supply approximately 5,940 distribution transformers. The system operates at 11kV except for about 20km of the Rangiahua feeder, which had been upgraded to 22kV. Figures 3.2 to 3.13 show the extent of the distribution system supplied from each of our zone substations.

The percentages of underground to overhead line are as follows:

Transmission	-	overhead 100%
Subtransmission	-	overhead 94%, underground 6%
Distribution	-	overhead 93%, underground 7%
Low voltage	-	overhead 26%, underground 74%

There are limited interconnections available between transformers at low voltage (LV) level, except in the urban areas of Kaikohe, Kaitaia, Kerikeri, Russell and Paihia. 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 is looping between network pillars. This allows for the rapid identification and sectionalisation of the system in the event of localised network faults.

Transformers on the distribution network follow the ISO standard sizing and 86% of distribution transformers are pole mounted. Pole mounting of transformers is now limited to ratings up to 100kVA for seismic purposes.

Pad (berm) mounted transformers are generally steel cabinet enclosed units and may include switch units (total pad type), depending on the application.

These transformers are of three types:

- Distribution transformers, which provide the low voltage supplied to consumers. 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 single wire earth return (SWER) line.
- Step-up transformers. These form the interface between the 22kV section of the Rangiahua feeder and the rest of the distribution network.
- Isolating transformers, which connect SWER lines to the core 11kV distribution network.

Table 3.3 shows the numbers and ratings of each transformer type as at January 2018.

[2] At time of writing. This will increase to 61 after completion of the Kaeo substation at the end of March 2018i.

Transformer size kVA	Number Pole Mounts	Number of Pad Mounts
Distribution Transformers		
Under 10	155	1
10	146	1
15	2,754	16
20	2	-
25	39	-
30	1,403	94
50	412	160
75	36	-
100	113	183
125	1	
150	19	57
200	17	177
300	1	87
400	-	8
500	3	30
750	1	14
1000	-	8
Isolating Transformers		
15	4	
30	1	
50	5	
100	52	
200	12	
Step-up Transformers		
50	2	
100	2	
1,500		2
2,000		1
3,000		1

Table 3.3: Transformers on the Distribution Network

Figures 3.2 – 3.13 below show the coverage of the distribution feeders supplied from each of our zone substations. Not shown are four NPL feeders supplying the Juken Nissho tri-board mill.

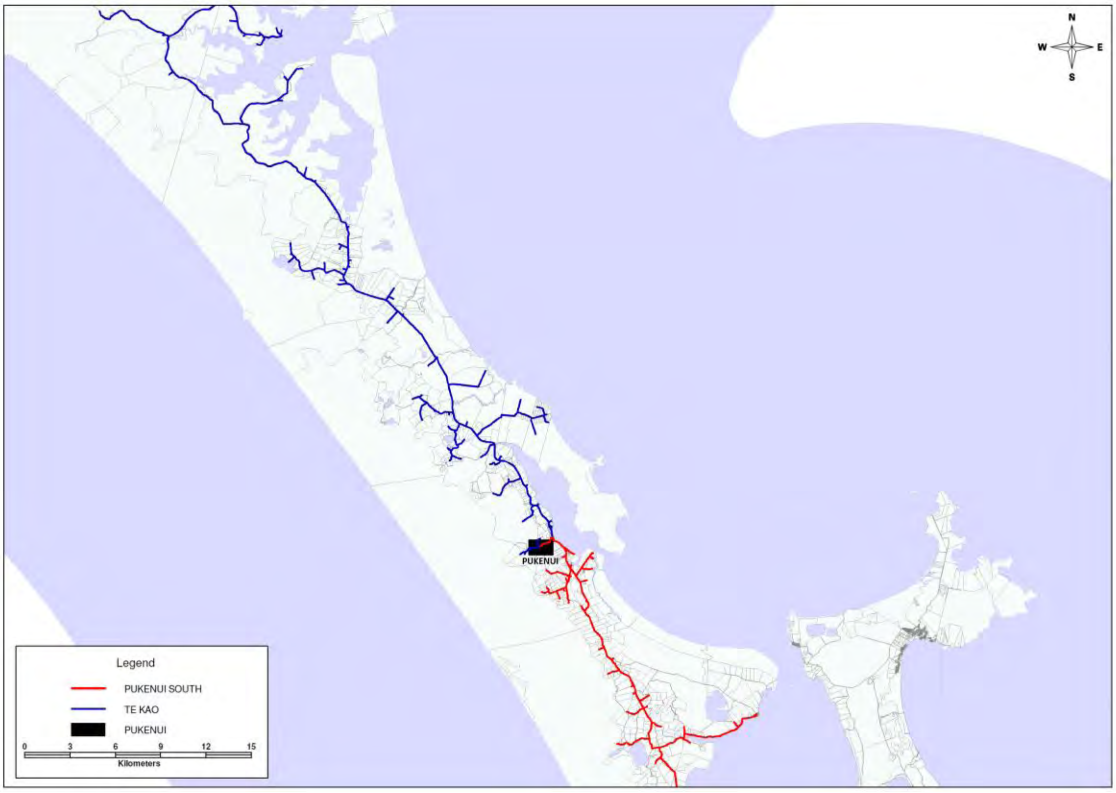


Figure 3.2: Geographic diagram of the Pukenui zone substation

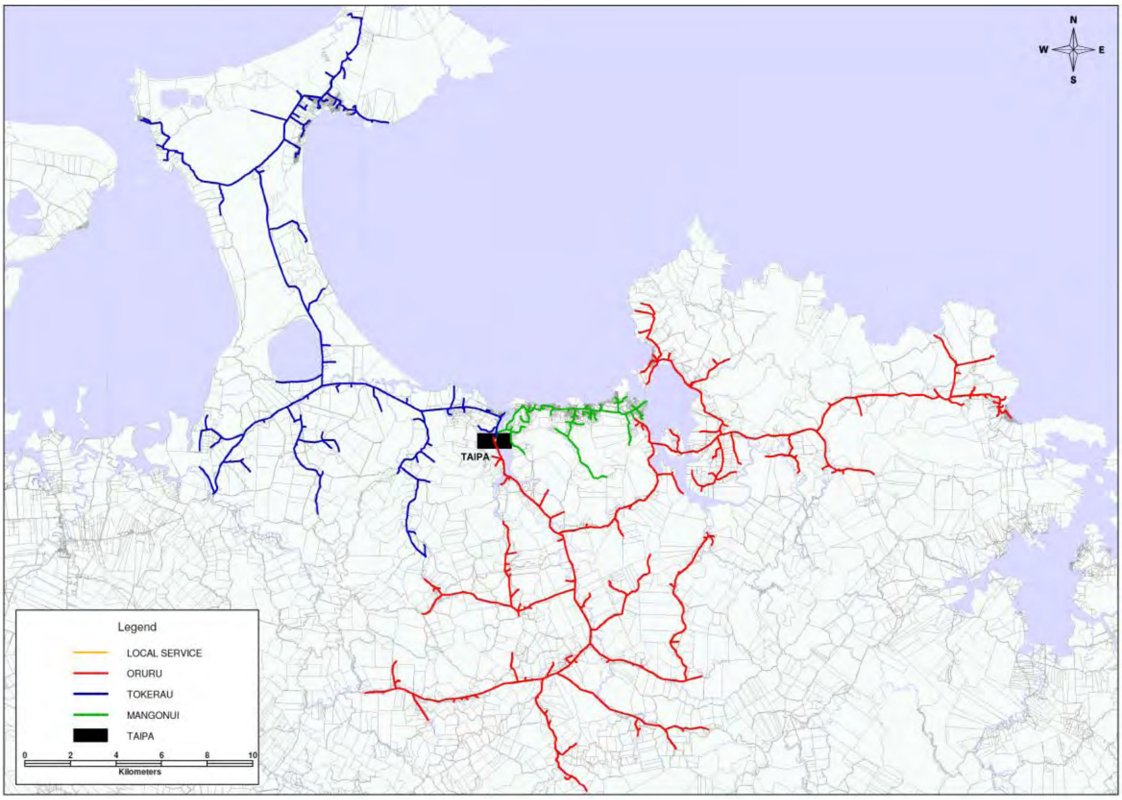


Figure 3.3: Geographic diagram of the Taipa zone substation

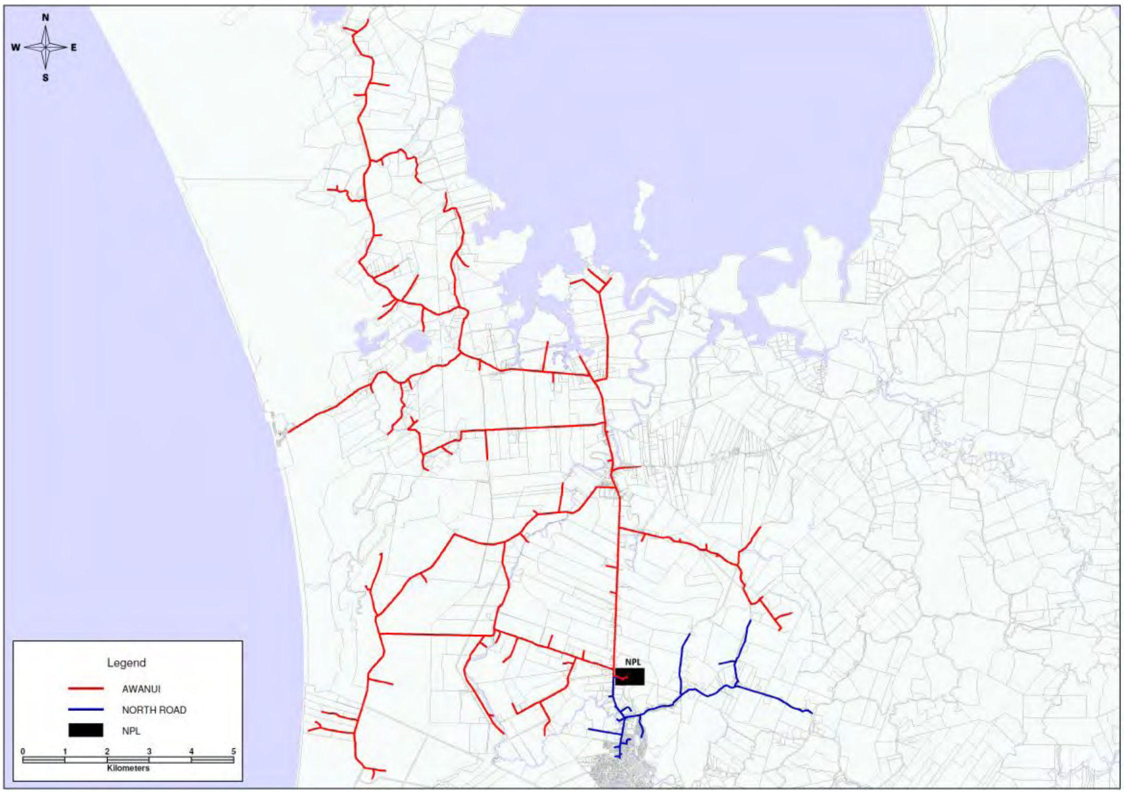


Figure 3.4: Geographic diagram of the NPL zone substation

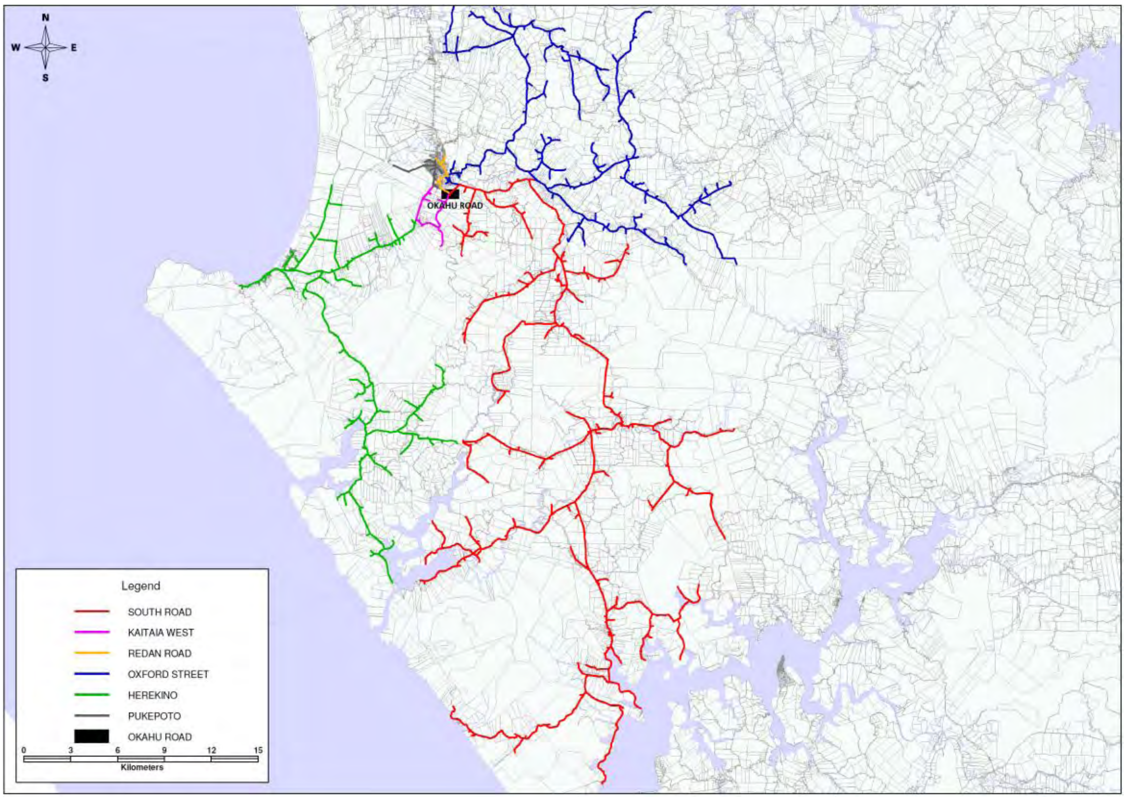


Figure 3.5: Geographic diagram of the Okahu Road zone substation

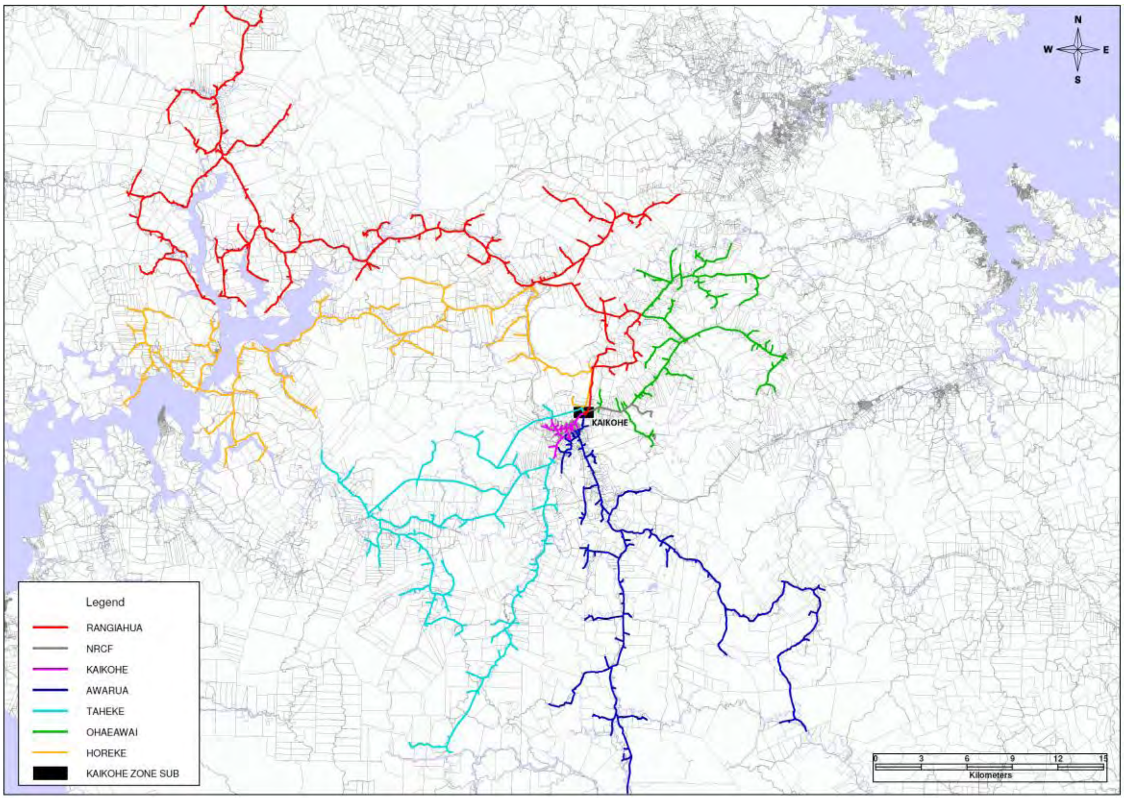


Figure 3.6: **Geographic diagram of the Kaikohe zone substation**

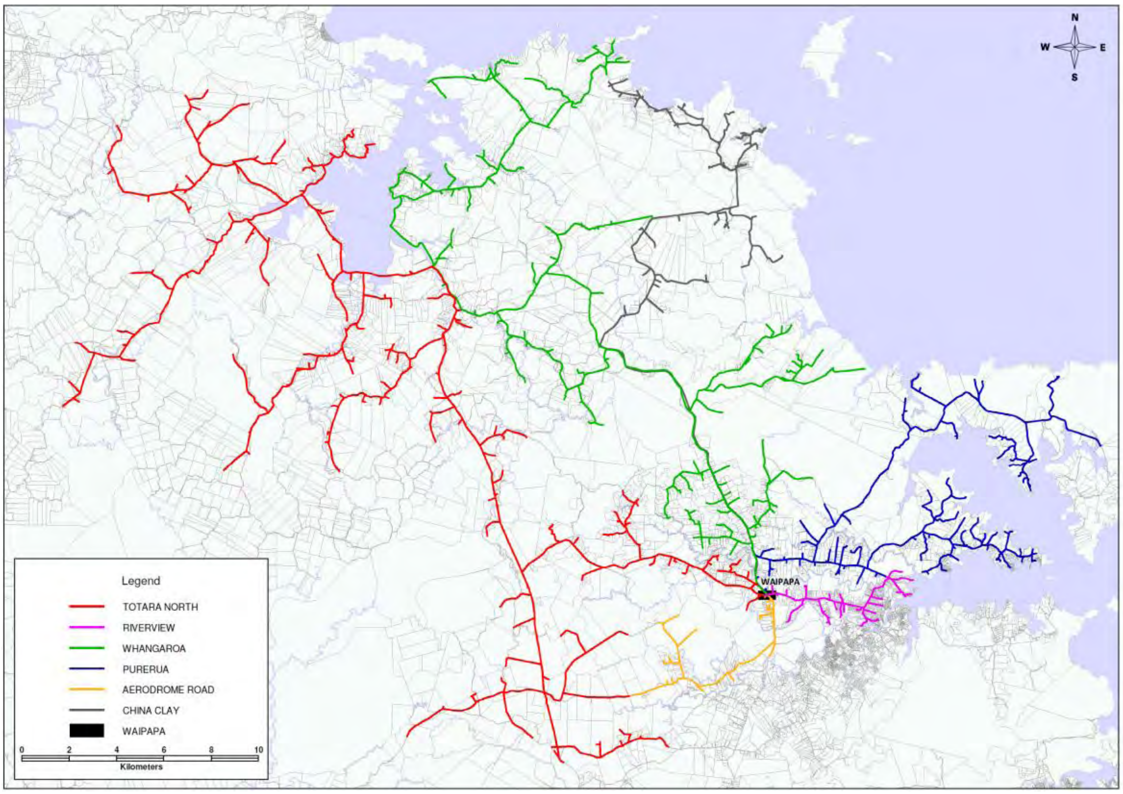


Figure 3.7: **Geographic diagram of the Waipapa zone substation**

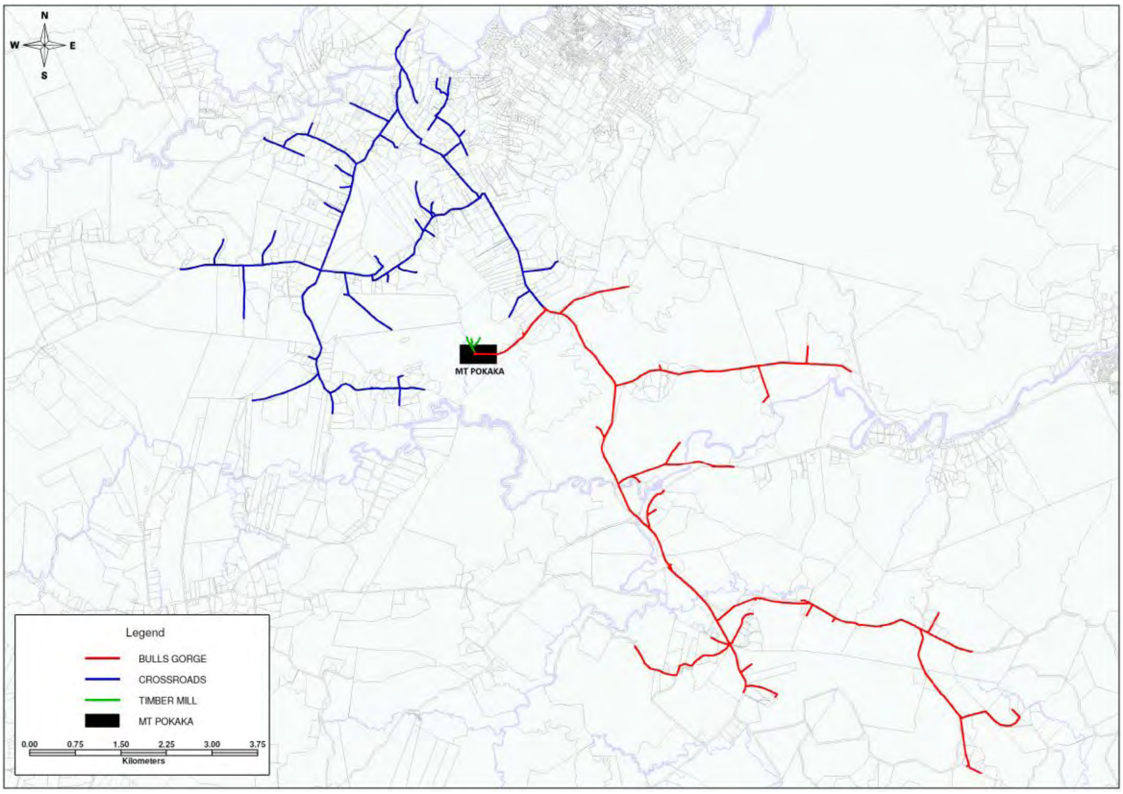


Figure 3.8: Geographic diagram of the Mt Pokaka zone substation

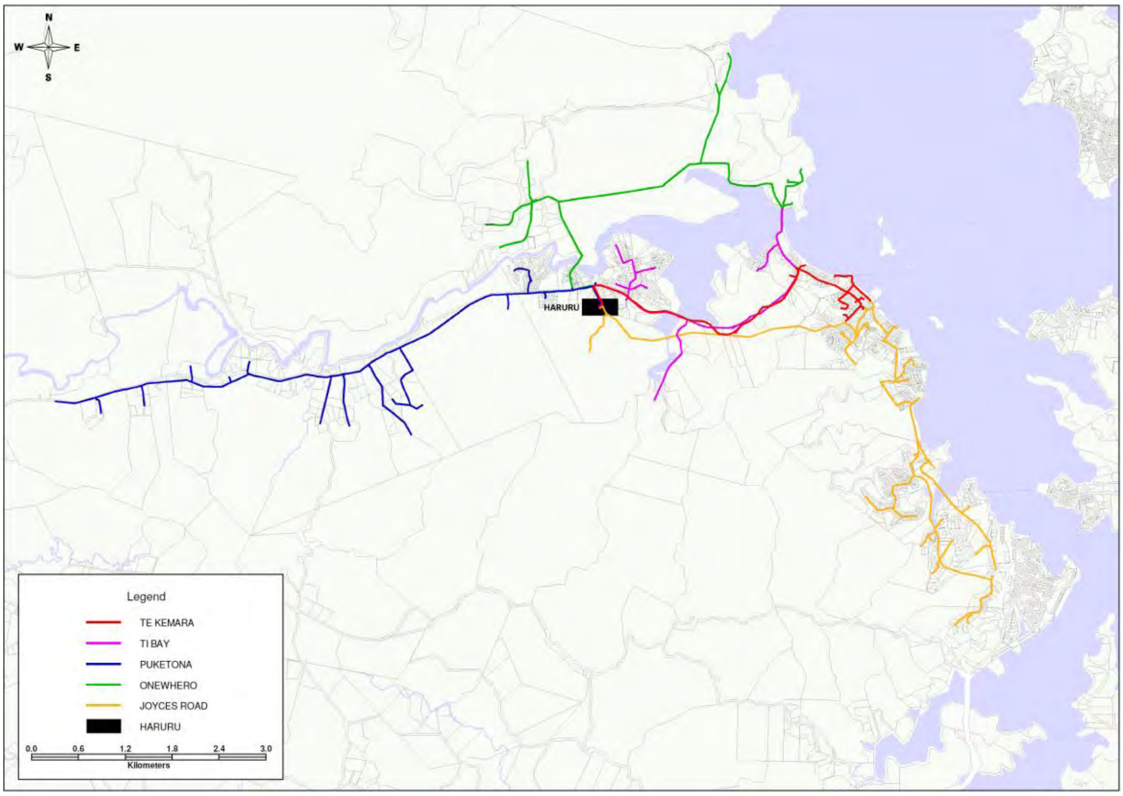


Figure 3.9: Geographic diagram of the Haruru zone substation

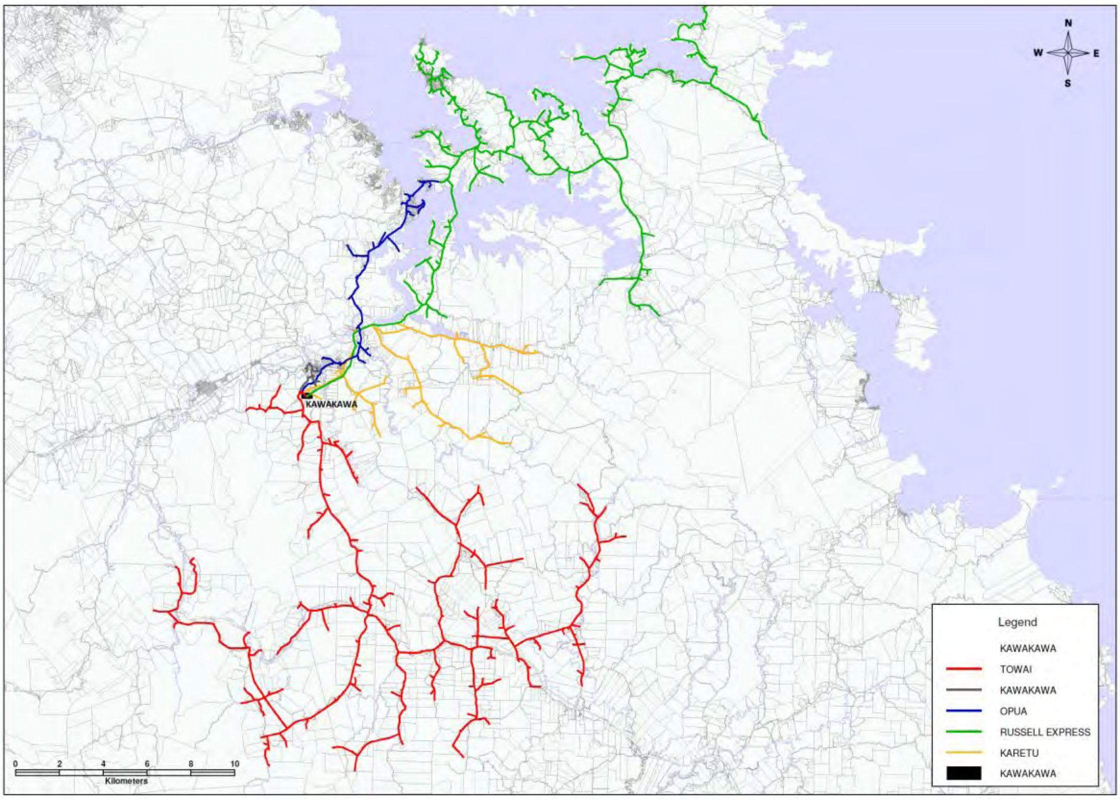


Figure 3.10: **Geographic diagram of the Kawakawa zone substation**

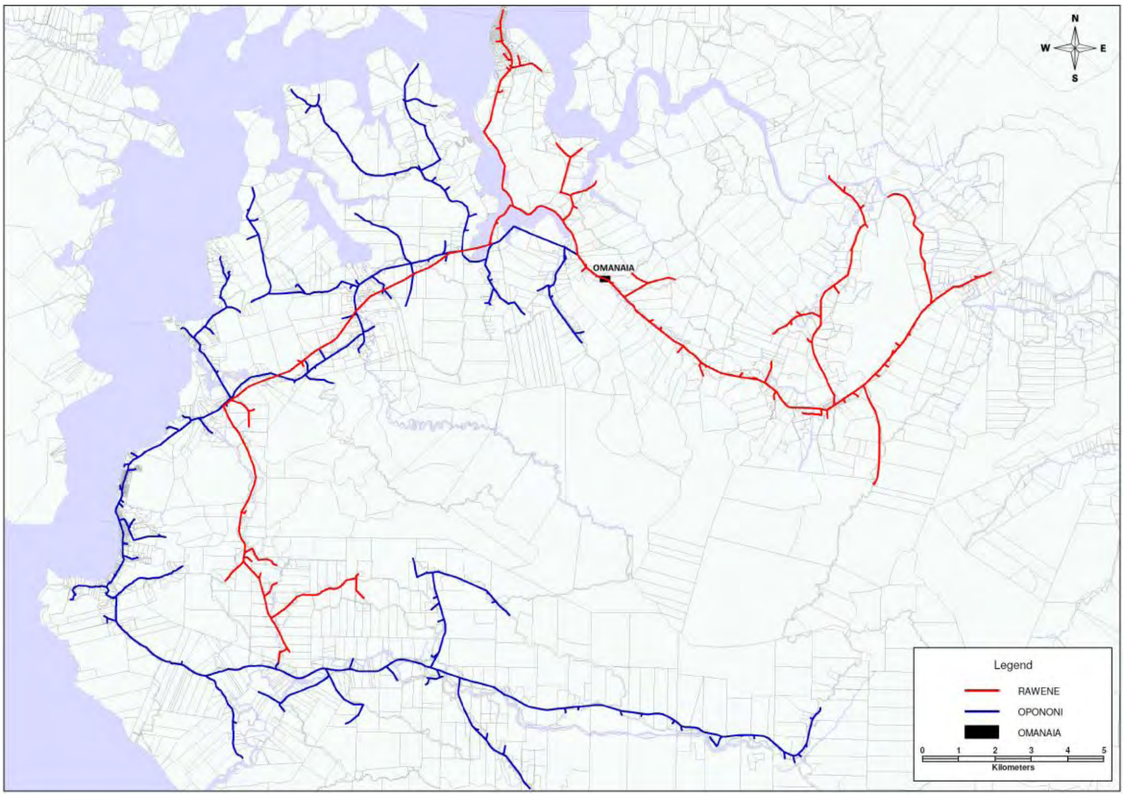


Figure 3.11: **Geographic diagram of the Omanaia zone substation**

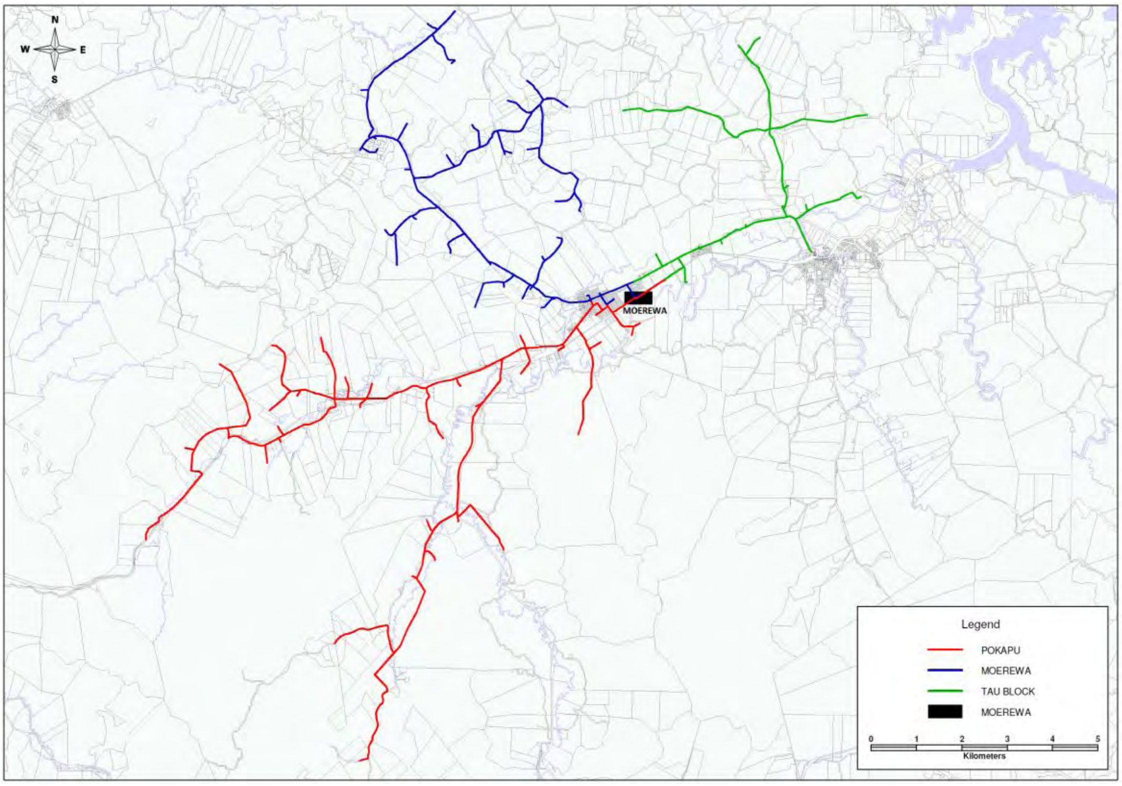


Figure 3.12: Geographic diagram of the Moerewa zone substation

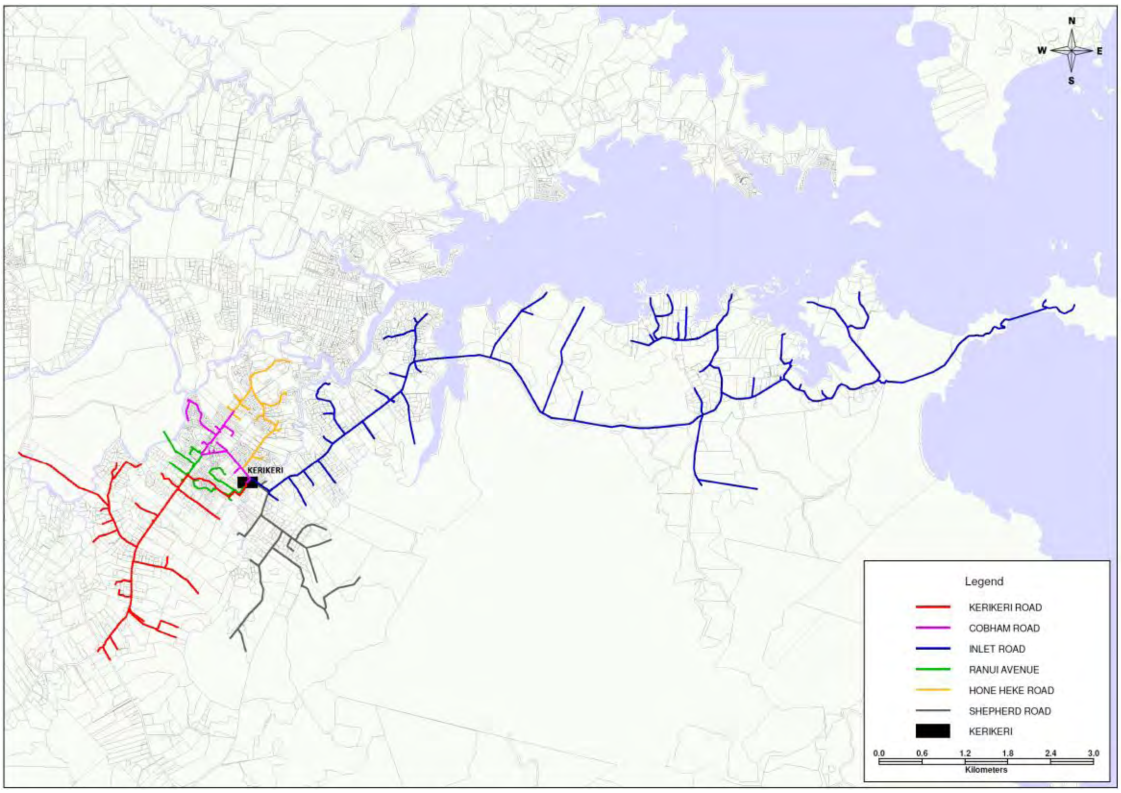


Figure 3.13: Geographic Diagram of the Kerikeri Zone Substation

Over 35% of our lines were originally 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 to 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, to the extent that continuing to supply many sparsely populated rural areas is not economic. However, 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, where 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), criteria based on an independent analysis of network costs undertaken by the then Ministry of Economic Development.

Based on our own review of our distribution network in November 2013 using the above criteria, 35% by length of our 11kV distribution network, serving just 9% of connected consumers, is potentially uneconomic. These lines are generally located in the more remote and rugged parts of the supply area, where maintenance costs per kilometre of line are higher, so it is likely that more than 50% of maintenance expenditure on the 11kV network is required only to ensure that supply is maintained to just 10% of consumers. Funding this cross subsidy is a significant burden on the remaining 90% of consumers and has created the current situation where underinvestment has left a network that is not capable of providing reliability that is taken for granted in other parts of the country.

Figure 3.14 shows the potentially uneconomic parts of our 11kV distribution network.

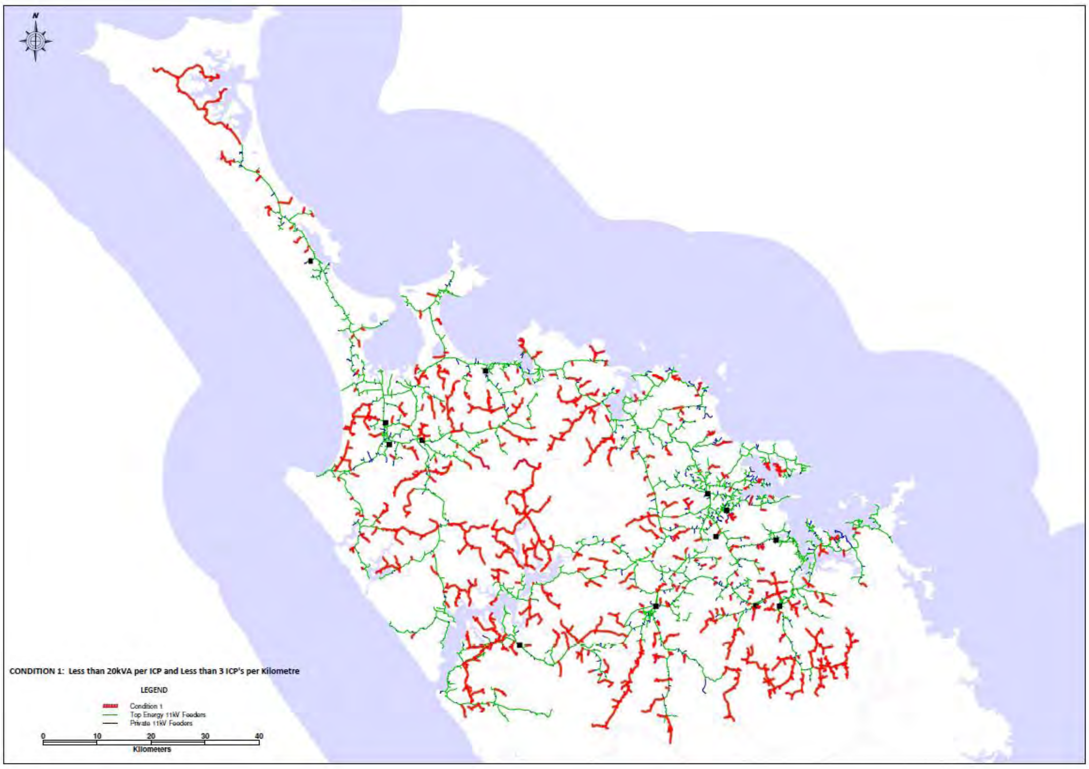


Figure 3.14: Uneconomic Segments of the 11kV Distribution Network

3.1.8 Secondary assets

3.1.8.1 Protection

We use a mixture of protective devices on our network including:

- electromechanical relays;
- numerical relays;
- integrated protective devices such as fuses, pole top reclosers and sectionalisers; and
- 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 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 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 the electromechanical protection relays in our zone substations and have also installed fibre-optic cable on most 33kV subtransmission lines so that on these lines we now have differential protection, which continuously compares the current entering and leaving a particular circuit and can thus operate more effectively in situations where the fault current is low. This allows the subtransmission lines and transformers at a particular substation to be operated in parallel, so that a single subtransmission fault will not result in a supply interruption.

3.1.8.2 SCADA and communications

Our System Control and Data Acquisition (SCADA) system operates out of our network control room, which was relocated from Kaikohe to our Kerikeri office (along with all our engineering staff) in November 2015, and uses an iPower SCADA system to operate and monitor the network. The SCADA system has been extended to include operation of the two transmission substations.

The iPower SCADA system communicates with various relays and integrated protective devices either using the Abbey base station or by directly communicating to the devices using the various communication drivers available within the system. We use multiple communication protocols over our own VHF network and a leased UHF broadband network. Existing communications links are being replaced by fibre-optic cable, which also provides the signalling required by the new differential protection schemes.

There is a standby control room installed at the Ngawha power station.

3.1.8.3 Load control system

We own and operate static ripple control plants, and injection is at 317Hz onto 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 load control plants are used to manage demand by allowing the control of a range of load types, and in particular water heating, to actively manage our peak transmission charges and potentially defer capital investment on the network. The large number of receivers 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 in order to fully capture the potential benefits of demand management.

3.2 Asset Details by Category

In accordance with the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012, Top Energy disclosed that its regulated asset base was valued at $237,830,000 as at 31 March 2017; an increase of $13,279,000 since 31 March 2016. This total was derived as shown in Table 3.4 and reflects the value of the assets commissioned in FYE2017 as part of our network development programme.

	$000
Asset Value at 31 March 2016	**224,551**
Add:	
New assets commissioned	16,730
Indexed inflation adjustment	4,864
Less:	
Depreciation	8,307
Asset disposals	7
Asset value at 31 March 2017	**237,830**

Table 3.4: Value of System Fixed Assets

The asset value shown in Table 3.4 is the value of our regulatory asset base, as measured for 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 because different valuation rules are applied and also because the regulatory asset base includes assets such as the land and buildings (such as substation control buildings), which form an integral part of the network, but which are recorded under other asset categories in the Group financial accounts. Neither value includes works that are under construction but have still to be commissioned, which had a disclosed regulatory asset value of $6.8 million as at 31 March 2017.

Table 3.5 disaggregates the value system fixed assets shown in Table 3.4 into its main asset categories.

	$000
Transmission / subtransmission lines	52,806
Subtransmission cables	9,039
Zone substations	38,050
Distribution and low voltage lines	47,791
Distribution and low voltage cables	36,917
Distribution substations and transformers	27,786
Distribution switchgear	16,193
Other network assets	5,199
Non-network assets	4,048
Total	**237,830**

Table 3.5: Disaggregated Value of System Fixed Assets as at 31 March 2017

3.3 Transmission Assets

Our transmission assets include transmission substations at Kaikohe and Pamapuria, 10km east of Kaitaia, and a single circuit 110kV transmission line between the two substations that is almost 56km long. The transmission line has a mixture of wood and concrete pole structures, except for sections over difficult terrain, including the Maungataniwha Range, which have steel towers. Each substation has two 110/33kV power transformers, three of which are single phase banks, while the new transformer at Pamapuria is a three-phase unit.

The 110kV substation switchyards and the 33kV switchyard at Kaitaia are all outdoor, with oil-filled circuit breakers. The 33kV switchyard at Kaikohe has been replaced by an indoor switchboard, which was commissioned in FYE2015.

3.3.1 Overhead Conductors

Information in our GIS database, based on data provided by Transpower, indicates that the overhead conductor on the Kaikohe-Kaitaia line was commissioned in 1983. However, this is after the commissioning of the Okahu Rd substation, which was constructed in 1979 and supplied from 110/33kV transformers at Pamapuria. The Pukenui substation control room was constructed in 1976, which likely coincided with the installation of the 33kV transformer[3]. It is therefore probable that the conductor is up to 10 years older than indicated in the GIS. Anecdotal evidence provided by former Bay of Islands Electric Power Board staff supports this.

There is a total circuit length of 56km coyote transmission conductor, all of which is on the Kaikohe-Kaitaia line. Based on a recent condition assessment, it is anticipated that the conductor will require replacement about 2030.

3.3.2 Poles and Structures

There are 288 twin pole structures, utilising both wood and concrete poles, and 13 steel towers on this line. As discussed in Section 6.3.1.2, the caged steel tower foundations and some non-critical tower members are badly corroded and are scheduled for upgrading or replacement. Many of the older wooden poles are also in poor condition. It appears that some of the wood poles on this line were second hand when initially installed. There was a major refurbishment in 1991-92, when Transpower replaced many older wooden poles with concrete.

The steel towers, which are not shown on the age profile, were installed in 1966 and originally operated at 50kV. Just prior to Christmas 2014 we discovered a land slip on the top of the Maungataniwha Ranges, which caused one of these towers to move almost 10 metres and some of the tower members to break. We were fortunate the damage did not result in a supply interruption, which would have impacted all consumers in our northern area and lasted some days until generators were brought in to restore supply. As it was, we were forced to have two planned day long interruptions within the space of two months to undertake repairs.

3.4 Subtransmission and Distribution Assets

The age profiles in this section use the asset information recorded in our GIS asset database. This database was created in the mid-2000s when the GIS system was installed, and asset ages were estimated where there were no installation records or other evidence (such as a nameplate or year of manufacture stamped on a concrete pole). A default installation date, such as 1970, was often assigned and this is evident in many profiles.

3.4.1 Overhead conductors

Overhead conductors are split into three categories; subtransmission (33kV), distribution (22kV & 11kV) and low voltage (400V).

The types of overhead conductor known to be installed on our network include a mixture of imperial and metric sized conductors of the following types:

- All Aluminium Alloy (AAA);
- Aluminium Conductor Steel Reinforced – ACSR;
- Hard Drawn All Aluminium Conductors – AAC;

---

[3] Pukenui was originally a government owned GXP supplied at 50kV but was transferred to the Bay of Islands Electric Power Board and operated at 33kV when the 110/33kV transformers were installed at Pamapuria.

- Bare Hard Drawn Copper;
- PVC Insulated Copper (LV); and
- Galvanised Steel Wire.

The network is close to the sea in many locations, where salt content in the atmosphere causes corrosion of ACSR conductor. To overcome this, we now use all aluminium alloy conductor (AAAC) on new transmission and subtransmission lines.

3.4.1.1 Subtransmission

Figure 3.15 shows the age profile of subtransmission overhead conductor, including the conductor on the Kaikohe-Wiroa line, which is currently energised at 33kV.

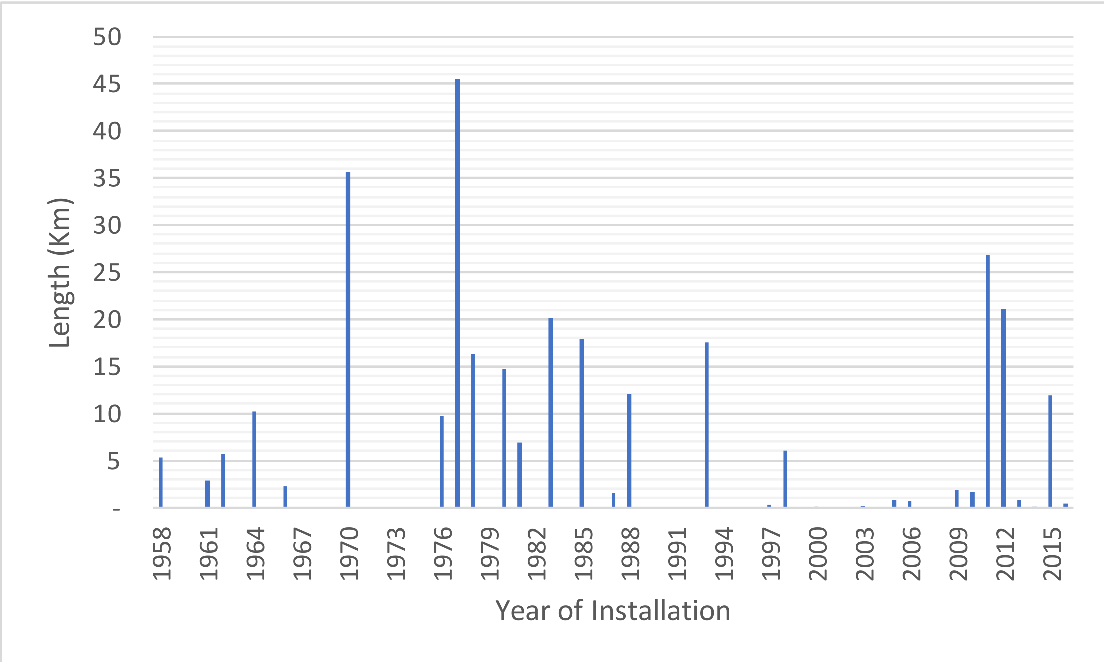


Figure 3.15: Age profile of subtransmission overhead conductors

There is a total of 297km circuit length of subtransmission overhead conductor, which is generally in an acceptable condition. Most of the conductor is AAC although conductor on the Kaikohe-Wiroa line is AAA. There is also 33.5km ACSR in areas where higher tensile strength is required.

3.4.1.2 Distribution

Figure 3.16 - 3.18 below shows the age profile of distribution overhead copper conductors.

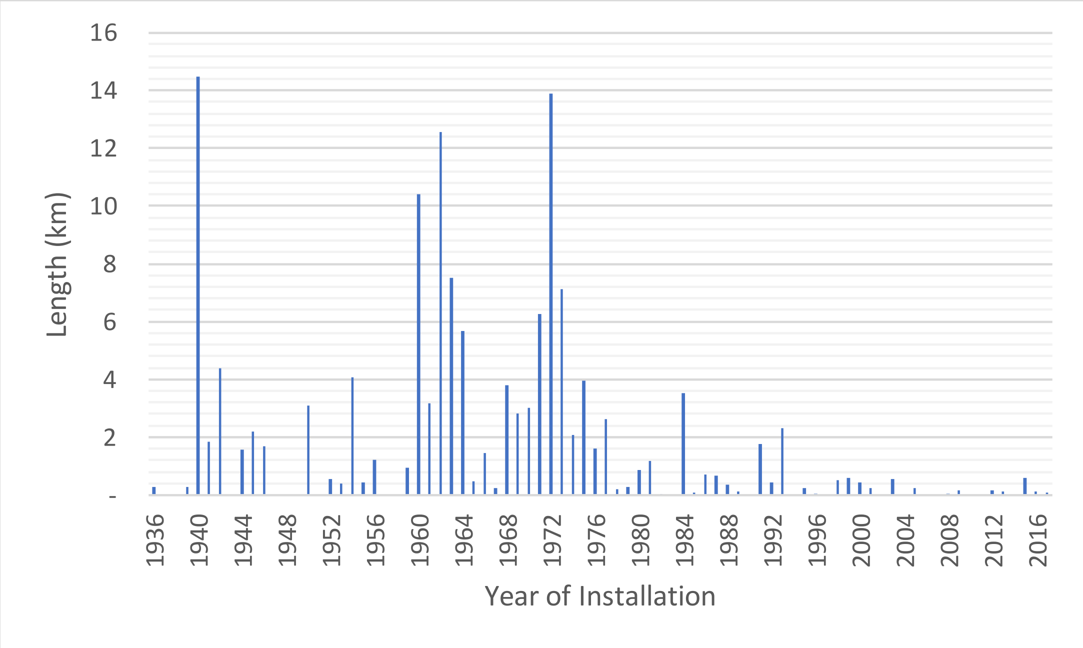


Figure 3.16: **Age profile of distribution overhead copper conductors**

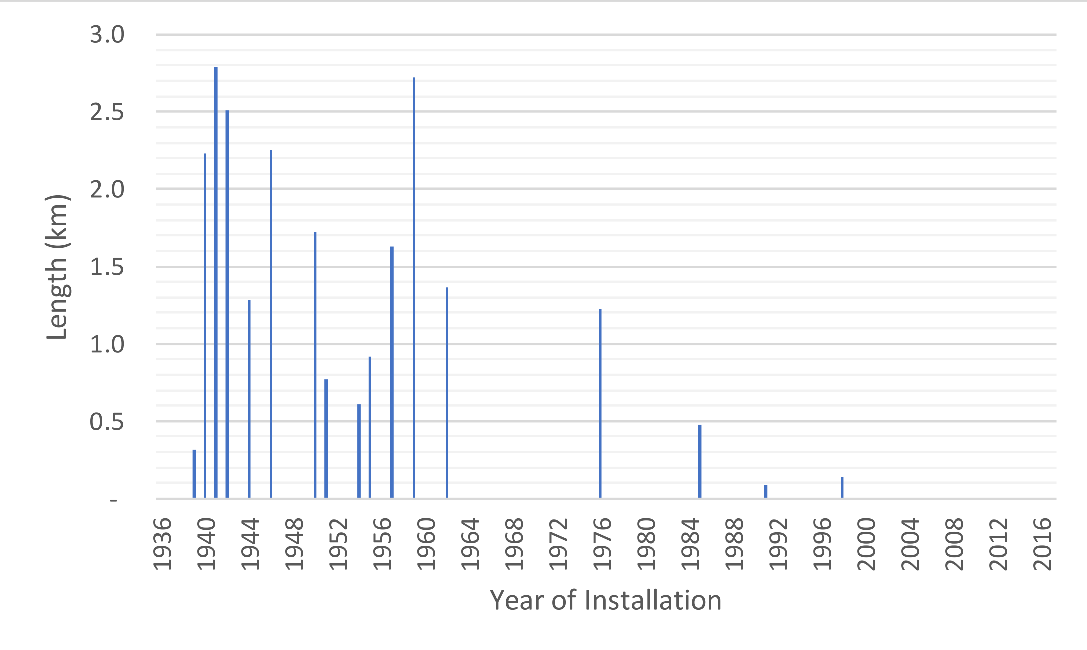


Figure 3.17: **Age profile of distribution overhead galvanised steel wire conductors**

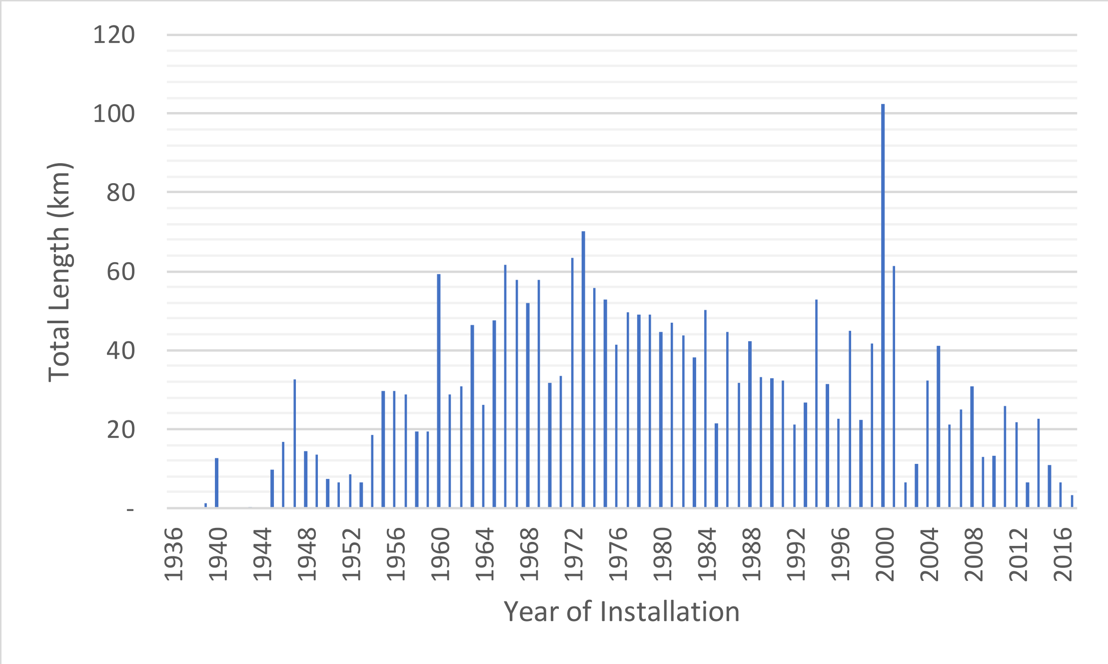


Figure 3.18: Age profile of distribution overhead aluminium conductor

There is a total of 2,597km circuit length of distribution overhead conductor. Of this 23km (1%) is galvanised steel and 142km (6%) is copper. The condition of main feeder conductors is generally acceptable; however, some older small conductor is reaching the end of its life and will require replacement during the planning period.

3.4.1.3 Low Voltage

Figure 3.19 and Figure 3.20 below show the age profile of low voltage overhead conductors.

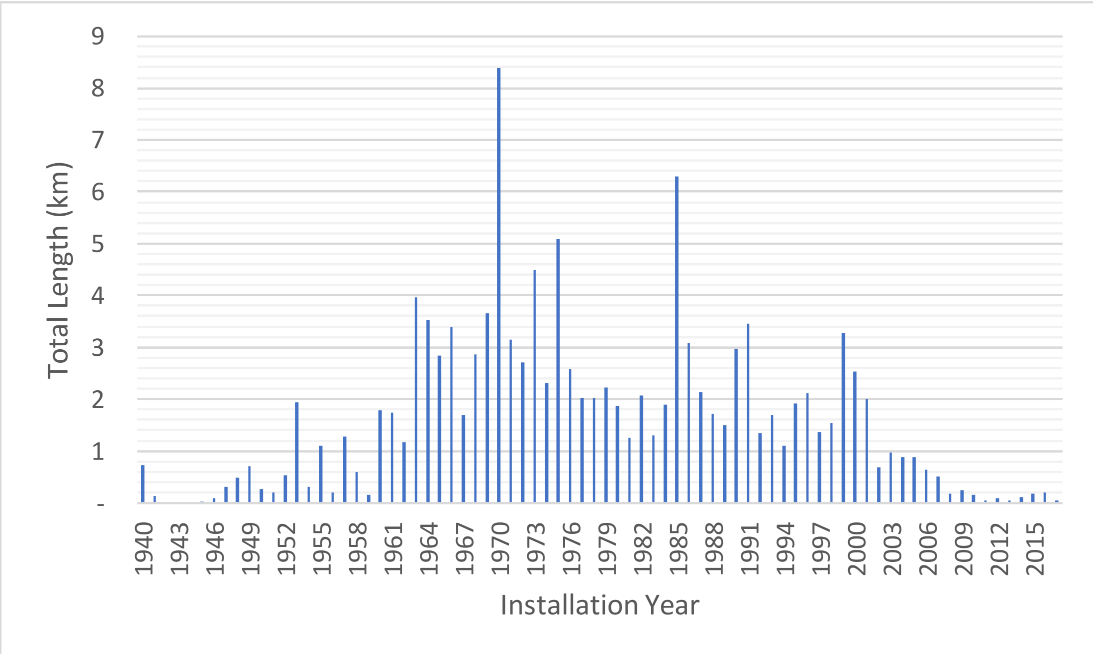


Figure 3.19: Age profile of low voltage overhead copper conductors

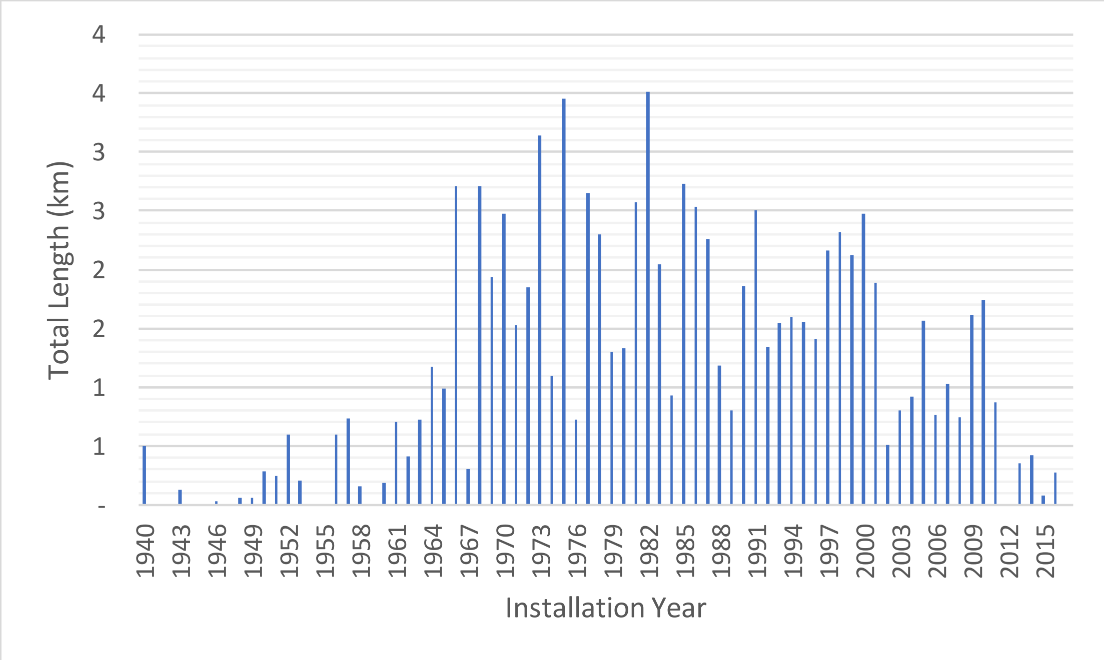


Figure 3.20: Age profile of low voltage overhead aluminium conductors

There is a total of 226km circuit length of low voltage overhead conductor. Of this 125km (56%) is copper conductor of various sizes and types, 90km (41%) is aluminium and the remaining 7km (3%) is of unknown type. The conductor is in average condition. The main problem is conductor clashing caused by vegetation. This is being targeted as part of the vegetation strategy described in Section 6. Replacement options for this conductor will be determined on a case-by-case basis, which could include the use of aerial bundled conductor or undergrounding.

3.4.2 Poles and Structures

Poles and structures are split into four categories: transmission, subtransmission, distribution and low voltage. Four types of poles and structures have been used: hardwood, softwood, steel, and concrete. We were an early adopter of concrete poles and hence the proportion of wooden poles on the network is not as high as on some networks. Wooden poles being phased out over a 10-year period for safety reasons. The pole assets for each voltage level are considered separately with a pole's voltage level determined by the highest voltage supported by it.

3.4.2.1 Subtransmission

Our subtransmission network has been built sporadically over the last 60 years and poles have been mainly concrete since the 1960s. Figures 3.21 and 3.22 show the age profile of our subtransmission poles, including those on the Kaikohe-Wiroa 110kV line, which is currently in service at 33kV.

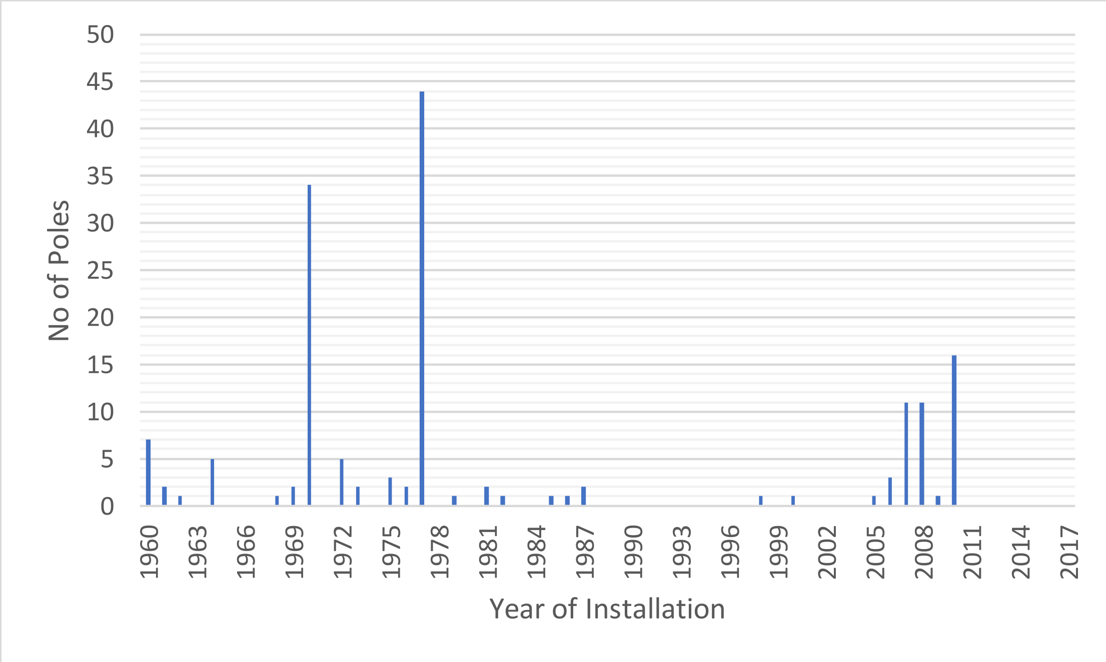


Figure 3.21: **Age profile of subtransmission wood poles**

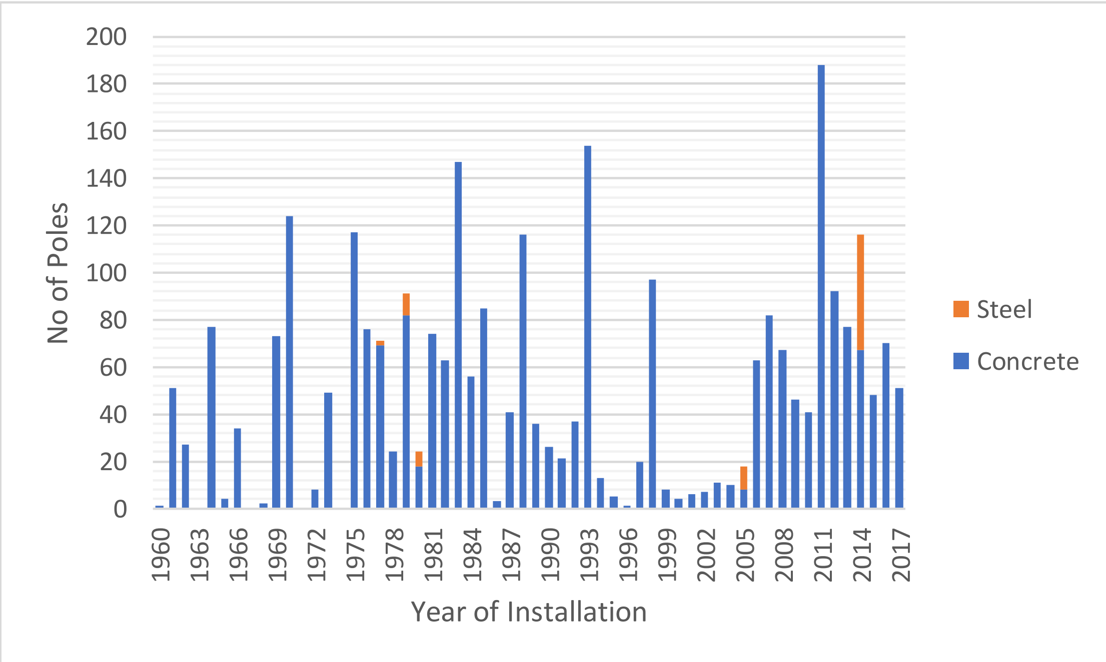


Figure 3.22: **Age Profile of Subtransmission Concrete and Steel Poles**

There are 3,014 subtransmission poles on our network (including those on the Kaikohe-Wiroa line), of which 92% are concrete 5% wood and 3% steel. The steel structures installed between 1977 and 1980 are on the Moerewa-Haruru line and are currently scheduled for replacement in FYE2019 and FYE2020.

3.4.2.2 Distribution

Figure 3.23 and 3.24 show the age profile of our distribution poles, as recorded in our GIS system.

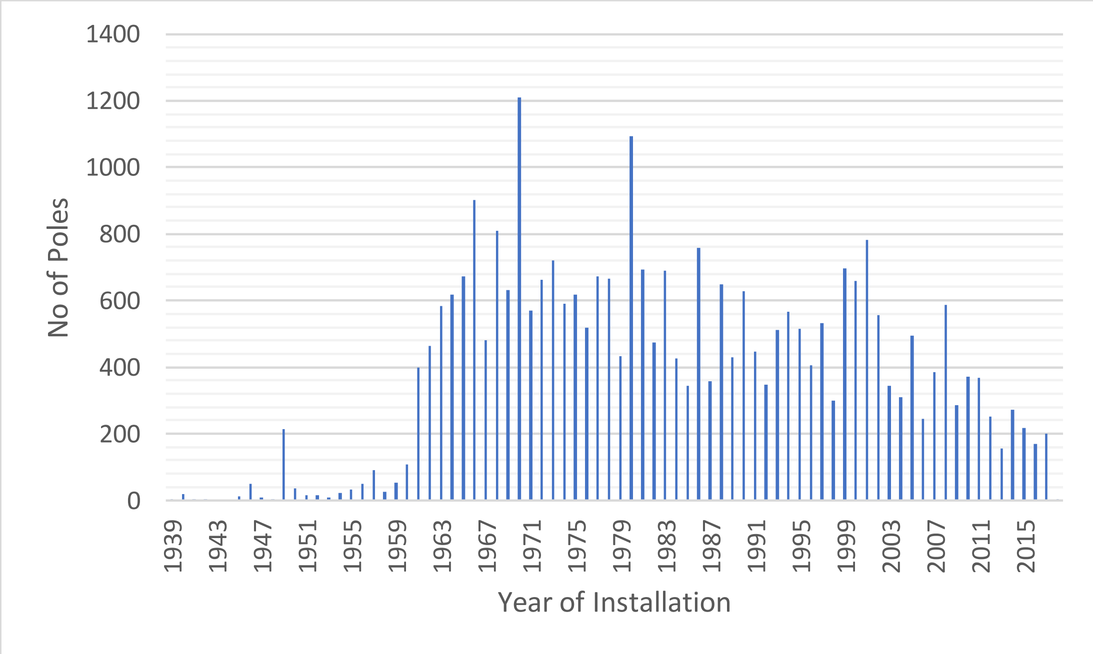


Figure 3.23 **Age profile of concrete distribution poles**

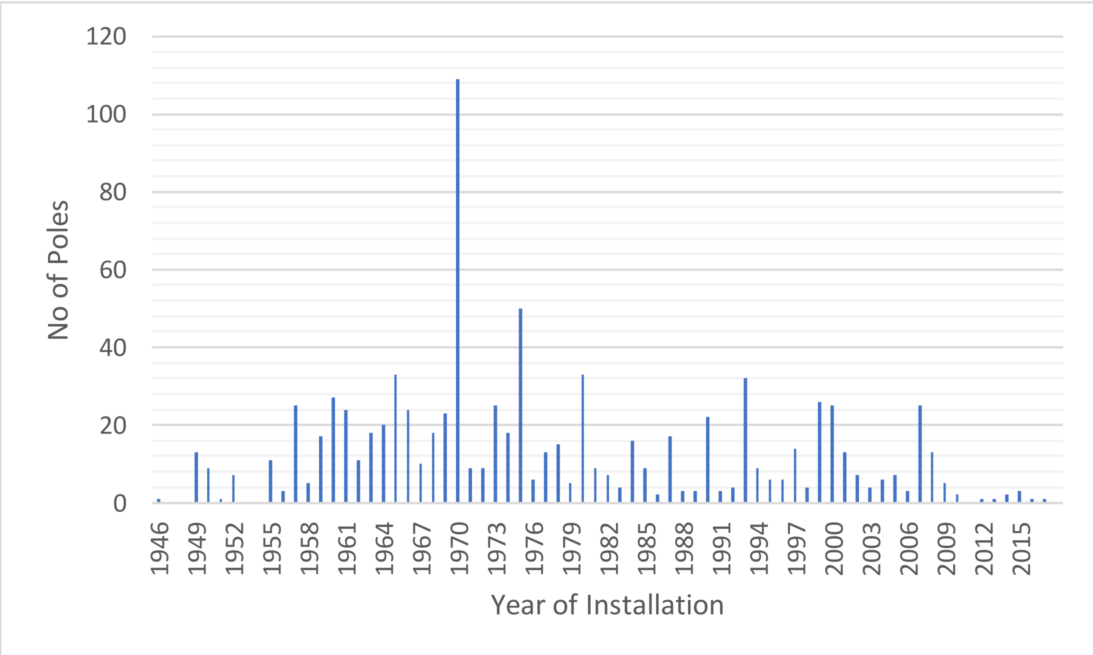


Figure 3.24: **Age profile of wood distribution poles**

There are approximately 31,400 distribution poles, of which more than 97% are concrete. Although our distribution poles are generally in good condition, there are any older wooden poles are on our SWER lines, which will be replaced by pre-stressed concrete poles over the next 10 years as part of our wood pole replacement programme.

3.4.2.3 Low Voltage

Figures 3.25 and 3.26 below show the age profile of low voltage poles.

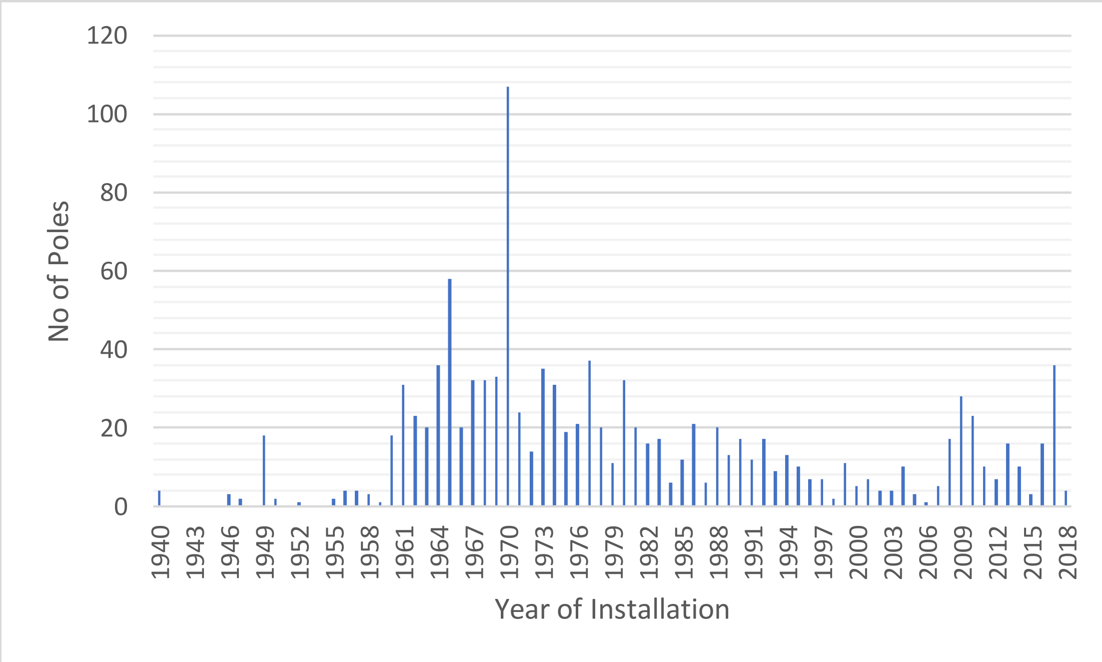


Figure 3.25: **Age profile of low voltage concrete poles**

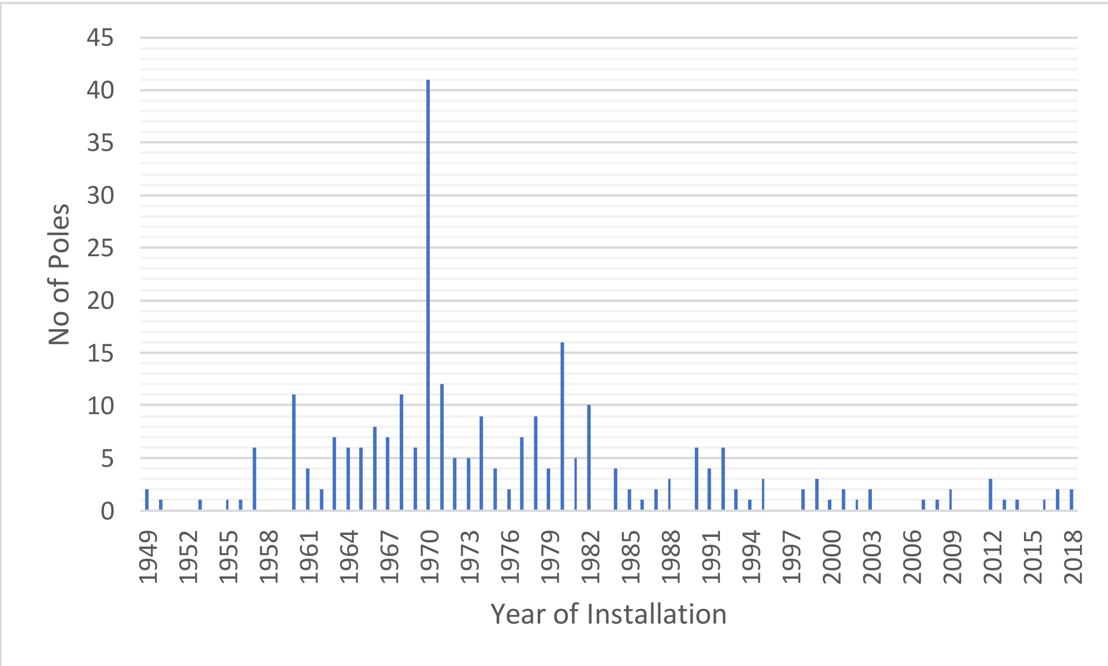


Figure 3.26: **Age Profile of low voltage wood poles**

There are over 1,400 low voltage poles, of which 81% are concrete. The condition of older assets will continue to be inspected on a regular basis and poles replaced as necessary.

3.4.3 Underground Cables

Similar to overhead lines, underground cables are split into three main categories: subtransmission, distribution and low voltage.

Cables used at 11kV, 22kV and 33kV are metric-sized single or three core cables that are either paper insulated lead covered (PILC) or cross-linked polyethylene (XLPE) insulated. However, at low voltage, we used imperial sized single core and metric 4 core PVC cables until 2008. We have now introduced the use of metric-sized single and four-core aluminium low voltage XLPE cables, which have replaced the single-core imperial PVC range.

3.4.3.1 Subtransmission

Our first subtransmission cable was 0.5km of 33kV Al cable (two circuits) exiting NPL substation, installed in FYE2001. In addition, a 0.2km length of cable exiting the Ngawha power station was installed in FYE2012 as part of the second 33 kV circuit between Ngawha and Kaikohe. More recently, underground cables were installed to supply the Kerikeri zone substation. All cables are aluminium conductor, XLPE insulated, and in good condition.

There is currently a total of 20km of subtransmission cable in service, most of which supplies Kerikeri substation.

3.4.3.2 Distribution

Figure 3.27 below shows the age profile of distribution underground cables.

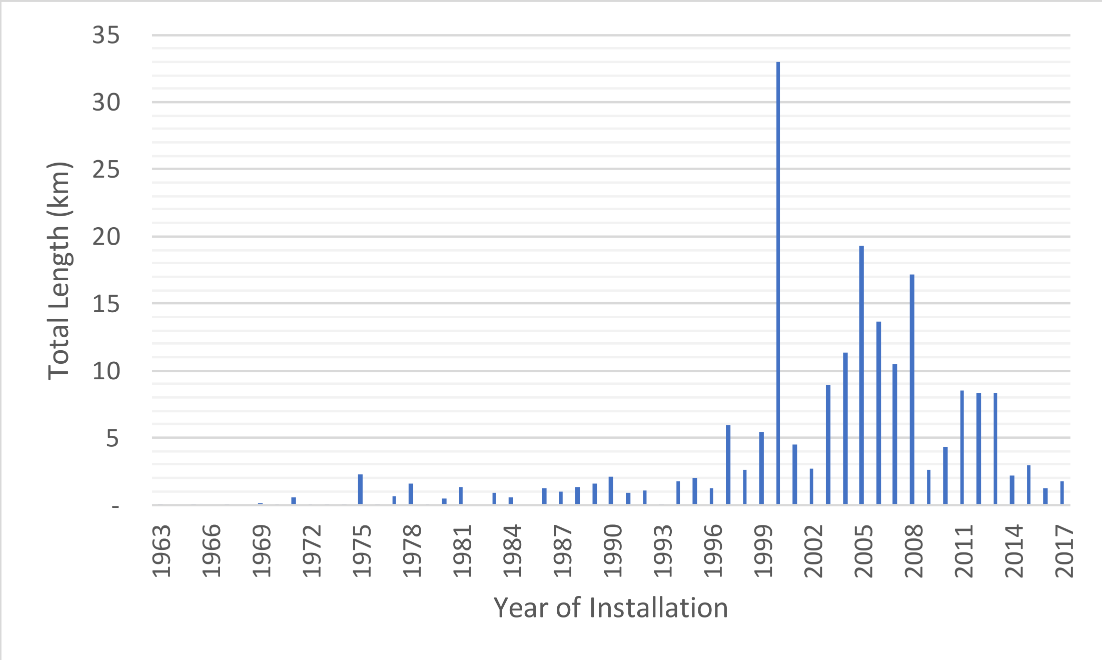


Figure 3.27: Age profile of distribution underground cables

There is a total of 198km of distribution underground cable, which is generally in good condition, with 61% of the in-service cable being 15 years old or less. Historically, we have experienced, on average, one high voltage cable fault every 3 to 5 years, with the majority of these being joint failures or third-party damage. This is reflective of both the limited amount and young age of our underground distribution system. Ongoing monitoring of system loadings and fault trends will continue through the planning period.

3.4.3.3 Low Voltage

Figures 3.28 and 3.29 below show the age profile of low voltage underground cables.

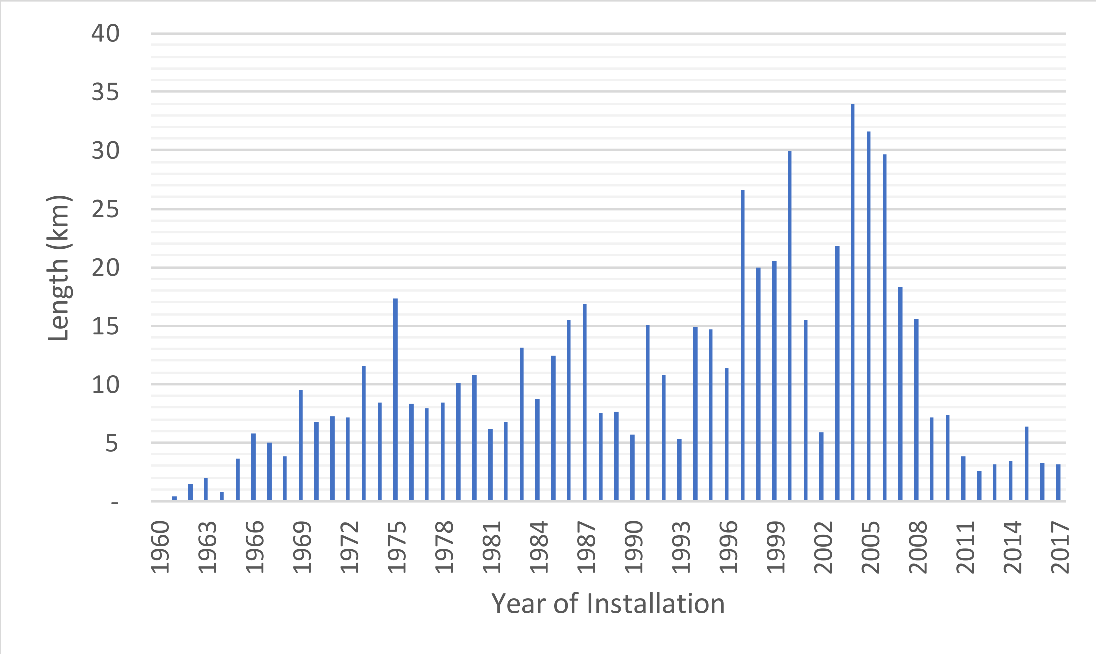
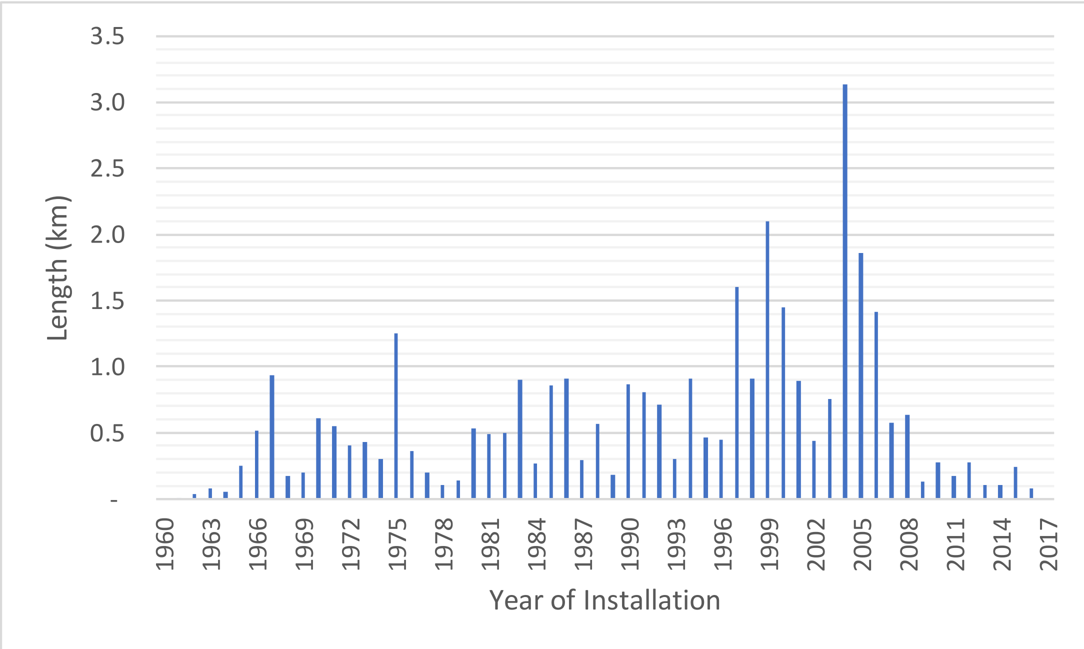


Figure 3.28: **Age profile of low voltage aluminium cables**



,

Figure 3.29: **Age profile of low voltage copper cables**

There is a total of 657km of low voltage underground cable, which is in average condition. We have used underground cable for many years, particularly in urban areas and for road crossings in rural areas, and there is now almost three times and much low voltage underground cable on the network as there is low voltage overhead conductor. The majority of our low voltage cable (94%) uses aluminium conductor, with only 5% being copper cable of various types and 1% unknown. Ongoing monitoring will continue to identify any developing fault trends.

3.4.3.4 Submarine Cables

We own 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 43 years of its nominal 70-year economic life.

The second cable is across the Veronica Channel between Opua and Okiato Point and is a single circuit 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.

3.4.3.5 Streetlight Conductor and Cable

Street light cable (327 km) has not been included in the above. In general, this cable has ample life remaining and should not require significant maintenance during the planning period. A strategy for dealing with street lighting in the longer-term, before maintenance becomes a significant issue, will be developed in conjunction with the light owners.

There is also approximately 10 km of overhead streetlight conductor in the asset base.

3.4.4 Distribution, Step-up and SWER Transformers

The age profiles of our in-service distribution and SWER isolating transformers are shown in Figure 3.30-Figure 3.32 below.

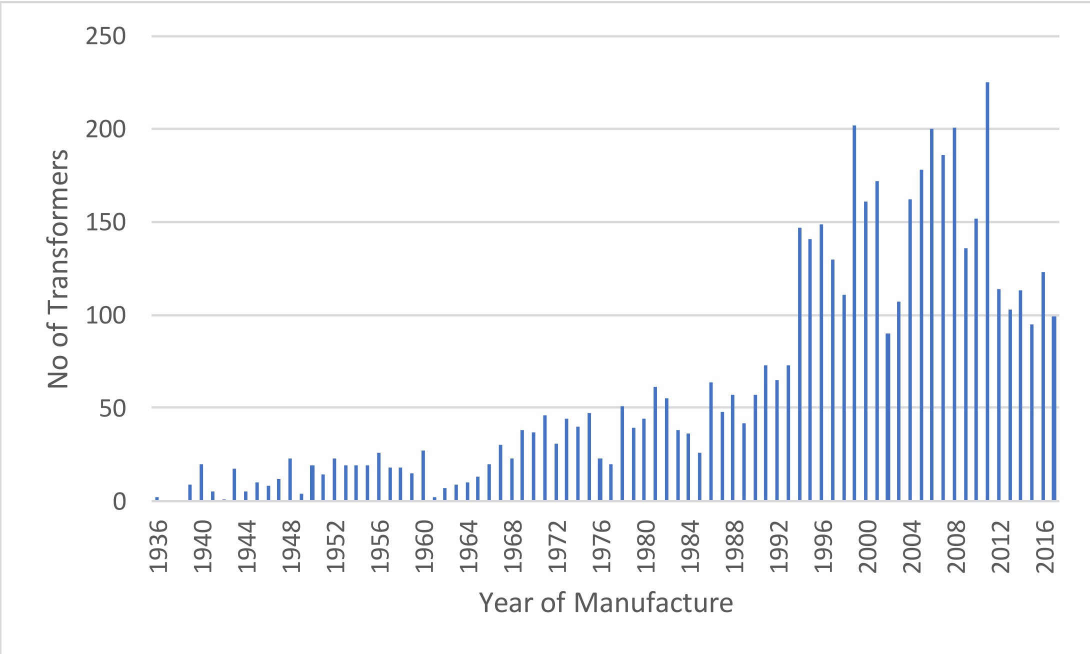


Figure 3.30: Age profile of pole mounted distribution transformers (all capacities)

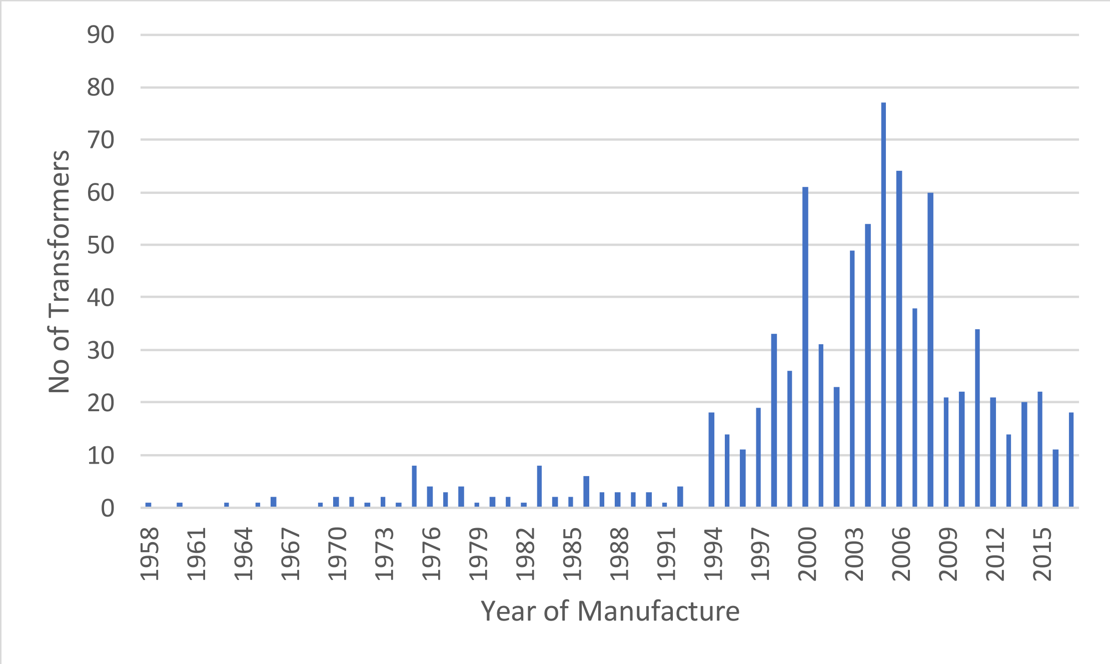


Figure 31: Age profile of ground mounted distribution transformers (all capacities)

There are approximately 5,100 pole-mounted and 840 ground-mounted distribution transformers of various capacities on the network, with a total capacity of 265MVA. While a small number of transformers installed prior to 1940 are still in service, the fleet is relatively young with over 61% being less than 20 years old.

In general, our transformer population is in average condition. We consider the most appropriate strategy for the management of smaller distribution transformers to be one of 'run to failure'. However, transformers that are deemed upon inspection to pose a risk to persons' safety, the environment or property are proactively replaced.

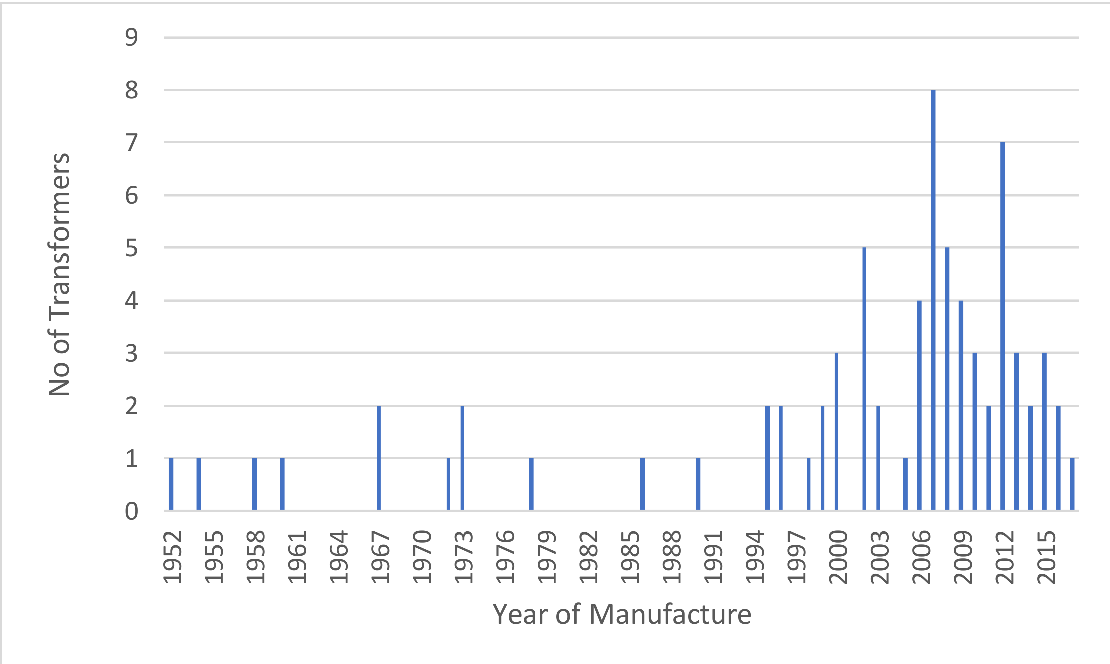


Figure3.32: Age profile of SWER isolating transformers (all capacities)

There are a total of 74 SWER isolating transformers, with the older units being in average condition. SWER transformers are managed on an individual basis, with replacement being driven largely by the need to increase the transformer capacity at a particular location. This has led to acceleration of the rate of replacement in recent years and 43% of the fleet is less than 10 years old.

The eight 11/22kV step-up transformers were installed in 2005 or later and are all in good condition.

3.4.5 Reclosers

Figure 3.25 below shows the age profile of reclosers on Top Energy's Network.

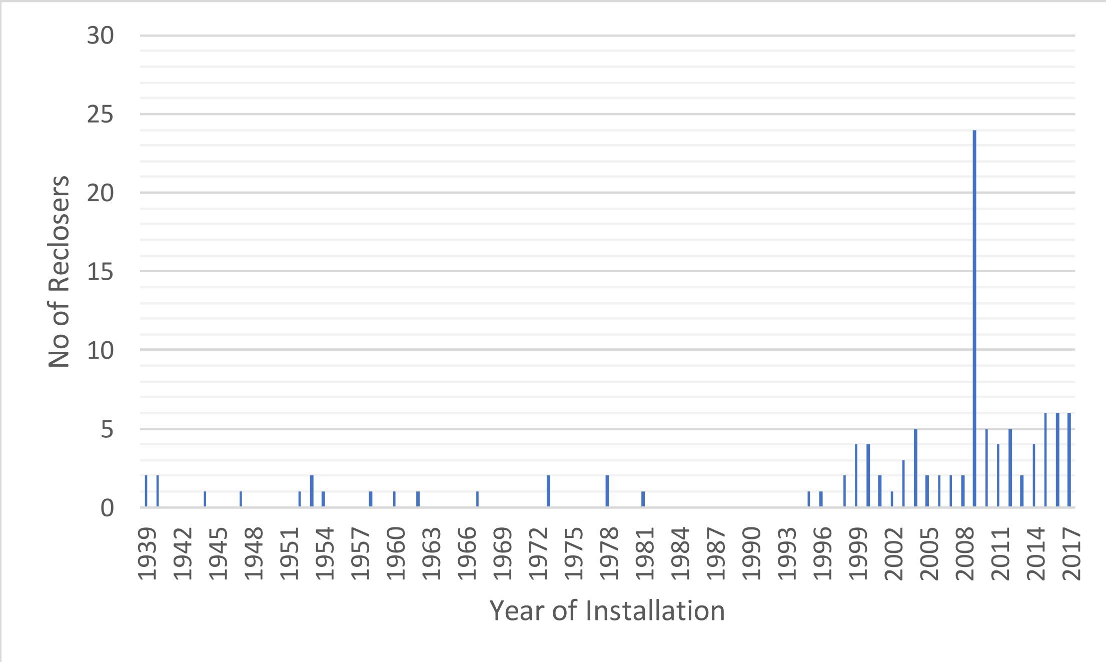


Figure 3.33: Age profile of reclosers

There are a total of 4 subtransmission and 112 distribution voltage reclosers on the network, about half of which (including all the subtransmission units) were installed as part the network automation project that commenced in FYE2008. The general condition of reclosers is good and an annual visual inspection is carried out to identify any maintenance or replacement requirements.

3.4.6 Voltage Regulators

There are a total of 27 single phase voltage regulators, arranged as six two-phase and five three-phase banks. The oldest was installed in 2002 and all are in good condition. An annual condition inspection is carried out to identify maintenance requirements.

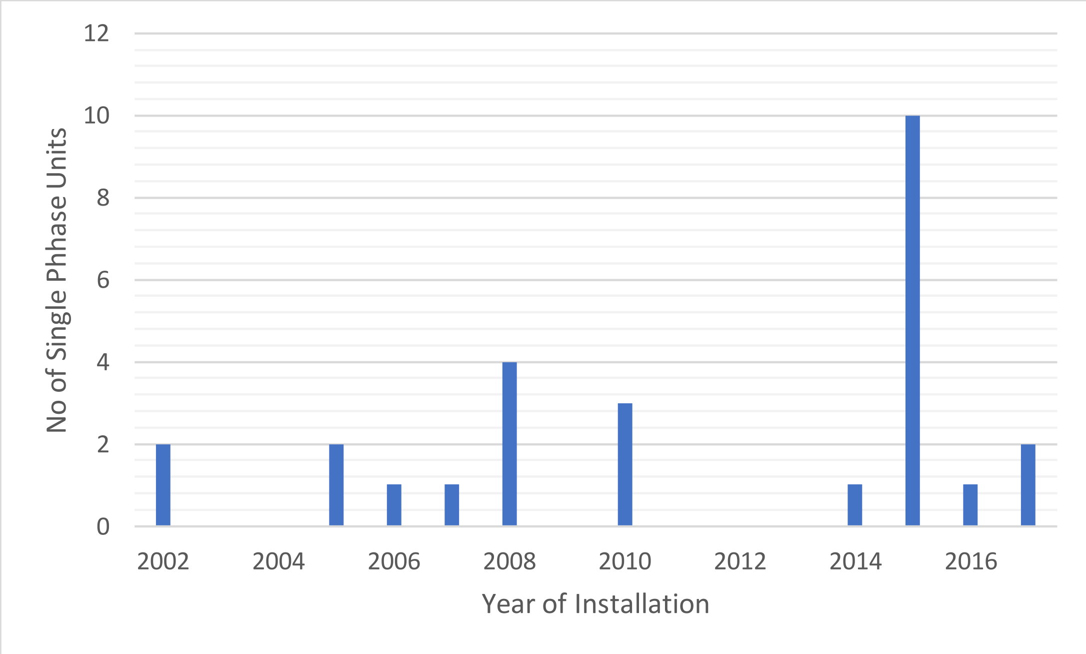


Figure 3.34: Age Profile of Voltage Regulators

3.4.7 Ring Main Units

Figure 3.35 below shows the age profile of ring main units (RMUs) on our network.

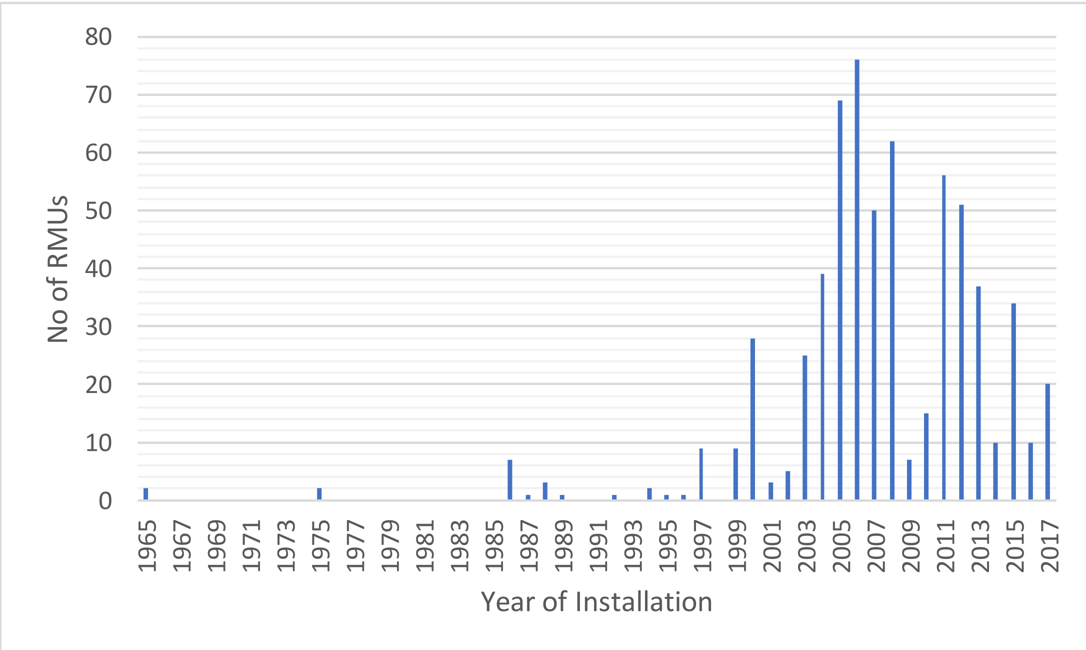


Figure 3.35: Age profile of ring main units

There are a total of 635 RMUs on our network. The condition of the older units is considered fair. A partial discharge issue has been discovered on the cable terminations of a small percentage of the population. Annual condition inspection together with partial discharge testing is carried out to identify replacement requirements. The RMUs are predominantly ABB SDAF units but these are now being phased out and new and replacement installations are non-oil filled units.

3.4.8 Sectionalisers

Figure 3.36 shows the age profile of sectionalisers on our network.

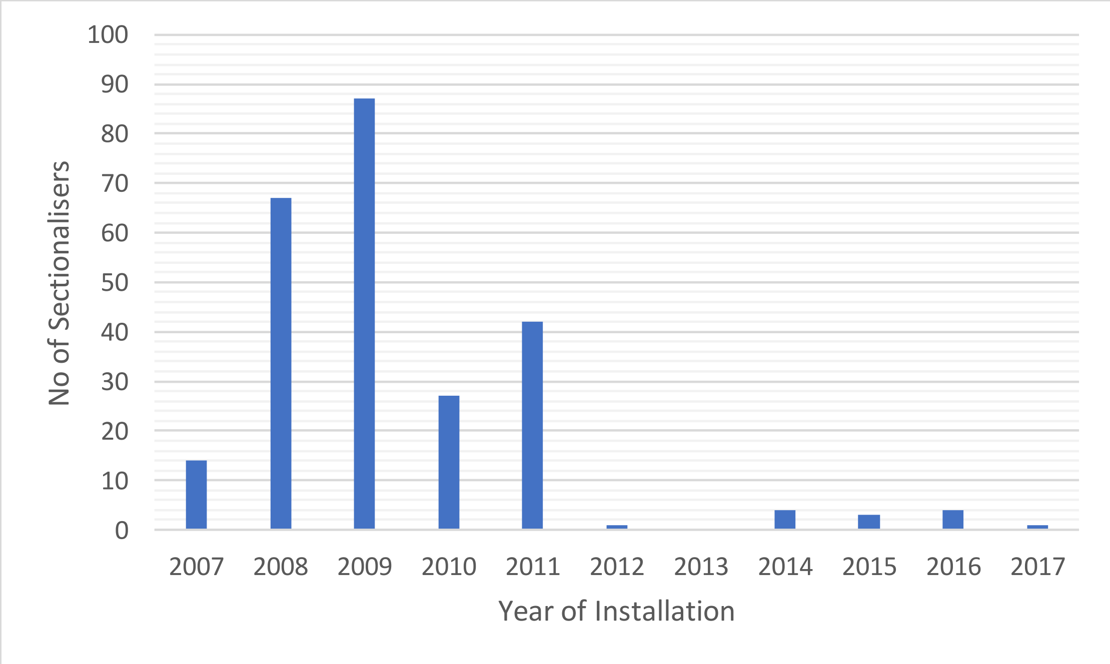


Figure 3.36: Age Profile of Sectionalisers

There are a total of 250 sectionalisers on our network, all of which are configured as remote-controlled switches. The oldest of these units were installed in 2007. They have been installed as part of the network automation project, allowing field switching of the network to take place remotely from the control room. This reduces the duration of supply interruptions by speeding up the location of faults and reconfiguration of the network, to restore supply to consumers not directly affected.

3.4.9 Air Break Switches

Figures 3.37 and 3.38 below shows the age profile of air break switches on our network.

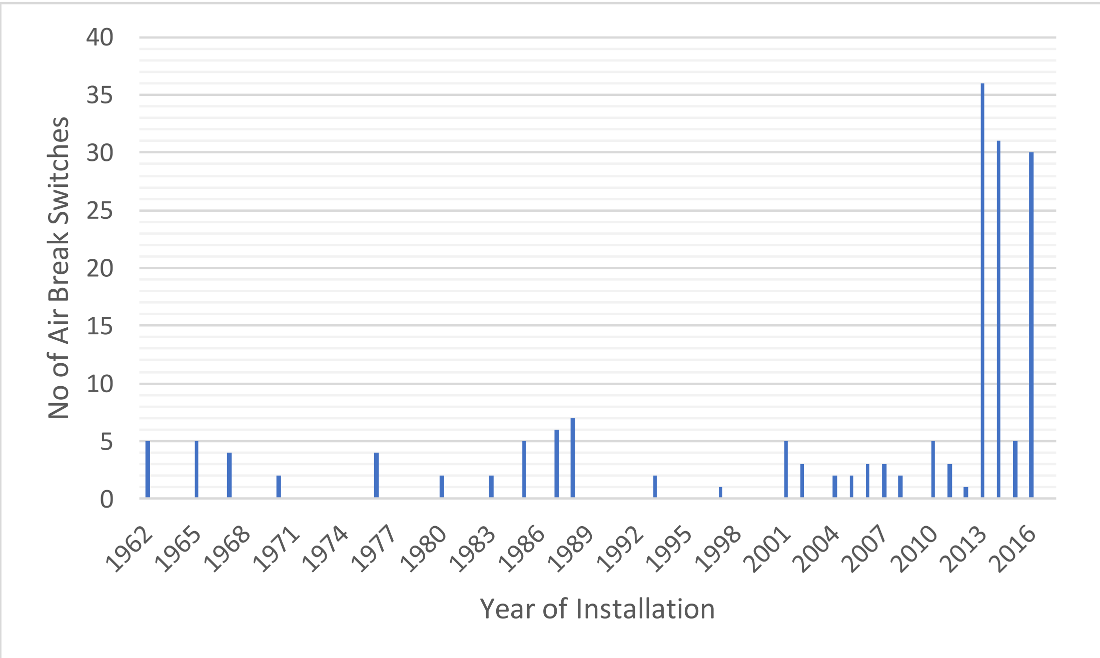


Figure 3.37: Age profile of subtransmission air break switches

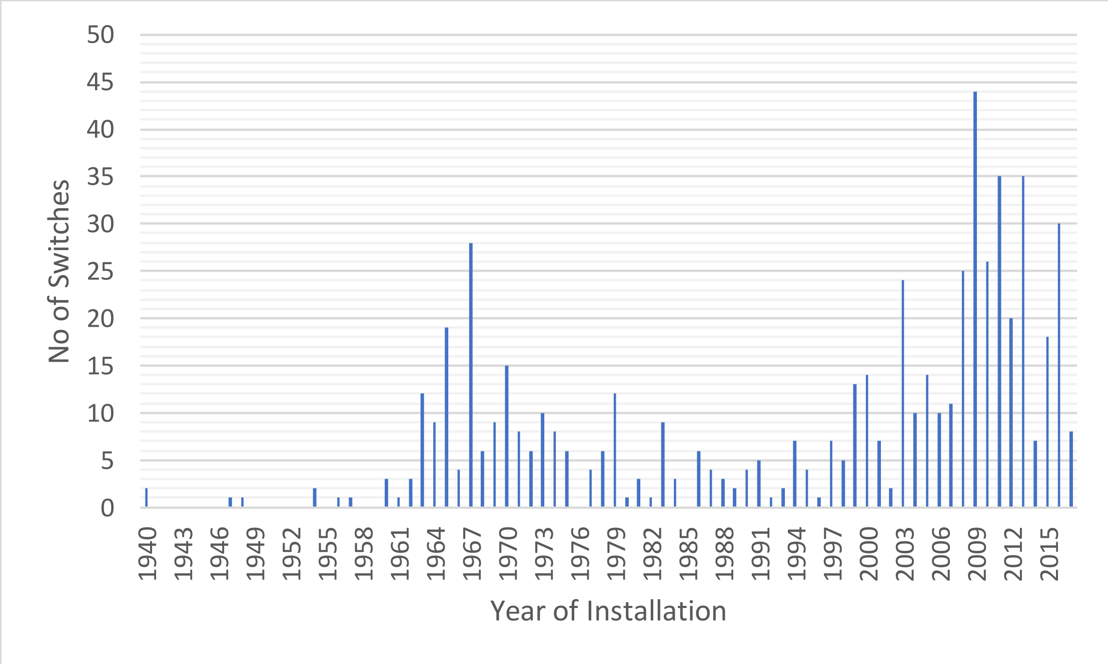


Figure 3.38: Age profile of distribution air break switches

There are a total of 775 switches on our network, of which 176 are subtransmission. We have a programme in place during the planning period to proactively replace older and unserviceable units. This is discussed in Section 6.12. New switches are vacuum break units rather than air break.

3.4.10 Capacitors

Figure 3.39 below shows the age profile of capacitors on our network

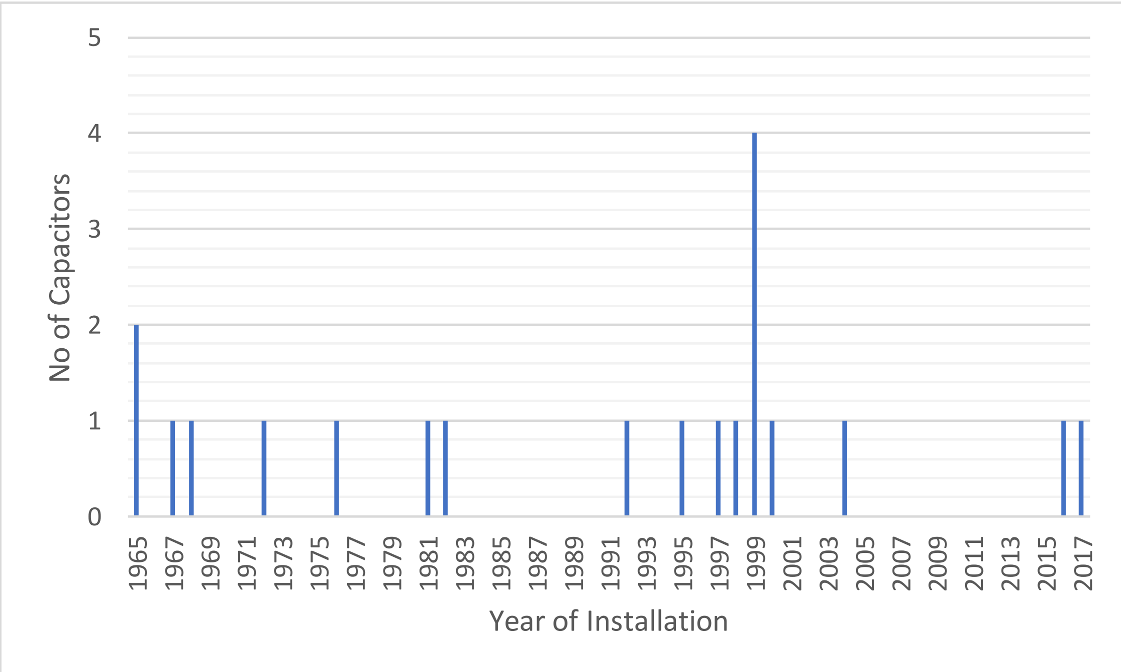


Figure 3.39 Age profile of capacitors

There are a total of 20 capacitors and they are in average-to-fair condition. Annual condition inspection is carried out to identify any replacement requirements.

3.4.11 Zone Substation Equipment

3.4.11.1 Power Transformers & Tap-changers

Table 3.6 below shows the details of power transformers located at our zone substations.

PRESENT SUBSTATION	UNIT	DESIGN RATING MVA	PRESENT RATING MVA	AGE[1]	DP
Southern					
Kaikohe	T1	11.5/23	17	49	518
Kaikohe	T2	11.5/23	17	49	531
Kawakawa	T1	5/6.5	6.5	57	730
Kawakawa	T2	5/6.5	6.5	57	511
Moerewa	T1	3/5	5	2	1200
Moerewa	T2	3/5	5	2	1200
Waipapa	T1	11.5/23	23	35	?
Waipapa	T2	11.5/23	23	35	?
Omanaia	T1	3/5	5	New	-
Haruru	T1	11.5/23	23	29	730
Haruru	T2	11.5/23	23	9	807
Mt Pokaka	T1	3/5	5	7	1200
Kerikeri	T1	11.5/23	23	3	1185
Kerikeri	T2	11.5/23	23	3	1130
Kaeo	T1	5/10	10	New	-
Kaeo	T2	5/10	10	New	-
Northern-					
Okahu Rd	T1	11.5	11.5	38	481
Okahu Rd	T2	11.5	11.5	38	614
Taipa	T1	5/6.25	6.25	52	527
Pukenui	T1	5/6.25	5	52	652
NPL	T1	11.5/23.0	23	30	709
NPL	T2	11.5/23.0	23	30	846
Mobile Substation					
Mobile Substation	T1	5/7.5	7.5	14	?

Note 1: As at 31 March 2018

Table 3.6: Power transformers installed at zone substations

The life expectancy of a power transformer is 60 years, where the transformer has not been heavily loaded and appropriate maintenance practices are in place. This applies to our fleet. The actual age at which a power transformer will be replaced will depend on its condition, loading, history and design; we expect that most of our transformers will last their full expected life.

Furan oil analysis has been used as a non-invasive indication of the degree of polymerisation (DP) of the transformer insulation. The remaining life of a transformer is assessed on the basis of these tests. The DP at start of a transformer's life is about 1,200 and at end of life around 150-200. Additional indications of cellulose degradation are levels of carbon monoxide (CO), carbon dioxide (CO_2) and the ratio of the two.

The DPs of all power transformers were measured during FYE2017, and the results are shown in Table 3.6 above.

3.4.11.2 Circuit breakers

a) Subtransmission circuit breakers

Figures 3.40 and 3.41 below show the quantities and age profile of the outdoor and indoor subtransmission circuit breakers installed within our zone substations.

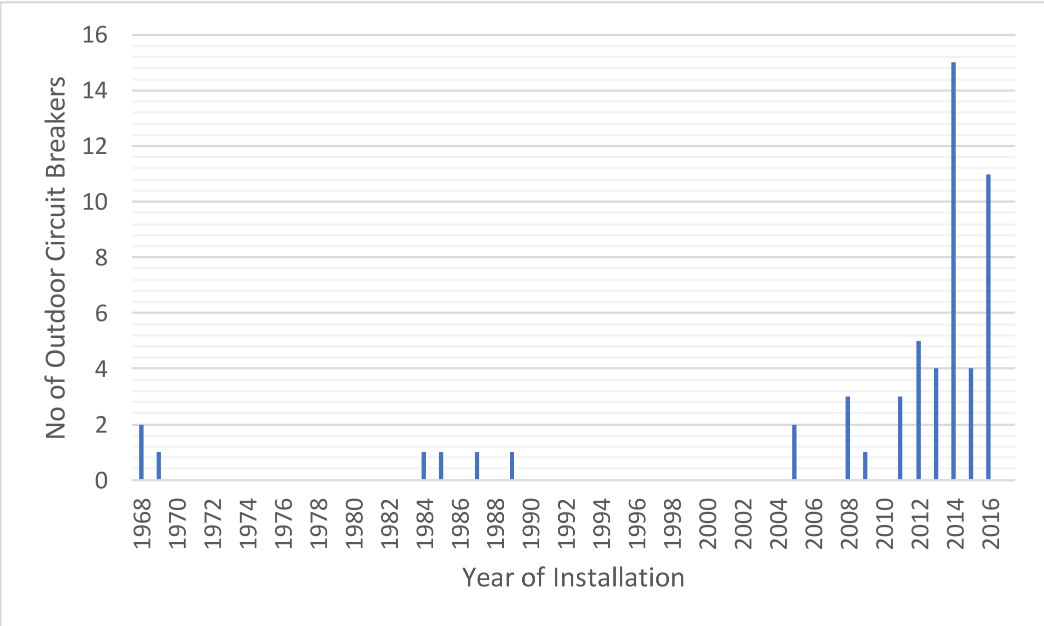


Figure 3.40: Age profile of outdoor subtransmission circuit breakers

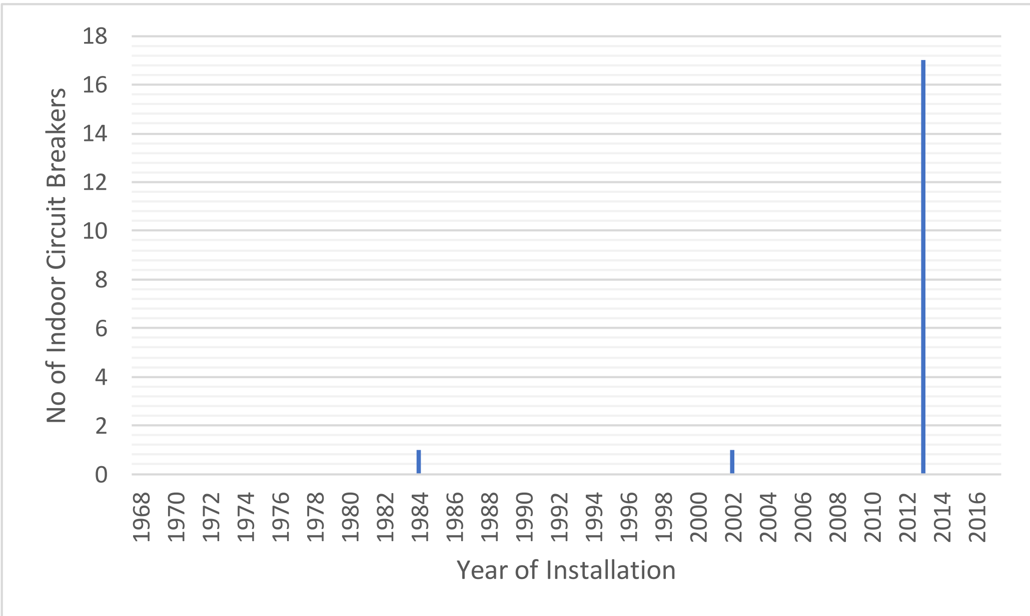


Figure 3.41: Age profile of indoor subtransmission circuit breakers

The oldest units are English Electric OKW3 minimum oil outdoor 33kV CBs. Minimum oil CBs are known internationally as having a major risk of failure if the maintenance programme is not rigorously followed. The first instance requiring replacement occurred in 2003 and a second replacement occurred in 2011. We have a programme in place to replace these units, generally with indoor switchboards, and have already completed replacements at Kaikohe and Moerewa substations. Until replacement of the remaining oil circuit breakers occurs, we will apply a strict maintenance regime on a 12-monthly cycle.

Circuit breakers that have been installed since 2002 all have vacuum interrupters.

b) Distribution Circuit Breakers

Figure 3.42 and 3.43 below show the age profile of 11kV distribution voltage circuit breakers presently in service on our network.

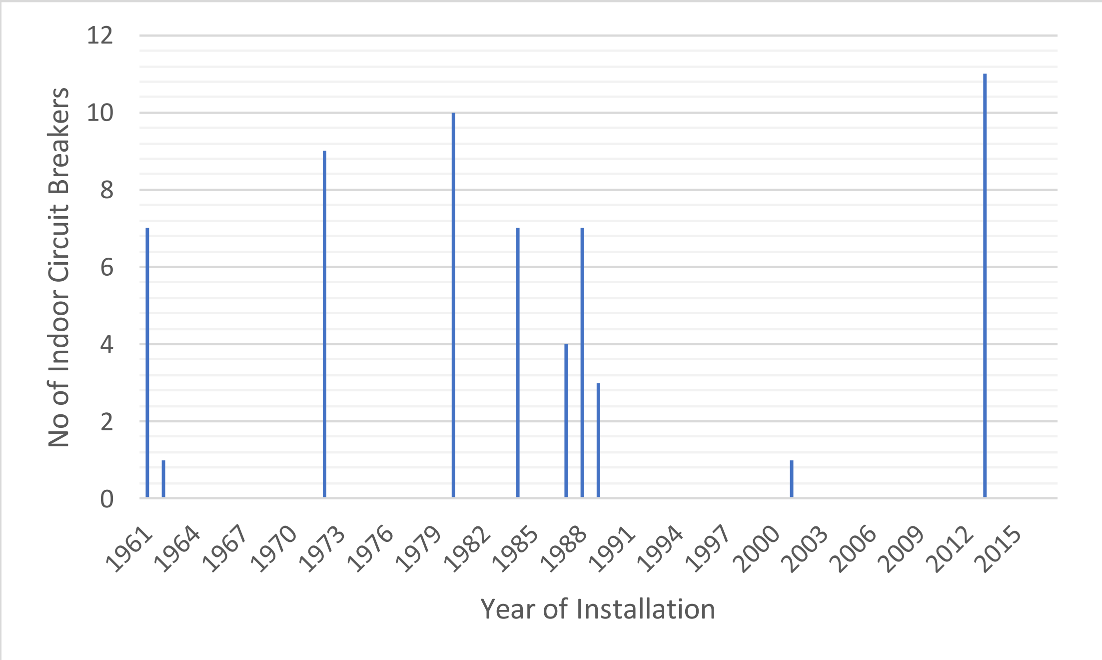


Figure 3.42: Age profile of indoor distribution voltage circuit breakers

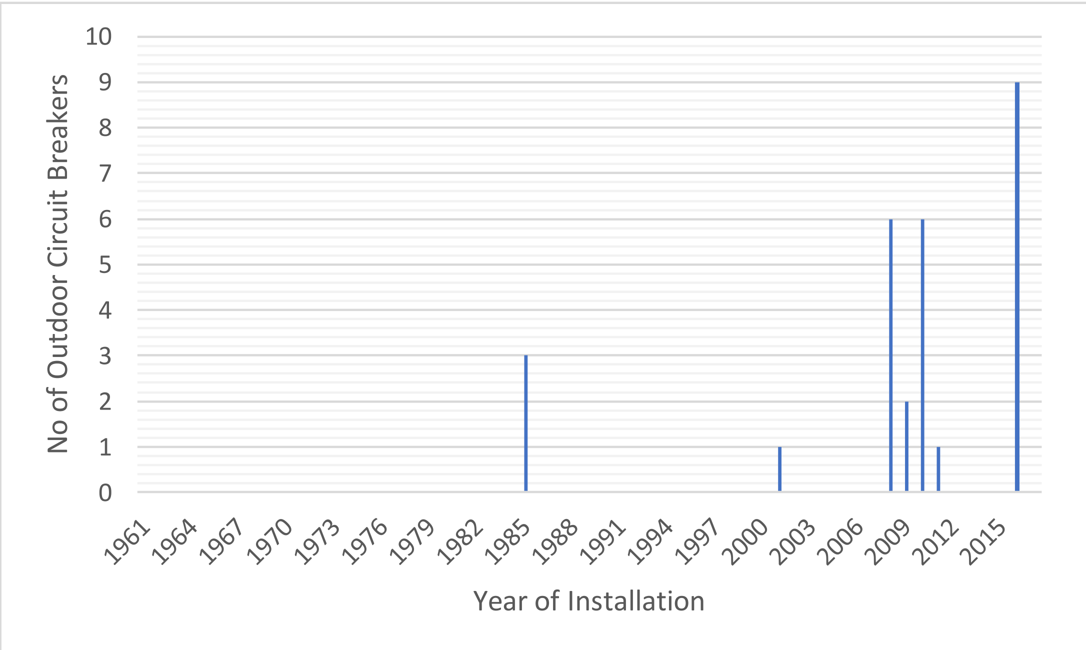


Figure 3.43: Age Profile of outdoor distribution voltage circuit breakers

The condition of these 61 indoor and 28 outdoor circuit breakers is considered sound, with a thorough testing and condition-based maintenance programme in place. While the low fault levels in the network increase the complexity of protection design, they have the advantage of extending the life of circuit breakers (and also reducing the risk of through-fault damage to power transformers).

3.4.11.3 Zone Substation Structures

Our outdoor structures, like overhead lines, have a long lifespan. Their condition is monitored visually and, because zone substation conductors carry relatively high currents, thermal imaging is used to check for deteriorating conductor connections. Because of the critical nature of the air insulated switches within substations, these are individually checked for correct operation every two years and maintained if necessary.

3.4.11.4 Zone Substation DC Systems

Each substation has two battery banks. We inspect and test the battery banks monthly and replace the whole bank at the end of its economic life.

3.4.11.5 Zone Substation Protection

At present, we have a variety of relay classes including electromechanical, solid state electronic and modern microprocessor relays.

We are progressively upgrading all zone substation protection relays, moving to a numerical type with improved discrimination and capable of data logging. We expect this to contribute to an improvement in supply reliability. The new relays will also log load and fault data, allowing for better network analysis and in turn service delivery. This will also assist in tariff and loss calculations, and the allocation of costs.

3.4.11.6 Zone Substation Grounds and Buildings

Our zone substation buildings are listed in Table 3.7 below.

SUBSTATION NAME	CONSTRUCTED
Kaikohe	1971
Kawakawa	1961
Moerewa	1970
Waipapa	1965
Omanaia	1983
Haruru	1988
Mt Pokaka	2010
Kerikeri	2013
Kaeo	2018
Okahu Road	1979
Taipa	1985
Pukenui	1976
NPL	1987

Table 3.7: Age profile of substation buildings

The buildings are all considered to be in reasonable condition, although maintenance such as roof repairs may be necessary on some buildings within the planning period. Regular building inspections and maintenance programmes ensure their ongoing utility.

3.4.12 Consumer Service Pillars

Consumer service pillars contain the fuses to protect/disconnect individual consumers from the LV supply network.

Figure 3.31 below depicts the age profile of consumer service pillars in service. There are 12,000 pillars installed on the network.

Consumer service pillars are generally allowed to run to failure, although any that are found to be damaged during routine asset inspections are repaired or replaced.

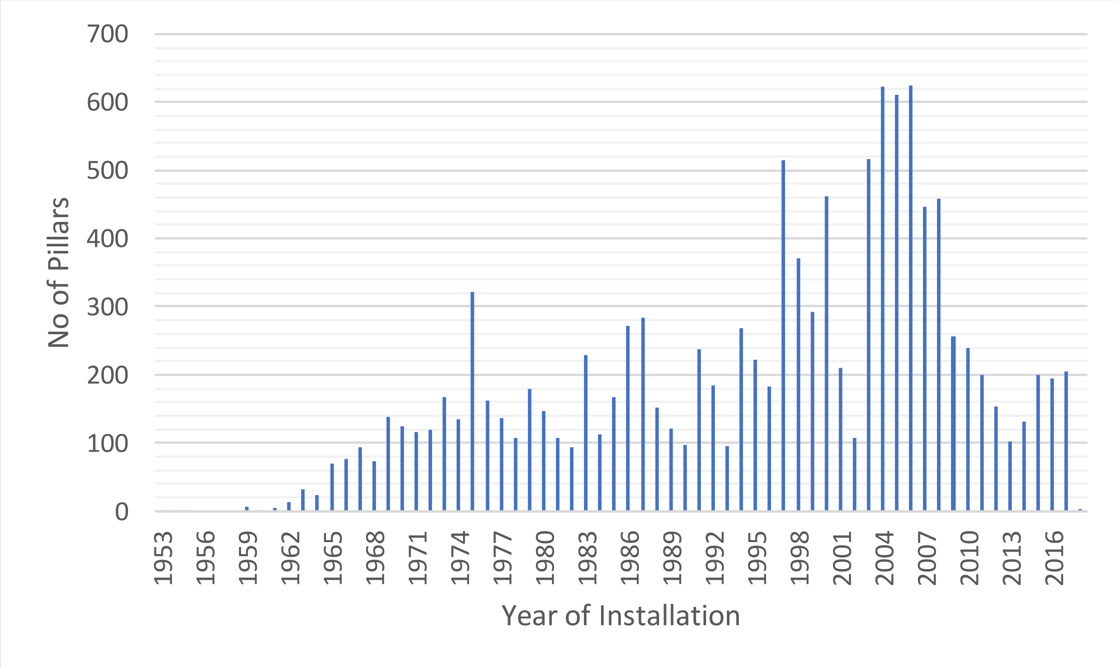


Figure 3.44: Age profile of consumer service pillars

3.4.13 SCADA and Communications

Our current SCADA system architecture was installed in 2004 with an upgrade of communications and protection at the NPL Substation, and installation of new software in the control centre.

The architecture consists of distributed data collection and operation via an Ethernet wide area network (WAN). Communication usually is 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.

Figure 3.45 below shows the location of communications repeater sites.

The existing radio communications system is reaching the end of its useful life and is not capable of providing some functions, such as protection signalling, which the network now requires, and is being progressively replaced by a modern system, primarily using fibre-optic cable, as part of the network development plan.

We relocated our main control room from Kaikohe to our Kerikeri head office in December 2015.

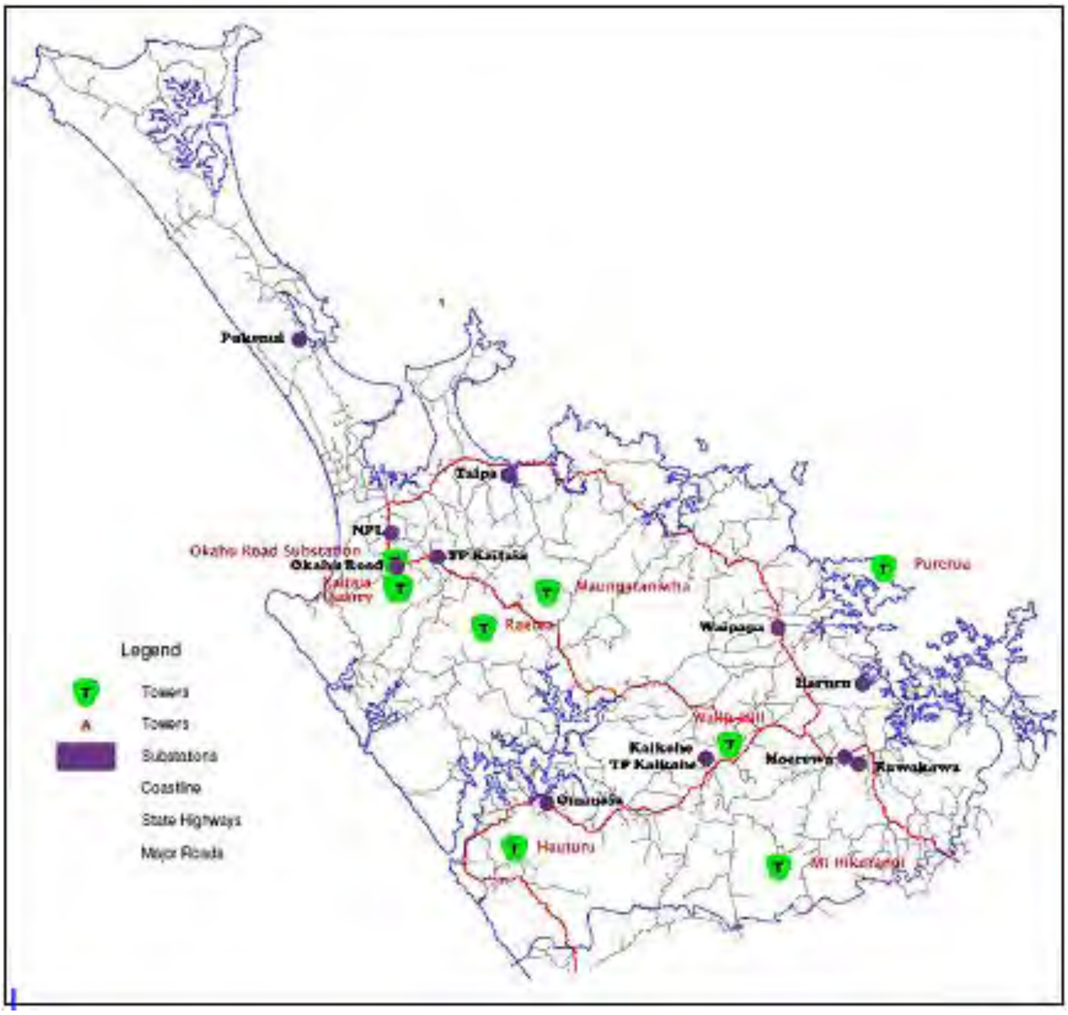


Figure 3.45: Repeater tower sites

We are now using the SCADA system not only to monitor and control zone substation equipment, but also to remotely control sectionalisers and reclosers located on the field.

3.4.14 Load Control Plant

We have three Zellweger decabit type injection plants operating at 317Hz connected to our northern and southern networks. The northern plant is rated at 33kV with 30MVA capacity, commissioned in 1991 and the southern plant is rated at 33kV with 80MVA capacity, commissioned in 2007. There is also a southern standby plant at Waipapa rated at 33kV with 30MVA capacity, commissioned in 1981.

There are 100 channels available for load control and we presently use 45 of these.

3.4.15 Mobile Substations and Emergency Generation

We own a 33/11kV, 7.5MVA mobile substation that was commissioned in FYE2003. However, its main function is to mitigate the risk of a transformer failure at one of our single-transformer zone substations, Taipa, Pukenui, Omanaia and Mt Pokaka. Relocation of the substation and re-energisation at its new site could take up to ten hours, depending on the travel time required.

We also installed two 2MW diesel generator sets at Taipa substation in FYE2014. This generation is used as a short-term backup supply in the event of a loss of the incoming subtransmission line or substation transformer. The generators are also used during maintenance shutdowns of the Kaikohe-Kaitaia 110kV transmission line. The load and the number of consumers supplied from Taipa is significantly larger than from the other single-transformer zone substations and the impact of a loss of supply from the substation on the measured reliability of the total network is correspondingly greater. In the event of a transformer failure, the generators would only be used until the mobile substation could be relocated, due to the high cost and environmental impact of diesel generation.

3.4.16 Non-Network Assets

Our non-network assets include computer hardware and software, motor vehicles assigned to TEN staff, office equipment and miscellaneous equipment such as survey equipment. Our TEN staff operate out of a rented office building and the non-network plant and equipment used for construction and maintenance is owned by TECS and is not covered by this AMP.

3.4.17 Average Asset Age

Table 3.8 below shows the average age of key asset classes and compares these with the standard asset lives in Schedule A of the Commerce Commission's Electricity Distribution Services Input Methodologies Determination 2012. For conductors and cables, the average age is weighted by length, but for other assets the age is unweighted. The average age of the remaining wood poles on the 11kV and low voltage networks is high and, as noted above, we are planning to replace these with concrete poles over a 10-year period. The average age of other assets does not give rise for undue concern over the planning period.

Asset Class	Average Age	Standard Life (years)
Subtransmission conductors	32	-
Distribution conductors - aluminium	37	-
Distribution conductors - copper	54	-
Distribution conductors – galvanised steel	67	-
LV conductors - aluminium	34	-
LV Conductors - copper	40	-
Subtransmission poles – concrete / steel	27	60
Subtransmission poles - wood	35	45
Distribution poles – concrete	32	60
Distribution poles - wood	41	45
LV poles - concrete	38	60
LV poles - wood	42	45
Distribution cable - PILC	23	70
Distribution cable - XLPE	13	45-55[1]
LV cable – aluminium	25	45-55[1]
LV cable - copper	26	45-55[1]
Air break switches – subtransmission	14	35
Air break switches – distribution	23	35
Ring main units	11	40
SWER transformers	17	45
Distribution transformers	21	45
Consumer Service pillars	23	45

Note 1: 45 years for cables installed before 1985

Table 3.8: Average Age of Subtransmission and Distribution Assets

3.5 Justification for Assets

Our network assets receive electricity from Transpower's grid exit point at Kaikohe, and from the Ngawha geothermal generation plant, and distribute this electricity to consumers in our supply area.

Our assets are a result of incremental development of a network constructed using industry standard equipment to provide consumers in one of the more remote, underdeveloped, sparsely populated parts of the country a supply of electricity at minimal cost. While these assets have historically met consumer requirements, expectations on the reliability of the electricity supply are now higher than the network was designed to deliver. We are therefore progressively implementing a network development plan (described in Section 5) which is augmenting the network infrastructure to meet the expectations of electricity users in the Far North for the next 20 years and beyond. This involves the installation of additional network assets, supplemented by diesel generation to provide supply security then elements of the network are out of service.

The network is essentially radial in nature and includes a 110kV transmission line, 33kV subtransmission lines, 22/11kV distribution lines and a 415/240V low voltage network. The different voltage networks are interconnected through substations, which transform the electricity from a higher to a lower voltage. The 22/11kV distribution network primarily consists of three-wire and two-wire overhead and underground lines, but also includes many SWER lines of varying lengths that serve remote areas. The low voltage network includes two, three and four wire lines, which are now largely underground. This network design met the standards of the time, but low-cost solutions such as one and two wire distribution lines were used more extensively than on many other rural networks.

3.5.1 Transmission System

Power is injected into our transmission network in bulk either directly from the national grid or from the geothermal power station at Ngawha. Our 110/33kV transmission substations at Kaikohe and Kaitaia are approximately 56km apart with a range of uninhabited hills in between, and inject power into our 33kV subtransmission network

Both transmission substations have dual 110/33kV transformers that allow the transformers to be maintained during off-peak periods without loss of supply. The transmission system is supplied from the Transpower grid using a double circuit 110kV line fed from the grid substation at Maungatapere. This line, which is prone to interruptions, supplies power to our Kaikohe 110kV substation, where is injected into our transmission system at the two incoming circuit breakers at Kaikohe. The Kaitaia transmission substation is, in turn, supplied by a single circuit from Kaikohe. Currently, it is not possible to maintain supply to all consumers connected to the northern distribution network if this circuit is out of service for any reason.

Ngawha generation also provides 25MW injection into our subtransmission network at 33kV, some of which is then injected into the transmission network to supply the northern part of our supply area. The Ngawha power station is situated approximately 7km from the Kaikohe GXP and is connected to the network using two single-circuit 33kV lines.

3.5.2 Subtransmission Network

The subtransmission network supplies power to our zone substations, which in turn supplies the high voltage distribution system, which distributes this electricity throughout our supply area.

3.5.2.1 Northern Subtransmission Network

Pukenui and Taipa zone substations are supplied using single 33kV lines. The two larger substations, Okahu and NPL, are supplied using a shared double circuit 33kV line, supplemented by a recently completed back-up circuit into NPL, which is a spur off the Pukenui circuit. This provides N-1 security against a pole failure on the double circuit line. There is 4MW of diesel generation capacity at Taipa to inject power into the distribution network when the incoming circuit is out of service.

3.5.2.2 Southern Network

There is a 33kV switching station at Wiroa, which is supplied by two incoming 33kV circuits from Kaikohe, one of which is designed for 110kV operation[4]. This switching station supplies the Waipapa, Kerikeri, Mt Pokaka, and Kaeo substations.

Haruru, Kawakawa and Moerewa substations are all supplied using shared 33kV circuits. Kaikohe substation is supplied directly from the recently commissioned 33kV indoor switchboard that also supplies all other 33kV circuits in the southern area.

Omanaia Substation is supplied using a single 33kV line from Kaikohe GXP.

3.5.3 Zone Substations

Zone substations in the network are separated by significant distances and, in general, by low density rural land. The number of zone substations is low by industry standards, given the level of demand and the size of our supply area.

We also own a 7.5MVA 33/11kV mobile substation that was commissioned in FYE2003 and provides backup for our single transformer substations. There is also some backup available for most zone substations from adjacent substations via the distribution network, but this is severely limited due to the voltage drop on the distribution feeders under contingent operations.

3.5.4 Distribution network

The distribution network is characterised by long feeder lengths, a high number of connected consumers per feeder and relatively few interconnections between feeders to ensure reliability of supply. This together with remote and in placed rugged terrain means the reliability of supply from this network is low by industry standards.

3.5.5 Distribution transformers

Distribution transformers reduce the electricity voltage for supply to consumers. The total number and capacity of distribution transformers is not excessive and the extent to which we are able increase our distribution transformer utilisation is limited by our low consumer density and the rural nature of our supply area.

3.5.6 Low voltage network

We provide no back up for LV circuits. Circuits are two-, three- or four-wire and use medium size conductor. Reviews of current and past designs indicate that a larger conductor would be required if we were to provide back up of LV circuits, but voltage drop rather than capacity is the predominant constraint. Increasing the conductor size is not the optimal solution in general.

New low voltage construction generally consists of underground cables. This is a requirement of the Far North District Council for urban areas. In rural areas, where consumers' service mains are not connected directly to a transformer, the extra cost of underground cables is met by means of capital contributions.

3.5.7 Voltage control devices

Voltage regulation is achieved at the zone substations using conventional on-load tap changers. In addition, we have voltage regulator banks located within the distribution network. These are on feeders over 30km long, where there is too much load at the end of the feeder to maintain statutory voltage without a regulator.

[4] While the Kaikohe-Wiroa line is constructed as a double circuit 110kV line, it currently operates as a single 33kV circuit with the two circuits bonded together.

We have a small number of fixed capacitor banks attached to the 11kV distribution network. These were placed to improve power factor and voltage quality on feeders. They are also needed to maintain the power factor at the grid exit point at the level required by Transpower, particularly when Ngawha power station is not operating.

3.5.8 Load control plant

We use Enermet (Zellweger) 33kV injection plant at Kaikohe and Kaitaia and a backup injection plant for the southern network at Waipapa. The lack of distribution voltage interconnection between the transmission substations prevents aggregation of these plants.

3.5.9 SCADA equipment

We use SCADA to monitor and control our zone substations, GXPs and strategic switches on the network from our control room in our Head Office at Kerikeri.

We have installed remote control equipment such as motorised switches, reclosers and circuit breakers at both subtransmission and distribution voltage level, to improve reliability. With only 56 distribution feeders and almost 2,600km of distribution circuit, the ability to reduce the time it takes to restore supply to parts of the feeder by remote control (while locating the fault) is necessary, to bring consumer service levels (the worst in the country) to more acceptable standards.

3.5.10 Spares

The most critical spares are distribution transformers. The numbers and sizes are defined in an agreement with the TECS store and are in addition to the normal construction stocks.

Section 4 Level of Service

4 Level of Service

4.1 Introduction

Historically, our consumers have experienced poor reliability relative to that of similar New Zealand EDBs. In part, this is a consequence of our fringe location and the resulting limitation of having only a single double circuit radial connection to the Transpower grid. A more strategically located rural network of similar size would typically have many more grid connections. Further, our grid connection and transmission substations are poorly located to serve the present load, since they were constructed during an era when the inland urban centres of Kaikohe and Kaitaia were the hub of both economic and population growth within our supply area.

Over the last twenty years, there has been a steady decline in the growth of Kaikohe, whilst our supply area has seen significant expansion in Kerikeri, the Bay of Islands and the eastern coastal peninsulas. The drift in population away from the areas that the distribution network was originally designed to serve has driven a network development focus on incremental capacity increases to the existing distribution network, rather than quality and performance improvement. The network is now characterised by long heavily-loaded distribution feeders supplying pockets of fringe development with inadequate subtransmission support.

To address these legacy issues and to improve security of supply, we will invest approximately $150 million capex during the ten-year planning period of this AMP, as we continue implementation of the single largest development in the history of the network. To facilitate this development, in 2012 we acquired the region's transmission assets from Transpower and we are investing in improving and upgrading these assets. We have also constructed a new 110kV transmission circuit between Kaikohe and Wiroa and are negotiating with landowners to secure a route to extend this line through to Kaitaia. When the line is built, supply to consumers in the northern area will no longer depend on a single transmission circuit. Furthermore, we have and strengthened the 33kV subtransmission system to increase the number of locations at which power is injected into the distribution network and, in most cases, avoid an interruption to supply should a fault occur in this part of our network. The result of this expansion is a significantly more secure and reliable subtransmission system to support future economic growth in our supply area.

We are now also investing in diesel generation to improve the reliability of the supply we provide to our consumers. We have already installed generation at Taipa zone substation, which is used to supply consumers in the Doubtless Bay and Peria areas when the incoming circuit supplying the substation is not available, either because of a fault or planned maintenance, and also when the 110kV Kaikohe-Kaitaia transmission line is out of service. During FYE2019 we will install a generator at Omanaia to provide security of supply to consumers in the South Hokianga area while we undertake a major refurbishment of the incoming 33kV subtransmission line. Finally, and perhaps most significantly, over the next two years we are planning to install sufficient diesel generation in our northern area to allow supply to be maintained to all consumers (except where other arrangements have been negotiated) during maintenance outages of the 110kV transmission line. While this was the primary purpose of our planned 110kV transmission line between Wiroa and Kaitaia, delays in securing a suitable line route, increases in the cost of constructing this line, and new health and safety requirements that prevent us from undertaking live line maintenance work on the existing line, have driven us to implement an alternative option for securing the supply of electricity to the Kaitaia area.

Transmission and subtransmission reinforcement is not the only focus of our strategic investment. Vegetation control, and other initiatives designed to increase the distribution network's ability to withstand adverse weather events, provide additional opportunities for significant performance improvement. In April 2009, we began a major reliability improvement programme targeting the clearance of trees and other vegetation near our lines and have now reached a point where the first cut is now complete[5]. We have also installed equipment to reduce the number of faults caused by lightning

[5] Under the Electricity (Hazards from Trees) Regulations 2003, an EDB is responsible for the first cut of trees that are interfering with electricity lines. Subsequent cuts are the tree owner's responsibility.

and have also installed more than 200 automated reclosers and remote-controlled switches in strategic locations to limit the impact on consumers affected by fault events. We are now introducing a design standard for the 11kV distribution network that will specify the maximum number of consumers connected to a single distribution feeder and the size of individual switching segments within a feeder. While the standard will still be aspirational for many parts of our network, it will provide a benchmark for ongoing network development and a basis for prioritising projects targeted at improving the reliability of the distribution network using objective and quantified analysis.

Overall, our network development work has been effective. The average total minutes off supply per consumer due to faults on our distribution network, as measured by network SAIDI, reduced from 924 minutes in FYE2009 to a low of 395 minutes in FYE2013 when the weather was abnormally benign. In FYE2017 customers experienced a total of 578 minutes off supply, but 258 of these (45%) were due to two major events - a severe storm on 25 May 2016 and a possum causing a close in fault on the 33kV network on 21 September 2016. In this latter case our 33kV circuit breaker fail protection did not operate as designed and the backup protection at Maungatapere operated, so the wrong line was patrolled, and restoration was delayed[6]. If the impact of these two events is removed, our SAIDI would have been 320 minutes, which compares well with our FYE2013 outcome, when the weather was much more benign, and no major events occurred[7].

We perform regular consumer research, including formal consumer surveys, to educate and seek feedback from consumers on what is an appropriate level of service. The results of these consumer interactions have been incorporated in the strategies discussed in this AMP and have guided development of the service level targets proposed within this chapter.

4.2 Consumer Orientated Service Levels

The consumer service targets included in this AMP are limited to the normalised industry performance measures used by the Commerce Commission to monitor the reliability of our network under its price-quality regime. The Commission has chosen these measures because it believes they are effective indicators of how well an EDB provides a reliable electricity supply to consumers. We agree with this. However, we have set ourselves more challenging targets than the benchmark service levels used by the Commission in monitoring our supply reliability, to ensure that our targets capture the benefits of our investment programme. The Commission's benchmarks are based solely on historic performance and therefore don't account for our planned improvements.

The two measures that we use for the development of consumer service targets are:

- SAIDI: System Average Interruption Duration Index. This is the accumulated total time that the average consumer connected to our network is without supply in any measurement year as a result of faults and planned outages within the network. The units are minutes;
- 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 as a result of faults and planned outages 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 service level targets set out in this AMP relate to the performance of our transmission, subtransmission and distribution networks.

In measuring our performance for internal management purposes and setting our own targets, we use the normalising approach taken by the Commission in measuring the reliability of supply provided by all

[6] We have now installed bus zone protection on our Kaikohe 110kV bus. Had this been installed at the time, there would have been no supply interruption as a result of this event.
[7] The analysis in the paragraph uses raw outage data and takes no account of the impact of normalisation as provided for in the quality standard in the Commerce Commission's price-quality path regulatory framework.

the EDBs that it regulates under the default price-quality path regime[8]. Normalisation of the raw performance measure 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 by limiting the extent to which events outside our control and response capacity impact the measured performance.

In the normalisation process, the impact of interruptions occurring on "major event days" is limited to a boundary value, which limits the SAIDI and SAIFI impact of any one extreme event. The SAIDI and SAIFI boundary values have been determined by a statistical analysis of the historic performance of the network, using the methodology defined by the Commission. The Commission has adopted this approach because, in practice, it has been found that the impact of interruptions over a year generally follows a statistical "log-normal" distribution where interruptions occurring on only one or two "major event days" each year have a substantial impact on the measured performance. These major event days correspond to days of severe storm activity or days on which another event occurs which we have not been able to manage effectively. By limiting the impact of interruptions experienced on major event days, the normalisation process produces a measure that is a better reflection of the overall network reliability to the extent that it can reasonably be controlled, given the resources available.

This normalisation methodology is based on IEEE standard 1366-2003, which has been developed for this purpose by the American Institute of Electrical and Electronic Engineers. The Commission's methodology, however, differs from the IEEE standard by requiring the actual impact of major event days to be replaced by a boundary value, rather than allowing major event days to be ignored altogether.

The normalisation process can have a significant impact on the reported reliability in years where reliability is poor due to a large number of abnormally severe storms. For example, in FYE2015 our actual SAIDI of 1,837 minutes was reduced by more than 67% to 600 minutes after normalisation.

The Commission's 2015-20 price quality path determination changed the methodology used to set the SADI and SAIFI limits, and also changed the normalisation methodology. It also introduced a reliability incentive, scheme, whereby we are rewarded with an increase in our allowed revenue if our normalised reliability in a given assessment year is better than the historic average. Conversely, if our reliability is worse than average, a penalty in the form of a reduction in our allowed revenue (which equates to a reduction in the prices that we are allowed to charge consumers) will apply. Under the scheme there is a cap on the available reward or penalty. The scheme is symmetric in that the maximum reward we can earn in any year is the same as the maximum penalty that can be applied.

Salient features of the new framework are:

- SAIDI and SAIFI are given equal weighting in the reliability incentive scheme. Half the maximum potential reward or penalty is allocated to SAIDI and half to SAIFI.
- The average normalized historical reliability over the ten-year period FYE2005-14 is the neutral point of the reliability incentive scheme, where we do not receive either a penalty or a reward. The reference dataset used as the basis for measuring historical reliability included the performance of both our distribution network and the transmission assets that we now own.
- The SAIDI and SAIFI limits that determine compliance with the Commission's quality threshold are set at one standard deviation above the historical average. Under the reliability incentive scheme these limits are also the level at which our penalty is capped at the maximum amount determined by the Commission.
- The collar for the reliability incentive scheme is the point at which the reward under the scheme will be the maximum allowed. Reliability better than the collar will not generate any further reward. The SAIDI and SAIFI collars are both set at one standard deviation below historic levels.
- Only 50% of the SAIDI and SAIFI impacts of planned outages are now included in the normalized SAIDI and SAIFI measures. This reflects the lower impact of planned interruptions on

[8] 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.

consumers, who receive advance notice of planned interruptions and are therefore able to minimize their inconvenience.

- Major event days, where the actual SAIDI or SAIFI are replaced by a boundary value for normalization purposes, can now only be triggered by unplanned interruptions. This change has put us at a disadvantage since a planned interruption of the 110kV transmission line can no longer be treated as a major event, even though its SAIDI impact is higher than the major event day boundary value even after the allowed 50% reduction. We are not aware of any other EDB that is in a position where an unavoidable planned interruption has a SAIDI impact that is higher than the boundary value set by the Commission.

Table 4.1 shows the SAIDI and SAIFI levels relevant to our quality incentive scheme for the FYE2016-20 regulatory period.

	Limit	Average	Collar
SAIDI	516.675	435.461	354.246
SAIFI	6.248	5.436	4.624

Table 4.1: Reliability Incentive Scheme Parameters

Table 4.2 compares the SAIDI and SAIFI limits and boundary values for the FYE2016-20 regulatory period with those that applied over the FYE2011-15 regulatory period.

	Limits		Boundary Values	
	FYE2016-20	FYE2011-15	FYE2016-20	FYE2011-15
SAIDI	516.675	579.681	29.364	50.931
SAIFI	6.248	7.663	0.347	0.783

Table 4.2: Commerce Commission Reliability Limits and Boundary Values

As noted above, notwithstanding the Commission's reliability criteria under the price quality path framework, we set our own internal reliability targets that better reflect the impact of the investments that we are currently making on network, and these internal targets have been disclosed in pervious AMPs and SCIs. However, the only year in which we have come close to meeting our target was FYE2013, a year in which very benign weather conditions were experienced over most of the country. It was also a year in which we aggressively used mobile generation to mitigate the impact of planned interruptions. Targets are of little value unless they are realistic and, given our subsequent experience, we no longer consider this level of reliability a realistic basis for setting targets going forward, given the current state of the network and the weather conditions typically experienced in our supply area in an average year.

We have therefore reset our reliability targets at what we consider to be more realistic levels. The SAIDI and SAIFI targets for each year of the AMP planning period (FYE2019-28) are shown in Table 4.3. They differ from the targets presented in our 2017 AMP in that they take account of the impact of an increased number of planned interruptions on the distribution network, as a result of our decision to discontinue the use of live line maintenance practices. However, beyond FYE2020 when additional generation has been installed in the Kaitaia area, there will no longer be a need for a planned interruption to supply when maintenance is undertaken on the our 110kV transmission line, and this has been allowed for in the reset targets. Going forward these targets have been incrementally reduced to reflect the improvements expected from our continuing investment programme.

The new service level targets include the transmission assets that were transferred from Transpower. An interruption of the Kaikohe-Kaitaia transmission circuit results in a loss of supply to over 10,000 consumers or approximately one third of our total consumer base. This has a significant impact on reported reliability – SAIFI increases by more than 0.3 and SAIDI increases by up to one minute for each three minutes of outage duration. Hence a planned interruption lasting 8 hours will have an actual SAIDI impact of up to 140 minutes, which reduces to 70 minutes after the allowed reduction for planned interruptions under the Commission's new normalisation methodology. The generation at Taipa will mitigate this to a small extent but, based on the normalised SAIDI impact of recent outages, we consider

60 minutes to be a prudent SAIDI target for each planned transmission interruption. This is well above our SAIDI boundary value of 29.364 minutes.

Our reset targets assume that:

- there will be one planned transmission related interruption each year until FYE2021, when the diesel generation at Kaitaia should be in service;
- weather conditions will be average for the area. The reliability of an overhead distribution network is strongly influenced by the weather, so targets are unlikely to be met in years where storm activity is significantly greater than normal. The measured reliability in FYE2015 was an extreme example of how weather conditions can impact network reliability;
- there are no unplanned outages of the 110kV Kaikohe-Kaitaia transmission lines. The measured reliability of our network is very sensitive to the performance of this line, as an outage will affect all consumers in the northern region. Hence, should a sustained unplanned transmission outage interrupt supply to all consumers in the northern area, the reliability targets are less likely to be met; and
- in the short term we will not use mobile generation to mitigate the SAIDI impact of planned interruptions, although the generation at Taipa will continue to be used to mitigate the impact of transmission outages and outages of the incoming 33kV circuit. Once we have our new generation in place and have gained some experience in the application of generation to manage both planned and unplanned outages, the forecasts may be improved.

The indicators measure only interruptions that originate within our network. Interruptions that originate outside the network, such 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 a 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.

The new SAIDI and SAIFI targets for each year of the planning period are shown in Table 4.3.

FYE	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
SAIDI										
Distribution Related	330	315	310	305	300	295	290	285	285	285
Transmission Related	60	60	-	-	-	-	-	-	-	-
Target	**390**	**375**	**310**	**305**	**300**	**295**	**2900**	**285**	**285**	**285**
SAIFI										
Distribution Related	4.3	4.2	4.1	4.0	3.9	3.8	3.7	3.6	3.6	3.6
Transmission Related	0.4	0.4	-	-	-	-	-	-	-	-
Target	**4.7**	**4.6**	**4.1**	**4.0**	**3.9**	**3.8**	**3.7**	**3.6**	**3.6**	**3.6**

Table 4.3: Consumer Service Level Targets

The change in these targets over the planning period is shown graphically in Figures 4.1 and 4.2 below, which also compare the targets with the historical reliability. The graph is indicative only as the historical performance is not directly comparable to the performance targets going forward. Firstly, performance prior to FYE2008 was estimated rather than directly measured. Secondly the reported actual performance prior to FYE2010 has not been normalised in accordance with the Commission's measurement methodology and finally the normalisation methodology has changed from FYE2016 onwards, as discussed above.

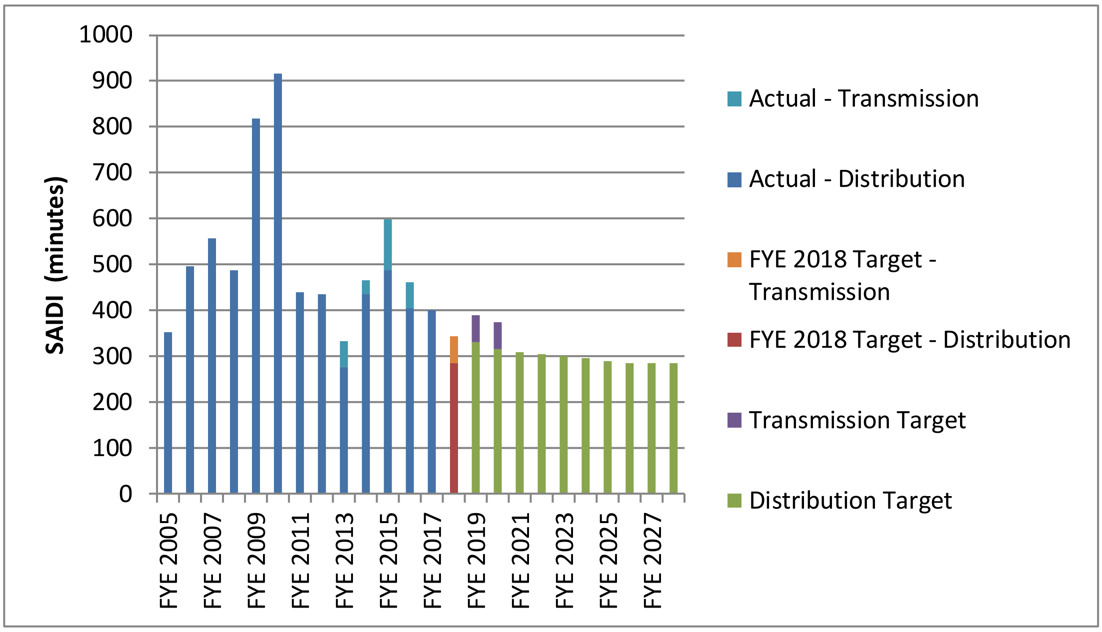


Figure 4.1: **Historical and Target SAIDI**

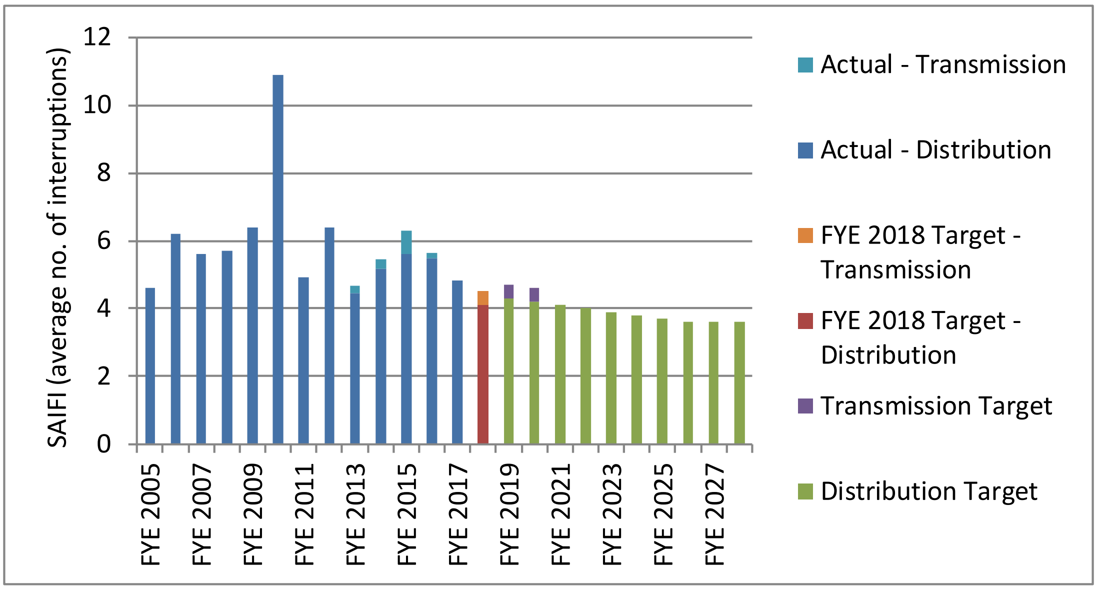


Figure 4.2: **Historical and Target SAIFI**

4.2.1 Outage Performance Reporting

The Commerce Commission's information disclosure requirements require us to disclose information on the reliability of the supply that we provide our consumers and the causes of supply interruptions. There is no industry standard as to how this information is to be measured and recorded. This results in EDBs setting their own rules, which means disclosures can be inconsistent if comparing one EDB with another. It is therefore important that consumers are aware of how we measure supply reliability and manage interruptions that affect them, particularly if they use our measure of the service levels we provide as a basis for determining their need for additional supply security (such as a back-up generator).

The ISO 55000 asset management standard requires performance indicators to measure the effectiveness of strategy against delivery on objectives. SAIDI and SAIFI are the main performance measures that we use to assess the effectiveness of our asset management strategy in delivering on TEN's strategic mission and objectives, given the need to balance reliability with cost and safety.

We have therefore clarified our outage reporting standard and, where appropriate, made changes to current practice for the following reasons:

- to improve consistency with other EDBs and international practice, so that benchmarking is more meaningful;
- to focus management on the issues that it can control or influence;
- to adapt practice to recent changes in safety management regulations;
- to clarify where a network wide response is demarcated from consumer specific issues;
- to align change and any impact it might have with the reset of the price quality path for the 2020-25 regulatory period;
- where outcomes created by driving performance indicators for regulatory purposes conflict with optimal outcomes being delivered to consumers, we will use our discretion to act in the interest of consumers – that is, we will optimize service rather than our regulatory position; and
- to communicate to consumers the service drivers that we apply to their supply.

These changes are documented in the provisional Outage Reporting Standard shown in Appendix E. This standard includes a detailed description of the intent of each rule and justification for the approach taken. We have requested regulator consideration of the merits of establishing a formal industry guide but will default to our disclosed internal standard in the interim.

4.3 Asset Performance and Efficiency Targets

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

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. We also considered including a target based on our capital expenditure, but the implementation of the network development programme may result in volatile capital expenditure ratio over the planning period. This limits the usefulness of this indicator as a measure of business performance.

4.3.1 Loss ratio

We have suffered historically from a poor loss ratio, defined as the ratio of energy losses to the energy flowing into the network.

Energy losses are measured as the difference between the energy flowing into the network and the energy sold out. They include both technical network losses due to the loss of energy flowing though 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.

It is interesting to note that the traditional approach of justifying capital expenditure by making savings in the cost of energy losses no longer applies under the present market structure, where energy retailers rather than network companies are responsible for the cost of technical losses. Notwithstanding this, we consider loss ratio to be a valid performance measurement indicator, since minimization of losses benefits all parties in the energy supply chain, including consumers.

Network losses are influenced by a number of factors but, in general, high losses reflect high asset utilisation. Because of this, networks with high losses tend to have low levels of reliability and low quality of supply – high losses can indicate excessive voltage drop and difficulty in maintaining consumer voltage within statutory limits. It is no coincidence that we have both low supply reliability and high loss ratio when compared to other EDBs.

Fortunately, the same assets that need to be upgraded to meet voltage quality compliance are also significant contributors to losses. Nevertheless, our low consumer density necessitates a high total transformer capacity to provide individual transformers for rural consumers, which in turn sets a higher level of standing losses than is typical for less rural networks.

From 1996 to 2001 our network high loss ratio was approximately 10%. In recent years, the loss ratio has improved somewhat to between 8% and 9%. However, in FYE2013 the network loss ratio increased to 9.5% as losses in the transmission assets were included for the first time and have further increased to 10.2% in FYE2015, possibly due in part to additional no load losses from the new power transformers at Kerikeri. Over time, distribution losses should also decrease incrementally as further investment in the network incrementally reduces distribution system losses. Nevertheless, there is a limit to the extent the losses can be mitigated. A large proportion of losses are on the low voltage network and these losses cannot easily be reduced.

Rural networks with low loss ratios tend to have a high number of injection or grid exit points but our fringe location on the network precludes this.

We have maintained the FYE2018 target though to the end of the planning period, even though actual losses in FYE2017 were materially lower, as the reason for this is unclear and we doubt that this performance can be sustained. The targets for the planning period are shown in Table 4.4 and Figure 4.3 compares these targets with the recent historical performance.

FYE2019	FYE2020	FYE2021	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027	FYE2028
9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%	9.3%

Table 4.4: Target Loss Ratios

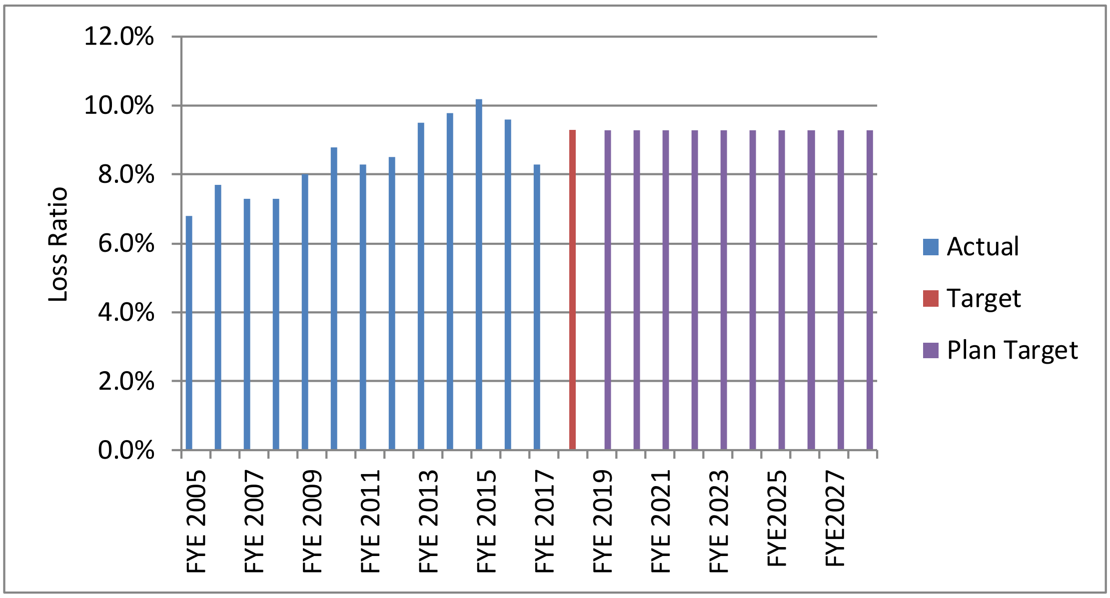


Figure 4.3: Loss Ratios of Top Energy since FYE2004

4.3.2 Cost Performance

Ideally, any financial performance indicator should be directly measurable for performance against a specific target and 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 relevant, 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.

FYE2019	FYE2020	FYE2021	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026	FYE2027	FYE2028
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.

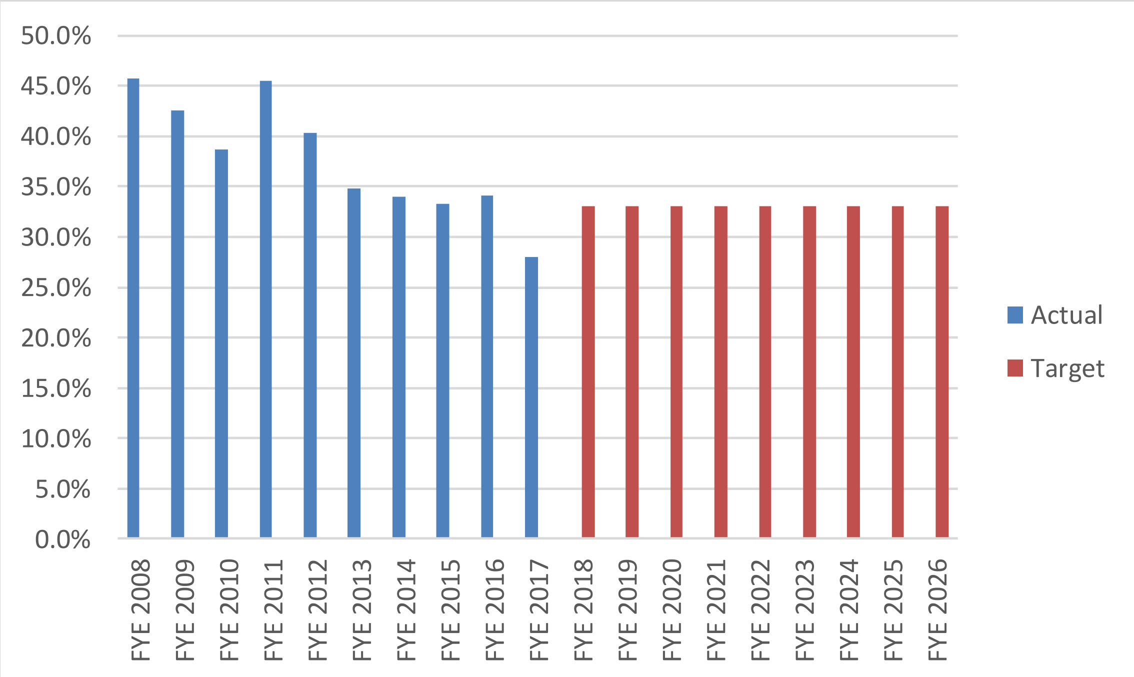


Figure 4.4: Ratio of Total Operating Expenditure to Total Regulatory Income since FYE2008.

4.4 Justification for Service Level Targets

Our service level indicators are designed to 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. An important economic consideration in setting service level targets is affordability of services, as our supply area is acknowledged as one of the poorest socioeconomic areas in New Zealand.

As discussed in Section 3.1.7, over 35% of our lines were originally built using subsidies provided by the Rural Electrical Reticulation Council (RERC) to assist with post-war farming productivity growth in remote areas and to provide an electricity supply to consumers in sparsely populated rural areas that would have otherwise been uneconomic to service. Currently 35% of our lines, which supply just 9% of its consumer base, are considered uneconomic.

Accordingly, the service level targets must ultimately reflect our Board's views on affordability, given this high proportion of uneconomic lines. This view was informed by the results of our consumer consultation.

It should be noted that, with the exception of FYE2015 when the weather conditions were extreme and there were two planned transmission outages, the underlying reliability of supply we have delivered to most of our consumer since FYE2011 has been a significant improvement on earlier years. This is a result of reliability improvement initiatives and targeted investment strategies in response to a strong message from consumers that the earlier network performance levels were not acceptable. As demonstrated in this AMP, we continue to explore and implement suitable strategies for performance improvement.

4.4.1 Supply Reliability Targets

The basis on which we have set our revised supply reliability targets is discussed in Section 4.2. The new targets continue to measure normalised SAIDI and SAIFI, but the normalisation methodology has been changed to be consistent with the Commission's revised approach to assessing reliability against the quality threshold in its price-quality framework for the FYE2016-20. Our internal targets, shown in Table 4.3, reflect a significantly higher level of reliability than the threshold levels specified by the Commission, and capture the impact of our network investment programme as well as expected reliability improvements over time. We believe the targets are achievable going forward, given the weather conditions experienced in our supply area in an average year.

The upgrades to the protection on our duplicated 33kV subtransmission system that we have been progressively implementing have now been completed. This has increased the resilience of the network to subtransmission faults, which should provide the short-term improvement in reliability needed to meet the still ambitious targets. However, a consequence of the introduction of the Health and Safety at Work Act 2015 is that we are no longer using live line work practices, and this has increased the number of planned interruptions of supply to our consumers.

4.4.2 Justification for Asset Performance and Efficiency Targets

4.4.2.1 Loss Ratio

Our loss ratio targets reflect the current 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 measured loss ratio, but this has now been deferred until after the end of the AMP planning period. The commissioning of the Kaeo substation will result in some reduction in line losses due to lower 11kV currents, but this will be largely offset by the losses on the new substation transformers. While continuing investment in the network over the planning period may result in an incremental reduction in network losses, we suspect that these will not be sufficient to reduce the loss ratio to a level significantly below the target we have set.

4.4.2.2 Ratio of Total Operational Expenditure to Total Regulatory Income

The level of operational expenditure on the network is now actively managed and it is expected that the ratio of total operational expenditure to total regulatory income will remain around the level achieved in FYE2016 throughout the planning period. There may be some reduction as we transition to the revised maintenance strategy discussed in Section 5, although much of the savings in asset inspection will be absorbed by additional expenditure on asset renewal.

Section 5 Network Development Planning

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, 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 strategic issues discussed in Section 2.6.

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; and
- 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; and
- 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.

5.1.1.1 Voltage Control Options

a) Zone Substation and Distribution Transformers

A new zone substation will address low voltage issues on heavily loaded 11kV lines serving remote areas experiencing significant population growth, and therefore allow the existing 11kV assets to be loaded closer to their thermal rating. It will also improve supply reliability by increasing the number of distribution feeders and reducing the number of consumers affected by an individual fault. In order to control the system voltage within the specified limits, we purchase zone substation transformers with a 15 step on-load tap changer (OLTC) facility, with tap ranges from -16.5% (voltage boost) to +4.5% (voltage buck).

Distribution transformers are rated at 240V and typically have a six step off load tap changer facility with -7.5% (voltage boost) to +5% (voltage buck).

b) Distribution Voltage Regulators

Distribution voltage regulators are used to manage the voltage at the end of a long radial 11kV feeder, generally supplying a more remote part of our supply area. We use two different types of voltage regulator:

- Single phase 32 step regulators with tap ranging from -10% (voltage boost) to +10% (voltage buck) with each tap of 0.625% on the primary side of the regulator. This type of voltage regulator gives fine voltage control over the range and keeps the voltage close to 11kV.

- Single phase 4 step regulators with -10 % (Voltage boost) tap, with each tap of 2.5% on primary side of the Regulators. This type of voltage regulator gives coarse voltage control and is no longer purchased.

Traditionally, we have connected voltage regulators in an open delta configuration to obtain 10% voltage regulation on two phases. As we have a significant number of two wire and single wire lines, a closed delta configuration is now being used as the standard to achieve balanced voltage output on all three phases up to the maximum 15% regulation.

c) Capacitor Banks

Capacitor banks will boost the voltage by injecting reactive power into the network. We typically purchase 200kVAr fixed tap capacitor banks to use on rural distribution feeders, but also have a 400kVAr switched capacitor bank with 200kVAr steps. The sites for capacitor banks are chosen to avoid the need to include expensive switching of capacitor banks and to avoid significant absorption of the 317Hz ripple injection signal used for load control.

d) Overhead Line Upgrades

Our network is predominantly rural, with long radial feeders and significant lengths of two wire and SWER lines. Therefore, to address voltage and capacity problems, we investigate the following options before determining the most economical and long-term suitable solution:

- convert 2-wire and/or SWER lines to 3-wire;
- use of capacitors and regulators;
- rearrange feeder routes close to substations to share load more evenly;
- increase the conductor size at critical areas to remove constraints; or
- upgrade the operating voltage on heavily loaded sections of line from 11kV to 22kV.

e) Diesel Generation

Diesel generation can be used to inject reactive power into the network to elevate the voltage at the end of a feeder. While the operating costs of diesel generation are relatively high, capital costs can be low compared to network augmentations, such as an overhead line upgrade, that achieve the same result. They also can have advantages in that they are self-regulating and generally can be relocated. As a voltage control and peak limiting device, they are potentially most useful for the management of seasonal loads. For example, a generator could be used to support a seasonal tourist driven load during the summer and relocated over the winter to provide voltage support at the remote end of a rural feeder with a high winter peak demand.

f) Emerging Technologies

Technologies are now emerging that provide more options for the management of energy and voltage, without the need to invest in an expensive network upgrade to address a small or temporary overload. Batteries can be used to regulate voltage by injecting energy into the network close to the load at times of peak demand and static sources of reactive power with variable output (statcoms) are now available. The ability to control such devices dynamically using increasingly sophisticated management systems increases their flexibility and the range of situations in which they can be applied.

5.1.2 Security of Supply

Our security of supply standard is shown in Table 5.1. This drives the design of our network and determines when an intervention to increase the network supply capacity is required. Our transmission and subtransmission networks are now compliant with this standard except for:

- Supply to the northern area. Compliance with the standard is contingent on the installation of standby diesel generation. This project has been approved by the Board, and is planned for completion in FYE2020, assuming that timely resource consents are obtained;

- Supply to Omanaia. This is contingent on the installation of a diesel generator at the substation. This is a committed project and is included in the FYE2019 work plan.

We own and operate a 7.5MVA mobile substation, which limits the maximum total outage duration should all transformer and generation capacity be lost at any substation. 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. The security standard assumes that the mobile substation is available for deployment and is not under maintenance or deployed to address a contingency elsewhere on the network. Furthermore, the capacity of the mobile substation is insufficient provide to full supply restoration capacity at larger substations. In this event the restoration will only be partial, and supply may need to be rotated at times of peak demand.

Our security standard, which is shown in Table 5.1, has been reformatted to include additional detail on:

- the indicative asset group to which each level of security applies;
- the number of affected customers in addition to demand;
- the intended voltage and distance;
- contingent capacity targets;
- targeted restoration times; and
- preferred resilience measures

However, the core peak demand and security level specifications (and our level of compliance) remains the same. The reformatted standard is based on EEA guidelines.

It has also been supplemented with standards for the lower voltages and for consumer connections. These however are our recommendations as consumers have some options over whether they choose to pay us for the level of security required or provide their own alternatives. They have been added to provide customers with a baseline against which they can assess their own security needs and then discuss investment options for customised solutions with us. New technology and a shift towards two-way energy flows at the edge of our network are providing consumers with more choice over opting in or out of network-centric security.

Adding standards for the distribution network are intended to drive reliability and resilience consideration in planning the development of the 11kV network, as distinct from pure security. These standards complement design standards around interconnection, excess capacity, generator support, automated restoration, etc.

Class	Group Peak Demand (MVA)	Asset Group	Customer Impact	Design Standards	Contingent Capacity	Security Level	1st Interuption	2nd interuption	Resilience Measures
Transmission									
T1	>60	Grid Exit Point - Kaikohe	>30000	80km @ 110kV	100% DG	n-1	Maintain 100% GPD	Repair time.	Dual circuits, islanding capability
T2	60 to 30	Main Load Centre plus its connection to GXP - Wiroa	<20000	300km @ 33kV	70% @ 33kV	n-1	Maintain 100% GPD	Repair time.	Dual circuits, off-road routes, H bus, bus sectioned,
T3	<30	Secondary load centre plus its connection to GXP - Kaitaia	<15000	100km @ 33kV	70% from generation	n-0.7	Maintain/Restore 70% GPD within 1h. 100% repair time.	Restore 70% GPD within 36hr 100% repair time	Start-up of deployed Standby DG. Disconnection of agreed non-essential load, rolling outages as required, emergency load management
T4	<60	Generation plus connection to GXP Ngawha	<10	Generation Plant	60% @ 33kV	n-1	Maintain 100% generation at 33kV	Restore 60% generation at 33kV 100% repair time	Interconnection to 33kV at Generator Bus,
Subtransmission									
S1	<30	**Line Segment of mesh**	<10000	75km	100% redundancy	n-1	Maintain 100% GPD	Best restore 100% switching time Worst 100%: repair time	33kV tie points, Dual or ringed circuits, 11kV tie capacity, load shifting
S2	12 to 25	**Urban/Industrial Zone Sub on Ring**: Kerikeri, Waipapa, NPL, Future Ngawha Energy Park	>5000	300km @ 11kV <3000 ICPs on 6 FDRs 2 x 23MVA Tfmrs	50% GPD of other 2 subs in group of 3	n-1	Maintain 100% GPD less interuptible industrial load	Restore 50% GDP within switching time Restore 100%: repair time	Indoor switchgear, higher component of UG network, higher level of interconnection, Load shifting, Interruptible load
S3	6 to 12	**Urban/Rural Zone Sub** Kaikohe, Okahu, Haruru, Future Wiroa	<5000	600km @ 11kV <4000 ICPs on 6 FDRs 2 x 11.5 MVA Tfmrs		n-1	Maintain 100% less holiday peak. Restore 60% GPD within 4h. Restore 100%: repair time.	Restore 60% GPD within 12h. Restore 100%: repair time	Extra contingent capacity for holiday peak load
S4	3 to 6	**Country Town Zone Sub** Kawakawa, Kaeo,	<2500	300km @ 11kV <3000 ICPs on 6 FDRs 2 x 9MVA Tfmrs		n-0.7	Restore 50% GPD within Switching Time, Restore 100%: repair time.	Restore 70% GPD within 12h. Restore 100%: repair time	Maintain 50% 11kV tie capacity
S5	1 to 3	**Rural Zone Sub** Pukenui, Taipa, Omanaia, Mt Pokaka	<1500	250km @ 11kV <3000 ICPs on 4 FDRs 5MVA Tfmr	Holiday peak demand	n-0.7	Restore 70% GPD within switching / genset startup tme	Restore 70% GPD within 12 Hr, Restore 100%: repair time	Intermediate or Mobile Sub 5/7.5MVA Standby Gensets
S5	< 5	**Rural Industry Zone Sub** Moerewa	<1000	200km @ 11kV <600 ICPs on 4 FDRs 2 x 3/5MVA Tfmr	Nil	n-1	Maintain 100% GPD less interuptible industrial load	Restore 70% GPD within switching time Restore 100%: repair time	Ring circuit 33kV, Dual TF,70% 11kV tie capacity.
S6	<30	**Spur to Rural Sub**	<1500	35km	Holiday peak demand	n-0.7	Maintain/Restore 70% GPD within switching/generator start up time. Restore 100%: repair time.	Restore 100%: repair time	Interconection to 11kV sections, Intermediate Sectionalising points, emergency load management
Distribution									
DC1	6 to 8	Feeder Cable	<1500	300mm2 Cable to first RMU Protected from adjacent cable faults	100% of 2 Tie feeders	n	Restore 100% within switching time	Repair Time	100% contingent capacity tie to other half of bus and/or other sub
DC2	4 to 6	Urban Cable Tie Points	< 1500	185mm2 feeder cable	100% of 2 Tie feeders	n	Restore 100% within switching time	Repair Time	Derated 30%, 100% contingent capacity tie to other half of bus and/or other sub
DC3	2 to 4	Urban Cable Spur	<500	185mm2 feeder cable	spare cable	n	repair time	Repair Time	
DC3	3 to 6	Overhead Main line Tie Points	<1000	Krypton	70% of tie feeders	n	Restore 70% in switching time	Repair Time	70% contingent capacity tie to other feeder, Sectionalising to reduce outage impact
DC4	4 to 6	Overhead Main line	<1200	Krypton	sectionalising	n	Repair time	Repair Time	feeder sectionalising to reduce outage impact
DC5	2 to 4	Overhead Spur Line	<500	Iodine	sectionalising	n	Repair time	Repair Time	feeder sectionalising to reduce outage impact
DC6	1 to 2	Remote End of Line	<200	Fluorine	sectionalising	n	Repair time	Repair Time	feeder sectionalising to reduce outage impact
DC7	< 1	2 wire	<200	Iodine	sectionalising	n	Repair time	Repair Time	feeder sectionalising to reduce outage impact
DC8	<0.5	SWER	<100	Fluorine	sectionalising	n	Repair time	Repair Time	feeder sectionalising to reduce outage impact
Transformers									
DT1	1 to 2	Ground Mount 3P	Major	Specific Design	customer may have standby generation	n	Repair time	Repair Time	May be LV tie points within Customer facility
DT2	0.5 to 1	Ground Mount 3P	Significant	Specific Design	customer may have standby generation	n	Repair time	Repair Time	spare unit in critical spares
DT3	0.1 to 0.5	Ground Mount 3P	<200	Specific Design		n	Repair time	Repair Time	spare unit in critical spares
DT4	< 0.2	Pole Mount	<80	Size based on connected ICPs		n	Repair time	Repair Time	spare unit in critical spares
DT5	<.2	Isolating, interconnecting	<80	Limited by earth bank		n	Repair time	Repair Time	spare unit in critical spares
Consumer									
C1	>5	Major Indusrial	>3GWh	Multiple 11kV feeders CB protected Closed rings	70% Cable and Transformer capacity	N-0.7	70% no interruption 100% within switching time	Repair Time	Duplication of supplies Ring feeds Customer owns TF and plant switchgear
C2	1 to 5	Medium Industrial	1 to 3GWh	Dual 11kV supply Dedicated <1MVA tfmrs on RMUs	50% excess cable capacity 30% excess transformer capacity	N-0.5	50% no interruption Restore 75% within switching time	Repair Time	Duplication of supplies Customer owns TFs and plant RMUs Customer provides essential supply backup
C3	0.5 to 1	Light Industrial	0.5 to 1GWh	RMU connected Single HV supply Dedicated transformer	0.3	N-0.3	30% supply from generator and UPS 100% restore: Repair time	30% supply from generator and UPS 100% restore: Repair time	Critical Spare TF Customer provides essential supply backup gen and UPS
C4	>100A	Large Commercial	<1GWh	RMU connected Single HV supply Dedicated transformer	0.3	N-0.3	30% supply from generator and UPS 100% restore: Repair time	30% supply from generator and UPS 100% restore: Repair time	Critical Spare TF Customer provides essential supply backup gen and UPS
C5	150A	Dairy Shed	35000	single HV service	nill	N	Repair Time	Repair Time	Replacement TF & Fuses in Stock
C6		Irrigation Pump		single HV service	nill	N	Repair Time	Repair Time	Replacement TF & Fuses in Stock
C7	60 to 100A	Medium Commercial	<100,000	single 3 phase LV	nill	N	Repair Time	Repair Time	Replacement TF & Fuses in Stock
C8	<60A	Std Commercial	<20,000	single 3 phase LV	nill	N	Repair Time	Repair Time	Replacement TF & Fuses in Stock
C9		Small	10000	single 3 phase LV	nill	N	Repair Time	Repair Time	Replacement TF & Fuses in Stock
C10	3x60A	Residential 3P	12000	single 3 phase LV	nill	N	Repair Time	Repair Time	Replacement TF & Fuses in Stock
C11	1 x 60A	Std Residntial 1P	7300	single phase LV	nill	N	Repair Time	Repair Time	Replacement TF & Fuses in Stock
C12		MUSH	As above according to demand		0.3	N-0.3	30% supply from generator and UPS 100% restore: Repair time	30% supply from generator and UPS 100% restore: Repair time	Critical Spare TF Customer provides essential supply backup gen and UPS

Table 5.1: Security of Supply Standard

Table 5.2 shows the level of security we currently provide at all our zone substations.

SUBSTATION	TRANSFORMERS	INCOMING CIRCUITS	SECURITY LEVEL
Southern Area			
Kaikohe	2	2	No interruption
Kawakawa	2	2	No interruption
Moerewa	2	2	No interruption
Waipapa	2	2	No interruption
Kaeo	2	1	No interruption for loss of a transformer. On loss of an incoming line, supply to most consumers would be restored at 11kV from Waipapa in switching time.
Omanaia	1	1	Currently 9.5 hours via the mobile substation. A generator is to be installed at the substation during FYE2019 to provide backup for loss of the incoming line or transformer.
Mt Pokaka	1	2	No interruption for loss on incoming line. For loss of the transformer, switching time for small use consumers. 9.0 hours for mill via mobile substation.
Haruru	2	2	No interruption
Kerikeri	2	2	No interruption
Northern Area			
Okahu Rd	2	2	No interruption
Taipa	1	1	Generator will restore supply to most consumers within 15 minutes. Full supply restored in repair time for loss of line and 9.5 hours (via mobile substation) for loss of a transformer.
Pukenui	1	1	Switching time. There is sufficient 11kV network capacity to fully restore supply following the line of either the line or transformer.
NPL	2	2	No interruption

Table 5.2: Zone Substation Security

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.

ASSET TYPE	CONDITION	PERCENT OF NOMINAL CURRENT RATING	
		Normal operation	Contingent operation
Transformers	Nominal	100	150
Overhead Conductors	Still Air 30 degrees	75	100
Underground cables	In Duct	75	100
Circuit Breakers	Nominal	75	100

Table 5.3: Design Capacity Limits

5.1.4 New Equipment Standards

In order to maximise cost efficiencies and reduce the required number of spares, we have developed and 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 one-, 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 (although the Kaikohe-Hariru Rd section of the 110kV Wiroa line uses concrete poles) 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 currently all aluminium conductor (AAC), except where long spans demand higher tensions. For these applications, the equivalent steel reinforced aluminium (ACSR) conductor is used. For new transmission and subtransmission lines, all aluminium alloy conductor (AAAC) has been adopted as standard.

Zone substation transformers have been standardised as 11.5/23MVA units, except for small sites where this capacity is not warranted, where 5/10MVA and 3/5MVA transformers are used. Transmission transformers with a 110kV primary winding are standardised at 40/60MVA, although a smaller transformer size will be used at Mangamuka. In our view, the relatively small number of standard transformer ratings is justified, given the small number of power transformers in the fleet, as it reduces carrying costs and 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 used as 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 generally 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 service provider, we recognise that the energy efficient operation of our network is in the long-term interests of all stakeholders. The following initiatives are in place to promote energy efficiency:

- Our measured network losses increased after the acquisition of the Transpower assets because the losses from these assets were material and had to be included in the measure. While loss minimization is not the primary objective of the network development plan, the reduction of network losses should be a positive outcome from the implementation of this plan.
- Our distribution network was constructed with long heavily loaded feeders, with augmentation generally being triggered by a need to reduce the voltage drop. We are progressively reducing feeder length and the load on individual feeders with the construction of more zone substations. Notwithstanding this, long distribution feeders remain on parts of the network and we are planning greater use of relocatable generation to manage the load and voltage drop on these feeders by injecting energy and reactive power at the end of a feeder at times of peak demand. This will lead to more proactive real-time management of the network, which in turn should result in more efficient use of our existing network assets and a reduction in losses.

- The Ngawha geothermal power station currently provides approximately 70% of the energy requirements of our consumers. It displaces generation located south of Auckland and thus 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. Completion of the Stage 1 expansion at Ngawha will result in an estimated 98% of our consumers' current energy requirements being generated locally, which will further reduce these losses.
- As discussed in Section 5.10, 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 thought to reduce our network maximum demand by approximately 10MW.
- 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 approved business plan. A job authority system controls authorisation of expenditure on major projects.

5.4 Project Prioritisation Methodology

Our network development plan can be categorised into major projects and incremental upgrades. Major projects are one-off, individually designed, major augmentations or upgrades of the network. Projects are allocated individual budgets and generally have long lead-times. Incremental upgrades are smaller, have shorter lead-times and are managed within budget envelopes.

As budgets for network development and augmentation are limited, project prioritisation is one of the key functions of asset management. Prioritisation determines the ranking of one project compared to another in the most practical and feasible way possible. It also determines whether a project 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. The primary drivers for this work are:

- improvement of supply security to the northern region, which is currently constrained by the existence of only one 110kV circuit between Kaikohe and Kaitaia;
- the need to improve reliability of supply; and
- the introduction of new technologies.

The introduction of new technologies makes the future industry landscape very difficult to predict. This favours the application of low cost measures with short life cycles to address network constraints, in preference to traditional solutions, as an interim measure until the future of the electricity supply industry is more certain. Nevertheless, it is necessary to keep development options open and not close off alternatives, particularly when it is unclear that new technologies will deliver solutions that fully meet long term requirements.

The major projects we currently plan to implement over the next ten years are described in Sections 5.13-5.16. Construction of the proposed new 110kV line between Wiroa and Kaitaia has been deferred due to the time it is taking to secure a line route and it is now intended to install diesel generation to provide a higher level of supply security to the Kaitaia area by the end of FYE2020. The higher level of security is needed for cover:

- an increased number of planned maintenance outages of the existing 110kV line due to the decision to cease using live line work practices; and

- resilience during low probability high consequence events such as an extended outage of the 110kV line due to a tower failure in the Maungataniwha Ranges.

5.4.2 Incremental Capital Upgrades

Incremental capital upgrades generally have short lead-times and are managed within budget envelopes. They include the use of diesel generation to defer a higher cost network upgrade or to manage a network constraint that is seasonal in nature. They also include asset replacement or refurbishment projects targeted at assets that have deteriorated to the stage where their reliability cannot be assured, and their failure could have significant consequences for our consumers. Further, incremental capital upgrades include initiatives like the installation of remote controlled switches or interconnections between feeders. As there are always more potential projects than can be resourced from the available funding sources, a process is needed to prioritise projects and ensure that those that provide the greatest benefits are implemented first.

We receive information regarding existing weaknesses and other areas where work is required on the network from a wide range of sources including:

- our staff;
- our control centre;
- TECS;
- network asset inspection reports;
- our Maintenance Manager;
- network modelling and study;
- analysis of fault statistics and causes;
- consumers; and
- Far North District Council plans.

We use his information to identify pressure points on the network and to formulate potential solutions for inclusion in the AMP. These projects are prioritised according to risk and consequence and fitted in around the major projects to form a projected work programme which, in turn, matches the financial and skilled labour resources that are expected to be available in each year of the planning period.

We accord a high priority to meeting our short-term SAIDI and SAIFI targets and the potential of a project to improve network reliability is therefore weighted highly in our prioritisation process. Within this overriding objective to improve supply reliability, we further prioritise projects that will benefit consumers that have a high value of lost load to minimise the consequence of poor reliability on our consumers.

We are developing a more structured process to prioritise projects to improve the reliability of the 11kV distribution network and this is discussed in Section 5.16.1.

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; and
- technology release and adaptation into society (e.g. photovoltaic cells, heat pumps, etc.).

Demand growth was forecast down to the distribution feeder level.

5.5.2 Forecast Methodology

We used our SCADA system data that provided the average current in each feeder for each half hourly period from 1 March to 31 December 2017 as the base data for the forecast. From this we were able to determine the maximum half hourly demand at each zone substation. Peaks due to the network not being in its normal operating state were not considered. The forecast incremental growth rates at each substation were based on historic trends for the substation, which in some cases were modified slightly to take into account probable changes in the local environment served by each substation, where these could reasonably be expected to impact the demand for electricity in each local area. As the data we used were measurements of current, we assumed a power factor of 0.98.

We have then overlaid on this base forecast major new block loads that have been consented, or are close to being consented, by the Far North District Council. These are the expected industrial load at the proposed Ngawha energy park, a proposed medium sized industrial development on land near our planned 110kV substation at Wiroa and a planned expansion of the Carrington resort on the Karikari peninsula in the far north.

We adopted a similar approach to the forecasting the peak demand at our Kaikohe and Kaitaia transmission substations and also our network peak demand. In each case, the diversity with the relevant undiversified zone substation demands was calculated as a sanity check and found to be within what we considered a reasonable range. Again, the observed FYE2018 peak demands were used as the basis for the forecasts and the growth rates used were the growth rates of the undiversified aggregate demand of the relevant zone substations.

Our forecast includes an adjustment for the Kaeo substation, which is expected to be commissioned by 31 March 2018. We estimated the demand of the Kaeo substation on the basis of loads on the Waipapa feeders that will be diverted into the new substation, as measured by the SCADA system. We have also allowed for a transfer of load from the Kawakawa to Haruru substations in FYE2023 following completion of the second feeder to supply the Russell peninsula.

5.6 Demand Forecasts

5.6.1 Forecast peak demand over planning period

Using the methodology described above, the winter peak demand forecast for each zone substation is shown in Table 5.4 below. The peak demands shown in the tables 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. All our zone substations have winter peaks, so PV is unlikely to have a material impact on our peak demand until battery storage becomes economically feasible.

We are developing our subtransmission network with the capacity to be reconfigured into a looped 110kV backbone with 33kV interconnections at the major load centres. Once this has been completed there is scope to rationalise and distribute the associated 110/33kV interconnection transformers to create interconnected voltage layers able to bypass and back each other up in the event of a segment failure. There are no constraints over the forecast period of this plan and the timing and order of when such reconfigurations will take place will be driven by what and where new major loads eventuate.

Consequently, no constraints are forecast over the next 10 years, and the development presented in the AMP is intended to signal to known potential developers that the network can meet their capacity needs.

	Actual FYE 2018	FYE 2019	FYE 2020	FYE 2021	FYE 2022	FYE 2023	FYE 2024	FYE 2025	FYE 2026	FYE 2027	FYE 2028
SOUTHERN AREA											
Kaikohe											
Base load	9.7	9.7	9.7	9.7	9.7	9.7	8.7	8.7	8.7	8.7	8.7
Energy Park	-	-	10.0	12.5	14.0	15.0	15.0	15.0	15.0	15.0	15.0
Total	9.7	9.7	19.7	22.2	23.7	24.7	23.7	23.7	23.7	23.7	23.7
Kawakawa	5.7	5.8	5.9	6.0	6.1	4.7	4.8	4.9	5.0	5.1	5.2
Moerewa	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Waipapa	11.4	7.6	7.6	7.6	7.7	7.7	7.7	7.7	7.7	7.7	7.7
Omanaia	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Haruru	6.1	6.2	6.4	6.5	6.6	8.2	9.3	9.5	9.6	9.7	9.8
Mt Pokaka											
Base load	1.0	1.1	1.133	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.4
Mill	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
New Industry	-		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total	2.4	2.5	3.0	3.0	3.0	3.1	3.1	3.1	3.1	3.2	3.2
Kerikeri	7.0	7.1	7.2	7.4	7.5	7.6	7.8	7.9	8.1	8.2	8.3
Kaeo	-	3.8	3.9	4.0	4.1	4.1	4.2	4.3	4.4	4.4	4.5
Mangamuka	-	-	-	-	-	-	2.0	2.0	2.0	2.0	2.0
NORTHERN AREA											
Okahu Rd	8.3	8.4	8.5	8.6	8.6	8.7	7.8	7.9	7.9	8.0	8.1
Taipa											
Base load	5.5	5.5	5.5	5.6	5.6	5.6	5.6	5.6	5.6	5.7	5.7
Carrington			3.0	4.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Total	5.5	5.5	8.5	9.6	10.6	10.6	10.6	10.6	10.6	10.7	10.7
NPL	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Pukenui	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6

Table 5.4: Zone Substation Demand Forecast – Winter (MW)

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

	Actual FYE 2018	FYE 2019	FYE 2020	FYE 2021	FYE 2022	FYE 2023	FYE 2024	FYE 2025	FYE 2026	FYE 2027	FYE 2028
Kaikohe	45.8	47.0	57.0	60.0	62.0	63.0	62.0	63.0	63.0	64.0	64.0
Mangamuka	-	-	-	-	-	-	2.0	2.0	2.0	2.0	2.0
Kaitaia	23.1	23.1	26.0	27.0	29.0	29.0	28.0	28.0	28.0	28.0	28.0
NETWORK	68.9[1]	69.7	83.6	87.7	90.9	91.5	92.1	92.7	93.4	94.0	94.6

Note 1: Estimated from SCADA data. May not correspond to disclosed demand in FYE2018 information disclosure.

Table 5.5: 110kV Transmission Substation and Network Demand Forecast – Winter (MW)

Tables 5.6 and 5.7 show the shoulder and summer demand forecasts for each zone substation.

	Actual FYE 2018	FYE 2019	FYE 2020	FYE 2021	FYE 2022	FYE 2023	FYE 2024	FYE 2025	FYE 2026	FYE 2027	FYE 2028
SOUTHERN AREA											
Kaikohe											
Base load	8.1	8.1	8.1	8.1	8.1	8.1	7.2	7.2	7.2	7.2	7.2
Energy Park			9.0	11.5	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Total	8.1	8.1	17.1	19.6	21.1	22.1	21.2	21.2	21.2	21.2	21.2
Kawakawa	5.3	5.4	5.5	5.6	5.7	4.3	4.4	4.5	4.6	4.7	4.8
Moerewa	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Waipapa	10.2	6.9	6.9	6.9	6.9	6.9	6.9	7.0	7.0	7.0	7.0
Omanaia	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Haruru	4.7	4.8	4.9	5.1	5.2	6.8	6.9	7.0	7.2	7.3	7.4
Mt Pokaka											
Base load	0.8	0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0
Mill	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
New Industry			0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total	2.2	2.2	2.7	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9
Kerikeri	5.9	6.0	6.2	6.3	6.4	6.6	6.7	6.9	7.0	7.1	7.3
Kaeo	-	3.4	3.5	3.6	3.7	3.7	3.8	3.9	4.0	4.0	4.1
Mangamuka	-	-	-	-	-	-	1.8	1.8	1.8	1.8	1.8
NORTHERN AREA											
Okahu Rd	7.2	7.3	7.4	7.5	7.5	7.6	6.8	6.9	7.0	7.1	7.1
Taipa											
Base load	5.4	5.4	5.4	5.4	5.5	5.5	5.5	5.5	5.5	5.6	5.6
Carrington			3.0	4.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Total	5.4	5.4	8.4	9.4	10.5	10.5	10.5	10.5	10.6	10.6	10.6
NPL	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Pukenui	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8

Table 5.6: Zone Substation Demand Forecast – Shoulder (MW)

	Actual FYE 2018	FYE 2019	FYE 2020	FYE 2021	FYE 2022	FYE 2023	FYE 2024	FYE 2025	FYE 2026	FYE 2027	FYE 2028
SOUTHERN AREA											
Kaikohe											
Base load	6.2	6.2	6.2	6.2	6.2	6.2	5.4	5.4	5.4	5.4	5.4
Energy Park	-	-	7.5	10.0	10.5	12.5	12.5	12.5	12.5	12.5	12.5
Total	6.2	6.2	13.7	16.2	16.7	18.7	17.9	17.9	17.9	17.9	17.9
Kawakawa	6.8	6.9	7.0	7.1	7.2	5.8	5.9	6.0	6.1	6.2	6.3
Moerewa	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Waipapa	8.1	5.1	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.3
Omanaia	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Haruru	4.3	4.5	4.6	4.7	4.8	6.4	6.6	6.7	6.8	6.9	7.0
Mt Pokaka											
Base load	0.7	0.7	0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0
Mill	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
New Industry			0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total	2.1	2.1	2.7	2.7	2.8	2.8	2.8	2.8	2.9	2.9	2.9
Kerikeri	4.9	5.0	5.1	5.3	5.4	5.6	5.7	5.8	6.0	6.1	6.2
Kaeo	-	3.0	3.1	3.2	3.3	3.4	3.4	3.5	3.6	3.7	3.7
Mangamuka	-	-	-	-	-	-	1.6	1.6	1.6	1.6	1.6
NORTHERN AREA											
Okahu Rd	6.1	6.2	6.2	6.3	6.4	6.5	5.8	5.9	5.9	6.0	6.1
Taipa											
Base load	4.9	4.9	5.0	5.0	5.0	5.0	5.1	5.1	5.1	5.2	5.2
Carrington	-	-	3.0	4.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Total	4.9	4.9	8.0	9.0	10.0	10.0	10.1	10.1	10.1	10.2	10.2
NPL	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5
Pukenui	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7

Table 5.7: Zone Substation Demand Forecast – Summer (MW)

5.6.2 Uncertainties in the demand forecast

While the block loads included in the forecast have been consented, or are close to being consented, we have not received any formal applications to provide supply and it is still uncertain which of these will go ahead. If they do proceed, the timing and magnitude of the additional demand still needs to be confirmed. Because of this, the forecast capital expenditure in this AMP has made no explicit provision to supply these new loads. We anticipate that expenditure to supply these loads will be funded, in part, by capital contributions rather than from regulated revenue.

The initial load at the Ngawha Energy Park is forecast to be about 10MW and to increase to around 14MW within three years. Our load forecast allocates this load to the Kaikohe zone substation, which is expected to be able to supply the initial demand at 11kV, but if the total forecast load materialises a new zone substation within the park will be needed. Our load forecast assumes that, for the project to proceed, an "anchor" tenant with a high demand will be needed, in which case new substation will be required to be commissioned in FYE2020 or FYE2021.

The Chinese owners of the Carrington Resort at Matai Bay on the Karikari peninsula have applied for resource consent to develop and expand the resort with the addition of approximately 800 rooms and we have been advised that the additional demand from this development will be approximately 5MW. The scale of the proposed development is such that we would not be able to supply the resort from the 11kV feeder currently serving the area. Local generation support at times of peak demand appears the most cost-effective option, since it can be installed relatively quickly and is scalable to match the actual load once the development is operational. Our forecast includes provision for the purchase of diesel generation, some of which could be located within the resort complex. Tourism ventures have a high value of lost load, so it is highly probable that a large resort in such a remote location will require local backup using diesel generation or new technology, rather than being totally reliant on a grid supply. When it is known that the development will proceed, we will liaise with the developer to negotiate a solution that best meets its needs.

The expected load of the Waipapa industrial development is around 500kW and there is sufficient spare capacity in the existing network to meet this requirement.

The Northland Maori tribes Iwi have yet to negotiate a treaty settlement with the Government that, when finalised, could inject well over $200 million into the Northland economy. The Government is encouraging the tribes to enter seriously into treaty negotiations. Our forecast makes no provision for the economic stimulus that an eventual treaty settlement could provide to our supply area.

5.7 Emerging Technologies

5.7.1 Background

In the past, consumers taking supply from a shared distribution network had little choice but to accept the level of reliability provided by their distribution business at a cost set by a monopoly electricity supplier. The more recent introduction of retail competition has provided some limited ability to manage cost and some control over service level, in that consumers can now choose whether loads such as water heating are controlled by their suppliers. Technologies are emerging that will offer consumers the ability to actively manage the cost of the electricity they use and how it is sourced. This places a cap on the revenues that can be extracted from a centralised market for electricity supply, which is therefore no longer a monopoly business. Whereas electricity consumers have had little choice but to connect to the grid, emerging technologies are providing alternatives to a grid connection, if the cost and level of service provided do not meet their requirements.

Emerging technologies are beginning to disrupt the traditional industry business model and, as their capability expands and costs decline, the extent of this disruption can only increase. We cannot stop this trend but must adapt by addressing the issues they present and delivering new services to the markets that this greater diversity will enable.

Emerging technologies include

- photovoltaic generation;
- battery storage and management systems;
- microgrid inverters;
- household energy management systems;
- smart appliances, the internet of things and artificial intelligence;
- electric vehicles, their associated charger technology and ability to be used by the network for energy storage; and
- advanced network control systems.

While technologies form the building blocks, the major capability advances will arise from software upgrades able to be incorporated into these base technologies. For example, electric vehicles only need a software change to become autonomous. Microgrid inverters and vehicle chargers may converge and become capable of home energy management with software enhancements. These technologies now exist, and their costs are declining and capabilities increasing very rapidly.

Accordingly, we face a high level of technology risk, which we will need to manage by not trying to pick winners and losers, remaining agnostic to brands and sellers, and not making investments that are better made by consumers. While we have no role to play in technology development, we will need to develop capabilities as system integrators to be able to apply new technologies as alternatives to traditional network solutions and support consumers wanting to interface their in-house applications to our network.

Currently there are more than 600 small photovoltaic generators injecting power into our network and this number is growing exponentially, in line with overseas trends. Our network is already transitioning from a traditional electricity distribution system to a distributed energy system (DES). This transition will accelerate as more photovoltaic and battery storage systems are connected. External parties will become involved in the mining and processing of mega-data and its application to a DES.

Mobile computing, the internet, cloud resident business solutions, intelligent devices in the field, smart phones, and the like. have become mainstream within our business over the past decade. The next decade will see a shift from poles and wires to a technology and soft asset-based business. Artificial intelligence will displace operational staff and our engineering capability will need to shift to a higher technology.

5.7.2 New Technology Challenges

5.7.2.1 Connection Costs

The present price point for connection of new consumers means that for consumers using less than 6,500kWh per year and located more than 1 km from the existing network, the least cost supply option is an off-grid remote area power supply (RAPS). RAPS technology has advanced to the point where self-management is no longer a hurdle (with lower cost and effort than managing a service line) and the security of supply is superior to what a grid connection can provide. At a conservative minimum, this technology is following a trend of halving in cost and doubling in capability over a 5-year period. Uptake is following this trend.

Our strategic options for managing the disruption this has the potential to cause include:

- using RAPS to avoid renewal of existing uneconomic grid connections;
- presenting consumers seeking new connections with a hybrid supply solution by actively supporting the consumer's decision-making options to provide an electricity supply tailored to its needs; and
- where it would benefit more than one consumer, developing a microgrid enabled low voltage network utilising ubiquitous technology solutions, and providing the operating support that a fully featured DES requires. Our input would create value for consumers choosing to connect.

5.7.2.2 Uptake

The potential adoption of new technologies is currently most relevant to consumers seeking a new power supply or needing to renew or upgrade an existing connection. The uptake of new technology such as photovoltaics is still in its early adoption phase and the early adopters are currently supplementing a full-service network connection with new technologies, which they use to enhance their existing supply, reduce grid supplied consumption, and improve efficiency, service, and resilience. Hence new technologies involving self-generation and storage are still generally used to supplement a grid connection rather than as a primary energy source. The rapidly advancing capability and features bundled with new technologies, and the new business models being developed to sell these to consumers, will gradually shift the primary supply role to self-generation and storage, particularly in parts of the network where customer density is low, and service limited.

We have New Zealand's second highest level photovoltaic penetration within our network – approximately 2% of consumers have installed photovoltaics amounting to almost 2MW of installed nominal capacity. The uptake in photovoltaic generation exceeds our base rate of growth in residential demand. If photovoltaics continues to follow same uptake curve as in Australia (which is largely servicing the NZ PV market) then we might expect to see:

- upwards of 30-40% of all residential supplies PV enabled by 2030. Uptake will be constrained by the number of New Zealanders that do not own their own homes and the relatively small number of homes that are not suitable for the retrofit of PVs; and
- half of these supplies (15-20%) with battery support from either dedicated battery storage packs or electric vehicles.

5.7.2.3 Transition to a Technology Enabled Distributed Energy System

The industry may suffer a public and regulatory backlash if it fails to position itself for the introduction of new technologies with minimum disruption. Public protest has resulted from a pricing change designed to claw back revenue lost to lower consumption where higher fixed charges were justified by a less efficient use of the network. The pricing was changed after consumers had made their decision to invest in the technology and this was perceived as unfair.

The Electricity Authority is also trying to ensure that electricity tariffs accommodate new technology within the bounds of cost and service reflective pricing. Establishing the terms and conditions for the service standards to be delivered would facilitate this.

Initially, while uptake in the use of new technologies is low, their application could have negative impacts on the management and operation of our network. Over time, as the penetration of these technologies increases, it will be feasible to install a more sophisticated distributed energy management system that will mitigate these problems. In the interim, measures are required to ensure that network costs arising from the uses of these technologies are not passed on to other consumers. To manage this issue, we are planning to introduce revised connection standards for each tariff.

We are still reviewing what should be included in our revised connection standards, but we expect them to pre-empt disruption from the use of new technologies by:

- constraining off-take and injection;
- creating an optimal load profile by limiting the size and control of hot water elements and electric vehicle chargers;
- specifying storage requirements such as the size of hot water cylinders;
- specifying energy efficiency requirements;
- prohibiting new high voltage SWER connections;
- requiring the use of standard designs and equipment when provided as part of our network;
- setting quality standards for connected plant.

The purpose of these new connection standards is not to take choice away from the consumer but to ensure that any additional costs we face as a result of the use of new technologies is paid for by the users benefitting from the technologies, and not by other consumers connected to the network. The standards will be consumer facing in that they will provide guidance on optimal design and signal efficient investment.

5.7.2.4 Electric Vehicles

Electric vehicles have the potential to accelerate photovoltaic uptake, particularly if vehicle suppliers bundle new vehicles with PV panels in a zero-fuel cost business model. This has happened overseas.

Most new vehicle sales in New Zealand are to corporate fleets. Employees using corporate electric vehicles are less likely to charge these vehicles at home at their cost – charging is more likely to occur during the day when PV resources are at their peak. Supermarkets and malls may also offer free charging from PV to their customers. Until electric vehicle charging trends become evident we will defer making any commitment to provision of charging stations on our own initiative. However, installing larger scale PV charging systems in car parks is an opportunity that we can communicate in our Statement of Opportunities and support with a trail installation.

Convergence of microgrid inverters, vehicle chargers and home energy managements systems will lower cost hurdles, stimulate the creation of new markets, improve efficiency, and accelerate uptake.

5.7.2.5 Battery Storage

Batteries are challenging assets to manage at the household deployment level. Their life and therefore economics is limited by how well charging and discharging is managed. The rise of the lithium-ion battery with its tolerance to operating in a partial state of charge, and the greatly improved battery management systems being integrated into microgrid chargers and inverters now mean that the cost of storing and reusing a unit of energy has reached parity with the cost of drawing a unit off the grid.

Further these systems are on a downward price trend (18% in Australia) and batteries could be half their current cost within five years. Under this scenario, limited battery life is no longer such an economic constraint. In the medium term, electric vehicle batteries will come to be viewed as a source of household energy storage and home energy systems will greatly improve their capabilities in the management of household load and energy storage. There is currently a very wide choice of inverter and battery technology in the market and some rationalisation is likely.

Battery storage in the home is therefore a risky market and we will not be looking to get directly involved. However, a technology agnostic pricing signal for the inclusion of storage and load management within an installation may be desirable.

Utility sized batteries for connection to a network are already available and offer the following potential applications:

- More efficient deployment in community scale microgrids;
- Ensuring frequency stability – particularly in a system with volatile renewable generation and slow response base load generation;
- Eliminating voltage disturbance and momentary loss of supply as standby generation is started, thereby providing an uninterrupted supply when backup generation is brought into service;
- Reducing the response time of interruptible industrial load by allowing instantaneous disconnection, with battery storage being used to supply the power needed for a managed plant shutdown;
- Adding storage to load management systems;
- Managing voltage as an alternative to regulators; and
- Managing peak demand through load shifting

As with peaking generators, the use of batteries in multiple applications improves their economics and they can be deployed in short term roles then relocated. There are niche roles where batteries may currently be the most cost-effective solution and their potential applications will increase as their costs reduce. Batteries will have a bigger role to play in a more developed DES, but they are not a key requirement in our current development plan.

5.7.3 New Technology Pilot Projects

Our capital expenditure forecast includes a constant price provision of $2.8 million for the implementation of pilot projects that trial the application of new and emerging technologies. Uneconomic lines reaching their end of life are presenting a problem in that the RERC funding model that built them is no longer available. Further technology disruption will threaten our business viability if we continue to meet our obligation to supply under the monopoly pricing regimes of the past.

Consistent with our key development strategy of shifting away from our asset intensive model, which supplies remote consumers from the end of long distribution lines, to a more asset efficient and resilient Distributed Energy System, we will work with consumers located at the edge of our network to determine the most cost-effective supply option and the appropriate balance between Top Energy's and the consumer's own investment. A non-network solution will not be affected by upstream network faults so is likely to be more reliable than the alternative, more expensive, network connection.

New solutions will involve new technology, new business models, enhanced service platforms, better customer engagement, better use of local resources, more regional independence, and decoupling from industry price path. Trials and pilots are needed for technical proof of concept, developing community partnerships, testing cost and ownership models, developing the operating capability, and asserting some standards over system integration in the interests of consumer protection.

The trials will have the following objectives:

- Development of a range of solutions that apply new technologies to address issues of poor service, high cost of supply, and the renewal of uneconomic networks;
- A focus on opportunities that are centred on distribution and the wider community in preference to individual service lines or consumers;
- A focus on projects where a community or business partnership might be developed; and
- Post-implementation analysis to determine appropriate demarcation between Top Energy and private sector or consumer investment, optimal design, build, and operation arrangements and associated commercial terms.

We have grouped potential pilot projects into six different categories:

1. Renewal of uneconomic lines:
    - Applying remote area power supply technology to a shared low voltage microgrid;
    - Locating core system components at a community centre, such as a marae or school – possibly where there may already be grid connected photovoltaic arrays in place but where the surplus energy generated is not used efficiently;
    - Eliminating marginal supplies (using less than 1,200kWh per year) – for example, stock water pumping using solar energy, or a generator hire service for woolsheds;
    - Extending the potential service area of low voltage microgrids using trickle chargers and battery storage;
    - Using alternative means of energy storage such as super insulated hot water cylinders or, pumped water.
2. Community hospital as host for a Top Energy owned generator:
    - Supplying standby generation to both the hospital and surrounding township;
    - Utilising waste heat energy;
    - Hosting larger scale photovoltaic array in car park.
3. Car parks such as supermarkets and retail centres.
    - Using photovoltaic arrays for car shading;
    - Locating electric vehicle chargers;
    - Matching photovoltaic generation to a large nearby air-conditioning load;
    - Using surplus photovoltaic generation to supply refrigeration.
4. Industrial uninterruptible power supplies targeting fast interruptible load;
    - Using battery storage to manage a controlled plant shutdown.
5. Alternative voltage regulator or load management node based on statcom technology with battery and generator support:
6. Dairy shed as an energy centre:
    - Balancing heating and cooling loads – for example hot water storage and ice banks;
    - Supplementing with photovoltaic arrays – located over feeding platforms or wintering sheds;
    - Biomass digestion;
    - Installation of a generator to also service wider area supplies.

The available research and development funding is limited and there are a wide range of possibilities, so we will be looking to implement projects in partnership with our community or with external parties such as energy retailers or equipment suppliers willing to share the cost and/or lead the delivery of new services in new markets that use our network.

5.8 Uneconomic Lines

In Section 3.1.7 we noted that 35% by length of our distribution network supplied just 9% of our consumers and was potentially economic. The issue is one of low customer density and low consumption, providing insufficient revenue to fund the capital and operating costs of assets used to provide supply. Uneconomic lines are a cost burden on other consumers when they require renewal. We are unable to disconnect consumers supplied from uneconomic lines as we are required by the Electricity Industry Act 2010 to continue to provide supply to existing consumers.

The Rural Electrical Reticulation Council (RERC) provided a revolving fund for the construction of approximately 12% of the nation's electricity reticulation. This fund worked by requiring consumers to guarantee certain levels of consumption for a long-term period (typically 20 years) on a take or pay basis at a higher energy tariff. Top Energy had the 4th highest share of RERC funding. It was hoped that economic development would provide sufficient revenue to meet replacement costs after 45 years, but this has not happened - with declining rural population and reducing energy consumption, revenue from RERC funded lines is declining while condition and safety driven maintenance costs are increasing. The scheme finished in 1970 and these assets are well past their nominal service life of 45years and most will need replacing over the next 10 years.

Our uneconomic lines are a public safety risk; their reliability is poor, and their maintenance costs are excessive. The scale of the issue presents some urgency – waiting for a new technology to resolve the issue is no longer realistic. Addressing this issue is therefore a key objective for the ten-year planning period of this AMP.

Assuming emerging technologies will not be available, potential options for funding the renewal of uneconomic overhead lines are:

1. creating a replacement revolving fund. This could be biased towards a network contribution to alternative supply arrangements;
2. differentiating pricing, so that consumers served by uneconomic lines pay more to reduce cross-subsidies. This may drive some consumers to reduce consumption or disconnect;
3. partnering with local communities that wish to undertake economic development and/or local generation projects by creating a development fund for projects that deliver value and efficiency;
4. requiring private service lines to be upgraded at consumers' cost before committing to a network upgrade. This could mean that consumers make more rational investment decisions regarding their electricity supply;
5. optimising design for least cost, and staging replacement of components (poles and conductors) to gain maximum life from assets. Design optimization could mean bigger spans, lighter poles, stronger conductor, and lower design standards in terms of resilience to extreme events. This is essentially the logic behind SWER construction. However, we will not be building more SWER lines due to their high public safety risk. Alternatively, we could limit supply capacity and provide supply at a lower voltage – for example providing 5kVA connections using a 3.3kV ploughed cable network;
6. socializing renewal costs across a larger consumer base. This may be an option where spurs can be formed into rings creating better service for economic connections or where there are reasonable prospects of future economic development;
7. renting generators to supplies such as woolsheds that have limited seasonal use. This would require a pool of suitable generators, connection standards and provision of a delivery and fuelling service.

Development of emerging technologies creates further possibilities for the management of uneconomic supplies. For example:

- The use of solar powered appliances such as solar pumps, solar electric fence units, or solar lighting, could make some grid connections unnecessary. While some consumers may be prepared to take full responsibility for their own installations (particularly for the lower cost/risk items) others may want support by way of a rental option with maintenance, fault service, and technology renewal provided by us. In this scenario, we would have control over quality and safety standards. This business model is similar to our provision of transformers.

- Solar power appliances could be augmented by equipment using an alternative energy source such as gas and solid fuel cookers, space heating or water heating. While we may offer consumer advice we do not seek a role in funding, installing, or servicing such equipment.
- Dairy sheds are generally an economic proposition. However, if they are located on the fringe of the network and connected to a line that is otherwise uneconomic, there are a significant number of energy efficiency opportunities that, combined with their seasonal load profile, make a RAPS a cost-efficient alternative to a grid connection. Their loads largely involve heating and cooling and are therefore able to be balanced for neutral energy consumption. They are generally in locations with a good solar resource and can capture and store energy between milkings. Solar energy could heat water directly, to reduce battery reliance. A RAPS can have a higher inherent security than a network connection.
- Dairy sheds could also host a microgrid for nearby supplies such as the rest of the farm or a neighbour.
- Microgrid inverters, and the rapid improvement in battery technology and cost, allow network supply capacity to be reduced to a trickle charge level (1kW or 5A at 230V). At this capacity and voltage, more consumers could be interconnected into a more extensive microgrid. The higher diversity of load on a microgrid allows more efficient sizing of PV, battery, and generator support and sharing of resources between consumers – for example not everyone would necessarily need PV at their site.
- Where communities, such as maraes, see merit in addressing their own resilience and/or managing social issues around the cost of supply, a microgrid solution could be a good option for them to consider and for us to encourage and support. Some such communities have already invested in PV. Adding a generator may resolve end of life performance issues sufficiently to wait until the addition of batteries to complete the final solution becomes more economic.

Not all possibilities would be applicable to a specific situation and there is a risk that, when consumers connected to an uneconomic line reduce their consumption through use of an alternative technology, the line would become even more uneconomic. Nevertheless, application of the technologies that are now emerging offers an increasing range of solutions that can be optimised to meet the specific needs of a unique situation.

5.8.1 Uneconomic Line Management Strategy

We are developing a strategy to lower the cost of satisfying the energy requirements of consumers connected to uneconomic sections of our network while at the same time meeting our obligation to supply in accordance with the requirements of the Electricity Industry Act 2010. This could include:

- pricing that encourages consumer investment in new technologies and better reflects the cost of supply;
- documented service levels that differentiate between different parts of our supply area and provide for a reduction in the level of service in areas that are uneconomic to serve;
- reductions in the cost of operating and maintaining the uneconomic network through:
    - applying risk management practices such as running assets to failure where it is safe to do so. This could mean changing works practices, such as banning pole climbing, to manage the risk of keeping assets in service for longer periods;
    - limiting the hours of fault response.
- assessing the economics of supply on an individual line by line basis and applying solutions optimized to meet the needs of specific situations;
- a communication plan that requires increased stakeholder interaction and that:
    - signals the end of service life to affected consumers, our options for managing this and how they will be affected;
    - consults with stakeholders on their vision for future development before planning an intervention;
    - requires consultation on alternative service levels and technology, and the price and investment impact of these; and
    - clarifies what we will provide and what consumers must contribute;

- a policy that requires service line and installation upgrades to be completed ahead of a network upgrade; and
- a requirement that any alternative system agreed with consumers be commissioned and proven before disconnecting and dismantling the existing network.

5.9 Distributed and Embedded Generation

The term "distributed generation" (DG - sometimes referred to as embedded generation) relates to any electricity generation facility that either produces electricity for use at the point of location or supplies electricity to other consumers through a local lines distribution network where it is connected at distribution rather than transmission voltage. Distributed generation connected to our network can be categorised as follows:

- Ngawha Power Station, which generates base load electricity for sale to retailers, large electricity users and the spot market, and which is currently connected to our Kaikohe 110kV substation at 33kV;
- Diesel generation installed to support the operation of the network by providing an alternative source of supply during a network outage or to offset localized shortfalls in network capacity. We are planning to increase the amount of network support generation over this AMP planning period, as discussed in Section 5.15, to reduce the cost of network development. Currently we own all the generation used to support our network, but we would welcome proposals from third parties to own and operate this generation.
- Generation installed by users of the network for their own purposes. Currently all such generation is small scale photovoltaic – we have a total of 2 MW connected photovoltaic generation spread across almost 600 different locations.
- We would welcome users wanting to connect larger generating units, perhaps utilizing the significant wind resource that is available in parts of our supply area, to our network. The discussion below relates to the connection of generation by external parties.

Our approach to user connected DG is based on the following key principles, as prescribed by the Electricity Authority.:

- DG can connect to our network on fair and equitable terms that do not discriminate between different DG schemes;
- the terms under which DG can connect and operate are as clear and straightforward as possible, within the limitations of maintaining a secure and safe electrical distribution network;
- all DG applications will be processed as quickly as possible;
- DG must comply with technical and safety standards based on industry practice;
- all relevant legislation and regulatory requirements must be adhered to;
- we reserve the right to limit the total capacity of DG connected to different parts of our network (in particular to each distribution feeder); and
- DG installations will be subject to normal industry connection requirements; in particular, those outlined in the Electricity Industry Participation Code.

We have adopted a formal Distributed Generation and Connection Policy and Technical Standards for DG proposals of less than 10kW, in the range 10kW to 500kW and greater than 500kW. These documents specify the:

- general procedure for applications and installation of DG (refer Figure 5.2 below);
- commercial terms;
- technical standards;
- liabilities of Top Energy and the applicant; and
- health and safety management.

Our policy and requirements for the connection of DG rated at less than 10 kW is available on our website. Proponents seeking to connect higher rated DG to the network are invited to contact us to discuss their specific requirements.

The process involved in connecting DG to our network is shown in Figure 5.1 below.

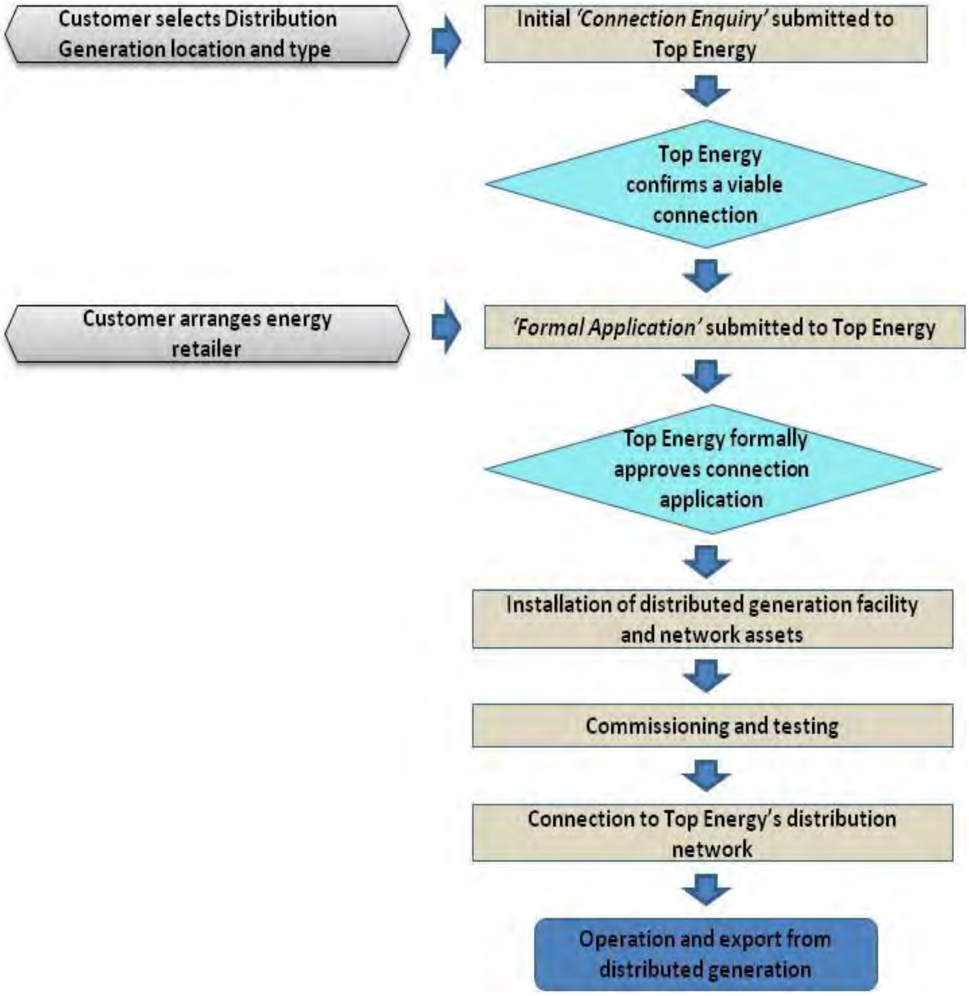


Figure 5.1: Distributed generation connection process

We consider potential supply-side options as an integral part of our project assessment process to determine whether capital expenditure can be deferred and also if maximum demand at the GXP can be reduced. This section briefly discusses our policies for supply-side options.

- **Embedded Generation (>5MW):** We encourage the provision of embedded generation by introducing potential consumers to suppliers, consultants and major energy companies that can assist in the development of such schemes.

  As a company, we have demonstrated its own commitment to embedded generation by establishing the 25MW Ngawha Power Station and we now have the necessary resource consents to increase the size of this power station by a further 50MW.

- **Dispersed Generation options (<5 MW):** Dispersed generation provides power to individual or small groups of installations. Where great distances separate potential electricity consumers from each other or from the grid, dispersed generation can be a cost-effective alternative to grid extension. Top Energy's recent installation of 4MW of diesel generation at Taipa substation is an example of this.

  The following options have potential for dispersed generation;

- small thermal generators. Generators installed as standby units in hospitals or industrial installations could potentially be synchronized to the network and used as part of a strategy to manage network peaks;
- solar panels (with or without battery storage). Solar panels connected through an inverter to the network have proved popular in Australia as a result of government subsidy programmes. Similar subsidies are not available in New Zealand but in spite of this approximately 2% of our consumers have already gone ahead and installed solar panels.
- mini and micro- hydroelectric; and
- wind power.

We use solar panels for some of our remotely controlled equipment to avoid the cost of a dedicated transformer.

The cost of supplying uneconomic consumers may create an opportunity to establish distributed generation solutions in place of upgrading old lines and we actively monitor the results of relevant research and pilot programmes currently being undertaken in New Zealand. However, there remain a number of legal and technical obstacles. In particular, standalone power supplies require intensive operation and maintenance and their installation would require the full cooperation of the consumers supplied. If these consumers are already connected to the network, we have a legal obligation to maintain supply.

We also note that now the capacity constraint at Kerikeri has been resolved and demand growth has abated, there are few capacity constraints that we need to address in the short term. In defining connection standards that specify the level of service and security that will normally be provided, we can negotiate specific arrangements for security sensitive consumers. Similarly, capacity upgrades will look at short-term provisions that allow a more affordable development path.

5.10 Non-network Options

Demand side management (DSM) refers to programmes or projects undertaken to manage a consumer's demand by changing the time of demand, therefore helping to reduce the network peak or maximum demand. By reducing demand at the network peak time, DSM options can reduce the use of existing network assets at the peak time, deferring the capital investment for additional capacity, and potentially also reducing our transmission charges. This could reduce the need to install diesel generation for network support. The selection of a viable DSM option starts with identification of all appropriate alternatives, their cost and performance characteristics.

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

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

- **Direct Load Management (DLM):** 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, random period after a total loss of supply to reduce switching spikes and avoid equipment overload. We estimate that the system currently reduces the actual peak demand on the network by 10MW.
- **Under-Frequency Load Shedding:** In order to prevent a total power system collapse under major grid disturbance conditions, Transpower requires that automatic tripping of certain percentages of each network's load should occur when an under-frequency event occurs on the system

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. In order 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 5.8 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 5.8: Emergency Load Shedding Specification

In terms of the quantity of load interrupted, Block 1 equals approximately 35% of our network maximum demand and Block 2 equals approximately a further 20% of the maximum demand.

5.11 Smart Metering

We have a contract with WEL Networks providing for the installation of a radio frequency (RF) mesh network within our supply area to facilitate the necessary communication network that smart meters require. This installation is now complete and a programme of smart meter installation for all Contact Energy (our incumbent retailer) consumers is now in its implementation phase. Smart metering offers opportunities for ourselves, our retailers, and our consumers, particularly over the medium and longer term. It 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 the communication link, avoiding the cost of monthly meter reading visits. Smart meters can be programmed to automatically advise when supply is lost, allowing a more proactive response to faults. Also, the more disaggregated demand data available using such meters should enable more effective planning of our network.

5.12 Network Development Plan

5.12.1 Introduction

We initiated a Network Development Plan in 2010 to address network constraints and reliability of supply. 8 years on the major network constraints have now been addressed but improvement to supply reliability continues. The following issues have still to be addressed:

- Approximately 10,000 consumers in our northern area are still reliant on a non-secure supply, since there is only one transmission line between Kaikohe and Kaitaia. These consumers are subjected to annual maintenance interruptions lasting approximately nine hours, as well as an elevated risk of unplanned fault interruptions.
- Supply reliability in areas not well served by existing zone substations is poor, due to the reliance on long feeders with high numbers of connected consumers. As the feeders are long, faults are more frequent, and the number of consumers affected by each one is high. Areas still of concern are the Russell Peninsula, the Hokianga, and the north east coast from Mangonui to the Karikari Peninsula.
- Outdoor switchgear at Waipapa is becoming technically obsolete and approaching end of life renewal.

5.12.2 Work Completed or Underway

The following components of the network development plan have been recently completed or, at the time of writing, were expected to be completed by the end of FYE2018.

- Upgrades to the protection systems on the core 33kV subtransmission network have been completed. These allow subtransmission assets to be operated in parallel, which permits supply to be seamlessly routed around faulted subtransmission network assets with no impact on consumers. Seamless N-1 redundancy is now provided at Okahu Rd, NPL, Kaikohe, Kerikeri, Waipapa, Haruru, Kawakawa and Moerewa;
- Synchronisers have been installed on the generators at Taipa so that consumers supplied from this zone substation do not experience a supply interruption before or after a planned maintenance outage of the 110kV line supplying Kaitaia;
- A new underground 11kV cable has been installed between Paihia and Opua. This will form part of a planned second 11kV feeder to supply the Russell peninsula;
- A full rebuild of the Moerewa substation involving the installation of new 33kV and 11kV indoor switchboards to replace the old outdoor switchgear and the installation of two new 3/5MVA transformers has been completed.
- Fans have been installed on both transformers at Kawakawa zone substation to increase their capacity and the transformers have been lowered to ground level to increase their earthquake resilience;
- A new zone substation at Kaeo is expected to be completed by the end of FYE2018. This will bring 33kV support and increase the reliability of supply to consumers in the Whangaroa area by reducing the number of consumers affected by each 11kV distribution network fault;
- Replacement of the old single-phase transformer bank at Omanaia with a new three phase unit was expected to be completed by the end of FYE2018, but will now be completed prior to the FY2019 winter;
- Refurbishment of the 33kV line supplying Pukenui will be completed by the end of FYE2018 and refurbishment of the line supplying Taipa has commenced and planned for completion by the end of FYE2019.

5.12.3 Planning Work in Progress

At the time of writing this AMP, we have not finalised standards, refined strategies and developed detailed action plans and supporting concept designs for projects that have still to be approved by the Board. Where concepts are robust enough to underpin projects likely to form part of our development strategy, these projects are provided for in our capital expenditure forecast. However, as with all major expenditure, implementation will subject to completion of supporting analysis and a detailed proposal with supporting cost benefit analysis for Board approval.

Development work and projects with this status are:

- *Distribution System Design Standard* – the gap analysis to determine the level of compliance with this newly introduced standard has not been completed. While the capital expenditure forecast includes provides for expenditure to increase the level of compliance, the work has still to be prioritized before planning and designs are finalized.
- *Security Standard* - The new security standard has been developed down to the distribution network and consumer connection level. There will need to be discussion with consumers regarding their needs and preferred solutions when non-compliance with the standard arises. It is not our intention to enforce security on consumers but to ensure they understand what level of security they are receiving and so that they can consider their risk exposure.
- *Uneconomic Lines* – This AMP presents a strategy for managing this issue and our expenditure forecast makes provision for some research and development on potential solutions for addressing the end of life transition from the existing situation to a new solution. It has not committed to specific transition approaches nor assessed priorities. An action plan is currently being developed and investment and funding is yet to be negotiated with those affected.
- *New block loads including Ngawha Energy Park* – These are included in the load forecast to reassure developers that the network is able to cater for their requirements. Funding has not

been provided for in the capital expenditure forecast because these require customised solutions and will be subject to commercial negotiations.

- *Mangamuka Substation* – this proposed new substation is expected to support a number of strategies and their associated projects. Until these have been finalized, the details of how the new substation is best connected to the network are unclear. However, it is highly likely that an additional injection point at Mangamuka will be justified irrespective of the final connection arrangement and the project is therefore provided for in the capital expenditure forecast.

5.13 Transmission Development

5.13.1 Strategic Issues Related to Transmission

Our GXP at Kaikohe (see Section 3.1.4) is supplied by a double circuit radial transmission line supplied from Transpower's Maungatapere substation. Each circuit has a winter rating of 77MVA and a summer rating of 63MVA. The fact that both circuits are carried on a single tower means the line is vulnerable to common mode faults affecting both circuits. This degrades the level of security provided and the current prohibition on live line work exacerbates this situation. As shown in Table 5.9, there has been an unplanned interruption of this line in each of the last four calendar years. However, transmission connection charges paid by our consumers are based purely on demand and are not discounted to reflect the reduced level of security compared to that provided to other EDBs. These transmission charges will increase substantially if the new Transmission Pricing Methodology being proposed by the Electricity Authority is implemented.

Date	Duration (hours)	Cause
17 November 2014	1.7	Lightning
9 October 2015	3.8	Unknown
8 December 2016	20.7	Vandalism
5 February 2017	6.2	Scrub Fire

Table 5.9: Grid Connection Interruptions

The function of our grid connection will change with the increase in capacity of the Ngawha geothermal power station. Currently the line is used primarily to import electricity for distribution to our consumers. Once the capacity of this power station to 53MW by FYE2021 the line will be used increasingly to export power south, and if the capacity is further increased to the consented level of 75MVA, then it will be used almost exclusively for export. In such a situation, consumers outside our supply area will benefit from the line and should therefore pay the transmission charges.

The horizontal axis in the demand profile in Figure 5.2 shows the percentage of the time each year that the total network demand exceeds a certain level. It shows that, currently, the total network demand is more than 50MVA for only around 12% of the time (about 1,000 hours a year) and that for 20% of the time (1,750 hours a year) it is less than 30MVA. Between these two points the curve is largely linear, with a slight "hump" in the middle which we think reflects increased demand during the summer tourist season. This load duration curve, which is typical of that experienced by most EDBs, shows that network peak demand occurs only during a few hours each year – currently our demand exceeds 65MVA for only 3 hours a year and 60MVA for only 90 hours per year. There is little point in investing large sums in grid augmentations to address network constraints that occur for such short periods as other less costly short-term approaches that can be implemented for short periods of time are generally available. That said, our network development plan is primarily designed to improve supply reliability and network resilience, rather than network overloads.

The installation of diesel generation within our supply area to address the security situation in the northern area means that our consumers could potentially be supplied exclusively from local generation once Ngawha is upgraded to 53MVA, if peak demand continues to be static. As shown in Figure 5.2, support from locally connected diesel generation would be required only about 10% of the time and we estimate that less than 1.5% of our consumers' total energy requirement would need to be supplied using diesel generation. If Ngawha's capacity was increased to 75MVA the power station could meet all current electricity demand within our supply area.

Reliance on diesel generation to meet demand peaks could be reduced further if we were to provide incentives for consumers to reduce load at appropriate times. Loads with a high thermal inertia such as heating, refrigeration and air conditioning are not time sensitive and could potentially be switched off during periods of peak demand with little impact on consumers.

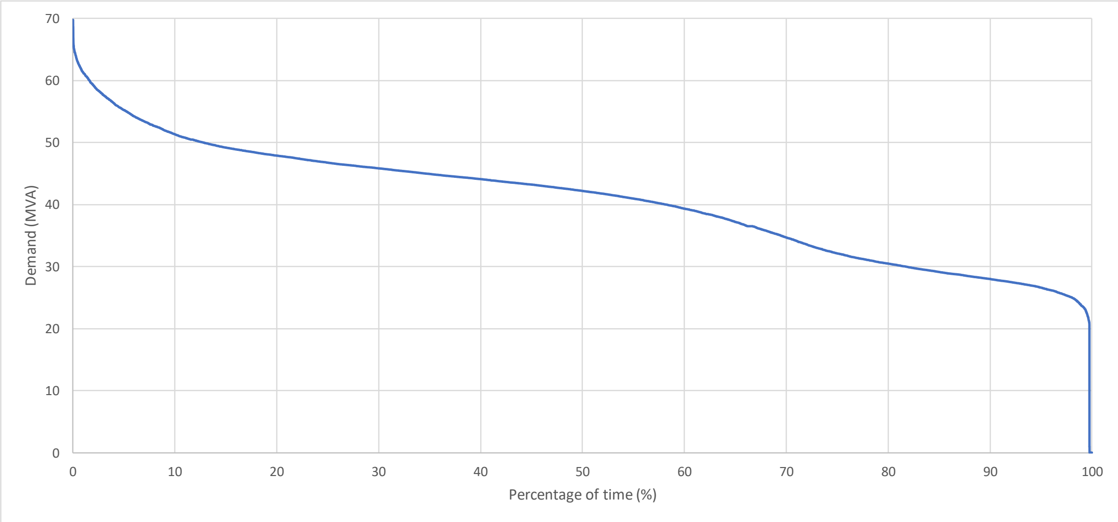


Figure 5.2: Top Energy Load Duration Curve

This raises two issues around the cost-quality trade-off with our existing connection to the Transpower grid that we will need to consult with our customers on:

1. Our transmission costs are currently $9 million per year and the distributed generation within our network has 96% reliability. What portion of our consumer base would be willing to forgo this grid connection to eliminate these transmission charges in favour of diversifying and increasing local distributed generation; and

2. Will generators still want N-1 security on their connection to the grid. If only N security is required, half the assets connecting our network to the grid could be turned off. To prevent such perverse outcomes, where Transpower assets become stranded simply because its pricing methodology does not recognize the rise of distributed energy systems, it will be necessary to negotiate transmission pricing on a notional basis.

5.13.2 Major Transmission Projects

5.13.2.1 Kaikohe-Wiroa-Kaitaia 110kV Line

The dependence of the Northern area on a single 110kV line from Kaikohe has been a source of concern to for many years. The existing line uses the most direct route and crosses the Maungataniwha Range, where the towers are relatively inaccessible and difficult to maintain. A second line operating at 50kV existed until the late 1980s but was abandoned because of its poor condition and the fact that it had insufficient capacity to provide full N-1 backup.

A number of options have been considered at various times to improve security to the northern area. The provision of a source of base load generation in the area has always been an alternative that on the surface, appears attractive, but which has proved elusive. Several generation projects have been proposed in the past, but none have progressed past the feasibility stage. The most probable option is wind generation and there have been at least two proposals. However, wind generation is not dispatchable and therefore cannot provide the controllable output necessary for a credible alternative supply unless it is integrated with a diverse mix of other generation.

The construction of a second line over a route parallel to the existing line has also been a continuing possibility that has been considered by Transpower and ourselves for many years. However, this option is expensive and difficult to justify when its only benefit would be to provide an alternative supply when the existing line is out of service.

The need to reinforce the network to address a capacity constraint in the Kerikeri area created an opportunity that did not previously exist, as it has made the construction of the second line over an alternative, relatively accessible coastal route, more economically feasible. This is because the line could also supply Kerikeri, Kaeo and eventually Taipa. Transpower's agreement to our acquisition of its assets in 2012 facilitated this plan, as it has avoided the constraints and additional costs that would have arisen had a new line over the coastal route been built and operated as part of the Transpower grid.

A second 110kV line between Kaikohe and Kaitaia would supply 110kV substations at Wiroa and Taipa, and over part of the route will also support an incoming 33kV supply to the planned new Kaeo substation. Construction of the double circuit southern section between Kaikohe and Wiroa is now complete and this section is in service, operating at 33kV. Work on securing a route for the new 110kV line between Wiroa and Kaitaia commenced in FYE2014 and still continues. While agreement has been reached with most affected landowners, three have appealed our plan to the Environment Court and the case is likely to be heard during FYE2019. While we are confident that we have a strong case, we cannot be sure that we will be able to build this line until this legal avenue has been exhausted.

We are now planning to install additional diesel generation in the northern area to augment that already installed at Taipa. This has a relatively low initial capital cost and, provided there are no delays obtaining the required consents, are expected to be in service by the end of FYE2020. The diesel generation will enable uninterrupted supply to be maintained (excepted for large consumers such as NPL where alternative arrangements have been negotiated) during planned transmission interruptions, and to be restored in less than an hour following an unplanned interruption. Diesel generation has high operating and maintenance costs and higher greenhouse gas emissions than grid connected generation, so is not viable as a permanent base load supply. It will be used to supply the network during transmission outages and may also be operated during system peaks to reduce or eliminate the need to import power from the transmission grid. Further information on our use of diesel generation is provided in Section 5.15.

There is a need to provide a base load supply to the northern area that does not depend on the existing 110kV transmission line by about 2030, when we anticipate that the existing line will need to be out of service for extended periods, so the conductor can be replaced. This AMP provides for construction of the Wiroa to Kaeo and Kaitaia to Peria sections of the second line over the period FYE2026-28 to allow for the second incoming 33kV circuit to Kaeo and a new 110kV circuit to supply the Taipa area to proceed.

This project is categorised as reliability, safety and environment, since its primary purpose is to improve the security of supply to our northern area.

Consumer Survey

In February 2018, we conducted a telephone survey of 400 randomly selected consumers in our northern area on the acceptability of using diesel generation to provide supply security to our northern area as an alternative to constructing the planned second 110kV circuit. The surveyed consumers were from the following consumer groups:

- domestic;
- industrial and commercial;
- tourism and hospitality; and
- essential services (schools, marae, ambulance, police etc.).

While the response rate was only 30%, some very clear views emerged. In particular:

- 78% of respondents said that the planned nine hour planned maintenance interruption on Sunday 26 November caused no more than minor inconvenience.
- Only 12% of respondents considered that diesel generation was not an acceptable alternative to a second line. 41% considered diesel generation to be an acceptable long-term solution while

slightly more (47%) thought that diesel generation was only acceptable as a short-term approach. 67% of industrial and commercial consumers considered that diesel generation should only be a short-term solution, whereas the other consumer segments were evenly divided between a short- and long-term.

- 79% of respondents considered that three days was the longest acceptable unplanned power interruption, given that the existing line crosses some rugged country that gets a lot of storms. Unfortunately, shorter periods were not given as alternatives to this question, so it cannot be assumed that a three-day interruption would be considered acceptable by all these respondents.

We conclude from this that our decision to secure supply in our northern area though the installation of diesel generators has the support of a majority of our consumers. While the occasional planned interruption lasting eight or nine hours on a Sunday is acceptable, it is not clear that this would still be the case if the frequency of such interruptions increased. Furthermore, we have been given a very clear message that unplanned interruptions with an extended duration are not acceptable to most consumers.

Now that we no longer undertake live-line maintenance on the 110kV line, more frequent planned outages of this line will be required. In addition, the tower failure that occurred in December 2014 showed that an expended unplanned outage of this line is a real possibility. Our plan to install diesel generation in the Kaitaia region addresses both concerns.

5.13.2.2 Ngawha Generation Connection

We plan to construct a 110kV spur line to connect the additional Ngawha power station capacity to the existing Kaikohe-Wiroa double circuit line, which is constructed at 110kV but currently operated at 33kV. While the detailed connection arrangement has still to be finalised it is anticipated that, following completion of Stage 1 of the Ngawha project, one circuit of the Kaikohe-Wiroa line between Kaikohe substation and the Ngawha tee will feed the electricity generated by the new Ngawha generator directly into the Kaikohe 110kV bus. The remainder of this line will continue to be energised at 33kV to supply Wiroa, as shown in Figure 5.3. This work is programmed for FYE2019-21. This arrangement is shown in Figure 5.3.

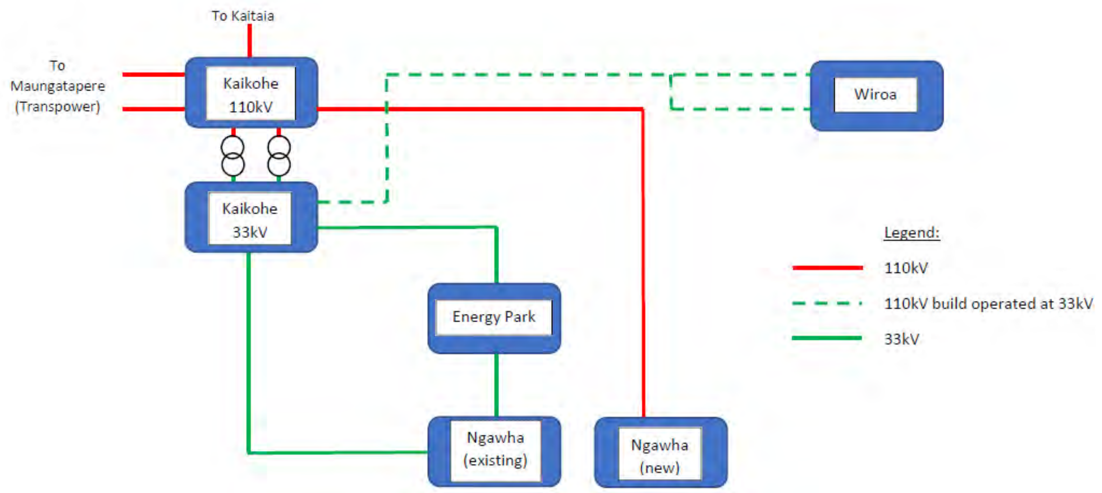


Figure 5.3: Potential Connection of Ngawha Power Station

5.13.2.3 Wiroa 110kV Substation

Lower than expected demand growth has allowed energisation of the substation at 110kV to be deferred and construction of the 110kV switchyard and commissioning of the first 110/33kV transformer is now planned for FYE2022, but its timing is dependent on what load develops at the Ngawha Energy Park.

This project is categorised as network growth.

5.13.2.4 Mangamuka 110kV Substation

We plan to construct a small 110kV substation at Mangamuka to inject power into the South Road and Rangiahua feeders. This will support the voltage on these feeders, which are two of the longest on our network. It will also improve reliability by segregating the two long feeders into shorter ones with fewer connected consumers. It will also reduce the load at Kaitaia and reduce the contingency provision required for the northern network.

This work is programmed for completion in FYE2023.

5.13.2.5 Sectionalisation of Kaikohe-Kaitaia 110kV Line

We plan to install a number of remote controlled disconnectors or remote indication fault locators along the Kaikohe-Kaitaia line to assist with fault finding by reducing the length of line that needs to be patrolled. When an unplanned fault occurs, the line will be sectionalised from the control room and progressively reenergised, to allow the location of the fault to be identified more precisely. After diesel generation is installed in Kaitaia, reenergisation for fault location purposes can occur from both ends to provide even more precise indication of the fault location.

This work will be funded from the transmission line maintenance budget allocation. Sectionalisation will be achieved gradually over time as the sectionalising devices can only be installed when the line is deenergised for planned maintenance.

5.14 Subtransmission Development

Construction of the new Kaeo substation and replacement of the transformer bank at Omanaia, which are both scheduled for completion by 31 March 2018, will complete our subtransmission development programme, apart from the provision of a second incoming supply to Kaeo. Initially the Kaeo substation will be supplied from a single incoming line from Waipapa, which was built to 33kV construction some years ago and has since been operated as an 11kV feeder. This line has recently been refurbished. The second 33kV incoming line will be constructed once the southern section of the Wiroa-Kaitaia line route is available. Our current plan is to construct the section of the new line between Wiroa and Kaeo as double circuit and to eventually run one circuit at 110kV and the second at 33kV.

However, an alternative approach would be to construct Wiroa-Kaeo line section as a single circuit, which could initially be operated at 33kV and then install a 110/33kV substation near Kaeo at the later date. This would leave open the possibility of injecting power into Manganui from the east without having to supply it at 33kV all the way from Wiroa. Construction of this Wiroa-Kaeo line section is currently planned for completion by FYE2028 to provide the second incoming supply into Kaeo by FYE2030.

A new energy park close to Kaikohe and the Ngawha power station, with seed money provided by the Far North District Council, has been consented and is currently in its final planning stages. Our load forecast assumes that this will proceed. The energy park location is close to a number of 33kV lines terminated at the Kaikohe zone substation and diverting one of the existing 33kV lines between Kaikohe and Ngawha, as shown in Figure 5.3, would allow the energy park to be supplied directly from the power station.

5.15 Generation Development

5.15.1 Objectives

The primary reason for Top Energy to connect embedded generation is that it can be a less costly means of achieving our desired level of supply security and reliability than a network augmentation. As discussed in Section 5.13.2.1, we are planning to install generation close to Kaitaia as an interim measure to secure supply to our northern region before the second 110kV line is completed or a more permanent solution with base load capability is developed. We are also planning to install diesel generation at Omanaia to provide supply security while the incoming 33kV single circuit line is refurbished, and this generation will be relocated to Kaitaia after this project is completed. These projects are committed, and funding is available. The Omanaia generation is scheduled to be commissioned by the end of FYE2019 and generation to support the northern load is scheduled to be in place by the end of FYE2020.

Smaller, mobile generating units can also be deployed to provide network support in other situations. For example, generation can be installed to provide supply at the remote end of a long radial feeder to minimise supply interruptions while an upstream line rebuild project is implemented. Diesel generation can also be used to inject reactive power into the network and can thus be used to provide voltage support to at the end of rural feeders. This approach could, for example, be used to avoid or defer the cost of a line upgrade to supply to supply a tourist driven seasonal load – supply to the Karikari peninsula is a potential application.

As discussed in Section 5.13.2 below, it is intended that this generation is dispersed across the network and made up of a range of unit sizes. The smaller units will be mobile so that can be moved around the network to meet operational requirements. With the plant being dispersed through the network and applied to a diverse range of network management applications, a key capability that we may need to develop is a Distributed Energy Resource Management System (DERMS). This would build on existing SCADA and load management systems and be integrated with Top Energy's current Advanced Distribution Management System (ADMS) project. Funding for this has not been provided in the capital expenditure forecast in this AMP but we plan to undertake an investigation into the costs and benefits of such a system and the capabilities required after the design of our ADMS has been finalised and generation is in place at both Kaitaia and Omanaia.

There is also potential for diesel generation to be used for demand management when the grid is connected, particularly during a dry year when the market price of electricity is high. In such situations it may be cheaper to generate electricity using diesel generators located close to the load than to generate the electricity using peaking plant in Huntly or Taranaki and transporting it to our network. However, if the generation is to be used in this way commercial arrangements will need to be in place so that we are reimbursed for the cost of generation. Top Energy is not a retailer and the desired commercial outcome will not be achieved if electricity generated for this purpose is cannot be sold, either into the wholesale market or directly to retailers.

5.15.1.1 Operation of an Islanded Network

Embedded diesel generation is also needed if Ngawha is to be used to supply the network in islanded mode when Transpower's incoming supply is not available. In this situation the generation will provide both a black start and a frequency keeping function.

Black Start

The Ngawha power station will shut down automatically if the connection to the Transpower grid is lost due to an unplanned interruption. Investigations have shown that it is not practical to design and configure the power station to ride through such a disturbance. It is possible for Ngawha to supply our consumers with our network in islanded mode without being connected to the grid but to do this it must be restarted after the grid connection is lost. This requires an external supply to power the auxiliary systems (pumps etc) needed to start and operate the generators. Diesel generators, which can be started without the need for auxiliary power (other than a battery), can be used to perform this function.

Frequency Keeping

In order to maintain power system frequency close to 50Hz the quantity of electricity being injected into the network must be continually adjusted to match the quantity be drawn off the network by consumers. If there is excess injection the frequency will rise and, conversely, if too much electricity is being drawn off the network then the frequency will fall. Thus, for our network to be successfully operated as an islanded power system, there must be connected generation that can change its output with a response speed that is sufficiently fast to match changes in demand. While diesel generation can achieve this, geothermal generation is too slow.

Once Stage 1 of the Ngawha power station expansion is commissioned, Top Energy is planning to have sufficient diesel generation connected to the network to allow the network to be operated in islanded mode at times of peak demand, taking due account of the potential to manage demand through use of our hot water control system and application of other load shedding arrangements that we can make with consumers. We estimate that we will need approximately 16MVA of connected diesel generation capacity to achieve this.

5.15.2 Planned Generation Fleet

An optimal generation fleet comprises a mix of generator ratings to provide for efficient dispatch and fuel consumption. There will also be a range of packaging to meet varying noise containment and transportation requirements. There should also be the ability to inject power at different voltages, the ability to operate in tied or island modes, and compatibility with a centralised DERMS.

Generators are often deployed in pairs so that they can share the load duty – their optimum performance is at 70% of their nameplate rating and their continuous rating is also 70%. They can peak at 110% of nameplate for 1 hour, provided they are in good mechanical condition. A large generator also has regulation and coking issues if run for extended periods below 40% of its rating. Pairing also reduces risk exposure during maintenance downtime. The DERMS needs to be able manage dispatch of the right combination of generators and at right generation levels in a dynamic fashion.

Our planned generator fleet comprises:

- three 650kVA generator sets. These will have a canopy type enclosure and be small enough to lifted and transported by TECS. They will have good noise containment so could be deployed in a wide range of temporary locations quickly without consenting issues. The mobility of these units makes them ideal to support feeder maintenance on radial feeders. These units can be uplifted and moved to a new location within a day and can be easily located – they could for example be placed in a car parking space on the side of a road.

- twelve 1,250kVA containerised generating sets: These are the standard building blocks in generator enabled networks. They will be containerised into 20ft containers and seven of the twelve units will meet very high noise control standards providing flexibility of location. These units could potentially be deployed on a seasonal basis to support summer holiday loads as they are sized to a large feeder. They are best deployed on a feeder where voltage is a constraint as a short-term alternative to installing voltage regulators or a conductor upgrades.

- two 2.25MVA containerised generating sets: These are the maximum size generator that can be containerised and have a limited level of noise control. Their primary role would be securing zone transformers and subtransmission where outages can be very long. They take approximately one week to relocate, so are not readily deployable in response to a major event response – they need heavy lifting equipment, over-weight transport permits, resource consenting, and have onerous refuelling requirements. We already have these units, which are currently deployed at Taipa.

5.15.3 Implementation Plan

Our deployment plan for the new generator fleet is shown in Figure 5.4. The two main generating stations will be at our NPL zone substation, which is in an industrial area where noise is less of an issue, and at the Kaitaia substation. While the Kaitaia substation is located in a rural area, the generators there will all be low noise units to minimise their impact on neighbouring properties. The remaining units will be dispersed across the northern network as shown in the diagram.

Three 1.25 MVA units will initially be installed at Omanaia to allow the refurbishing of the single circuit incoming line 33kV line from Kaikohe and will be transferred to Kaitaia and NPL when this work is complete. The generators currently installed at Taipa will be transferred to NPL and replaced with smaller generators located remote from the substation on the Karikari, Mangonui and Oruru feeders.

A 1.25 MVA unit will be installed near Broadwood on the South Road feeder and the three small units will be installed on the Herekino, and two Pukenui substation feeders.

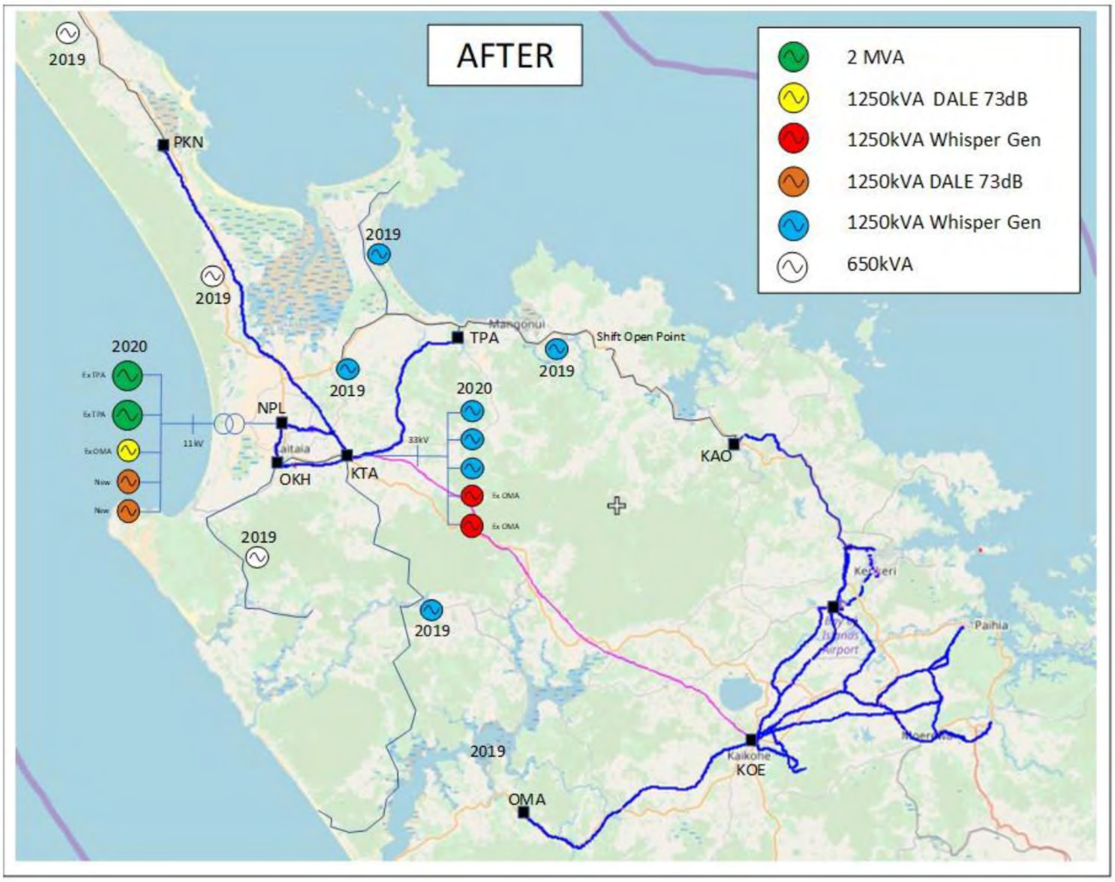


Figure 5.4: **Generator Deployment Plan**

5.16 Distribution Network Development

It is not cost effective to secure supply to consumers connected to the distribution network with a comprehensive N-1 full redundancy strategy. A more practical strategy is to limit the size and length of feeders to reduce the area affected by an outage and enable faults to be found more quickly. Feeders should be interconnected into rings or a mesh, with sufficient redundant capacity to allow the load to be supplied from the remote end to allow fast restoration of supply to areas not directly affected once a fault has been found. Ideally the network should incorporate sectionalising points so that the full impact of a fault requiring an extended repair is limited to a few consumers within a relatively small area and supply to consumers outside this area can be restored before a fault is repaired. Sectionalising points can be as simple as a line break where disconnection requires the manual removal of bolted joints. Response and flexibility can be improved by sectionalising, using remote and locally operated switches, auto-restoring protection equipment and new technology such as an advanced distribution management system.

Now that we have our subtransmission and zone substation infrastructure in place, we will focus on improving the reliability of the distribution network. Initially this will involve the development of distribution system design standards that will define our standard network architecture. We anticipate these standards will specify:

- the maximum circuit length, peak demand, and number of connected consumers for distribution feeders supplying urban, rural, and remote parts of the network;
- the standard conductor size and other line design parameters that define the capacity of the line and the contingent load that a feeder must be able to deliver to interconnection points;
- criteria for determining the points at which a feeder needs voltage support, busing and sectionalizing;

- criteria for determining the type of sectionalizing equipment to be used at different sectionalizing points to ensure consistency of fault finding, isolation and supply restoration; and
- standard design solutions to address these issues.

These standards are expected to underpin operating practice and service delivery. Network design, particularly the system architecture, has a bigger impact on service delivery and life cycle cost than other influencers such as maintenance, effectiveness of fault response practices, etc.

Table 5.10 summarises the architecture of the typical distribution feeder currently on our network.

	Urban	Rural	Remote
Total Feeder			
Peak demand (MW)	1.4	1.3	1.3
Annual energy delivered (MWh, excluding ICPs > 1GWh)	7,200	7,000	7,200
Total ICPs	720	750	950
Total length (km)	12	75	160
No. of transformers	35	150	300
Connected transformer capacity (kVA)	5,000	6,750	9,000
Average transformer size (kVA)	140	45	30
ICPs per transformer	23	7	3
Transformers per km	3	2	4
ICPs per km (connection density)	65	10	6
KWh per ICP	10,000	9,250	7,500
MWh per km (Load density)	650	90	45
Feeder Backbone			
No of reclosers	0.3	1	1
No of sectionalisers	1	2	3
No of air break switches	4	7	9
Backbone length (km)	7	20	45
No of sections	7	11	16
Backbone length per section (km)	4	3	5
No of transformers per section	8	5	8
No of ICPs per section	365	90	400
Automated switch spacing (km)	-	8	13
Manual switch spacing (km)	1.2	2.6	3.1

Table 5.10: Typical Feeder Architecture

5.16.1 Distribution Development Plan

Our network is characterised by long, remote, radial feeders which, by their very nature, exhibit poor reliability and security of supply. Few have any interconnections with other feeders to provide an alternative source of supply should an outage occur. Sectionalising devices are primarily locally operated air break switches. Hence, when a fault occurs, consumers can be without power for extended periods while fault staff drive to the area to begin the switching needed to identify the part of the feeder where the fault is located and restore supply to upstream consumers. This is even before the fault is found and repair commences. From previous development initiatives, all feeders have some automatic sectionalising and remote switching, which has helped reduce outage times. However, cutting feeders into yet smaller sections and increasing the number of automatic sectionalisers and remote switches will reduce outage times still further.

Perhaps the worst example is the South Rd feeder, which supplies the North Hokianga area. This feeder consists of 220km of 11kV line and supplies almost 850 consumers. It has experienced, on average 36 faults per year over the past 5 years adding 60 SAIDI minutes per year to our measured system reliability. This means that the average consumer supplied from this feeder is without supply for a total of almost 38 hours a year when the impact of all faults is aggregated. It currently has 15 switches along its length of which only 3 are automated, and except for the first 5km, there is no interconnection with any other feeder.

To improve the performance on South Rd feeder and others like it we are planning to install more automatic sectionalisers and remote-control switches on those parts of the network where the performance is poor. In addition, we plan to construct new overhead lines to interconnect feeders to provide an alternative supply in the event of a fault. Nine interconnection possibilities have been identified and these have been incorporated into the capital expenditure forecast.

To provide some structure to planning and prioritising distribution network improvements, we have prepared a draft distribution network design standard. This still needs further refinement and review to confirm its cost effectiveness and alignment with the level of service we expect to provide to consumers connected to different parts of our network. Once the standard has been finalised, we will undertake a gap analysis to identify those parts of the network that do not comply with the standard and the extent of the non-compliance in each case. It is likely that completion of the gap analysis and finalisation of the standard will be an iterative process to deliver an outcome that is not overly ambitious, meets our funding constraints, and provides a consistent level of service across the network for feeders of the same type.

The gap analysis will identify the extent of non-compliance in different parts of the network and provide an initial basis for the prioritisation of distribution network development process. It may be that this structured approach will expose significant non-compliances that we have still to identify. In any case, this structured approach should allow the extent of significant non-compliances to be quantified to allow the benefits of alternative network upgrades to be objectively assessed.

Having identified those parts of the distribution network most in need of an upgrade, we will then investigate the cost effectiveness of different upgrade options available in each case, taking due account of expected long-term development requirements. In many cases it may be possible to implement low cost interventions, such as reconfiguration of open points that reduce the extent of non-compliances even if they do not fully eliminate them.

We expect the outcome of this process to be a set of projects, ranked through a cost benefit analysis as delivering the most benefit at the lowest cost. It is important that we quantify the benefits of each intervention so that after a project has been completed its success can be objectively assessed.

In the absence of this structured analysis, this AMP makes provision for development projects that address known weaknesses in the distribution network as it currently exists. These projects include:

- installation of the Kaeo substation. This work is scheduled for completion by 31 March 2018. It will create seven new distribution feeders and significantly reduce the circuit length and reduce the number of connected customers on individual feeders serving the Whangaroa area;
- installation of five remote control switches and an additional sectionaliser on the South Rd feeder in FYE2019;
- installation of a new 110/11kV substation at Mangamuka to provide a new point of injection that will reduce the length of the Rangiahua and South Road feeders, two of the longest distribution feeders on our network. This is planned for completion in FYE2023. The project will include an 11kV switching station at Broadwood to limit the impact of faults on the 11kV distribution network serving the North Hokianga area.
- installation of interconnections between feeders to enable them to be supplied from the remote end in the event of a fault. This work will be undertaken progressively between FYE2020 and FYE2025;

- installation of a new 11kV cable that will provide a second permanent feeder into the Russell peninsular. While the existing Russell feeder is supplied from the Kawakawa substation the new feeder will be supplied from Haruru and will utilize the existing backup submarine cable between Opua and Okiato Point. When complete, Russell town will be supplied from Haruru using the submarine cable between Opua and Okiato Point and Rawhiti will be supplied from Kawakawa using the submarine cable across that Waikare inlet. There will be a normally open interconnection between the two feeders at the Okiato Point Rd junction. This work is scheduled for completion in FYE2020.

While the above work is focused on improving the resilience of the distribution network to faults, our expenditure forecast also provides for the replacement or reconductoring of 11kV distribution lines that have reached the end of their economic lives.

5.17 Implementation Timeline and Costs FYE2019 – FYE2023

Planned expenditure on network development, with larger projects and programmes separately itemised is shown in Table 5.11 below.

$ million (real)	FYE				
	2019	2020	2021	2022	2023
System Growth					
Consumer connections (incl. capital contributions)	1.28	1.27	1.50	1.50	1.50
New 110kV transformer T2 at Kaitaia			0.52	3.58	
11kV feeder reconstruction			0.45	2.07	1.20
Kaeo-Manganui voltage regulator	0.21				
Wiroa ripple injection plant					0.69
Ngawha power station interconnection	1.96	7.03	6.06		
Total growth (including capital contributions)	**3.46**	**8.30**	**8.56**	**7.14**	**3.38**
Capital contributions	1.06	1.06	1.06	1.06	1.06
Total growth (net of capital contributions)	**2.40**	**7.24**	**7.50**	**6.08**	**2.32**
Reliability, Safety and Environment					
110kV line route property rights	1.38	0.76	0.22	0.25	0.05
Mangamuka 110kV substation		0.16			2.72
Asset management data updates	0.22	0.67	0.08	0.03	0.03
Research and development	0.17				1.04
Kaitaia bus tie circuit breaker			0.67		
11kV feeder interconnections		1.66	0.73	0.75	1.22
Distribution network architecture	0.30	0.37	0.55	0.90	0.51
Diesel generation – northern area	5.06	5.07			
Diesel generation - Omanaia	2.63				
Mobile generator implementation				0.49	
Russell reinforcement			0.61	0.67	
Protection, Communication and SCADA	0.56	0.20	0.13	0.06	0.06

$ million (real)	FYE				
	2019	2020	2021	2022	2023
Other	0.38	0.39	0.51	0.52	0.53
Total reliability, safety and environment	**10.70**	**9.28**	**3.50**	**3.67**	**6.06**
Asset Replacement and Renewal					
Air break switch replacements			0.29	0.29	0.29
11kV line replacements	0,24		0.35		0.32
110kV line tower painting	0.11	0.12	0.12	0.12	0.12
Transmission protection replacements	0.21	0.12			
Omanaia 33kV line refurbishment	0.24	0.43	0.41	0.41	
Low voltage pillar replacements					0.26
Distribution transformers earth remediation	0.19	0.19	0.19	0.19	0.19
Wood pole replacements	0.57	0.91	0.91	0.91	0.91
Ring main unit replacement	0.11	0.27			
Moerewa-Haruru line steel tower replacements	0.33	0.48			
110kV line structure replacements	0.53	0.53	0.54	0.54	0.54
Waipapa Substation reconstruction			4.36		
SWER replacement					0.33
Taipa 33kV line upgrade	0.23	0.23			
Other	0.50	0.16	-	-	0.26
Subtotal	**3.02**	**3.44**	**7.16**	**2.45**	**3.22**
Maintenance and Faults	3.33	2.81	2.28	2.27	2.29
Total asset replacement and renewal	**6.35**	**6.25**	**9.44**	**4.72**	**5.51**
TOTAL NETWORK CAPEX (net of capital contributions)	**19.45**	**22.77**	**20.44**	**14.47**	**13.89**

Table5.11 CAPEX Forecast and Timeline FYE2019 to FYE2023

5.17.1 FYE2019 Capital Expenditure Work Plan

The tables in this section provide a more detailed breakdown of the FYE2019 capital expenditure budget, as approved by the Board.

System Growth Expenditure

Project	Description	Budget ($000)
Manganui	Install regulator to supply Manganui feeder from the new Kaeo substation if required.	208
Ngawha	Interconnection of expanded power station to the network	1,955
Consumer connections	Connection of new consumers to the network including consumer contributions	1,280
Other		13
Total		**3,456**

Table 5.12: Breakdown of System Growth Capex Budget FYE2019

Reliability, Safety and Environment Expenditure

Project	Description	Budget ($000)
Mobile substation	Refurbish substation and peripherals	205
ADMS data	Checking and updating data prior to implementation of new advanced distribution management system	185
Communications	Installation of new high bandwidth 5G radio backbone	181
11kV distribution	Installation of additional sectionalisers and switching on South Rd feeder	141
Omanaia generation	Installation of generation at Omanaia	2,631
Kaitaia generation	Installation of generation at Kaitaia	5,064
11kV distribution	Upgrades to improve power quality	149
110kV Wiroa-Kaitaia line	Acquisition of property rights	1,380
Protection	Upgrade of substation protection systems	166
Research & development	Pilot project on use of emerging technologies to replace uneconomic lines	166
Distribution transformers	Retrofitting data loggers to ground mount transformers	132
Other		299
		10,699

Table 5.13: Breakdown of Reliability, Safety and Environment Capex Budget FYE2019

Asset Replacement and Renewal Expenditure

Project	Description	Budget ($000)
Omanaia 33kV line	Replacement of poles	240
Kaikohe-Kaitaia 110kV line	Tower painting and refurbishment	115
11KV distribution defect remediation	Defect remediation while lines are deenergised for project work	123
11kV RMU	Replacement of five ring main units	109
11kV distribution	Replacement of distribution line along Ahipara foreshore	242
Kaikohe-Kaitaia 110kV line	Structure replacements	528
110kV protection	Relay replacements - Kaitaia	110
11kV reclosers	Replacement of autolinks with fuse savers	122
110kV protection	Relay replacements - Kaikohe	102
Distribution transformers	Earth system remediation	189
11kV distribution	Pole replacements	572
33kV Moerewa-Haruru line	Steel tower and hardware replacement	332
33kV Taipa Line	Line Refurbishment	234
Total		**3,018**

Table 5.14: Breakdown of Asset Replacement and Renewal Capex Budget FYE2019

5.18 Capital Expenditure FYE2024 to FYE2028

The following sections provide a high-level overview of the projects that could be required over this period and that have been used as the basis for the longer-term forecasts in this AMP. Budgets shown in the tables below represent the currently forecast expenditure over the period FYE2024-28 and may not represent the total cost of a particular project or programme.

System Growth Expenditure

Project	Budget ($M, real)	Indicative Timing (FYE)	Comment
New 110kV transformers at Kaikohe	5.1	2025-26	Replace existing transformers with larger units
Wiroa 110kV substation	8.5	2024-5	
Kaeo substation 33kV line	1.9	2027-28	Construction of the 33kV line between the 33kV circuit on the 110kV Wiroa-Kaitaia line and the Kaeo substation site. This will provide the second incoming supply to the substation.
Other	2.6	2022-26	Approximately $1.7 million per year is expected to be required for other work, including new connections and load driven upgrades to the distribution network. Of this approximately $1 million per year is expected to be recovered from capital contributions.
Total	**24.2**		

Table 5.15: Breakdown of System Growth Capex Forecast FYE2024-28

Reliability, Safety and Environment Expenditure

Project	Budget ($M, real)	Indicative Timing (FYE)	Comment
110kV Wiroa-Kaitaia line	15.3	2026-28	Construction of Wiroa-Kaeo and Kaitaia-Peria sections.
11kV interconnections	1.1	2024	Construction of interconnections between adjacent 11kV feeders
Other	6.1	2024-28	
Total	**22.5**		

Table 5.16: Breakdown of System Reliability, Safety and Environment Capex Forecast FYE2024-28

Asset Replacement and Renewal Expenditure

Project	Budget ($M, real)	Indicative Timing (FYE)	Comment
Kaikohe substation	1.2	2026	Replace or refurbish the 33/11kV transformers.
Kaitaia 110kV substation	2.3	2027-28	Replace outdoor 33kV switchyard with an indoor switchboard.
Planned asset replacement	15.4	2024-28	Provision for other proactive asset replacements across the network.
Miscellaneous	11.7	2024-28	Provision for reactive fault and defect driven asset replacements.
Total	**30.6**		

Table 5.17: Breakdown of System Replacement and Renewal Capex Forecast FYE2024-28

5.18.1 Consumer Connections

Approximately $1.5 million per year (real) is provided for work undertaken on the network directly as a result of the connection of new consumers or, occasionally, as a result of existing commercial or industrial consumers increasing their maximum demand. About two thirds of this expenditure is recovered through capital contributions. The connection to the Ngawha power station will also be funded by a capital contribution from Ngawha Generation Ltd.

5.19 Advanced Distribution Management System

Over the two-year period FYE2019-20 we will be upgrading our network control operation through the installation of an advanced distribution management system (ADMS) for a budgeted capital cost of $2.6 million. The initial deployment in FYE2019 will include a new SCADA master station and an automated Outage Management System (OMS). The OMS will combine 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 SAIDI impact of supply interruptions, leading to more timely and accurate management reporting.

In FYE2020 a Distribution Management System (DMS) module will be added. This will overlay the above systems with a real time model of the network, using inputs from SCADA, the GIS and our SAP Asset Management System (AMS). It will provide a decision support system for the operation of the network by making real time information on network status and asset condition available to operators through a user-friendly graphical interface (with the architecture shown in Figure 5.5), automatically producing switching schedules, ensuring that all required isolation procedures are undertaken before operators issue field staff a permit to work and in many other ways. This will reduce operator error, support the enhanced safety procedures we are introducing and optimise the operation and management of the network.

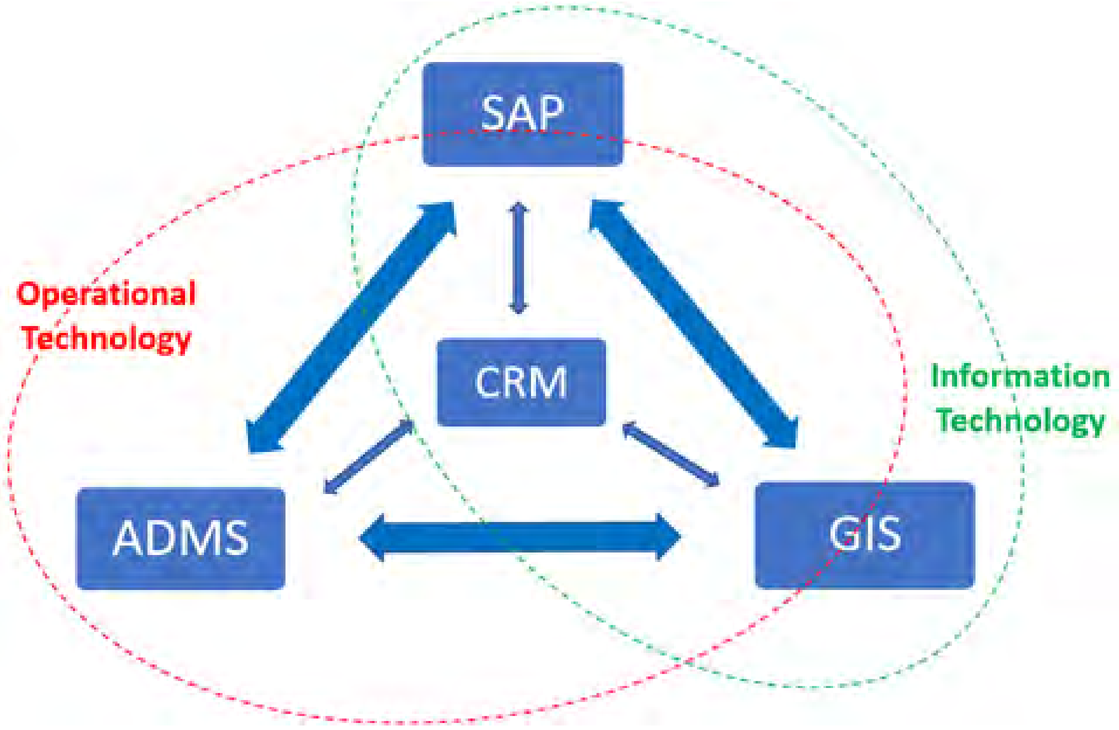


Figure 5.5: ADMS Architecture

The installation of the ADMS is timely in that our network will become significantly more complex and difficult to operate with the installation of new diesel generation in FYE2019-20. The ADMS can potentially be configured to optimise the use of this plant by automatically starting relevant generators following an interruption or when needed to alleviate localised network constraints.

The system will also have the potential to access and control in real time smart meters connected to our network. Restoration times should reduce as we anticipate that smart meter data will often provide our control room staff with sufficient information to accurately predict the cause of a fault before a repair crew is dispatched. The system will also have the potential to prevent unnecessary truck rolls as control room staff will be able to determine whether a consumer reporting a fault has power to its meter (in which case the consumer will be advised to call an electrician). Disconnections and reconnections could be undertaken remotely without the need to visit the site.

The installation of the ADMS will be a key tool in the operation of a network that is open to the use of new technologies and in our transition from a distributor of electricity to a manager of a distributed energy system. The system we plan to install has been future-proofed and modules to support distributed energy resource management (DERM) and demand response management (DRM) have already been developed by ADMS vendors and can be added as required. This is shown in Figure 5.6.

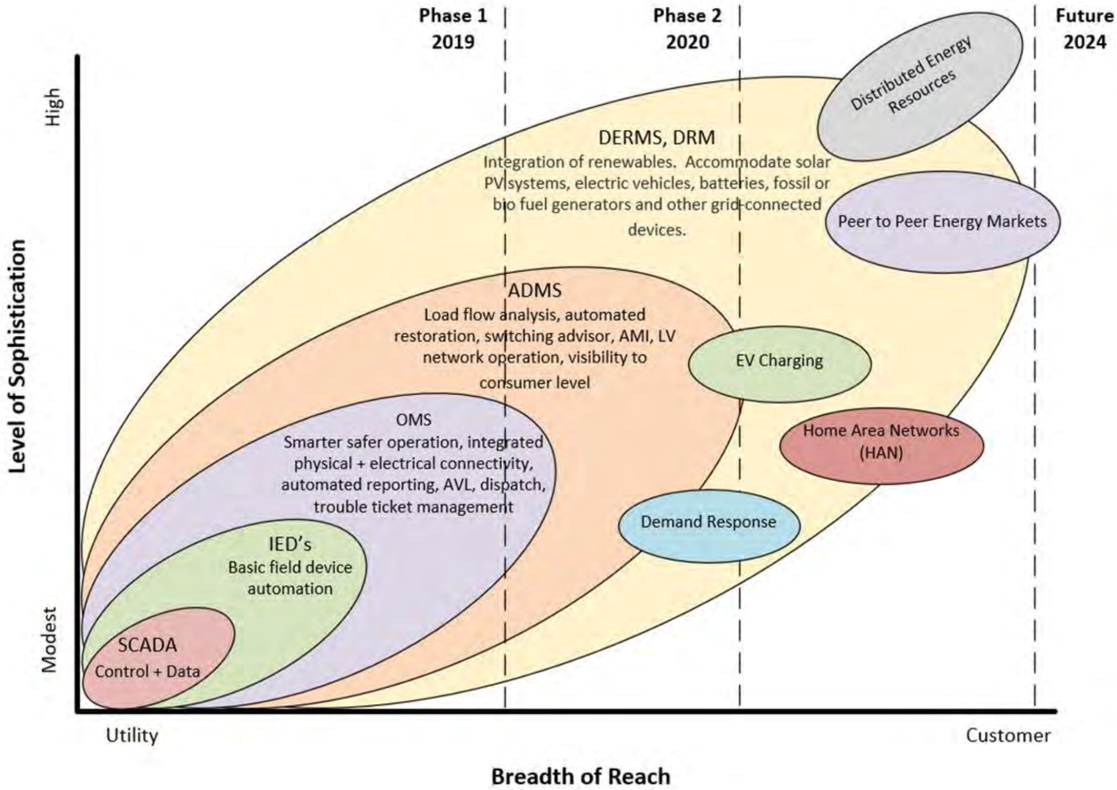


Figure 5.6: Features of an ADMS

The implementation of the ADMS is being managed by the Group's IT department and its cost is included in the non-network capital expenditure forecast.

5.20 Breakdown of the Capital Expenditure Forecast

A summary of forecast capex on network assets for the full ten-year planning period is shown in Table 5-18 below and shown graphically in Figure 5.7. There forecast categories map directly into the corresponding forecast CAPEX categories in Schedule 11a, except that in the Schedule the two asset replacement categories have been aggregated. The proportion of our projected capex that is allocated to improving supply reliability, including expenditure on the second 110kV line, is clearly apparent.

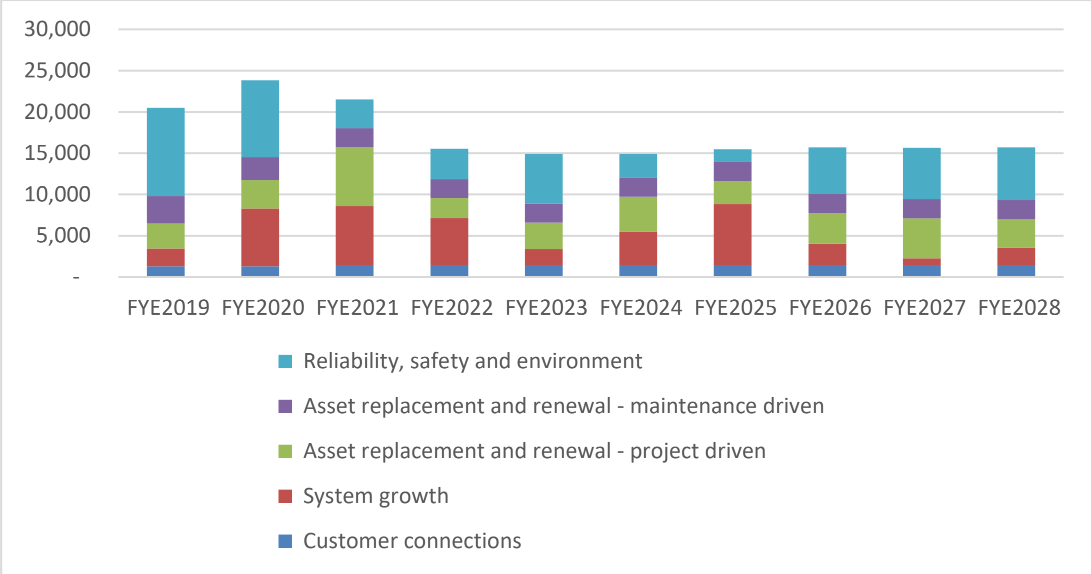


Figure 5.7: Capital Expenditure Forecast Profile FYE2019 to FYE2028 (including capital contributions)

($000, real)										
FYE	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Consumer connections	1,280	1,269	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488
System growth	2,176	7,030	7,075	5,647	1,886	4,033	7,362	2,549	764	2,085
Asset replacement and renewal - project driven	3,018	3,438	7,163	2,454	3,219	4,214	2,771	3,718	4,853	3,391
Asset replacement and renewal - maintenance driven	3,330	2,806	2,278	2,268	2,287	2,306	2,326	2,346	2,366	2,386
Reliability, safety and environment	10,699	9,285	3,502	3,666	6,056	2,876	1,522	5,586	6,188	6,325
Asset relocations										
Non-network assets	2,845	1,400	400	400	400	400	400	400	400	400
Total	**23,348**	**25,228**	**21,907**	**15,923**	**15,336**	**15,318**	**15,869**	**16,087**	**16,059**	**16,076**

Table 5.18: Forecast Annual CAPEX FYE2019 to FYE2028

Section 6 Life Cycle Asset Management

6 Lifecycle Asset Management

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

6.1 Maintenance and Renewal Planning Criteria and Assumptions

The overall objective of our asset management practices is to deliver an improved level of service whilst achieving the lowest possible lifecycle cost for our assets. This means that installation costs, maintenance costs, any mid-life refurbishment and end-of-life replacement costs need to be considered holistically to achieve the most cost effective long-term outcome for key stakeholders. To achieve this, we have a business philosophy that focuses on the continuous improvement of asset management practices, processes, systems, and plans.

We use a risk-based approach to ensure that the required level of service is delivered. Risk exposure is managed through:

- a regular review of the risk management plan and implementing risk mitigation measures where risk exposure is incompatible with our corporate risk policy. Risk management is discussed in detail in Section 7; and
- undertaking performance and condition monitoring of critical assets.

Our life cycle expenditure is split into five different categories as described below.

6.1.1 Emergency and Fault Maintenance

This covers fault, near-fault and high-risk situations where an asset requires immediate or urgent attention. These activities are not planned in advance and are driven by asset failure resulting from third-party interference, foreign interference, storm events or sudden component failure. Budgeting for this activity is based on actual reactive maintenance costs in previous years.

We operate a 24-hour emergency and fault maintenance service from our control room, which is staffed at all times.

Field staff are on standby at all times outside normal working hours and are available to restore supply or remedy defects that require urgent attention because they pose a risk to public safety or property. Control room operation is funded through the system operations and network support budget, while the fault and emergency maintenance budget presented in this section covers the cost of responding to faults and undertaking emergency maintenance.

6.1.2 Routine and Preventative Maintenance

We currently operate a time-based inspection and maintenance programme, where all assets are regularly inspected to identify defects that require repair. The programme includes non-invasive condition assessments and invasive maintenance interventions that are implemented on a regular time-based cycle.

The programme of non-invasive asset testing and scheduled maintenance interventions is designed to ensure that the rate of asset deterioration is managed to ensure that assets continue in service for their total economic life. It is particularly applicable to substation assets and includes condition monitoring activities such as power transformer oil testing as well as regular tap changer and circuit breaker contactor maintenance.

However, we are intending to replace the time-based programme with a risk-based inspection and maintenance programme as described in Section 6.1.2.1.

6.1.2.1 Asset Health Indicators

We use the Electricity Engineers' Association's (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. The Commerce

Commission uses a four-point categorisation to describe asset condition for information disclosure purposes. This maps directly into the EEA scale as is also shown in Table 6.1.

EEA Asset Health Indicator Guide		Commerce Commission
H5	As new condition -no drivers for replacement	Grade 4
H4	Asset serviceable – no drivers for replacement, normal in-service deterioration	Grade 3
H3	End of life drivers for replacement present, increasing asset related risk	
H2	End of life drivers for replacement present – high asset related risk	Grade 2
H1	Replacement recommended	Grade 1

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

The failure rate of our assets across their life cycle is consistent with a standard "bathtub curve". Newly constructed and commissioned assets, categorised H5 on the EEA's AHI scale, may have an elevated failure rate as manufacturing and installation defects become apparent. This is followed by a period of high reliability and performance during the middle period of an asset's life, where it has an AHI of H4, when the failure rate is low. As an asset approaches the end of its expected service life it enters a period of unreliability where the failure rate again starts to increase. At this point the asset is considered to have reached its "onset of unreliability" and its AHI transitions to H3. We have assessed the performance of our assets to identify the age at which a particular asset type can be expected to reach its onset of unreliability.

Our approach to asset inspection and maintenance under our planned risk-based strategy will therefore depend on the age of the asset relative to its expected asset life.

- Newly constructed assets will be inspected and checked for compliance with relevant regulatory requirements at the point at which their AHI transitions from H5 to H4, which is normally about 5 years after commissioning. For line assets this will include a pole top inspection and tightening as required.
- Following this initial maintenance inspection, when their AHI is H4, assets can be expected to perform with a low risk of failure. No formal asset inspection is needed over this period and any maintenance will be reactive. Assets will only be repaired or replaced following an event. Where the cause of an event is not understood, the assets concerned will be inspected or tested to ensure they remain in a serviceable condition.
- Assets will begin to fail after they reach the onset of unreliability and, from that point onwards, assets will have a bell-shaped failure curve. Some assets will fail early, most will fail about the median point of this failure curve and some will last longer. The objective of the risk-based inspection approach is to determine, on the basis of a condition assessment, the point on this failure curve that an individual asset is likely to fail and to time the maintenance or replacement of the asset to avoid an in-service failure. In order to capture those assets likely to fail early we will undertake a condition assessment of all assets in a particular asset class at the expected onset of unreliability for that asset class. This condition assessment will determine:
    - o the expected remaining life of each individual asset;
    - o any changes in operating practice necessary to keep staff and public safe but still get the optimum service life out of the asset. An example might be to avoid climbing a pole once it has deteriorated to the point where a pole's strength has reduced to below a prescribed level;

   - any temporary life extending techniques that might economically be applied to align an asset's remaining life with that of similar assets surrounding it. This ensures that assets are renewed as a group as opposed to spot replacements, which are less efficient in terms of cost and service disruption;

  Following this condition assessment, we will create a population priority list ranking all assessed assets in terms of their relative condition and serviceability. We anticipate this will be a dynamic list that may change as every new asset assessment record is completed. Our objective will be to replace each asset slightly ahead of its predicted failure such that the overall condition of the population improves to the point where there is an optimal planning period that ensures all assets are renewed on time within acceptable compliance standards.

- A small percentage of assets in a population may survive beyond the life of the rest of the population. These are most likely assets that have been repaired or maintained prior to their initial condition assessment, or assets where their age was inaccurately recorded during their initial condition assessment.

The outcome of this revised approach will be a reduction in inspection costs, as assets will not be inspected where there is a low probability of a serious defect being found. These savings will be used to accelerate the rate of asset renewal and end of life replacement. Over time, this is expected to lead to an improvement in the overall condition of the asset base and a corresponding reduction in the incidence of interruptions caused by defective equipment.

Assets are installed to the prescribed design and safety conditions of the day and are certified as compliant during the commissioning process and recertified for the scope of that work every time safety critical work is undertaken. However, assets are not normally retrospectively upgraded to new standards until they are replaced at the end of their service life. Such assets are classed as "unsafe" as defined in current legislation and managed in accordance with our NZS7901 certified public safety management system. In this context the term "unsafe" is a legal definition, which does not imply that the asset cannot remain in service. This is discussed further in Section 7.3.

6.1.3 Vegetation Management

The clearing of vegetation in proximity to lines is critical to both network reliability and public safety. The Electricity (Hazards from Trees) Regulations 2003 came into force in early 2004. These provide a framework of requirements and responsibilities to mitigate risks from problematic trees within the proximity of power lines and underpin our vegetation management strategy.

Under these regulations we are required to pay the initial tree trimming/removal costs; however, as the tree owners are identified, and the compulsory first cut and trim on the tree is complete, ongoing maintenance becomes the responsibility of the tree owner. Our preference has been to remove trees during this first cut where it is practical and economic to do so, to minimise ongoing maintenance cost and risks. We will continue to maintain a perpetual programme to assess and mitigate tree interference, as new trees grow and existing trees re-grow into power lines.

This first cut has now been completed across our asset base and we have moved into a phase where part of the cost of our vegetation management programme will be recovered from tree owners.

6.1.4 Replacement and Renewal Maintenance

Replacement and renewal maintenance is condition-based maintenance that is triggered by the findings of the inspection and condition assessment programmes described in Section 6.1.2. Our renewal maintenance philosophy entails performing maintenance only when safety, reliability and performance are compromised, as discussed in Section 7.3.3 for our line assets. The objective of the renewal maintenance programme is the prevention of unplanned faults through optimal use of maintenance resources and maximising the operational and economic life of network assets. While age does not directly determine the need for the renewal maintenance of a particular asset, the age profiles of different asset categories are used to assist us to assess and budget future renewal maintenance and asset replacement requirements.

Whether 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 cross arm, 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.

6.1.5 Capital Replacement

Replacement of network assets is necessary when continuing to maintain an existing asset is no longer cost-effective. Long-term replacement forecasting is based upon condition assessment and typical age replacement profiles for different asset classes. The replacement forecast will be refined with increasing use of probabilistic planning, as age-at-failure and age–at-renewal data is collected. We expect that, in time, the increased availability of historic asset condition information in SAP will allow us to make more reliable assessments of the appropriate time to replace an asset.

Short-term renewal plans are based upon condition assessment.

- **Risk:** The risk of failure and associated impacts justifies action (e.g. cost implications, impact and extent of supply discontinuation, probable extent of environmental damage, health and safety risk).
- **Asset performance:** Renewal of an asset when it fails to meet the required level of service. Non-performing assets are identified by the monitoring of asset reliability, capacity and efficiency during planned maintenance inspections and operational activity.
- **Economics:** It is no longer economic to continue repairing the asset (i.e. the annual cost of repairs exceeds the annualised cost of renewal).

Capital replacement work is discussed in more detail in Section 6.25.

6.2 Application of Maintenance and Renewal Criteria

As noted in Section 6.1, the overall objective of our asset management practices is to deliver an improved level of service while achieving the lowest possible lifecycle cost for its assets. This involves managing the risk of asset failure. This risk is a function of the probability of failure, which increases as an asset ages and its condition deteriorates, and the consequences of failure, which is a function of the potential loss of load resulting from the failure, the number of consumers affected, and the time required to repair or replace the asset after it fails.

For our transmission system and the more highly loaded parts of the subtransmission network, where the consequences of failure are high, the risk is ideally managed by building redundancy into the system to ensure that, in the event of an asset failure, there is an alternative path of sufficient capacity to carry the load so there is no loss of supply to consumers. A key weakness of our existing network has been that the level of redundancy in the transmission and subtransmission systems does not meet current industry standards in many areas and the network development plan described in Chapter 5 is designed to address this.

On the distribution network the consequences of an asset failure are lower as loads are not as great and fewer consumers are affected by any one failure. Hence the level of redundancy is lower and, consistent with industry norms, any asset failure will result in some loss of supply to consumers. Risk management involves reducing the probability of asset failure through effective maintenance, as well as limiting the consequences of asset failure by designing the network to minimise the number of consumers affected by a failure and implementing operational strategies that ensure supply is restored as quickly as possible to consumers not directly affected.

Reducing the probability of asset failure includes ensuring an asset is replaced before it fails. There is an economic cost to this since premature replacement of an asset results in the loss of the use of the asset between the time it is replaced and the time it would have failed naturally had it been left in service. Economically, the optimal time to replace an asset is when the economic consequence of an asset failure is equal to the economic service potential lost through premature asset replacement. This implies that assets that are critical to maintaining supply reliability should be replaced earlier in their life cycle than less critical assets.

As noted in Section 3.1.7, approximately 35% of our distribution network serving just 9% of consumers is uneconomic to supply because of its low loading and the small number of consumers served. Maintaining these parts of the distribution network is a burden on other consumers. Given the lower consequence of an asset failure on these fringe parts of the network, these assets should be left in service for longer before being replaced.

We are therefore changing our maintenance strategy for the uneconomic parts of the distribution network. This involves minimising the level of maintenance and letting assets run to failure where this is possible without compromising safety. For example, letting a transformer supplying a single connection run to failure presents no significant safety risk and will not materially impact interruption statistics. Where an alternative solution is warranted for the renewal of an uneconomic line, it is desirable to keep all associated assets in service until the alternative solution is implemented.

Protective devices will be located to ensure that the 91% of consumers connected to the more economic upstream parts of the distribution network are not affected by this policy and that there is no material degradation in the reliability of supply provided, on average, to consumers connected to the network.

6.3 Transmission Assets

We acquired our transmission assets from Transpower on 1 April 2012. Transpower used a well-established maintenance programme to monitor the condition of the lines asset but, while the condition of the assets was generally good for their age, the assets are old. The transmission assets are the most critical on the network and a high level of maintenance and continuing asset replacement is necessary if target levels of reliability are to be achieved.

6.3.1 Transmission Line

6.3.1.1 Inspection and Routine Maintenance

As the transmission line is one of the most critical assets on the network, we visually inspect it annually over its whole length and annually keep all vegetation clear of the line.

6.3.1.2 Replacement and Renewal

A full condition assessment of the line asset was undertaken in December 2014. This involved a visual inspection of concrete poles and associated hardware as well as an ultrasound analysis of the wood poles. The ultrasound analysis provided an accurate assessment of the remaining solid timber, which can then be used to determine the overall remaining strength of the pole. The loading on all poles was also assessed.

The assessment of the wooden poles revealed that 31 poles needed attention due to reduced cross-sectional area from decay. The wooden poles in worst condition have been replaced with concrete poles and we have a programme in place to manage these transmission line structures to ensure continuing reliability of supply. This involves the prioritisation and progressive replacement of these wooden poles with the octagonal steel poles being planned for the Wiroa-Kaitaia line.

An assessment of the steel towers has also been completed. This identified corrosion issues, including serious corrosion on non-critical members at the base of two towers, as well as steel corrosion in the grillage foundations used on all towers. A programme has been developed to replace severely corroded steel tower members, excavate and repair the corroded grillages, and then backfill with concrete and over time to remove the rust and repaint all towers.

A provision of approximately $500,000 per year has been included in the asset replacement capital expenditure budget to fund this work.

An assessment of conductor condition has also indicated that this will need to be replaced around 2030 if the line is to remain in service. As this is outside the planning period, this work is not provided for in this AMP.

6.3.2 Substations

The overall condition of the substation assets was generally good for its age at the time of the acquisition, apart from the issues with the Kaitaia transformers and the Kaikohe circuit breakers discussed in Section 5. Replacement of the 33kV circuit breakers at Kaikohe with an indoor switchboard has been completed and one of the 110/33kV power transformers at Kaitaia has now been replaced. Provision has also been made in the asset replacement capital expenditure forecast for the replacement of the second Kaitaia transformer and the Kaitaia 33kV switchyard during the planning period.

Other assets at both substations are still serviceable. However, many assets either have exceeded their expected economic life or are nearing the end of their life and the technology used in some of the secondary assets is now obsolete. Funding has been included in the asset replacement forecast for the progressive replacement of these assets to manage their reliability over time and ensure that the situation does not arise where a large number of assets require urgent replacement at the same time. Replacements will be prioritised based on condition and in a way that ensures that the long-term cost of the asset replacement effort is minimised. Provision has been made in the asset replacement capex budget to fund this ongoing work.

We have also engaged an external contractor to provide the preventive maintenance servicing and testing of the transmission substation electrical equipment. The long-term objective of this arrangement is to provide training and experience to our asset management and contracting staff to allow the eventual transition of the full maintenance function back to TECS.

6.4 Overhead Conductors

6.4.1 Failure Modes and Risks Associated with Overhead Conductors

Failures and tripping by conductor failure occur mostly due to:

- vegetation interference;
- animal interference;
- vehicular interference (e.g. cranes, excavators and farm equipment working in the vicinity);
- insulator failure;
- tension and non-tension connection failure due to corrosion and fatigue;
- retention device failure (e.g. binders, dead-ends, and armour rods);
- corrosion in coastal and geothermal environs; and
- human interference (e.g. foreign objects thrown into lines or trees felled through lines).

Many of these have strategies in place to minimise these occurrences; however, areas of most concern are pencil connectors and No. 8 steel wire conductor. Pencil connectors are grease filled aluminium sleeves used as a bimetal connector. These have oxidised over time causing LV and HV connection failures. A programme to eliminate these connectors is in place.

6.4.2 Planned Inspection & Maintenance Practices for Overhead Conductors

We have no formal programme in place for assessing the condition of overhead conductors, other than discovery through reactive patrols resulting from faults and safety management inspections. We plan to replace all remaining copper and galvanised steel conductor on the high voltage distribution network within the planning period of this AMP, except where a need to extend the life of an uneconomic line takes precedence. We monitor and record conductor fault and breakage rates and use this data, as a proxy for onset of unreliability condition assessments, as a basis for determining the requirement for proactive replacement of other conductors on the network. While conductor replacement requirements are currently relatively low, the conductor age profiles in Figures 3.18-3.20 indicate the rate of replacement of aluminium conductor on the high voltage distribution network, and both aluminium and copper conductor on the low voltage network, may need to increase by the end of this AMP planning period. We will monitor this.

Table 6.2 summarises our provisional asset management data for overhead conductors. Currently there is no requirement for the replacement of subtransmission conductors on our network.

	Copper	Steel	Aluminium
Average service life (years)	65	55	70
Period of unreliability (years)	10	10	10
Age at onset of unreliability	60	50	65
Current length in period of unreliability (all voltages, km)	44	21	116
Expected annual replacement rate (current, all voltages, km)	17	4	13
Asset criticality (33kV)	Critical: Moderate:	N level security N-1 level security	
Asset criticality (22kV, 11kV)	Moderate: Low:	urban and roadside rural off road	
Asset criticality (low voltage)	Moderate/low: Low:	urban and roadside rural off road	

Table 6.2: Asset Management Strategy for Overhead Conductors

6.4.3 Vegetation Management Strategy

As discussed in Section 6.1.3, vegetation management is undertaken in accordance with the Electricity (Hazards from Trees) Regulations 2003. We undertook an intensive three-year programme during FYE2010-12 to increase the level of vegetation control to improve reliability by reducing the incidence of vegetation related faults, and we have transitioned to a more sustainable maintenance phase. Now that our first cut is complete, we are looking to recover more of the cost of vegetation management from tree owners, although this is proving difficult. We are planning to implement a new policy to ensure tree owners keep their trees clear of our lines as discussed in Section 6.4.3.4 below.

6.4.3.1 Regulatory Compliance

The most onerous requirement under the Electricity (Hazards from Trees) Regulations 2003 is to maintain records of all trees that grow into the lines and the course of action taken. This must be done throughout the life of the tree and for any new tree that could grow into the power lines; historically, this has not been done. We now store this information in our Vegetation Management Application (VMA). This system is overlaid with GIS to record geographically the location of trees that pose a risk to overhead lines, the tree cutting work performed on each recorded tree and the details of the owner of each tree.

6.4.3.2 Far North District Council Relationship

The Far North District Council (FNDC) has significant numbers of trees that affect our power lines. We have an informal relationship with the FNDC that allows us to trim trees that are encroaching statutory clearance distances. However, this informal agreement is becoming unworkable as the District Plan evolves, making resource consent necessary for tree trimming activities. It would ultimately be in our best interest for the vegetation to be completely removed at ground level. Application of the Electricity (Hazards from Trees) Regulations 2003 would place the onus onto the FNDC to effectively manage its own tree population after the first cut/trim. We continue discussions with the FNDC over this issue.

6.4.3.3 Targeted Cutting Strategy

Vegetation management in FYE2019 is budgeted at $1.75 million, and expenditure is expected to be maintained at this level in real terms throughout the planning period.

The vegetation management strategy includes:

- a full vegetation inspection of the 110kV transmission line route. Tress encroaching the growth limit zone (GLZ) defined in the Electricity (Hazards from Trees) Regulations 2003 will be trimmed clear of the zone;
- an inspection of all 33kV lines with action taken to ensure that all trees remain outside the notice zone, as defined in the Regulations;
- an inspection of all 11kV lines to manage any trees that constitute an immediate hazard to conductors; and
- a management programme targeting selected feeders, to ensure that trees remain outside the notice zone as defined the Regulations. Feeders are selected based on their contribution to network SAIDI.

Figure 6.1 shows the information flows used to manage the vegetation control programme.

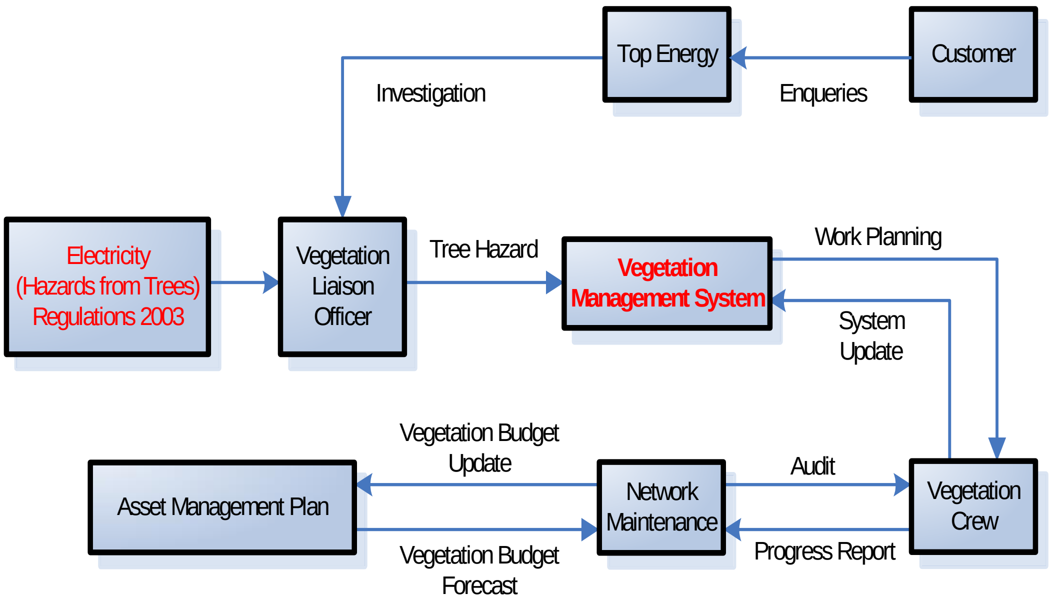


Figure 6.1: Information Flow – Vegetation Management

6.4.3.4 Vegetation Management Policy

We are introducing a new policy on the management of privately owned trees that grow into our lines. This is necessary as trees continue to be a major contributor to outages due to the following:

- trees contacting lines as a result of growth, wind sway, or sagging when wet;
- trees falling through lines from a distance due to high winds and wet ground; and
- planned shutdowns for tree clearing and forestry harvesting.

We have benchmarked our vegetation management costs against that of other electricity distribution businesses. Our expenditure per km of line on tree management is approximately 116% above our peer group average but our incidence of tree related interruptions is 95 minutes compared to, an average of only 13 minutes for our peers. Reasons for this include:

- The Electricity (Hazards from Trees) Regulations 2003 require tree owners to arrange their own cutting contractor and fund the cutting. However, we have no regulatory support to assist us enforce this requirement. We are not the regulator and are not responsible for enforcing the compliance of tree owners.
- Tree owners do not always have the economic resources to fund cutting and may not have access to local cutting contractors prepared to do this work at reasonable rates. Tree owners that can afford cutting are reluctant to do so if their neighbours are not able to do it.

We undertake default cutting only when an issue becomes an urgent safety matter and trees start burning in a line. Regulations obligate us to "make safe" or eliminate the hazards without delay where we discover such issues. Our limited response is the result of our resources being over-extended by the failure of tree owners to meet their obligations. This is exacerbated by high growth rates, the prevalence of brush and bamboo type vegetation that is impractical to fell permanently, and a high level of road reserve vegetation which has additional traffic and safety management challenges.

We therefore plan to adopt the following policy, which will be formally communicated to tree owners:

> We will not patrol and issue notices for service lines nor undertake private cutting work. Where tree owners do not maintain acceptable clearance from their private lines, we will require a protection device to be installed at the point of connection to our works. After this device is installed, the private line will not be re-livened until tree clearances are compliant.
>
> Our vegetation contractors will focus on cutting the most urgent and hazardous trees (as distinct from enforcing fully compliant regulatory clearances). Where tree cutting is planned we will issue a tree owner a forced-cut notice that will specify a scheduled average costed rate and the planned date (compliant with the regulated notice period) on which the forced-cut will be undertaken. A forced-cut will exclude debris clean up and trees will be felled at ground level when reasonable to permanently eliminate the hazard and/or the cost is lower than trimming, subject to tree owners confirming agreement that this is the best long-term solution where they cannot afford or lack the motivation to manage safety. Discretion may be exercised where a tree has a high amenity value. Our justification for this approach is that the owner has failed to meet its obligations under the Electricity (Hazards from Trees) Regulations 2003 and as a result there is a safety hazard and the reliability of supply to other consumers is reduced.
>
> Where other trees within the vicinity of a forced safety cut are found to be safe from a network operational perspective yet encroaching on the clearances that the tree owner is responsible for maintaining, the matter will be discussed with the tree owner and referred to appropriate tree management service providers. Any contribution from Top Energy will be conditional on tree owner agreement to enrol with an independent on-going cyclic inspection and trim service
>
> As required by the Health and Safety at Work Act, we will work with forest owners to effectively manage the risk that trees in lines present throughout the lifecycle of the forest, particularly at planting and harvesting. Furthermore, to effectively manage the health and safety of our staff, we will not enter forests in high winds to repair damaged lines until we have received clearance from the forest owner or manager that the trees are stable, and hazards have been removed. This protocol will be adhered to even when consumers beyond the forest are without power. Constructive solutions, such as relocating lines away from the forest or developing alternative supplies for affected consumers will be sought in the interests of hazard elimination, increasing land productivity, and reducing harvesting cost.

Our objective in limiting vegetation management to forced cutting will be to achieve shorter more frequent cutting cycles, less delay and disruption to work programs, and minimisation of costs to all concerned. We will advertise extensively to remind tree owners of their obligations under the Electricity (Hazard from Tress) Regulations, the need for them to actively manage the growth of trees near power lines and the hazards associated with fall distance.

We will also reactivate discussions with the FNDC and the New Zealand Transport Agency (which is responsible for state highways) to seek memorandums of understanding on coordinated safety management and work methods such as hedge trimming cycles, poisoning, total removal, and identification and management of trees they hold an interest in.

It is our tree management objective to reduce tree related SAIDI over the FYE2021-25 regulatory reset period to the existing peer group average of 13minutes with an associated expenditure target of $202/km (based on FYE2019 prices).

6.5 Poles and Structures

6.5.1 Failure modes and risks associated with poles and structures

Failures from wooden cross-arms involve failure of the cross-arm itself or collapse of the mechanical support for insulators and/or cross-arm.

A wooden pole will decay steadily over a long period of time, but this is not always immediately apparent. Decay is dependent on many factors, such as tree species, timber treatment and ground conditions. Wooden poles can fail suddenly when loading on the pole is altered.

Unassisted failure is possible. Failure due to climbing or reconfiguring conductors is rare, as poles are assessed prior to any work. Likely failure modes are either high winds or foreign interference, such as vehicles, falling trees or possibly even stock pushing on them. Most of our wooden poles are hardwood, treated pine and a few larchwood. We have stopped the installation of wooden poles in favour of pre-stressed concrete. Wooden poles are now being phased out over a ten-year period on the basis of hazard elimination rather than end of life.

A concrete pole will degrade extremely slowly and therefore maintain consistency of condition throughout its life. Changes in manufacturing techniques and quality control of this process are producing superior poles. Some environmental conditions, such as coastal or sulphurous areas which are both present within our supply area, can affect concrete poles.

Early concrete poles were manufactured internally by the Bay of Islands Electric Power Board. The oldest of these are beginning to spall, exposing the reinforcing. Some poles have stay wires to assist with their loading and these stay wires are connected to ground anchors. Stays and anchors may deteriorate and this, if not identified and remedied through regular inspection and maintenance, could result in reduced pole service life.

All structures within, or close to, the road reserve are subject to the risk of vehicle impact. Poles in off-road locations are subject to a much lower risk of vehicle impact from farm equipment, erosion, and movement by stock.

The potential consequences of all the above modes of failure are live conductors on the ground or low conductors, which pose a real safety risk. Our primary strategy to protect people and property from live bare conductors is to elevate them out of reach.

6.5.2 Asset Management Practices for Poles and Structures

The inspection schedule currently in place for poles is as follows:

Ground-Based Inspections: Thermal imaging and a radio frequency discharge detector are used on the subtransmission circuits to assess the condition of each insulator and connection. Hazardous poles are identified, tagged as necessary and recorded in SAP. In FYE2017 we commenced a programme of ultrasonic scanning of all wood poles on our network to determine the amount of remaining good wood on each pole. This programme is currently 50% complete and will be completed during FYE 2020. This information will be used as an input to the process of prioritising poles for early replacement in developing our programme to replace all wood poles in the network by the end of the ten-year AMP planning period, as discussed in Section 7.3.4. Concrete poles are inspected visually for exposed reinforcing and possible degradation of the concrete.

The first cycle of our time-based asset inspection programme is due for completion by the end of FYE2019 and this programme will continue until completion. At this stage there should be a condition record in SAP for every pole on the network, and we will then move to the risk-based inspection programme described in Section 7.3.3.4.

Pole-Top Inspection: Ground-based inspections with pole top hardware being inspected using binoculars is considered sufficient and pole top inspections requiring poles to be climbed or using an elevated bucket are not normally carried out unless work such as line tightening is being undertaken on the pole.

Tables 6.3 to 6.6 summarise our asset management strategies for the different pole fleets in our network. Over time, we plan to further refine these strategies by:

- capturing data to differentiate between mass reinforced and prestressed concrete poles. The two pole types should be separately managed;
- updating the asset health indicators that underpin the asset management strategies in the tables and reassessing renewal priorities and annual quantities based on the updated data;
- replacing all wood and "L section" concrete poles within the ten- year planning period of this AMP;
- revising age profiles where these appear to be based on default dates or where the data may not be completely accurate.

Table 6.3 summarises our provisional asset management strategies for subtransmission poles

	Concrete	Hardwood	Softwood	Steel
Average service life (years)	70	50	40	60
Unreliability duration (years)	20	10	10	10
Age at onset of unreliability inspection (years)	50	40	30	50
Annual onset of unreliability inspections	49	3	1	-
Forecast annual pole replacements (all drivers)	8	17	1	-
Frequency of visual asset patrol	Annual			
Asset criticality	High/moderate	Double circuit poles; Poles on N security circuits; Roadside poles.		
	Moderate	Other poles on N-1 security circuits.		

Table 6.3: Provisional Asset Management Strategy for Subtransmission Poles

Table 6.4 summarises our provisional asset management strategies for high voltage distribution poles.

	Concrete	Hardwood	Softwood	Steel
Average service life (years)	70	50	40	60
Unreliability duration (years)	20	10	10	10
Age at onset of unreliability inspection (years)	50	40	30	50
Annual onset of unreliability inspections	455	9	20	-
Forecast annual pole replacements (all drivers)	43	47	44	-
Frequency of visual asset patrol	Five yearly			
Asset criticality	High/moderate	Urban and roadside poles;		
	Moderate/low	Other poles on N-1 security circuits.		

Table 6.4: Provisional Asset Management Strategy for High Voltage Distribution Poles

Table 6.5 summarises our provisional asset management strategies for low voltage poles.

	Concrete	Hardwood	Softwood
Average service life (years)	70	50	40
Unreliability duration (years)	20	10	10
Age at onset of unreliability inspection (years)	50	40	30
Annual onset of unreliability inspections	455	9	20
Forecast annual pole replacements (all drivers)	44	14	32
Frequency of visual asset patrol	Five yearly		
Asset criticality	Moderate/low Low	Urban and roadside poles; Rural, off-road poles.	

Table 6.5: Provisional Asset Management Strategy for Low Voltage Poles

6.6 Underground & Submarine Cables

6.6.1 Failure Modes and Risks Associated with Underground & Submarine Cables

The main cause of failure in cables is third-party damage, usually caused by an excavator or directional drill. In the case of submarine cables, damage can occur due to anchor strike. We offer a cable location service to encourage people to reduce this risk. We also have a process to manage the activities of people working near cables, when we are aware of the activity. Submarine cables are marked on the shoreline and appear on nautical charts.

The failure of a cable usually results in an outage to consumers. The risks from explosion or contact are considered low as the cables are buried, and such an event would normally be associated with a dig-in. The loss of supply associated with a damaged cable usually takes longer to alleviate than an overhead incident, due to the repair time involved.

For HV cables, failure of a termination or joint is much more likely than electrical failure of the cable itself. Ongoing failure of HV cable terminations has prompted an investigation of terminations for partial discharge (PD) and transient earth voltages (TEV). The result of this investigation has revealed poor construction techniques leading to premature failure. PD and TEV monitoring of cable terminations is now a part of the preventative maintenance programme to mitigate potential costly faults.

For XLPE cables, the mechanisms of insulation deterioration leading to failure are now well understood. We regularly monitor the latest information on the condition of cables installed in other parts of New Zealand to help identify any areas of risk.

Low voltage cables are predominantly single core, double-insulated aluminium. These are looped into service pillars and lugged onto a piece of paxolin board. This system is unsealed, allowing water ingress. It is not uncommon to find (during inspection) that the aluminium cable around the lug is badly - and in some cases - completely oxidised through. All new installations are four-core aluminium cables utilising a completely sealed system. Existing installations will be changed over to the sealed system as damage prone areas are identified and age and condition dictate.

6.6.2 Planned Inspection & Maintenance Practices for Underground & Submarine Cables

As these assets are buried, it is not possible to carry out a visual inspection of their condition. However, where they are terminated onto other plant (e.g. switchgear), they can be seen and are included as part of the condition inspection for that item.

Maintenance testing is five-yearly on line partial discharge mapping of all 11kV and 33kV cables entering zone substations. Submarine cables are tested five-yearly and a submarine inspection is carried out every ten years.

The most important way of ensuring a long life for cables is to ensure they are correctly installed and appropriate tests are carried out to confirm this has happened. When commissioning all cables (apart from very short lengths i.e. <15m), specific tests like polarisation index (PI), 5kV step voltage (SV), temperature corrected sheath integrity and very low frequency, high potential (VLF high pot) tests are carried out.

For faulted cables, we carry out controlled DC impulse testing during fault location; and post repair, PI, SV, and sheath integrity tests are carried out. A decision to repair or replace the cable is dependent on the cost and practicality of repairing the cable. Temporary repairs are generally made to restore power which is then followed up with a cable replacement where required.

6.6.3 Asset Renewal Programme

As a general principle, cable replacement planning is based on reliability or load growth. As such, provisions have been made for cable replacement for unplanned outages.

Our cable population is generally 'young' and has a significant service life remaining. Accordingly, underground cables do not have a planned refurbishment programme. Replacement will occur when the cost of repairs become uneconomic.

6.7 Distribution and SWER Transformers

6.7.1 Failure Modes and Risks Associated with Distribution and SWER Transformers

The main causes of failure of distribution and SWER transformers are lightning, corrosion, overloading, and oil leaks.

We have reduced the number of transformer failures resulting from lightning events by fitting lightning arrestors to all new pole-mounted transformers and by retroactively fitting lighting arrestors on pole mounted transformers in lightning prone areas.

Most our consumers live in rural or coastal locations. Farmland tends to have a low-density population, whereas coastal areas tend to have a higher, and somewhat seasonal population. Therefore, many assets (including transformers) are located in coastal areas, exposing them to harsh coastal environments that result in premature aging.

Overloading of transformers has historically occurred primarily due to demand growth, without proper consideration of transformer impacts when new connections are made. No new connections are now made without analysis of the loading that a new connection will have on its distribution transformer and the impact that a new or larger transformer could have on the network.

Transformers use mineral oil as an insulating and cooling medium. Unfortunately, this oil is an environmental hazard. There are alternative oils that are considered safer but come at a significant cost. Fortunately, leaks are relatively uncommon and when they do occur, it is usually just enough to stain the side of the transformer. Significant leaks are rare and unpredictable and thus the response is always reactive.

6.7.2 Planned Inspection and Maintenance Practices for Distribution and SWER Transformers

Generally, modern distribution transformers have low maintenance requirements. Older units with signs of significant degradation or damage are replaced and the old unit is refurbished or scrapped, depending on condition. When a transformer pole is changed, we also to replace or upgrade any transformer and its associated substation that is assessed as having less than 15 years remaining life.

	Pole Mounted	Ground Mounted
Average service life (years)	35	35
Period of unreliability (years)	10	10
Age at onset of unreliability	30	30
Current population in period of unreliability	773	30
Annual onset of unreliability inspection rate	90	30
Expected annual replacement rate	60	7
Asset criticality	Moderate: Low:	Urban, ground mounted Pole mounted

Table 6.6: Distribution Transformer Asset Management Strategy

6.7.3 Asset Renewal Programme

While most distribution transformers are relatively new, there are still a significant number that are nearing the end of their service life. Many of these are small and located in remote areas. As the failure rate of these units is relatively low, and the service impact and safety risk following a failure is low, the most effective practice is to run to failure. In some circumstances it may be appropriate to change units in association with other planned work in the area. A minimum stock holding of critical spare transformers is maintained accordingly.

New distribution transformer units are hermetically sealed for life and factory-fitted with surge arresters. Tanks have additional corrosion protection measures provided.

6.8 Auto-Reclosers

6.8.1 Failure Modes and Risks Associated with Auto-Reclosers

The main causes of failure of auto-reclosers are electronic controller failures. Moisture ingress and oil contamination has led to catastrophic failure, causing oil to vent from the failed unit. This is an environmental hazard and is costly to clean up. The risk of personal injury as a result of such an incident is low.

6.8.2 Planned Inspection and Maintenance Practices for Auto-Reclosers

Auto-reclosers have a two-yearly inspection programme covering electronic controller checks and an external visual inspection. Diagnostic data and operational settings are also captured at the same time. In addition, there is a six-yearly battery replacement programme in place.

Maintenance of the interrupter assembly and oil replacement is based on a variety of regimes dependent upon the model. These are based on aggregated fault duty and number of mechanical operations.

6.8.3 Asset Renewal Programme

A significant proportion of auto-reclosers are relatively new and are SF_6 or vacuum units. There are few oil-filled auto-reclosers left in operation. The oil-filled units are being phased out, with the last few being replaced with resin-encased vacuum units.

6.9 Regulators

6.9.1 Failure Modes and Risks Associated with Regulators

The main causes of failure of regulators are electronic controller failures and mechanical failure of the tap changer. Corrosion around the lid, bushing and control box can allow water and contamination to enter and is also a problem.

6.9.2 Planned Inspection and Maintenance Practices for Regulators

Regulators are inspected annually. This includes general overall site inspection as well as operational tests using local control. At four-year intervals or 100,000 operations (whichever occurs first), the regulators are returned to the workshop for complete servicing after being replaced with fully serviced units.

6.9.3 Asset Renewal Programme

As all voltage regulators are less than ten years old, there is no renewal programme required.

6.10 Ring Main Units (RMU)

6.10.1 Failure Modes and Risks Associated with Ring Main Units

The main causes of failure of RMUs within our geographical area are third-party vehicle accidents and corrosion due to the harsh coastal conditions.

6.10.2 Planned Inspection and Maintenance Practices for Ring Main Units

RMUs are included as part of the routine condition assessment regime. Routine oil testing occurs once every six years, with a partial discharge test of the cable terminations every two years. Routine inspection includes an annual hazard inspection and visual condition assessment. Oil filled units are no longer purchased.

6.10.3 Asset Renewal Programme

A significant proportion of RMUs are relatively new. Older units are replaced as required.

6.11 Sectionalisers

6.11.1 Failure Modes and Risks Associated with Sectionalisers

The main causes of failure of sectionalisers are lightning and sudden mechanical failure.

6.11.2 Planned Inspection & Maintenance Practices for Sectionalisers

Oil filled sectionalisers have a two yearly external visual inspection. After 100,000 operations or four years' service, the sectionaliser is replaced with a fully serviced unit and it is returned to the workshop for servicing and testing.

New link type air insulated sectionalisers have a two-yearly visual inspection. These units are completely replaced if there is any doubt about their operation.

6.11.3 Asset Renewal Programme

The majority of sectionalisers were installed within the last five years and the remaining units continue to be monitored. There is no programme for renewal at this time.

6.12 Air Break Switches

The average age of air break switches on the subtransmission system is 14 years and 23 years on the distribution system. Many units are older, and some have exceeded their expected economic life of 35 years. Whilst the ongoing maintenance of these units has ensured many years of service, new technology, increased loads, and changes in operational requirements have prompted the replacement of the older units with modern vacuum break units. These come with many features that enhance the operability, such as:

- no handle at ground level eliminates the risk of harm to the public;
- no handle at ground level increases the security against interference with the unit by the public;
- operation by a fuse stick eliminates the need for earths and the subsequent risk from copper earth conductor theft;
- cost neutral in purchase and installation through the elimination of the need for an earth system;
- more economic due to the elimination of ongoing earth system condition monitoring;
- vacuum break interruptions eliminate the risk of fire and harm through total containment of the arc throughout the operation;
- retains a visible break; and
- environmentally friendly, containing no greenhouse gasses.

A replacement programme is in place and older switches are proactively being replaced, particularly on the subtransmission system.

6.13 Capacitors

6.13.1 Failure Modes and Risks Associated with Capacitors

The main causes of failure of capacitors are lightning and sudden mechanical failure.

6.13.2 Planned Inspection & Maintenance Practices for Capacitors

They are included as part of the condition monitoring regime and are inspected from the ground to examine for signs of deterioration. These include:

- leakage;
- cracked insulators;
- bulging tank;
- flash-over carbon marks; and
- tank rupture.

6.13.3 Asset Renewal Programme

There are currently no renewal programmes in place for these assets, but units are replaced as required following routine inspection of their condition.

6.14 Zone Substation Transformers

6.14.1 Failure Modes and Risks Associated with Zone Substation Transformers

There are environmental risks associated with zone substation transformers, as they contain significant quantities of insulating oil. All zone substation transformers have been tested for PCB, but none has been found. This risk of an oil leak or spill is highest with the mobile transformer, which uses biodegradable vegetable oil to minimise the environmental risk should an accidental spill occur during transportation.

All zone substations have oil management systems on site and some have oil interception facilities in their ground water systems. There are oil management systems at depots and clean-up equipment is kept ready in case of accidental spillage. Bunding and oil interception facilities have recently been installed at Kawakawa and provision is made in the in the capital expenditure forecast for bunding and oil interception facilities at Waipapa.

The risk of transformer failure is primarily managed through a comprehensive condition-based maintenance and protection regime.

The risk from seismic activity is low in our area, and all transformers and auxiliaries have been appropriately secured.

Lightning arresters are provided to protect the transformers from lightning strike. These may not necessarily protect the substation against a direct strike but, based on a risk analysis, the substantial costs of providing such protection is considered prohibitive.

6.14.2 Planned Inspection and Maintenance Practices for Zone Substation Transformers

An annual programme of dissolved gas analysis (DGA), as well as monthly, yearly, and five-yearly inspections are undertaken based on accepted international best practice. Each year, a radio frequency discharge detector is used to observe the condition of transformer connection bushings. A five-yearly infra-red thermography programme is undertaken on each switchyard, which includes monitoring the transformers and auxiliaries.

We undertake our own interpretation of oil test data and have built a spreadsheet programme to assist with this. Levels, limits, and rates of total dissolved combustible gases (TDCG) and individual gases (key gases) outlined in IEC 60599 are the first indicators of an incipient problem. In the event of any concern arising, an increased monitoring programme is implemented. If necessary, a remedial action plan will be developed that takes into account:

- IEEE Standard C57.104 (the prescriptive method is ascertained as one of the inputs to final decision of the course of action);
- Rogers Ratios (invoked only when gas levels reach a certain level); and
- other tests, condition assessment, history, circumstances, age, and design.

The IEEE C57.125-1991, “Guide for Failure Investigation, Documentation and Analysis for Power Transformers and Shunt Reactors” and IEEE Std62-1995 “Guide for Diagnostic Field Testing of Electric Power Apparatus – Part 1 Oil Filled Power Transformers, Regulators and Reactors” are followed.

Silica gel maintenance is rigorous. The crystals are recharged by a thorough oven dry-out, before canisters reach a 50% level. While silica gel desiccant systems are not perfect, they are sufficient for our needs. Alternative refrigeration principle (e.g. Drycol) and pumped filtration systems (e.g. Drykeep) have been assessed but are not considered necessary. Instead, silica gel plus oil refurbishment (as required) will continue to be undertaken to manage moisture ingress issues.

Oil is refurbished or reclaimed based on oil quality tests. Units are streamline filtered depending upon moisture content and level of saturation, in accordance with the IEEE standard. Secondary indicators of this are voltage breakdown and dissipation factor. The decision to streamline filter with oil treatment by Fuller’s earth is made where there are indications of sludging or is triggered by acidity and interface tension (IFT) measurements.

Mid-life refurbishment incorporating a major overhaul, including insulation dry out and magnetic circuit core clamp re-tightening, is undertaken based on condition assessment (including a visual assessment of likely moisture ingress sites e.g. corrosion, explosion vent condition, seal conditions, radiator condition) and the detailed diagnostics noted above. It is not undertaken automatically based on age. With a thorough transformer maintenance and monitoring programme, it should be possible to avoid or delay the need for such a major invasive maintenance intervention.

The overall condition of our zone substation transformers is above average, according to current oil tests. Primary condition concerns are oil leaks. Old-style earthquake restraints comprising of welded wheels bolted to rail tracks are of concern, but the risk is considered low and earthquake restraints will be upgraded along with future bund upgrades. The transformers at Kawakawa have already been lowered to ground level and it is planned to lower the Waipapa transformers during the AMP planning period.

On load tap changers have their oil changed two-yearly. Parts are replaced or refurbished based on inspected conditions and manufacturers' recommendations per cyclometer reading (i.e. number of operations).

6.14.3 Asset Renewal Programme

As noted in Section 5.10.3, the three, old single-phase transformers at Omanaia substation are currently being replaced. The 33/11kV transformers at Kaikohe substation are also scheduled to be replaced or refurbished during the AMP planning period.

6.15 Circuit Breakers

6.15.1 Failure Modes and Risks Associated with Circuit Breakers

Circuit breakers fail most commonly as a result of ingress of moisture, loose connections, and inadequate maintenance. Failure of a circuit breaker whilst it is being operated poses a significant risk to the operator. As a result, routine maintenance is carried out on all our circuit breaker classes.

6.15.2 Planned Inspection and Maintenance Practices for Circuit Breakers

Monthly site inspections and recording of cyclometer readings are performed. The maintenance programme for circuit breakers is coordinated with maintenance of any associated transformer and protection, to optimise maintenance work and minimise the risk of actual outages and overall costs.

We have adopted following maintenance strategy:

- 11kV incomers and tie breakers are serviced four-yearly;
- 11kV feeder vacuum indoor circuit breakers are serviced four-yearly;
- 11kV feeder indoor or outdoor oil interrupter/oil insulated circuit breakers are serviced two-yearly. This is done more frequently if the number of operations since last service is greater than 15;
- 33kV vacuum interrupters are serviced four-yearly; and
- 33kV minimum oil circuit breakers are serviced annually.

These frequencies are increased if the cyclometer readings indicate high numbers of operations.

Oil circuit breaker maintenance includes oil change, checking tabulators and contacts. The manufacturer's manual on lubrication and other tests is followed. Vacuum interrupters have gaps checked as per the manufacturer's recommendations. This technology, however, is relatively low maintenance. Two-yearly partial discharge testing occurs on all zone substation switchgear, including the metal clad VT/bus chamber switchgear.

6.15.3 Asset Renewal Programme

Circuit breakers that are considered to be beyond economic repair are programmed for replacement within a defined period. Circuit breakers are also replaced routinely as part of larger scale zone substation refurbishment programmes and new indoor 33kV and 11kV switchboards have been installed at Moerewa, as part of the recently completed substation rebuild.

6.16 Zone Substation Structures

6.16.1 Failure Modes and Risks Associated with Zone Substation Structures

Zone substation structures can fail as a result of inadequate maintenance, animal intrusion and weather conditions, such as localised lightning strikes.

6.16.2 Planned Inspection and Maintenance Practices for Zone Substation Structures

Outdoor structures have a long lifespan. Their condition can be monitored visually, and with the use of thermal imaging and partial discharge testing. Because of the critical nature of this equipment, air break switches in outdoor zone substation structures are individually checked for correct operation every two years and maintained if necessary.

6.16.3 Asset Renewal Programme

Pukenui substation has undergone refurbishment, with the bus reconfigured to allow the mobile substation to be connected and obsolete switchgear replaced. Modern protection systems have been installed. The outdoor switchyard at Moerewa substation has also been replaced with indoor switchboards.

6.17 Zone Substation DC Systems

6.17.1 Failure Modes and Risks Associated with Zone Substation DC Systems

Zone substation DC systems generally fail as a result of animal (vermin) intrusion and failure of backup batteries or charging systems.

6.17.2 Planned Inspection & Maintenance Practices for Zone Substation DC Systems

Routine inspection of all DC systems, including voltage and current checks, charging system check, and visual condition checks, are performed monthly.

6.17.3 Asset Renewal Programme

Due to the limited population, there are currently no formal renewal programmes in place for these assets. Individual asset replacement will occur as a result of specific condition inspection. Should this reveal a systemic issue, a renewal programme may then be developed.

6.18 Zone Substation Protection

6.18.1 Failure Modes and Risks Associated with Zone Substation Protection

Failure of protection systems within a zone substation can lead to non-operation of circuit breakers, alarms, and other safety devices. Protection systems generally fail due to poor local conditions, lightning activity. and age.

6.18.2 Planned Inspection and Maintenance Practices for Zone Substation Protection

The maintenance regime for older type relays is as follows:

- functional tests, minor visual inspection of settings and condition occur two-yearly;
- calibration tests occur four-yearly; and

- more frequent testing than the above two-yearly functional and four-yearly calibration test regime are considered for very old relays, where there is evidence of drift or degradation.

The adoption of modern, microprocessor-based numerical relays has provided the opportunity to increase the interval of calibration testing beyond four years at some locations.

We carry out CT and VT ratio checks five-yearly to check for drift that can occur due to core movement with resin type embedded construction.

6.18.3 Asset Renewal Programme

We have a capital expenditure programme covering the entire network in place to address the current issues surrounding ageing and ineffective protection systems, which will all eventually be upgraded to numerical type relays.

6.19 Zone Substation Grounds and Buildings

6.19.1 Failure Modes and Risks Associated with Zone Substation Grounds and Buildings

The Omanaia Substation is subject to flooding, if the drainage waterways near it become clogged. To manage this risk, the waterways are inspected monthly as part of the substation inspection and cleared as necessary, particularly after a major storm.

6.19.2 Planned Inspection and Maintenance Practices for Zone Substation Grounds and Buildings

A building maintenance plan details requirements for yards, roofs, external walls, doors, windows, plumbing, electrical services, and the interior. Buildings are serviced by contract cleaning staff at monthly intervals. An asbestos management plan is also being finalised for implementation at the beginning of FYE2019.

6.19.3 Asset Renewal Programme

Due to the limited population and the nature of the asset, there are currently no formal renewal programmes in place for these assets. Individual asset replacement will occur as a result of specific condition inspection. Should this reveal a systemic issue with the asset, a renewal programme may then be developed.

6.20 Consumer Service Pillars

6.20.1 Failure Modes and Risks Associated with Consumer Service Pillars

Failure of a pillar is commonly due to foreign interference or poor installation. Poor installation will lead to internal failure, resulting in loss of supply and internal damage. There is very little risk beyond this, with the exception of a neutral connection failure. Foreign interference by vehicle or vandalism can lead to live internal parts being exposed, which could result in personal injury.

6.20.2 Planned Inspection and Maintenance Practices for Consumer Service Pillars

All consumer LV pillars are inspected at three-yearly intervals for hazardous conditions. During this condition assessment, minor maintenance is undertaken; such as replacing missing Allen key screws or removing vegetation (grass) growing up into the enclosure. This work is part of the condition monitoring process for field equipment.

Low voltage cables supplying service pillars are terminated onto a piece of paxolin board. This board is prone to breaking, should the connection be over-tightened, installed incorrectly or subject to any form of impact. This may result in the bare lugs inside shorting, leading to loss of supply. Care must be taken when opening a service pillar, as any movement could cause bare lugs on a broken paxolin board to short. When these are identified the paxolin board is removed and 'GelPorts' are installed. These are sealed units that provide waterproofing and protection against accidental contact.

Service pillar fuse bases are a constant source of failure commonly due to a loose connection into the fuse base. This can result from poor installation, vehicular vibration, or any form of impact. We have introduced the use of a sealed service fuse base incorporating the use of a shear-off bolted insulation piercing connection. The shear-off connection ensures that the connection is correctly tightened and should address the ongoing issue of failure from poor connections. Being sealed, these units also provide waterproofing and protection against accidental contact.

6.20.3 Asset Renewal Programme

Pillars are not complex assets. There are a few remaining fibreglass pillars that are replaced upon discovery due to the fibreglass deteriorating. These have only survived replacement to date due to misidentification. Pillars are replaced when they can no longer be secured or when repairs are not economical.

6.21 Earth installations

6.21.1 Failure Modes and Risks Associated with Earth Installations

Failure of an earth installation can result from a variety of reasons, including: vandalism, foreign interference, the environment, and poor installation. This is identified through visual inspection and through earth resistance testing. The risks associated with an earth installation not functioning correctly are primarily protection systems not working and earth potential rise, which can be a particularly serious safety issue on SWER lines where earth installations carry the full load current.

6.21.2 Planned Inspection and Maintenance Practices for Earth Installations

Distribution equipment earths are tested three-yearly, whereas zone substation earth mats are tested annually.

Since 2006, we have managed touch and step potential issues according to a risk assessment approach based on the NZECP 35, taking into account the circuit distance from the nearest zone substation and the assessed frequency of people in the vicinity. As this has resulted in a requirement for higher quality earthing than previously used, a significant amount of remedial work is required. Remedial work identified is prioritised to focus on SWER lines and areas with the highest frequency of people (i.e. shopping areas, schools).

6.21.3 Asset Renewal Programme

Earth systems for distribution equipment have historically been very simplistic and reviews of earthing practices have shown some inadequacy. Our earthing standards have therefore been revised and aligned with industry best practice. This, in conjunction with regular inspections, has revealed that significant investment is necessary to improve system reliability and safety. Earth systems on SWER lines and those with high earth resistance test readings and below standard construction in high risk areas will be targeted first. The remainder will be systematically upgraded.

6.22 SCADA and Communications

6.22.1 Failure Modes and Risks Associated with SCADA and Communications

SCADA systems can fail for a number of reasons, including: telecommunications, supply availability, relay failure and server failure. Failure of the SCADA system, although recoverable, leaves the control room operators without an active view of the network. Careful recovery plans are then instigated to manage the situation.

6.22.2 Planned Inspection and Maintenance Practices for SCADA and Communications

Recent installations of new Foxboro & Schweitzer Engineering remote terminal units (RTUs) and associated Ethernet communications equipment, combined with the decommissioning and removal of legacy equipment, has prompted a review of the maintenance strategy. The installation of this new equipment with its on-board diagnostics information has made it easier to monitor the systems and alarm the network assets for operation outside of normal parameters.

At two-yearly intervals, all analogue transducers and remote terminal inputs are checked, recorded, and adjusted if necessary, and power supplies are checked at the master station and all remote terminals.

At 12-monthly intervals, all VHF and UHF radio sites are visited. The operational levels are checked, recorded, and adjusted if necessary. All aerials and power supplies, along with site security and accessibility, are also checked and rectified as necessary. At four-yearly intervals, a more detailed inspection of aerials and equipment is undertaken, and major operational adjustments made if necessary. Central zone substation remote alarms are checked monthly, from a common alarm test facility at each remote site.

The master station systems (hardware and software) are inspected annually by the system vendor under a support contract to ensure they are operating to the appropriate levels of service. Minor server maintenance is handled as required by SCADA support staff in conjunction with IT.

With the installation of optical fibre communications, responsibilities and standards need to be defined for the safe and optimum operation and maintenance of these assets. These systems will be developed in conjunction with specialist external specialist consultants.

6.22.3 Asset Renewal Programme

Replacement of the RTU cabinets at selected substations has been undertaken and a number of smaller RTUs in the field will also be replaced to provide consistency of RTUs across installation types and provide spare parts for RTUs that are no longer supported by the manufacturer.

6.23 Load Control Plant

6.23.1 Failure Modes and Risks Associated with Load Control Plant

Failure of load control plant can result in us incurring additional transmission charges and could also result in the overload of highly loaded sections of our network. The risks to the plant are mitigated by:

- operating plant within its limits;
- having a limited number of critical spare parts immediately available; and
- holding a support contract with the system vendor, including access to specialist parts if required.

6.23.2 Planned Inspection and Maintenance Practices for Load Control Plant

Ripple plant equipment and load control software systems are visually inspected and operationally tested monthly. There is also a detailed annual inspection by the system vendor under the terms of the support contract. Maintenance or adjustments to the systems arising from vendor inspection reports are then programmed to be carried out at the earliest convenient opportunity.

6.23.3 Asset Renewal Programme

Waipapa substation is currently the only ripple plant scheduled for renewal during the planning period, where it will be replaced with a new unit at Wiroa, after that substation is upgraded to 110kV

6.24 Breakdown of Network Maintenance OPEX Forecast

Sections 6.24.1 to Section 6.24.3 below provide a breakdown of our forecast network maintenance opex in accordance with the standard management categories currently used by Top Energy. Expenditure on routing maintenance and inspection is forecast to reduce in real terms over the AMP planning period as the revised inspection and condition assessment strategy described in Section 6.1.2.2 is implemented.

Table 6.7 shows how these categories have been aggregated into the Commission's standard maintenance OPEX forecast categories presented in Schedule 11b of Appendix A.

<table>
<tr><th></th><th>Disaggregated expenditure
Sections 6.23.1 – 6.23.3</th><th>Summary
Section 6.23.4</th><th>Schedule 11b
Appendix A</th></tr>
<tr><td>FT (all categories)</td><td>Service interruptions and emergencies (broken down by asset category)</td><td>Service interruptions and emergencies</td><td>Service interruptions and emergencies</td></tr>
<tr><td>MP – INSPECTION (distribution)</td><td>Routine maintenance and inspection (distribution)</td><td rowspan="4">Routine maintenance and inspection</td><td rowspan="4">Routine and corrective maintenance and inspection</td></tr>
<tr><td>MP – SAFETY & COMPLIANCE (distribution)</td><td>Safety & compliance (distribution)</td></tr>
<tr><td>MP – INSPECTION (transmission)</td><td>Routine maintenance and inspection (transmission)</td></tr>
<tr><td>MP – SAFETY & COMPLIANCE (transmission)</td><td>Safety & compliance (transmission)</td></tr>
<tr><td>MP - VEGETATION (distribution)</td><td>Vegetation (distribution)</td><td rowspan="2">Vegetation</td><td rowspan="2">Vegetation management</td></tr>
<tr><td>MP - VEGETATION (transmission)</td><td>Vegetation (transmission</td></tr>
<tr><td>MR (all asset categories – distribution)</td><td>Replacement and renewal (distribution – broken down by asset category)</td><td>Replacement and renewal (distribution)</td><td rowspan="2">Asset replacement and renewal</td></tr>
<tr><td>MR (all asset categories – transmission)</td><td>Replacement and renewal (transmission – broken down by asset category)</td><td>Replacement and renewal (transmission)</td></tr>
</table>

Table 6.7: Mapping of Top Energy's Asset Forecast

6.24.1 Service Interruptions and Emergencies

($000, real)	FYE									
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Lines and poles	519	577	571	539	455	445	373	305	298	235
Cables and pillars	190	190	190	190	190	190	190	190	190	190
Transformers	129	129	129	129	129	129	129	129	129	129
Buildings and grounds	2	2	2	2	2	2	2	2	2	2
Switchgear and protection	135	135	135	135	135	135	135	135	135	135
Secondary systems	227	227	227	227	227	227	227	227	227	227
Total	**1,200**	**1,258**	**1,252**	**1,220**	**1,136**	**1,126**	**1,054**	**986**	**979**	**916**

Table 6.8: Service Interruptions and Emergency Maintenance OPEX by Category

6.24.2 Routine and Corrective Maintenance

($000, real)	FYE									
	2019	2020	2021	2022	2023	2024	2024	2026	2027	2028
Routine maintenance & inspection	**1,687**	**1,711**	**1,759**	**1,745**	**1,744**	**1,750**	**1,687**	**1,711**	**1,759**	**1,750**
Safety & Compliance	**180**	**180**	**180**	**180**	**180**	**180**	**180**	**180**	**180**	**180**
Vegetation	**1,750**	**1,750**	**1,750**	**1,750**	**1,750**	**1,750**	**1,750**	**1,750**	**1,755**	**1,780**
Asset replacement & renewal										
Lines and poles	700	700	700	700	700	700	700	700	700	700
Cables and pillars	27	27	27	27	27	27	27	27	27	27
Transformers	265	265	265	265	265	265	265	265	265	265
Buildings and grounds	36	36	36	36	36	36	36	36	36	36
Switchgear and protection	69	69	69	69	69	69	69	69	69	69
Secondary systems	24	24	24	24	24	24	24	24	24	24
Subtotal – replacement & renewal	**1,120**	**1,120**	**1,120**	**1,120**	**1,120**	**1,120**	**1,120**	**1,120**	**1,120**	**1,120**
TOTAL	**4,737**	**4,761**	**4,809**	**4,795**	**4,794**	**4,800**	**4,737**	**4,761**	**4,814**	**4,830**

Table 6.9: Breakdown of Routine and Corrective Maintenance

6.24.3 Summary of Maintenance Opex Forecast

($000, real)	FYE									
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Service interruptions and emergencies	1,200	1,258	1,252	1,220	1,136	1,126	1,054	986	979	916
Routine maintenance and inspection	1,867	1,891	1,939	1,925	1,924	1,930	1,867	1,891	1,939	1,930
Vegetation	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,755	1,780
Replacement and renewal	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120
Total	**5,937**	**6,019**	**6,061**	**6,015**	**5,930**	**5,926**	**5,791**	**5,747**	**5,793**	**5,745**

Table 6.10: Breakdown of Total Maintenance Opex Forecast

6.25 Forecast Asset Replacement and Renewal Expenditure

Asset replacement and renewal expenditure can be categorised as opex or capex depending on the nature and scale of the work. As a rule, maintenance work undertaken to remedy a defect identified during the asset inspection programme is categorised as "other maintenance" (and hence by the Commission as asset replacement and renewal opex) unless it involves the replacement of a complete asset, in which case it is capitalised. Hence the straightening of a pole or the replacement of a cross arm or insulator is deemed opex, but the replacement of the pole and pole top furniture would be capitalised.

Asset replacement and renewal capex is further categorised into:

- planned one-off projects. These are proactive and individually developed and scoped to address an identified need or weakness in the network. Examples include outdoor-indoor switchgear conversions and major line refurbishment projects such as the pole replacement on the Kaitaia-Pukenui 33kV line, which is currently in progress. These projects, where the cost is individually estimated, are the responsibility of the Programme Delivery Manager and implementation is seamlessly integrated with the delivery of the network development programme. Large, pre-planned, one-off asset replacement and renewal capex projects are therefore discussed in Sections 5.13-5.16.
- maintenance capex. These are reactive asset replacements, undertaken either in response to a fault or other emergency or to remedy defects identified during asset inspections. The asset replacement and renewal capex forecast in Table 5.18 includes a provision for this work as a separate line item, the cost of which is largely based on actual historic costs. Maintenance capex provisions are included in the capex forecasts in Sections 5.17 – 5.18. However, for clarity, this maintenance capex provision is extracted from the asset replacement and renewal capex forecast in Section 5 and disaggregated by asset category in Table 6.11.

6.26 Non-network Capital Expenditure

As noted in Section 3.4.16, 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 described in Section 5.19. This situation is not expected to change over the planning period and, apart from the new ADMS, expenditure is 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 a for the purchase of the ADMS and other non-network assets.

6.27 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 plan to achieve these service levels and accommodate the forecast increase in demand for electricity; and
- 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 2.3; and
- 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 consistent with the Commission's regulatory requirements.

Table 6.8 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, real)	FYE									
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Transmission and subtransmission lines	233	196	159	159	160	161	163	164	166	167
Transmission and zone substations	233	196	159	159	160	161	163	164	166	167
Distribution lines	1,365	1,151	934	930	938	946	954	962	970	978
Distribution cables	233	196	159	159	160	161	163	164	166	167
Distribution substations and transformers	1,032	870	706	703	709	715	721	727	733	740
Distribution switchgear	233	196	159	159	160	161	163	164	166	167
Total	3,330	2,806	2,278	2,268	2,287	2,306	2,326	2,346	2,366	2,386

Table 6.11: Breakdown of Maintenance Capex Forecast

($000, real)	FYE									
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System operations and network support	5,206	5,426	5,566	5,677	5,791	5,907	6,025	6,145	6,268	6,394
Business support	4,446	4,535	4,626	4,718	4,812	4,909	5,007	5,107	5,209	5,313
Total	9,652	9,961	10,192	10,396	10,604	10,816	11,032	11,253	11,478	11,707

Table 6.12: Non-network Opex Forecast

Section 7 Risk Management

7 Risk Management

7.1 Risk Management Policy

Governance of divisions of the Top Energy Group is the responsibility of the Board of Directors. The Executive Management Team (EMT) is 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 have been included in this process, including exposure to risk, which is a critical aspect in the effective discharge of management responsibilities. The Board is accountable for risk, but delegates policy execution to the EMT.

Our approach to risk management starts at the senior management level with its risk management policy. This policy delegates responsibilities for risk management to different functional areas (and individuals) within the business through the use of a corporate risk register. This risk management policy fulfils the need for an efficient, effective, and demonstrable risk management process, which is commensurate with the size of the business. The policy is consistent with established principles of risk management and with the ISO 31000 risk management standard. The policy is authorised by the EMT.

In order to ensure that risk management is recognised and treated as a core competency, the Group has established a corporate level risk 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. Particular 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 EMT with findings reported to the Audit & Risk Committee (ARC) of the Board of Directors; and
- 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.

7.1.1 Corporate Risk Management Committee

Risk management is an on-going cyclical process that is managed by the Corporate Risk Management Committee. This Committee comprises the Chief Executive and the General Managers from each division of the business, together with the Risk Regulatory & Commercial Manager and various specialists who may be co-opted onto the Committee from time to time.

7.1.2 Networks Risk Management Committee

TEN has its own specialised network risk committee consisting of the following personnel:

- General Manager Network;
- Network Maintenance Manager;
- Network Operations Manager;
- Network Planning Manager; and the

- Network Project Delivery Manager.

One member is nominated to manage the committee, organise four-monthly meetings, second other internal expertise as required and be responsible for updating the risk register.

The network risk committee is responsible for reviewing and maintaining 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; and
- 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: Risk management review and reporting cycle

7.1.3 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 takes into account that risk events of high consequence are more often characterised by uncertainty or surprise than classical probability, which relies on historical occurrence. Historical events are not necessarily a useful guide to future events; consequently, a systematic and rigorous process has been adopted to identify high risk possibilities.

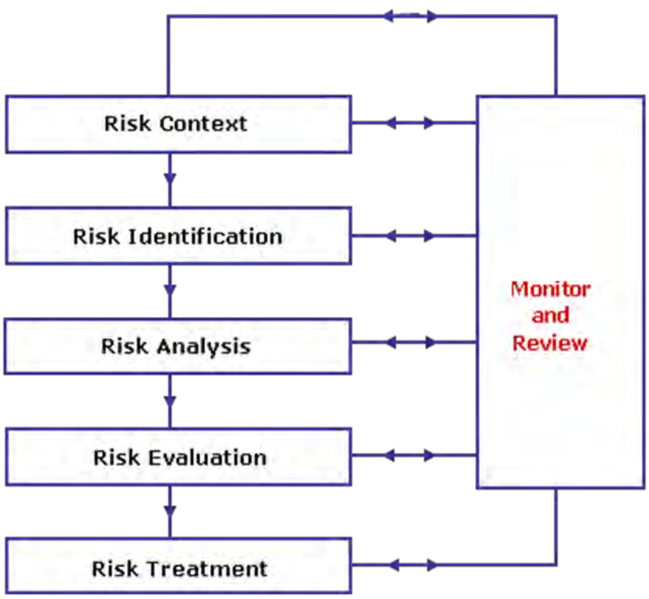


Figure 7.1 Network risk management process

RISK MANAGEMENT

Our network risk process is consistent with AS/NZS 4360:2004 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:

GENERAL MANAGEMENT	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
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 TEN, to recognise, assess and manage risk before possible adverse impact on public, personnel, and 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 in particular by the key individual associated with the risk domain. Once approved, it forms part of the risk register and is then managed and/or mitigated.

  Significantly, for an infrastructure asset manager the risks considered must not be limited to current risks but must 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 delivers 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, which is used to assess each risk that is recorded within the Network Risk Register, is included as Appendix C to this AMP.

- **Risk treatment:** Defining the actions to remove, mitigate or prepare for the risk. This involves contingency plans where appropriate.

7.1.4 Risk analysis outcome

Table 7.3 schedules the top network risks identified in our risk analysis, together with the existing controls associated with these risks and further risk mitigation actions to be implemented.

Risk Centre	Risk Source	Type	Sub-Type	Risk Description (What could happen?)	Consequence	Probability (existing today)	Outcome	Management Effectiveness	Existing Controls	Further Action / Control / Mitigation
41	Asset Management	Regulatory Compliance	Health & Safety	HV Conductor on ground. Risk to life	Major	Likely	Extreme	Strong	Protection regime, and ongoing targeted line rebuilds based upon condition assessment and age	
41	People Risk	Regulatory Compliance	Health & Safety	Accident or incident due to failure to comply with Safety Rules & Regs	Major	Likely	Extreme	Strong	Weekly audits and ongoing training	
20	Asset Management	Network	Subtransmission & Distribution	Future lack of capacity in 33kV network	Major	Likely	Extreme	Moderate	Revised 10-yearr network development plan focused on capacity and security of supply incl. a meshed 33kV.	Upgrade subtransmission network as per AMP
12	Technology and IT	Business	Telecommunications	Loss of both ISDN or loss of Alcatel PABX (support agreement with Cogent Communications Auckland)	Major	Possible	Extreme	Moderate	Backup of 2 analogue circuits to Kaikohe. Further backup of Telecom cell phones, Vodafone cell phone and data card for internet use. Transpower NISN analogue extension is available in control room	Gateway between IP phones to be provided at zone subs + NGA provides backup for PABX and/or ISDN circuit fail. VOIP in all substations not yet complete.
20	Asset Management	Network	Subtransmission & Distribution	Network condition, rise in SAIDI, injury to persons, damage of TE and private assets	Major	Possible	Extreme	Moderate	Condition based targeted maintenance procedures and long-term security of supply plan	Continue reliability and maintenance programmes as set out in AMP
24	People Risk	Network	Operations	External parties making contact with live lines	Major	Possible	Extreme	Strong	Close approach procedures and public education programme	Review annually
41	People Risk	Regulatory Compliance	Health & Safety	Death or injury to consumers cutting trees to clear lines	Major	Possible	Extreme	Weak	Public notice campaign and specialist contractors employed. Consent process. Compliance with notification regulations	Extend public education process
20	Business Model	Regulatory Compliance	Regulatory Compliance	Law change affecting network sustainability	Major	Possible	Extreme	Weak	Monitoring and lobbying	
20	General Management	Network	Public	Breakdown in PR over major line builds associated with 110kV projects	Major	Possible	Extreme	Moderate	Liaison, management, and monitoring	
20	General Management	Network	Subtransmission	Capital projects over-running budgets	Major	Possible	Extreme	Moderate	Tight project management, regular monitoring, and review	
20	Asset Management	Network	Subtransmission & Distribution	Major storm event	Moderate	Almost certain	Extreme	Moderate	Emergency preparedness plans. Weather tracked. Efficient first response resources	Upgrade subtransmission network as per AMP
22	Asset Management	Network	Subtransmission - 33kV Lines	33kV lines - loss of supply for extended periods.	Moderate	Almost certain	Extreme	Moderate	Live-line procedures + maintenance regime. Detailed contingency plans for specific assets	Upgrade subtransmission network as per AMP
22	Asset Management	Network	Subtransmission - 33kV Lines	33kV Zone substation failure.	Moderate	Almost certain	Extreme	Moderate	Regular maintenance. Dual bank configurations and mobile substation.	Upgrade subtransmission network as per AMP
22	Asset Management	Network	110 kV - Transmission assets	Failure of single component: conductor, suspension equip, tower, pole, cross arm	Moderate	Likely	High	Moderate	Comprehensive engineering assessment completed December 2012 - followed by ongoing programmed asset inspection cycle	Ensure availability of critical spares. Develop in-house 110kV skills. Construct 2nd circuit as per AMP
22	Asset Management	Network	110kV KOE/KTA Transmission circuit	Sustained tropical depression over Far North. Damaging winds, slips and severe flooding. Loss of 110kV	Moderate	Likely	High	Moderate	1st response Top Energy personnel. Backup agreement with external contractor	Backup from Wiroa 33kV in 2014. Construct 2nd 110kV circuit as per AMP

Table 7.3: Profile of Top Network Risks

7.2 Risk Mitigation

Examples of new risks, plus some of the more important risk treatments and controls we recognise, are described in the following sections.

7.2.1 Update on Networks Current Risk Profile

- Our exposure to transmission risk changed following the April 2012 acquisition of Transpower's 110kV assets. We are now positioned to improve asset management and operational performance in this area. Conversely, ownership of these assets has increased our physical exposure to risk.
- Load growth has flattened over the since FYE2012 and this has resulted in a modest reduction in load related risk.
- The network development plan is progressing well. This will mitigate some of the risks associated with a potential breach of the Commission's quality threshold in its price-quality regulatory regime.

7.2.2 Ongoing Risks

7.2.2.1 Health and Safety Policy

The safety of our employees, contractors and the general public is of utmost importance in the operation, maintenance, and expansion of the network. We operate under an industry-recognised health and safety system that meets 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 general 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; and
- management of contractors and sub-contractors.

Further, a high standard is being 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); and control room operator. This demonstrates commitment to employee development and increases our ability to maintain the network efficiently.

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 unsupervised on and around the network. This assessment process ensures the safety of employees as they only work within their proven competency.

To reinforce this, the Group launched a company-wide "values programme" in early 2013 and the current AHC system has been updated to integrate the EWRB's competency-based refresher classes. We maintain a proactive role in staff competency, monitoring industry safety issues and implementing training and guidance where required.

7.2.2.2 Transmission and Distribution Risks

Transmission risks are relatively high, because the transmission system carries high loads and a loss of supply due to a failure of the transmission system affects large numbers of consumers. The acquisition of transmission assets transferred much of this risk from Transpower to Top Energy. We manage this additional risk exposure through the following measures:

- an investment in staff training, and a willingness to optimise fault response and minimise the duration of single circuit transmission outages;
- a comprehensive condition assessment of our 110kV assets. This was completed in December 2014;
- contracting the maintenance of 110kV line and substation assets to an experienced external service provider. This contract is now in place;
- establishment of a programme to develop in-house 110kV skills for both emergency response and maintenance activities;
- a plan to provide prioritized remediation of identified defects;
- a commitment to facilitate regular site visits and engagement with owners of property over which our 110kV assets are situated; and
- our commitment to install additional generation in our northern area. When this project is completed there will be no need for planned transmission system interruptions supply will be restored more quickly following unplanned interruptions.

The backlog of distribution defects identified during the asset inspection programme and requiring remediation was increasing and, if this trend continued, achievement of the reliability targets set out in Section 4 of this AMP could have been at risk. This risk has now been largely mitigated through the introduction of SAP, which has allowed much closer control of the maintenance effort and by making TEN staff more accountable for asset inspection and managing maintenance activities.

Ongoing expenditure on vegetation management is forecast at what we consider a sustainable level. However, insufficient expenditure could adversely impact future reliability. The situation is being monitored closely to ensure that vegetation management remains in-step with actual outage data and risk profiles.

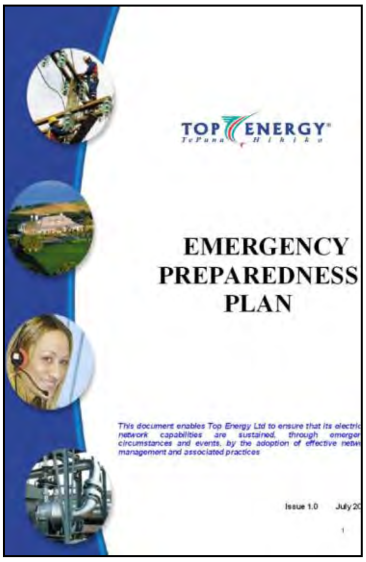
7.2.2.3 Network Critical Spares

We maintain an inventory of critical spares where there could be long delivery times in the event of network equipment failure.

Our electrical network is mainly of overhead construction. In most cases, the equipment is of modular design and can be relatively easily replaced using our inventory of equipment held to maintain and expand the network. However, we maintain a regularly reviewed level of specialised spares and have joined a cooperative group of other EDBs to provide mutual risk mitigation in this area.

For the 110kV transmission assets, critical spares have been procured for standard hardware, cross arms, insulators, and poles. An informal arrangement has also been made with Transpower to obtain a 110/33kV transformer bank at short notice if required.

7.2.3 Emergency Response Plan



We have well-established disaster readiness and emergency preparedness plans. Our formal Emergency Preparedness Plan ensures that our network capabilities are sustained as much as practical through emergency circumstances and events, through the adoption of effective network management and associated practices. The plan ensures 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 objectives of this plan and associated arrangements are:

- to provide general guidelines to be combined with sound judgment, initiative, and common sense in order to address any potential emergency, irrespective of whether that particular set of circumstances has been previously considered.
    - to provide defined 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 general public;
    - protection of property and network assets;
    - protection of the environment;
    - ongoing integrity of the electricity network; and
    - 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; and
    - 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 networks during an emergency.

The plan addresses the management of emergencies related to:

- our electricity network management facilities and capabilities for our network, Transpower’s supply to Top Energy and the coordination of responses and communications; and
- our major consumers and the coordination of responses and communications.

The plan addresses major emergencies to electricity supply addressing the following four ‘R’s:

- **Reduction** (mitigation) of potential and actual threats/impacts arising from a diversity of natural and man-made hazards/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 ‘residual’ risks/threats beyond those alleviated by other means;

- **Response** to a potential and actual emergency to stabilise the situation and prevent further danger, damage, and unnecessary outages; and
- **Recovery** following Response, to restore full normal services and functions.

The plan is a comprehensive document, which 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 and subsequently reviewed to capture the lessons learnt from our management of that event.

7.2.4 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.

The Group aims to co-ordinate efforts to reduce the vulnerability of Northland's lifelines to hazard events and to make sure 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 all authorities and organisations (including local authorities and network operators) 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.; and
- 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 voluntarily 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 stakeholders 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; and
- the protocols for testing and reporting of system failures.

7.2.5 Load Shedding

We maintain a load shedding system to meet our regulatory requirement to ensure, at all times, 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 (each block being a minimum of 16% of the total pre-event demand at that grid exit point), when the power frequency falls below specified minimum requirements.

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 for AUFLS (Automatic Under-Frequency Load Shedding) requirements. This is discussed further in Section 5.10.

7.2.6 Contingency Plans

We have standardized 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 operations centre at Ngawha Power Station, and training programmes provide for regular operator familiarisation and testing activities.

7.2.7 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.

This unit can also be used to facilitate maintenance on zone substations and therefore reduce planned consumer outages.

7.3 Safety Management

As noted in Section 2.4, 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, operate our network, ensure that we meet all legal compliance requirements and interface with our contractors and other external organisations, the general public and the users of our network.

Section 63A of the Electricity Act 1992 requires us to have a Public Safety Management System (PSMS). Our PSMS is certified as complying with NZS 7901 and is regularly audited by external auditors 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. Regulation 48(1) of the Electricity Safety Regulations 2010 (ESR) allows us to do this rather than comply with the prescriptive requirements of Regulation 49 and 50 of the ESRs. 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 energise.

A new strategy we have adopted is to separate out inspections undertaken to manage asset life cycle, as discussed in Section 6.1.2.1, from work supporting safety management as the two workstreams have different drivers. We think that treating safety separately from condition assessment will lead to better safety outcomes. For example, managing close approach to live assets by checking clearances prior to work, advising staff and contractors before they work on the network of the hazards we are aware of that should be considered in their safety plan, is a more proactive and safety focussed approach than simply trying to capture relevant data during asset condition assessments.

7.3.1 ESR Driven Safety Management Practices

Regulatory requirements related to the design of a safe network are prescribed in Part 4 of the ESR. The essential elements are:

- ESR 34 Protection – from both short circuit and earth fault;
- ESR 41 Structural loading – more specifically compliance with AS/NZS 7000 and NZECP 34;
- ESR 42 Earthing Systems - more specifically compliance with NZECP 35; and
- ESR 43 Isolation – provisions for the disconnection of works from energy sources.

Safety of consumer installations is prescribed in Part 5 of the ESR, which is focused on compliance with the Wiring Rules specified in AS/NZS 3000. Part 5 covers assets that do not supply multiple consumers and include service lines and street lighting systems.

Part 3 of the Regulations covers safe systems of supply prescribing voltage and quality standards which relate to the design of connection provisions. For example, ESR 31 requires compliance with New Zealand Electricity Code of Practice 36 (NZECP 36) relating to limiting the potential interference from electrical harmonics. There are also requirements relating to the interaction of live networks with other utilities such as telecommunications, and also to special scenarios such as grid tie inverters, hospitals, marinas, and generation.

Our practices that address the key requirements of safety regulations are described below:

7.3.1.1 Network Safety Checks

ESR 39 specifically provides that compliance with our NZS 7901 certified PSMS is an approved approach to meeting our obligations to ensure that our network is maintained in a safe condition. We use this approach as an alternative to compliance with the prescriptive default requirements of the ESRs and associated NZECPs. Our ongoing compliance with our PSMS is regularly audited by an external auditor.

7.3.1.2 Protection

Our network protection scheme relies largely on expulsion fuses. This has the following limitations:

- Fuses are an overcurrent device that have limited effectiveness in protecting against earth faults. In places, our network may not have sufficiently high earth fault levels to operate the fuse;
- Fuses operate individually for each phase. Hence, fuse operation may not isolate all three phases to provide full isolation;
- Correct operation of a graded fuse protection system[9] is dependent on the appropriate size fuse being used in a particular location. Network configuration changes affect the fault level and the required grading.
- Fuse protection systems can trigger fires when a fuse expels molten metal or when contact with vegetation fails to create a sufficiently solid fault to operate the fuse.
- Fuse operating curves are extremely inverse, making them difficult to coordinate with modern protection equipment such as reclosers.
- Using a fuse as an isolation point may result in the effective removal of all protection on the circuit being worked on.

The primary protection devices on our 11kV distribution network are the feeder circuit breakers at our zone substations – these need to be coordinated with our downstream protection equipment on each 11kV feeder. This feeder protection may not detect low resistance faults at the end of a feeder or correctly grade with our expulsion fuses. To address these limitations, we have circuit breakers or reclosers and sectionalising devices on our 11kV feeders. The protection on these devices is designed to coordinate with upstream devices and the feeder circuit breakers.

Maintaining accurate coordination is therefore vital to the effective operation of overall distribution network protection scheme. When this is wrong there can be a high level of unreliability due to the

[9] In a graded system fuse sizes are selected to ensure that only the affected section of a network is isolated in the event of a fault.

spurious tripping of feeder sections not affected by a fault. A protection scheme that isn't working effectively generally indicates the following design issues:

- The application of a protection device is sub-optimal in respect where the device is positioned in the network, how it is connected, configured, etc. This requires competent engineering; or
- The protection settings or fuse sizes are not correct perhaps because a device has been shifted, the network has been reconfigured, or fuse links have been inadvertently replaced with the wrong size.

There is therefore a need to:

1. model the protection coordination whenever there is a network design change;
2. review the system fault levels on which protection design is based every five years, or when significant new growth occurs, or new block loads are added;
3. check devices are programmed and function correctly as part of their regular maintenance cycle. This should include secondary injection trip testing as a minimum; and
4. regularly check fuse sizes against system records

Our protection safety management system consists of the following:

1. Maintaining a power flow model of the network. As indicated in Section 2.9.4, our power flow model uses the Digsilent power system analysis software. All our subtransmission networks have been modelled as have feeder backbones, but some spurs have been simplified as lump loads. While modelling to this level meets most needs, we are working with the software provider to create a power flow model directly from our GIS system, which will mean that the model will be automatically updated as the network configuration changes;
2. Maintaining a full-set of protection coordination diagrams for every feeder. This information is currently available in various forms but not as a collated set. We plan to undertake a full feeder protection review in FYE2019, when this information will be properly collated;
3. As part of the asset management process, we regularly review equipment selection criteria in respect of equipment technology, standardisation, application, and obsolescence. Similarly, the overall protection scheme is regularly reviewed to ensure its sustained fitness for purpose. Our 33kV line protection has recently been upgraded as part of our network development plan and we plan to undertake a full 11kV feeder protection review in FYE2019.
4. Undertaking trip testing and programming checks as part of the maintenance cycle;
5. Logging all fault events attributed to protection system coordination/design issues for follow-up review and assessment of the need for design improvements. Currently protection issues on the 33kV subtransmission network are prioritized and resolved quickly. Protection problems on the 11kV distribution system are also logged, but resolution can be slower;
6. We should also check fuse sizes on a regular basis and maintain a history of dates when they were changed or checked. Currently we do not do this, but we plan to include this process in the next review of our PSMS.

The low voltage system has a different set of safety issues.

- The ability to isolate from high voltage is the most significant long-term design issue, which is being addressed through asset management and safety by design;
- Low voltage distribution fuses are typically sized to protect cables from overload and therefore may not clear faults. Specifically, they do not provide earth fault protection;
- Service line fuses may not operate effectively due to voltage drop and poor earthing conditions which can result from aging and load growth in a consumer's installation. Regulations currently do not require periodic checking and compliance upgrades of low voltage systems as they do for high voltage. There is also a demarcation issue regarding who owns and operates these assets and who has the responsibility for managing safety;

- There remain some assets, such as rewireable fuse bases, which are defined as "unsafe" in the ESR but are not required to be retrospectively brought up to compliance.

Our asset management and safety by design processes now use the following practices for delivering safe low voltage protection in new and upgraded installations:

- Use of insulation piercing connectors and a policy of replacing replace all "unsafe" fittings on discovery;
- Installation of incoming pillars with full shrouding and ganged fuses to distribution frames;
- Service line safety assessments and, where necessary, requiring consumers to upgrade the service line to compliance with current safety requirements when reconnection to the network is required following faults, connection upgrades, etc. This is a public safety management process;
- We also plan to initiate a data capture project to progressively gather information on service lines to manage the above safety initiatives and maintain updated records.

7.3.1.3 Structural Loading

The ESR require all structures to be designed to AS/NZS 7000, which is a structural design standard for overhead lines, and NZECP34, which addresses issues of electrical clearances. We are required to keep records of design and to use these to determine whether their physical condition is adequate to meet the minimum strength requirements of the design. Our challenge is that we have no historical records of structure design and consequently we have limited ability to assess remaining strength against the original design requirement. Further, condition assessment techniques tend to deliver results based on an assessment of remaining strength, which is relative to whatever the installed strength was and not an absolute measure that can be compared directly with an assessment of what the required design strength was.

Our structure design and pole condition management practices are based on the following:

- Wooden poles are required by Electricity Engineers' Association practice guides to be treated as unsafe to climb until an action has been undertaken to prove they are safe to climb. We are planning to implement a new safety management process that will require any wooden pole that cannot be accessed by a bucket or held with a crane to receive a below ground inspection, an assessment of pole top load, and a permit to climb. We are also planning to eliminate this hazard within ten years by replacing all wood poles remaining on our network;
- Structures have been standardised to a limited set of pole top assemblies allowing tighter control of materials specifications and coordination of component strength. Component approval is subject to a "safety by design" assessment and selection process. These assemblies are then able to be modelled as elements in structural design tools;
- We use CATAN as our distribution line design tool. This assesses the strength of structures as an integral part of a line i.e. their strength requirements in terms of the pole top loadings presented by conductor size, span and angle, and the resolution of strength issues via stays, foundations, and structure modifications. Transmission and subtransmission lines are designed by external consultants;
- CATAN is informed by our Overhead Line Design Manual, which identifies the key assumptions for local environmental conditions; for example, the maximum wind speed we design structures to withstand;
- CATAN can also provide information on potential conductor clashing, clearance to ground, etc. However, these in-situ details require the capture of terrain profiles;
- To address the lack of design records for old structures a set of typical structures has been modelled and tested to determine a benchmark strength;
- There is a large population of concrete poles that have replaced hardwood poles over the past 20 years and for which there are no design records. These may be under-designed or overloaded in some locations because a concrete pole generally has lower strength than a hardwood pole.

This is because a concrete pole can be manufactured to more homogenous and consistent standards. Accordingly, concrete poles are not designed to high safety factors. Concrete poles also perform differently under certain loading conditions so generally require better staying and foundation design;

- The other weakness in regard to historical practice that specific design can resolve is conductor tensioning and sagging.

7.3.1.4 Earthing

We operate a multiple earth neutral (MEN) system. Earthing at multiple points lowers the earth loop impedance and therefore ensures a lower resistance path for fault current and consequently a higher probability that the fault current will be sufficient to operate fuses and other protection devices.

The MEN is less effective when there are fewer earthing points e.g. in rural areas with minimal low voltage interconnection, where the earth electrodes have a high resistance to earth, or where the conductor is small and long with a high resistance. We provide an earthing point at every item of high voltage equipment, every transformer, every high voltage cable termination, every metal clad installation, and at the end of every low voltage distribution line. Every main switchboard in consumer installations also has an earth.

The earthing system is also required to limit touch and step potentials resulting from earth potential rise[10] during fault events. We engage external consultants to design the earthing systems within our zone substations, and all earthing points elsewhere on our network are designed and installed in accordance with standard industry practice. The resistances of high voltage earths are now tested at the time of installation and measures are taken to lower the earth resistance where necessary. We also have a programme in place to periodically test earths for their continuing integrity and to remediate where necessary.

Earthing issues are:

- Past design of earthing may not meet modern requirements, particularly in respect of the need to keep earth potential rise below a hazardous level. Modern design keeps the high voltage earth fault path separate from the low voltage earthing system. Further the condition of old earths may have deteriorated since new;
- Load growth or modifications to consumer installation may have resulted in earthing systems no longer being adequate for effective protection;
- Past practice was poor in regard to the management of step and touch potentials and potential hazards may remain on the network as a result. There was a lack of bonding of operating mechanisms and conductive material not intended to carry fault current may not be effectively isolated. An example of this is a failure to install an insulator on stays. There may be fortuitous earthing connections that could exhibit a hazardous earth potential rise during faults. This is a public safety matter if the public can access the assets involved;
- The power supply to telecommunication cabinets may have insufficient barrier to prevent high voltage fault currents using the copper communications network as a return path.

Our approach to managing compliance with earthing requirements is:

1. We assess the strength of the MEN – the number of earthing points connected and combined earth impedance. Where a high earth test is discovered, we will upgrade the system to modern standards and if necessary add additional earthing points to achieve an acceptable outcome;
2. We ensure that all new ground mounted equipment is either earthed metal clad with an equipotential earth mat or loop or, alternatively, insulated. The design standards to which we

[10] During a fault event the current flowing to earth can be very high. If the earth resistance is high, the voltage of metallic material connected to earth will rise, and in extreme cases the magnitude of this rise can be dangerous to people and stock nearby.

build incorporate compliant earth systems, and inspection and testing at commissioning ensure that the installed earth systems are effective.

7.3.1.5 Isolation

The ESRs require that we provide the capability of isolating our works from their source of supply. To prevent disruption to others and make day-to-day operation of the network pragmatic, the network is designed with specific switching points that also provide isolating capability.

The main legacy issue is the demarcation between service lines and works. Historically, we owned all high voltage assets connected to our network. Regulatory change has now dictated that high voltage assets (except transformers) on a consumer's property are now owned by the consumer, who is responsible for the management and maintenance of these assets. A consequence of this change is that there may not be isolation and protection at the boundary between our works and a consumer's dedicated supply assets. All new high voltage service connections to our network now require a set of drop out fuses at the ownership boundary providing both protection and an isolation point. These fuses replace the ones that have traditionally been installed on the transformer pole.

We also adhere to the following design standards:

- Switchgear is rated for load break, fault make duty, so that it can be safety operated under all loading conditions;
- We maintain a visual air gap requirement for high voltage isolation, and do not rely on the insulation rating of circuit breakers and other equipment.

The majority of our isolation points are drop-out fuses. These require special consideration when being used for load breaking as each phase is individually operated. Specifically:

- In some situations, earth fault protection could operate during phase-by-phase isolation. This would cause the feeder circuit breaker to operate, disconnecting the feeder.
- There is a potential for ferro-resonance to be initiated between cables and larger ground mount transformers. This could damage the equipment.
- Restrike might occur when breaking loads with high levels of stored energy.

Such occurrences are unusual. If they were identified we would supplement the drop out fuses with a three-phase load breaking device, such as a load break switch or an air break switch fitted with a load breaking head.

Low voltage isolation in the distribution system is limited. For example, historically we have not installed incoming links between a transformer and its low voltage distribution frame. Fortunately, there is limited LV interconnection between distribution substations, so low voltage distribution fames can generally be isolated by isolating the transformer. Nevertheless, as these substations do not meet current safety requirements, the ESRs class them as "unsafe" and they are managed accordingly. These non-compliances are addressed when the ground mounted transformers and their associated LV networks are upgraded.

7.3.2 Integrated Safety Management

We use our NZS 7901 certified PSMS as the basis for managing the risks that our network poses to the public and also to our employees and contractors, and to ensure compliance with ESRs. We are currently revising our PSMS to reduce the reliance on condition assessment as a safety measure and to put in place additional proactive measures to keep our employees, contractors and the public safe. These measures include:

- a requirement that wooden poles are treated as unsafe to climb until they have been inspected below ground level, consistent with the EEA guide to work on poles and pole structures, and a permit to climb has been issued.
- a requirement that all new work has a formal inspection record or certificate of compliance that confirms compliance with the ESRs and the Wiring Rules before the work is livened;

- a requirement that all repair work is tested for safety before livening and that completion of these tests is formally recorded;
- a system of recording and processing defect, safety and compliance issues reported by staff and the general public outside of formal PSMS processes; and
- a requirement that assets be patrolled after a fault has occurred where supply has subsequently been restored without the fault cause being found.

7.3.3 Management of Pole and Structure Condition

7.3.3.1 Regulatory Background

We manage pole and structure condition in accordance with the ESRs. The following regulations are applicable:

- Regulation 40 (ESR 40) Safety Checks of Works; and
- Regulation 41 (ESR 41) Structural Loadings on Works.

These two regulations have prescriptive requirements, particularly in relation to periodic asset inspections and the management of overhead line poles. However, as noted above in Section 7.3, ESR 39 states that compliance with ESR 40 and ESR 41 is not mandatory if there is an accredited safety management system such as an NZS 7901 certified PSMS in place that provides equivalent outcomes.

At present our PSMS largely mirrors ESR 40 and 41 in that it provides for asset inspections irrespective of asset age and the replacement of defective poles within predetermined timeframes. We are revising this to require inspections at reasonable intervals. These intervals will be determined by the stage of an asset's life cycle and any specific condition issues known about an asset that our safety management must adapt to. Unnecessary inspections devalue the quality of the inspections through "safety fatigue" and waste resource that could otherwise focus on meaningful safety management. This is discussed further in Section 6.1.2.2.

Poles with the strength to withstand the loads to which they are subjected can remain in service. The increased use of elevated platforms and the ability to support poles with mobile truck mounted cranes means that the ability to climb an unsupported pole need not be the criterion that determines whether a pole can remain in service, provided alternative strategies are in place to ensure worker safety. Our new safety procedures will require workers to undertake an on-site assessment of structural integrity and obtain a permit to climb from the control room before climbing any wooden pole. This is consistent with the EEA guide on work on wood poles and pole structures, which states that all wood poles should be deemed unsafe to climb until their structural integrity has been confirmed. All our poles are uniquely numbered and poles approaching the end of their expected life will have a detailed assessment of pole condition in our asset management database. This information, as well as the mandated onsite assessment of structural integrity, will be used by control room staff in deciding whether to issue a permit to climb.

The sections below describe our proposed new approach to pole management in more detail. There will be a transitional period while our procedures are modified, and the new arrangements are put in place.

7.3.3.2 Application

The ESRs and our NZS 7901 accredited PSMS apply only to assets that we own[11]. They exclude service line assets which are categorised as installations in that they are owned by the consumer from the point of connection to our works, which is generally the point where the assets are both dedicated to and contained within a consumers' property or property over which they have property rights (i.e. an easement).

---

[11] Regulations prescribing requirements to ensure electrical safety distinguish between assets owned by a lines business ("works") from assets owned by a consumer ("installations"). The ESRs specify requirements for the safety of "works" while the Wiring Rules (AS/NZS 3000) specify requirements for the safety of "installations".

The demarcation point between our works and a consumer's installation has changed during the industry reforms over the last twenty years and is not consistent for both high voltage and low voltage assets. We limit management of service line condition to matters that impact public and worker safety. Specifically:

- we check pole condition before our staff or contractors are permitted to climb or work on service line poles;
- at the Network Manager's discretion, we address urgent non-compliances with the relevant safety regulation, such as line clearance clearances over roadways. In exercising this discretion, the Network Manager considers the public risk from an in-service pole failure;
- we notify service owners of any discovered regulatory non-compliances; and
- we ensure a service line is safe to liven before connecting it to our network or reconnecting it following a fault repair.

Hence our PSMS extends our sphere of influence beyond the management of our own works. However, we do not:

- provide an inspection service for privately owned service lines; nor
- have a database or other record of consumer owned service line assets, or design, or inspection records as a basis for managing these assets.

7.3.3.3 Structural Loading and Design

We design our poles and other supporting structures to AS/NZS 7000 requirements. Transmission and subtransmission structures are designed by external consultants and distribution structures are designed internally using the CATAN design tool. The Standard specifies material standards, seismic and environmental assumptions such as the relevant extreme wind loading event assumption. These are recorded in our Overhead Line Design Manual. Lines are designed as integral of conductor, poles, foundations, stays, and any equipment adding load to the pole top such a transformer. Pole top load capacity is greatly increased when supported by conductor, stays, and the poles either side.

However, we cannot assume that legacy structures are compliant with the Building Code (for example, the wood treatment of hardwood poles may not meet current code requirements), even if the structure is in good condition. Where a wooden pole has been replaced with a legacy concrete pole, the replacement pole may not have had the required strength since, historically, hardwood poles were used in situations where additional strength was required, as hardwood poles when new were stronger than the concrete poles historically used.

Pole deterioration will weaken a structure, but not necessarily to the point where it becomes unserviceable. In an extreme situation, the conductors and stays supporting the top of a pole could contribute sufficient support to keep a pole in service even though it is completely broken at ground level. A deteriorated pole carrying light conductor may have sufficient strength to remain in service, if the structure was originally built to a standard design intended for a heavier conductor.

The objective of pole condition management is to ensure that structures retain sufficient strength, before they are replaced, to support the loads imposed by the operating conditions they are exposed to. This does not mean that a structure should routinely by replaced once a defect or deterioration is found, if other means are available to keep the structure in service without compromising worker or public safety. The service life of a pole can be extended by changing the conditions under which it operated, by managing safety through changed operating practice. An example would be not allowing a suspect pole to be climbed and supporting it with a mobile crane when changing pole top loading. Public safety can be ensured by re-checking condition before deferring replacement for a limited period.

7.3.3.4 Risk Based Inspections

Our pole management process is:

- Poles will be designed and installed in accordance will all relevant structural and safety requirements. They will be certified as compliant and records updated to "as built" following construction.

- A pole will be closely inspected, and fittings tightened approximately five years after installation. This inspection will also confirm safety compliance.
- There will be no further planned asset management inspections of a pole until its population is demonstrating through defect and condition monitoring that it is approaching its onset of unreliability, which is the age at which experience has shown that rates of failure start to increase (see Section 6.1.2.2). Over this period, any outage and defect reports will be analysed for unfavourable trends that could be indicators of premature failure. An example might be binder failure related to a specific make of component, or vibration damage. If necessary, the timing of the onset of unreliability inspection will be adjusted.
- The onset of unreliability inspection will closely examine each pole to identify those poles that have the highest probability of early failure. The inspection will also look for the presence of other issues, such as rot, that may be accelerating its end of life. This assessment will include below ground testing at the point on the pole where the maximum bending moment acts. The results of this inspection will be a determination of remaining strength relative to required strength, from which an engineering judgement can be made of the expected remaining life of the structure. This is not an exact science. The objective is to make an informed judgement about how quickly a pole's strength is deteriorating over the end of life period during which failure can be expected. The asset management output of this process is a ranking that determines which poles need replacing, and prioritises the replacement of these poles. It will also identify poles that can be left in service to be reassessed at a subsequent inspection. For wooden poles ultrasound inspections are already being used to provide more consistent and reliable assessments of a pole's strength.
- We follow a Safe Operating Practice where all wooden poles are assumed to be unsafe for climbing until assessed for structural integrity to determine under what set of safety measures the pole can be climbed. This will require each pole to be inspected before it is climbed. We will control this process by requiring a Permit to Climb to be issued for every wooden pole climb, should auditing determine that staff or contractors are failing to comply with the Safe Operating Practice. Hence the inspection regime for wooden poles will be overlaid with an operational regime of mandated inspection, regardless of age and wood type, which will alert us to the presence of poor condition or unclimbable poles that we have not identified. These poles will be tagged as a warning to others, logged as a hazard and given a public safety risk assessment.
- Similarly, poles may be given a higher replacement priority for reasons other than pole strength. Such reasons could include proximity to trees, public safety risk or the criticality of the pole location. We would anticipate, for example, that replacement of poles on feeder backbones close to their zone substation will be prioritized for replacement over a pole on a spur line close to the end of a rural feeder.

7.3.3.5 Pole Tagging

We have changed our system of pole tagging so that tags will used as a warning to others.

Red tags indicate an issue such as the presence of rot that may be accelerating the deterioration of the pole. This signals the need for more vigilant monitoring and condition assessment. They will no longer mean that the pole is "condemned" (a legacy industry term rather than a regulatory definition) as field assessment is too subjective to determine this status.

Yellow tags mean that it is suspected that the pole has insufficient strength to be safely climbed without additional pole support. These would typically be poles that have significant loss of diameter or are carrying high loads such as a transformer or terminating structure. A yellow tagged pole will require a formal inspection to be initiated and a safety management system put in place.

The industry is currently investigating a standardised tagging system.

7.3.4 Pole Replacement Programme

The pole management programme discussed in Section 7.3.4 will be overlaid with a work program to replace every wood pole on the network within the next ten years. Pole replacements will be prioritised based on the assessed pole condition and remaining life and will have the following structure:

- Poles that require attention more urgently than others in the line segment that they are part of, will be replaced on a spot pole replacement basis.
- Where time allows, it is preferable to rebuild entire line segments as this allows for line design improvement, relocation to more accessible/suitable sites, etc. Spot pole replacements may be deferred where the remaining line supporting that structure has sufficient integrity, provided that the risks associated with failure are low and closer monitoring is put in place. Alternatively, the line rebuild may be brought forward resulting in earlier than planned renewal of the other poles in the line – this would normally be triggered by the closer monitoring of the poor condition poles.
- Replacement of service line poles owned by us may also be deferred where there is an issue with the condition of the poles on the same service lines that are owned by a consumer. If the consumer's line has a compliance issue, then this needs to be resolved before that service can be reconnected. In practice consumer lines tend to be in poorer condition, less well maintained and built to lesser design standards and therefore drive the urgency of pole replacement. Where we identify an issue with our poles on such a line, we will initiate a process of checking the consumer owned assets and notifying them of non-compliances.
- Where it is not our intention to rebuild a line at the end of its service life – it may be uneconomic or in an inaccessible location – poles may be left to fail in service. Affected property owners will be informed of this and of any hazard issues.

Urgent pole replacements may sometimes be deferred where access conditions present a bigger risk than in-service failure.

7.3.5 Other Pole Management Issues

Not all structure strength issues are pole condition related. Some are design related (overloaded, missing stays, etc.) and some are hardware related (cross arm condition, for example). These issues will also be captured by inspection and recorded in defect registers and may drive early pole replacement.

Poles get replaced opportunistically as part of other asset management work programmes and maintenance, for example, replacement of a pole with a heavier pole on which to hang a transformer.

Softwood poles occasionally fail as a result of preservative system failure, causing them to rot significantly earlier than warranted. We will not approve service line designs for connection to our network where softwood or other non-approved poles are involved.

Concrete poles may suffer cracking as result of an incident such as a traffic accident. Where this does not adversely affect the integrity of the line and any critical contribution the pole makes to the line design, then they are programmed for replacement at the next opportune time in the work programme. Given that the approximately 80% of pole structures are only providing a simple propping function, damage to the pole would need to be severe and obvious to demand urgent replacement. This may involve refining the design to reduce the probability of a repeat incident.

Section 8 Evaluation of Performance

8 Evaluation of Performance 213
8.1 Reliability 213
8.1.1 Review of Network Reliability 213
8.1.2 Targeted Improvements 214
8.2 Asset Performance and Efficiency 215
8.3 Financial and Physical Performance 216
8.3.1.1 Network Capital Expenditure 216
8.3.1.2 Network Maintenance Expenditure 216
8.4 Asset Management Improvement Programme 217
8.5 Further Work 217
8.5.1 Cost of Service and Value of Lost Load 217
8.5.2 Resilience 218

8 Evaluation of Performance

This section presents a review of our financial and service level performance for FYE2017, the most recent period for which a full year's results are available. Discussion is centred on the various factors that influenced our performance and comparisons are made with industry benchmarks where appropriate.

Detailed discussion of performance measures and targets is included in Section 4 of this AMP.

8.1 Reliability

8.1.1 Review of Network Reliability

Consistent with the requirements of the both the regulatory default price-quality path and information disclosure regimes, network reliability is measured by SAIDI and SAIFI. However, in resetting the default price-quality path for the FYE2016-2020 regulatory period, the Commerce Commission changed the methodology to be used in normalising the raw SAIDI and SAIFI measures before assessing regulatory compliance. No corresponding change has been made to the information disclosure regime, so the normalisation approaches in the measurement of reliability that are applied under the two regulatory frameworks are now different.

For internal management purposes, we now set our reliability targets using the new default price-quality path normalisation methodology, and this approach is assumed in setting the forward service level targets shown in Table 4.3.

The most recent disclosure year for which complete reliability measures are available is FYE2017, when there were a total of:

- 409 unplanned supply interruptions; and
- 207 planned outages.

Table 8.1 shows the reliability of our network over the period FYE2011-17, with all measures normalised according to the *information disclosure* requirements. The table shows interruptions arising from within the network only; interruptions due to a loss of grid supply are not included.

FYE	2011	2012	2013	2014	2015	2016	2017
SAIDI	440	435	333	465	600	516	465
SAIFI	4.9	6.4	4.7	5.8	6.4	6.3	5.4

Note 1: Prior to FYE2013, faults on the 110kV transmission system acquired from Transpower are not included in the above table.

Table 8.1: Network reliability – normalised using information disclosure methodology

Table 8.2 shows SAIDI and SAIDI normalised in accordance with the requirements of the Commission's *default price-quality path* regulatory regime and compares our performance with our internal management targets and the relevant threshold denoting a potential quality path breach[12]. The measures normalised for price-quality path assessment are lower than the corresponding measures normalised for information disclosure, primarily because the weighting of planned interruptions is reduced by 50% under the price-quality path methodology.

[12] As this methodology was first introduced in FYE2016, measures for prior years are not available.

FYE	2016			2017		
	Threshold	Target	Actual	Threshold	Target	Actual
SAIDI	517	324	462	517	350	401
SAIFI	6.25	4.20	5.64	6.25	4.60	4.82

Table 8.2: Network reliability – normalised using price quality path methodology

Table 8.1 shows that our network reliability was highest in FYE 2013, a year in which weather was abnormally benign across the country. Our worst reliability was recorded in FYE 2016, a year in which our network was hit by the remnants of Tropical Cyclone Ita in April 2014, a severe weather event that lasted more than three days and caused a slip that closed State Highway 1 south of Kawakawa for almost a week in July 2014, and a slip in the Maungataniwha Ranges in December 2014 that caused a tower on our 110kV transmission line to move more than 10 metres and required two planned line outages to undertake repairs. In other years, our normalised reliability has hovered between these two extremes. These fluctuations in measured reliability show how sensitive our network performance is to weather. This volatility is so extreme that it obscures the improvements that we have been able to achieve since we introduced a targeted network reliability improvement programme in FYE2012.

Nevertheless, our efforts to improve the reliability of our network must continue, both by improving the architecture of the network to limit the impact of faults that do occur, and by increasing the effectiveness of our maintenance and asset renewal expenditure.

Network development plan initiatives discussed in Section 5 that are designed to limit the impact of faults that do occur include:

- the completion of the Kaeo substation, which will create six new feeders in the Whangaroa and north eastern seaboard area. This will reduce the length and number of connected consumers on each feeder and should significantly reduce the impact of distribution network faults in the area between Waipapa and Mangonui;
- the installation of generation in the northern area, which will not only reduce the impact of both planned and unplanned outages of the 110kV line supplying Kaitaia, but will also improve the reliability of supply following localized interruptions on long rural feeders;
- the installation of additional protection devices on the South Road feeder, including the installation of a generator and automated switching station at Broadwood. South Rd is our worst performing feeder;
- refurbishment of the 33kV circuits supplying Taipa, Pukenui, and Omanaia zone substations, which each have only one incoming supply; and
- the installation of additional interconnections between neighbouring feeders to provide an alternative supply in the event of a fault.

8.1.2 Targeted Improvements

We have benchmarked our FYE2017 network operations and maintenance expenditure (Note: excludes the capital expenditure in each of the same categories) against that disclosed by other New Zealand EDBs with largely rural supply areas. This has shown that:

- our total maintenance expenditure per km is approximately 24% higher than the average of our peers, which equates to additional expenditure of around $1 million. This is not yet fully reflected in a lower incidence of faults as we are still improving condition assessment processes, more accurate targeting, and higher levels of more formally planned maintenance;
- our expenditure on vegetation management is, on average, 116% higher than our peers for the same level of performance indicating it is time to refresh strategy and policy as the very high historical level of tree related outage has been bought down to industry norms;
- we are spending on average 12% more than our peers on routine maintenance. Most of this is on inspection and condition assessment. Now that we have implemented the bulk of our investment

program it is necessary to establish maintenance programs for these new assets to manage them through their life cycle;

- our operational expenditure on asset renewal is 34% below the average. Our asset renewal programs are largely delivered through capital investment programs. This maintenance expenditure is targeted at components of assets that need replacement for the asset to maintain serviceability to the end of its service life – an example being crossarms which have a shorter life expectancy to pole structure they are part of; and
- our reactive (fault and emergency) maintenance is higher than our peers by 21% on average. This is not all directly related to fault repair as our efficiency in this area is limited by the tools currently available to our control room and operational staff. The ADMS should drive more efficiency in this area, as will other projects targeting SAIDI improvement.

The key messages from this analysis are that our total network operations and maintenance expenditure is high but as we realise the benefits of the high investment we have made over the past decade this will now be able to be reduced over time.

We are reprioritising our expenditure on network maintenance and asset renewal to focus on reducing the impact of unplanned interruptions on the reliability of supply to our consumers at minimum cost. This strategy, which is described elsewhere in this AMP, involves:

- reducing the cost of routine asset inspections by no longer inspecting assets where experience has shown that the probability of an asset failure is low;
- reducing expenditure on vegetation management by focusing on trees that are causing a safety hazard and where, for this reason, landowner consent to address the problem is not required;
- focusing our maintenance effort on monitoring and maintaining older assets so that they remain in service for longer without materially increasing the risk of asset failure; and
- increasing staff awareness of the importance of maintaining safe work practices and implementing enhanced safety management strategies to ensure that maintenance of worker and public safety is less dependent on asset condition.

In summary, our revised maintenance strategy will substantially reduce expenditure on the inspection of assets that are likely to still be fit for service. Instead the focus will be on applying more intensive monitoring and a higher level of maintenance on the subset of the asset base that is reaching the end of its expected life, to ensure that these assets remain fit for service. In parallel with this, we are enhancing our safety procedures to mitigate any additional safety risk arising from the less intensive monitoring of the bulk of our asset base.

8.2 Asset Performance and Efficiency

Table 8.4 compares our achieved asset performance and efficiency measures in FYE2017 with the target levels set out in the 2016 AMP.

PERFORMANCE MEASURE	FYE2017 TARGET	ACTUAL PERFORMANCE	VARIANCE
Loss Ratio	9.3%	8.3%	(1.0%)
Operational Expenditure to Total Regulatory Income	33%	28.1%	(4.9%)

Table 8.3: Comparison of actual asset performance and efficiency with target levels for FYE2013

As indicated by the table, both performance indicators were bettered during FYE2017. Our assessed performance against both measures is taken from our audited FYE2017 information disclosures.

The relatively high loss ratio is a reflection of the current state of our network. As noted in Section 4.3.1, it is no coincidence that our network has both a low reliability and the high loss ratio when compared to other EDBs. That said, our loss ratio now also includes transmission losses so is not directly comparable with many other EDBs.

While our performance against both targets was pleasing, in both cases the outcomes were significant improvements on what has historically been achieved, and it is not clear that our measured FYE2017 performance can be maintained.

8.3 Financial and Physical Performance

A comparison of our actual expenditure in FYE2017 for both network capital expenditures and network maintenance with the budgeted expenditures, as presented in the 2016 AMP is provided in Table 8.4. While there are variances between the difference expenditure categories, total spend over the year was within 3% of budget.

Variances between actual and budgeted expenditures are discussed in detail in Sections 8.3.1.1 and 8.3.1.2 below.

EXPENDITURE CATEGORY	AMP BUDGET FYE2017	ACTUAL SPEND FYE2017	VARIANCE	
Network capital expenditure ($000)				
Consumer connection	1,480	1,260	(220)	(15%)
System growth	3,574	2,431	(1,143)	(32%)
Asset replacement and renewal	5,376	6,536	1,160	22%
Reliability, safety and environment	4,077	4,238	161	4%
Asset relocations	-	-	-	-
Subtotal – network capital expenditure	**14,507**	**14,465**	**(42)**	**-**
Maintenance expenditure ($000)				
Service Interruptions and emergencies	1,200	1,635	435	36%
Vegetation management	1,833	1,762	(71)	(4%)
Routine and corrective maintenance and inspection	1,765	1,947	182	10%
Asset replacement and renewal	939	548	(391)	(42%)
Subtotal – maintenance expenditure	**5,737**	**5,892**	**155**	**(3%)**
TOTAL DIRECT NETWORK EXPENDITURE	**20,241**	**20,257**	**16**	**-**

Table 8.4: Comparison of actual and budget network capex and network maintenance opex in FYE2017

8.3.1.1 Network Capital Expenditure

As shown in Table 8.4, almost all budgeted capex for FYE2017 was utilised. System growth expenditure was lower than forecast, primarily due to deferral of construction of the Kaeo substation. Our preferred substation site in Martins Rd, which Top Energy had owned for many years, was found to be unsuitable due to unforeseen geotechnical problems so construction was delayed while a new site in Omanu Rd was consented and purchased. Preliminary civil works on this new substation site commenced in January 2017 and the substation is now due for completion in March 2018.

Funds allocated to Kaeo substation construction were used to accelerate the refurbishment of the 33kV lines supplying Pukenui and Taipa and in particular to refurbish the line that will provide the incoming supply to Kaeo. This line was built to 33kV construction many years ago but has been operated as an 11kV feeder. Refurbishment of this line included the replacement of all insulators and crossarms. Expenditure was also incurred in reinforcing the Opua and Joyces Rd feeders in preparation for the Russell reinforcement project.

8.3.1.2 Network Maintenance Expenditure

As shown in Table 8.4, network maintenance expenditure in FYE2017 was also on budget. While expenditure on system interruptions and emergencies, which is reactive and therefore largely outside our direct control, was higher than forecast, this was offset by reductions in operational expenditure on asset renewal and, to a lesser extent, by reductions in vegetation management expenditure. Nevertheless, the expenditure reduction in opex on asset renewal was more than offset by the additional capex on asset replacement.

8.4 Asset Management Improvement Programme

Our organisational philosophy is one of continuous improvement across all Top Energy's business units and our certification to certification to ISO 9001 early in FYE2016 is testimony to this. This was the culmination of a major business improvement initiative that had been running for several years and affected all business units within the Group. We now have both a public safety management system and a quality system that are both externally certified and subject to regular external audits.

Our asset management improvement programme will continue to focus on improving those areas that we have identified as weak and are impediments to our overarching goal of meeting stakeholder expectations as efficiently as possible. Weaknesses still exist at the interface between TEN and TECS and efforts to improve the communication links between these two business units within the Group will continue. Furthermore, we plan to shift our asset management focus from regulatory compliance to meeting consumer expectations, particularly in the management of supply reliability and network maintenance.

As discussed elsewhere in this AMP, our asset management goals for FYE2019-FYE2021 include:

- the installation of more diesel generation within our network to secure supply in the northern area when our 110kV transmission line is out for maintenance, improve supply reliability during both planned and unplanned interruptions, and also to manage localised and seasonal network constraints;
- the installation and implementation of an ADMS to improve the effectiveness of our management of service interruptions and emergencies, and to manage the increased embedded generation within our network. We anticipate that this new operations management system will prove a key tool in our transition from a distributor of electricity to manager of a distributed energy system utilising a network that interconnects embedded electricity generators and consumers;
- developing and operating a network that is open to the use of new and emerging technologies by both consumers and generators. This will include trialling the use of these technologies in situations where they have the potential to reduce the cost of network development and operation, or to better meet the expectations of consumers and other network users in the efficient utilisation of electrical energy;
- increasing the efficiency of our network maintenance by focusing expenditure on assets that are nearing the end of their expected life and therefore have a higher probability of failing in service; and
- mitigating the risk of reducing the level of monitoring of assets that are less likely to fail in service by introducing enhanced safety management systems that are not reliant on asset condition.

8.5 Further Work

8.5.1 Cost of Service and Value of Lost Load

We are progressing further work to establish the cost of service this under our new strategic direction for network development. Specifically:

- We are developing an updated and enhanced cost to serve model that will provide resolution down to load groups and network segments. This model will also support the cost and service reflective pricing initiatives all EDBs are currently engaged in at the behest of the Electricity Authority. It will also have relevance to the development of preferred solutions for addressing uneconomic line renewal and the application of new technologies.
- We are also developing a more detailed value of lost load (VoLL) model that will be segmented by consumer type, network layer and segment. We currently use the values estimated by

PricewaterhouseCoopers in its 2015 report to the Electricity Authority[13], which disaggregates VoLL by industry sector. We expect the average VoLL in different parts of our network to vary; for example, locations like Paihia will have a higher representation of consumers in the tourism sector.

8.5.2 Resilience

Resilience has emerged as a key issue for our consumer and regulator stakeholders. We are undertaking a review of how these interests are addressed in our development plans, security, standards, contingency provisions, etc.

[13] *Estimates of North Island VoLLs,* Pricewaterhouse Coopers, May 2015.

Section 9 Appendices

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

Company Name	Top Energy
AMP Planning Period	1 April 2018 – 31 March 2028

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												
9	**11a(i): Expenditure on Assets Forecast**	$000 (in nominal dollars)										
10	Consumer connection	1,560	1,280	1,294	1,548	1,579	1,611	1,643	1,676	1,709	1,743	1,778
11	System growth	10,295	2,176	7,171	7,360	5,993	2,040	4,453	8,291	2,928	895	2,492
12	Asset replacement and renewal	5,768	6,348	6,369	9,823	5,011	5,960	7,199	5,739	6,965	8,457	6,905
13	Asset relocations	-	-	-	-	-	-	-	-	-	-	-
14	Reliability, safety and environment:											
15	Quality of supply	3,961	10,699	9,471	3,644	3,891	6,556	3,176	1,714	6,417	7,251	7,559
16	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment		-	-	-	-	-	-	-	-	-	-
18	**Total reliability, safety and environment**	3,961	10,699	9,471	3,644	3,891	6,556	3,176	1,714	6,417	7,251	7,559
19	**Expenditure on network assets**	21,584	20,503	24,305	22,375	16,473	16,167	16,470	17,420	18,019	18,347	18,734
20	Expenditure on non-network assets	450	2,845	1,428	416	424	433	442	450	459	469	478
21	**Expenditure on assets**	22,034	23,348	25,733	22,791	16,897	16,600	16,912	17,871	18,478	18,815	19,212
22												
23	*plus* Cost of financing	210	320	320	320	320	320	320	320	320	320	320
24	*less* Value of capital contributions	1,100	1,071	1,077	1,099	1,121	1,143	1,166	1,189	1,213	1,237	1,262
25	*plus* Value of vested assets	-	25	26	26	27	27	28	28	29	29	30
26												
27	**Capital expenditure forecast**	21,144	22,622	25,001	22,038	16,123	15,804	16,094	17,030	17,614	17,927	18,300
28												
29	Assets commissioned	22,116	22,622	25,001	22,038	16,123	15,804	16,094	17,030	17,614	17,927	18,300
30		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31												
32		$000 (in constant prices)										
33	Consumer connection	1,560	1,280	1,269	1,488	1,488	1,488	1,488	1,488	1,488	1,488	1,488
34	System growth	-	2,176	7,030	7,074	5,647	1,885	4,033	7,362	2,549	764	2,085
35	Asset replacement and renewal	-	6,348	6,244	9,441	4,722	5,506	6,520	5,096	6,063	7,218	5,777
36	Asset relocations	-	-	-	-	-	-					
37	Reliability, safety and environment:											
38	Quality of supply	-	10,699	9,285	3,502	3,666	6,056	2,876	1,522	5,586	6,188	6,325
39	Legislative and regulatory	-	-	-	-	-	-					
40	Other reliability, safety and environment	-	-	-	-	-	-					
41	**Total reliability, safety and environment**	-	10,699	9,285	3,502	3,666	6,056	2,876	1,522	5,586	6,188	6,325
42	**Expenditure on network assets**	1,560	20,503	23,828	21,506	15,523	14,935	14,918	15,469	15,686	15,659	15,676
43	Expenditure on non-network assets	450	2,845	1,400	400	400	400	400	400	400	400	400
44	**Expenditure on assets**	2,010	23,348	25,228	21,906	15,923	15,335	15,318	15,869	16,086	16,059	16,076
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses											
48	Overhead to underground conversion											
49	Research and development											

Company Name	Top Energy
AMP Planning Period	1 April 2018 – 31 March 2028

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
50												
52												
53	**Difference between nominal and constant price forecasts**	$000										
54	Consumer connection	-	-	25	60	91	123	155	188	221	255	290
55	System growth	10,295	-	141	286	346	155	420	929	379	131	407
56	Asset replacement and renewal	5,768	-	125	381	289	454	679	643	901	1,239	1,127
57	Asset relocations	-	-	-	-	-	-	-	-	-	-	-
58	Reliability, safety and environment:											
59	Quality of supply	3,961	-	186	142	224	499	299	192	831	1,062	1,234
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
62	**Total reliability, safety and environment**	3,961	-	186	142	224	499	299	192	831	1,062	1,234
63	**Expenditure on network assets**	20,024	-	477	869	950	1,231	1,553	1,952	2,332	2,688	3,058
64	Expenditure on non-network assets	-	-	28	16	24	33	42	50	59	69	78
65	**Expenditure on assets**	20,024	-	505	885	975	1,264	1,594	2,002	2,392	2,757	3,136
66												

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
68		**11a(ii): Consumer Connection**						
69		*Consumer types defined by EDB**	$000 (in constant prices)					
70		All types	1,560	1,280	1,269	1,488	1,488	1,488
71								
72								
73								
74								
75		**include additional rows if needed*						
76		**Consumer connection expenditure**	1,560	1,280	1,269	1,488	1,488	1,488
77	*less*	Capital contributions funding consumer connection		1,071	1,056	1,056	1,056	1,056
78		**Consumer connection less capital contributions**	1,560	209	213	432	432	432
79		**11a(iii): System Growth**						
80		Subtransmission		1,955	7,030	6,056	-	-
81		Zone substations		13	-	572	3,578	694
82		Distribution and LV lines		208	-	446	2,069	1,191
83		Distribution and LV cables		-	-	-	-	-
84		Distribution substations and transformers		-	-	-	-	-
85		Distribution switchgear		-	-	-	-	-
86		Other network assets		-	-	-	-	-
87		**System growth expenditure**	-	2,176	7,030	7,074	5,647	1,885
88	*less*	Capital contributions funding system growth						
89		**System growth less capital contributions**	-	2,176	7,030	7,074	5,647	1,885
90								

Company Name	**Top Energy**
AMP Planning Period	**1 April 2018 – 31 March 2028**

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*
91							
92							
93	**11a(iv): Asset Replacement and Renewal**	**$000 (in constant prices)**					
94	Subtransmission		1,448	1,762	1,224	1,223	1,129
95	Zone substations		679	574	4,519	159	250
96	Distribution and LV lines		2,302	2,187	2,197	1,843	2,184
97	Distribution and LV cables		233	196	159	159	160
98	Distribution substations and transformers		465	466	448	447	886
99	Distribution switchgear		1,221	1,059	895	892	898
100	Other network assets						
101	**Asset replacement and renewal expenditure**	-	6,348	6,244	9,441	4,722	5,506
102	*less* Capital contributions funding asset replacement and renewal						
103	**Asset replacement and renewal less capital contributions**	-	6,348	6,244	9,441	4,722	5,506
104							

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
105							
106							
107	**11a(v): Asset Relocations**						
108	*Project or programme**	**$000 (in constant prices)**					
109							
110							
111							
112							
113							
114	**include additional rows if needed*						
115	All other project or programmes - asset relocations						
116	**Asset relocations expenditure**	-	-	-	-	-	-
117	*less* Capital contributions funding asset relocations						
118	**Asset relocations less capital contributions**	-	-	-	-	-	-
119							

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
120							
121							
122	**11a(vi): Quality of Supply**						
123	*Project or programme**	**$000 (in constant prices)**					
124	110 kV line property rights		1,380	763	218	245	45
125	Generation		7,696	5,071	-	486	-
126	Mangamuka substation		-	160	-	-	2,721
127	Feeder interconnections		-	1,664	734	752	1,224
128							
129	**include additional rows if needed*						
130	All other projects or programmes - quality of supply		1,623	1,627	2,551	2,183	2,066
131	**Quality of supply expenditure**	-	10,699	9,285	3,502	3,666	6,056
132	*less* Capital contributions funding quality of supply						
133	**Quality of supply less capital contributions**	-	10,699	9,285	3,502	3,666	6,056
134							

Company Name	**Top Energy**
AMP Planning Period	**1 April 2018 – 31 March 2028**

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

*Project or programme**	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	$000 (in constant prices)					
**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

*Project or programme**	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	$000 (in constant prices)					
**include additional rows if needed*						
All other projects or programmes - other reliability, safety and environment						
Other reliability, safety and environment expenditure	-	-	-	-	-	-
less Capital contributions funding other reliability, safety and environment						
Other reliability, safety and environment less capital contributions	-	-	-	-	-	-

11a(ix): Non-Network Assets

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
Routine expenditure						
*Project or programme**	**$000 (in constant prices)**					
**include additional rows if needed*						
All other projects or programmes - routine expenditure	450	375	400	400	400	400
Routine expenditure	450	375	400	400	400	400
Atypical expenditure						
*Project or programme**						
Advanced distribution management system		1,970	1,000			
CRM/ICP		500				
**include additional rows if needed*						
All other projects or programmes - atypical expenditure						
Atypical expenditure	-	2,470	1,000	-	-	-
Expenditure on non-network assets	450	2,845	1,400	400	400	400

Company Name	Top Energy
AMP Planning Period	1 April 2018 – 31 March 2028

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

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

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,433	1,200	1,283	1,303	1,295	1,230	1,219	1,187	1,133	1,147	1,095
11	Vegetation management	1,512	1,750	1,785	1,821	1,857	1,894	1,894	1,971	2,010	2,056	2,127
12	Routine and corrective maintenance and inspection	2,354	1,867	1,929	2,017	2,043	2,083	2,089	2,103	2,172	2,272	2,307
13	Asset replacement and renewal	1,167	1,120	1,142	1,165	1,189	1,212	1,212	1,261	1,287	1,312	1,339
14	**Network Opex**	6,466	5,937	6,139	6,306	6,383	6,419	6,414	6,522	6,601	6,787	6,867
15	System operations and network support	4,592	5,206	5,426	5,566	5,677	5,791	5,907	6,025	6,145	6,268	6,394
16	Business support	4,246	4,446	4,535	4,626	4,718	4,812	4,909	5,007	5,107	5,209	5,313
17	**Non-network opex**	8,838	9,652	9,961	10,192	10,396	10,604	10,816	11,032	11,253	11,478	11,707
18	**Operational expenditure**	15,304	15,589	16,101	16,498	16,779	17,022	17,230	17,553	17,854	18,265	18,574
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 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,433	1,200	1,258	1,252	1,220	1,136	1,126	1,054	986	979	916
23	Vegetation management	1,512	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,755	1,780
24	Routine and corrective maintenance and inspection	2,354	1,867	1,891	1,939	1,925	1,924	1,930	1,867	1,891	1,939	1,930
25	Asset replacement and renewal	1,167	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120
26	**Network Opex**	6,466	5,937	6,019	6,061	6,015	5,930	5,926	5,791	5,747	5,793	5,746
27	System operations and network support	4,592	5,206	5,320	5,350	5,350	5,350	5,350	5,350	5,350	5,350	5,350
28	Business support	4,246	4,446	4,446	4,446	4,446	4,446	4,446	4,446	4,446	4,446	4,446
29	**Non-network opex**	8,838	9,652	9,766	9,796	9,796	9,796	9,796	9,796	9,796	9,796	9,796
30	**Operational expenditure**	15,304	15,589	15,785	15,857	15,811	15,726	15,722	15,587	15,543	15,589	15,542
31	**Subcomponents of operational expenditure (where known)**											
32–33	Energy efficiency and demand side management, reduction of energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance	227	251	251	251	251	251	251	251	251	251	251
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												
39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	25	51	75	94	93	133	147	168	179
43	Vegetation management	-	-	35	71	107	144	144	221	260	301	347
44	Routine and corrective maintenance and inspection	-	-	38	78	118	159	159	236	281	333	377
45	Asset replacement and renewal	-	-	22	45	69	92	92	141	167	192	219
46	**Network Opex**	-	-	120	245	368	489	488	731	854	994	1,121
47	System operations and network support	-	-	106	216	327	441	557	675	795	918	1,044
48	Business support	-	-	89	180	272	366	463	561	661	763	867
49	**Non-network opex**	-	-	195	396	600	808	1,020	1,236	1,457	1,682	1,911
50	**Operational expenditure**	-	-	316	641	968	1,296	1,508	1,966	2,311	2,676	3,032

Company Name	**Top Energy**
AMP Planning Period	**1 April 2018 – 31 March 2028**

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												**% of asset forecast to be replaced in next 5 years**
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	
10	All	Overhead Line	Concrete poles / steel structure	No.	2.00%	7.00%	17.00%	68.00%	6.00%	31.00%	4	1.00%
11	All	Overhead Line	Wood poles	No.	17.00%	30.00%	9.00%	36.00%	8.00%	48.00%	4	50.00%
12	All	Overhead Line	Other pole types	No.							N/A	
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	11.00%	9.00%	15.00%	61.00%	4.00%	-	2	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	12.00%	47.00%	41.00%	-	2	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	10.00%	7.00%	26.00%	57.00%	-	2	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km							N/A	
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km							N/A	
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km							N/A	
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km							N/A	
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km							N/A	
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km							N/A	
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km							N/A	
23	HV	Subtransmission Cable	Subtransmission submarine cable	km							N/A	
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	15.00%	62.00%	23.00%	-	3	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	20.00%	80.00%	-	67.00%	3	20.00%
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	14.00%	43.00%	9.00%	34.00%	-	38.00%	4	20.00%
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	18.00%	12.00%	14.00%	56.00%	-		4	
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	5.00%	12.00%	6.00%	22.00%	55.00%	-	2	17.00%
30	HV	Zone substation switchgear	33kV RMU	No.							N/A	
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.							N/A	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	20.00%	80.00%	-	-	3	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	13.00%	-	14.00%	55.00%	18.00%	-	2	13.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	13.00%	54.00%	33.00%	-	2	-
35												

Company Name	**Top Energy**
AMP Planning Period	**1 April 2018 – 31 March 2028**

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
36					**Asset condition at start of planning period (percentage of units by grade)**							
37												
38												
39	HV	12	50	22	8.00%	22.00%	12.00%	50.00%	8.00%	-	4	8.00%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2.00%	2.00%	18.00%	73.00%	5.00%	-	2	-
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km							N/A	
42	HV	Distribution Line	SWER conductor	km	18.00%	11.00%	13.00%	54.00%	4.00%	-	2	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	15.00%	62.00%	23.00%	-	2	-
44	HV	Distribution Cable	Distribution UG PILC	km	17.00%	-	17.00%	66.00%	-	-	2	-
45	HV	Distribution Cable	Distribution Submarine Cable	km	17.00%	-	17.00%	66.00%	-	-	2	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	4.00%	16.00%	64.00%	16.00%	10.00%	4	-
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.							N/A	
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	3.00%	4.00%	15.00%	60.00%	18.00%	14.00%	4	-
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.							N/A	
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	3.00%	14.00%	15.00%	59.00%	9.00%	35.00%	4	10.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	1.00%	13.00%	17.00%	66.00%	3.00%	17.00%	4	-
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	1.00%	4.00%	18.00%	72.00%	5.00%	26.00%	4	-
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	5.00%	21.00%	74.00%	-	2	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	20.00%	80.00%	-	-	3	-
55	LV	LV Line	LV OH Conductor	km	2.00%	3.00%	19.00%	74.00%	2.00%	-	2	-
56	LV	LV Cable	LV UG Cable	km	1.00%	5.00%	18.00%	71.00%	5.00%	-	2	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	-	20.00%	78.00%	2.00%	-	2	-
58	LV	Connections	OH/UG consumer service connections	No.	1.00%	26.00%	13.00%	53.00%	7.00%	39.00%	4	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	13.00%	4.00%	14.00%	69.00%	-	3	-
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	20.00%	80.00%	-	-	3	-
61	All	Capacitor Banks	Capacitors including controls	No.	10.00%	10.00%	14.00%	56.00%	10.00%	-	3	-
62	All	Load Control	Centralised plant	Lot	-	-	10.00%	40.00%	50.00%	-	3	-
63	All	Load Control	Relays	No.							N/A	
64	All	Civils	Cable Tunnels	km							N/A	

Company Name	**Top Energy**
AMP Planning Period	**1 April 2018 – 31 March 2028**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

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

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
9	Kaikohe	10	17	N-1	1	60%	17	60%	No constraint within +5 years	
10	Kawakawa	6	7	N-1	3	92%	7	76%	No constraint within +5 years	1.5MW to be transferred to Haruru in FYE2022.
11	Moerewa	3	5	N-1	2	69%	5	69%	No constraint within +5 years	
12	Waipapa	12	23	N-1	6	52%	23	35%	No constraint within +5 years	3.2MW to be transferred to Kaeo in FYE2019.
13	Omanaia	3	-	N-0	-	-	-	-	Transformer	Mobile transformer available. Generator also available in FYE2020. There is a single incoming subtransmission circuit.
14	Haruru	6	23	N-1	1	28%	23	38%	No constraint within +5 years	
15	Mt Pokaka	3	-	N-0	1	-	-	-	Transformer	Mobile transformer available. Sufficient transfer capacity available to supply all small use consumers.
16	Kerikeri	7	23	N-1	6	32%	23	35%	No constraint within +5 years	
17	Kaeo	-	-	N-1		-	10	37%	Subtransmission circuit	New substation. There will be only one incoming subtransmission circuit until the southern section of the 110kV line is completed, expected to be in FYE2028.
18	Okahu Rd	9	12	N-1	4	76%	12	80%	No constraint within +5 years	
19	Taipa	6		N-0	4	-	-	-	Transformer	Transfer capacity is standby diesel generation installed at the substation site. There is also a single incoming subtransmission circuit
20	NPL	12	23	N-1	4	53%	23	53%	No constraint within +5 years	
21	Pukenui	2	-	N-0	-	-	-	-	Transformer	Mobile transformer available. There is also a single incoming subtransmission circuit
22	Kaikohe 110kV	48	30	N-1	25	161%	30	221%	Transformer	Transfer capacity is Ngawha generation, which is connected to the 33kV subtransmission network and which is normally in operation. This transfer capacity is expected to increase to 50MVA in FYE2021
23	Kaitaia 110kV	24	25	N-1	4	97%	40	76%	Subtransmission circuit	Transfer capacity is Taipa generation. Firm capacity limited by single incoming 110kV circuit.
24						-				
25						-				
26						-				
27						-				
28						-				

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Company Name: **Top Energy**
AMP Planning Period: **1 April 2018 – 31 March 2028**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref								
7	**12c(i): Consumer Connections**							
8	*Number of ICPs connected in year by consumer type*				**Number of connections**			
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
11	*Consumer types defined by EDB**							
12	Residential		320	320	320	320	320	320
13	Commercial		5	5	5	5	5	5
14	Industrial				3	1	1	
15								
16								
17	**Connections total**		325	325	328	326	326	325
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections							
21	Capacity of distributed generation installed in year (MVA)							
22	**12c(ii) System Demand**							
23			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)**	for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
25	GXP demand		44	45	59	38	41	42
26	*plus* Distributed generation output at HV and above		25	25	25	50	50	50
27	**Maximum coincident system demand**		69	70	84	88	91	92
28	*less* Net transfers to (from) other EDBs at HV and above							
29	**Demand on system for supply to consumers' connection points**		69	70	84	88	91	92
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		170	170	225	200	140	140
32	*less* Electricity exports to GXPs		15	15	5	-	70	70
33	*plus* Electricity supplied from distributed generation		200	200	200	250	400	400
34	*less* Net electricity supplied to (from) other EDBs							
35	**Electricity entering system for supply to ICPs**		355	355	420	450	470	470
36	*less* Total energy delivered to ICPs		322	322	380	410	425	425
37	**Losses**		33	33	40	40	45	45
38								
39	**Load factor**		59%	58%	57%	58%	59%	58%
40	**Loss ratio**		9.3%	9.3%	9.5%	8.9%	9.6%	9.6%

Company Name	**Top Energy**
AMP Planning Period	**1 April 2018 – 31 March 2028**
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9		for year ended	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
10	**SAIDI**							
11	Class B (planned interruptions on the network)		220.0	220.0	220.0	100.0	100.0	100.0
12	Class C (unplanned interruptions on the network)		450.0	300.0	280.0	275.0	270.0	270.0
13	**SAIFI**							
14	Class B (planned interruptions on the network)		0.70	1.65	1.65	0.65	0.65	0.65
15	Class C (unplanned interruptions on the network)		4.00	4.00	3.80	3.75	3.70	3.65

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2018 – 31 March 2028**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY

This schedule requires information on the EDB'S self-assessment of the maturity of its asset management practices .

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
3	Asset management policy	To what extent has an asset management policy been documented, authorised and communicated?	2	We have an approved management policy consistent with PAS 55 requirements. However it still has to be formally communicated throughout the organisation.		Widely used AM practice standards require an organisation to document, authorise and communicate its asset management policy (eg, as required in PAS 55 para 4.2 i). A key pre-requisite of any robust policy is that the organisation's top management must be seen to endorse and fully support it. Also vital to the effective implementation of the policy, is to tell the appropriate people of its content and their obligations under it. Where an organisation outsources some of its asset-related activities, then these people and their organisations must equally be made aware of the policy's content. Also, there may be other stakeholders, such as regulatory authorities and shareholders who should be made aware of it.	Top management. The management team that has overall responsibility for asset management.	The organisation's asset management policy, its organisational strategic plan, documents indicating how the asset management policy was based upon the needs of the organisation and evidence of communication.
10	Asset management strategy	What has the organisation done to ensure that its asset management strategy is consistent with other appropriate organisational policies and strategies, and the needs of stakeholders?	3	Our network asset management strategy and its alignment with the mission, vision and values of the wider Top Energy Group are described in Section 2.2 of the AMP. The strategy was agreed with the Board at a strategic planning workshop. Improvement in network reliability over time is the main objective of the strategy and this is well understood within the organisation and has been communicated extensively with external stakeholders.		In setting an organisation's asset management strategy, it is important that it is consistent with any other policies and strategies that the organisation has and has taken into account the requirements of relevant stakeholders. This question examines to what extent the asset management strategy is consistent with other organisational policies and strategies (eg, as required by PAS 55 para 4.3.1 b) and has taken account of stakeholder requirements as required by PAS 55 para 4.3.1 c). Generally, this will take into account the same polices, strategies and stakeholder requirements as covered in drafting the asset management policy but at a greater level of detail.	Top management. The organisation's strategic planning team. The management team that has overall responsibility for asset management.	The organisation's asset management strategy document and other related organisational policies and strategies. Other than the organisation's strategic plan, these could include those relating to health and safety, environmental, etc. Results of stakeholder consultation.
11	Asset management strategy	In what way does the organisation's asset management strategy take account of the lifecycle of the assets, asset types and asset systems over which the organisation has stewardship?	3	We are implementing a network development programme that is focused on improving reliability over time and adapting to the application of emerging technologies. This is guiding our investment in the creation of new assets. We also have an inspection programme in place that is controlled through our SAP asset management database. Measuring points and assessment criteria for all asset types are well defined.		Good asset stewardship is the hallmark of an organisation compliant with widely used AM standards. A key component of this is the need to take account of the lifecycle of the assets, asset types and asset systems. (For example, this requirement is recognised in 4.3.1 d) of PAS 55). This question explores what an organisation has done to take lifecycle into account in its asset management strategy.	Top management. People in the organisation with expert knowledge of the assets, asset types, asset systems and their associated life-cycles. The management team that has overall responsibility for asset management. Those responsible for developing and adopting methods and processes used in asset management	The organisation's documented asset management strategy and supporting working documents.
26	Asset management plan(s)	How does the organisation establish and document its asset management plan(s) across the life cycle activities of its assets and asset systems?	3	Once the AMP is prepared, project delivery and maintenance plans are prepared which describe in more detail how the capital and maintenance budgets for the first year of the plan will be spent and how the work will be delivered. This must be consistent with the higher level work plan for described in the AMP. We continue to develop systems that ensure that the maintenance spend is more efficient that is currently the case.		The asset management strategy need to be translated into practical plan(s) so that all parties know how the objectives will be achieved. The development of plan(s) will need to identify the specific tasks and activities required to optimize costs, risks and performance of the assets and/or asset system(s), when they are to be carried out and the resources required.	The management team with overall responsibility for the asset management system. Operations, maintenance and engineering managers.	The organisation's asset management plan(s).

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2018 – 31 March 2028**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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

Company Name	Top Energy Ltd
AMP Planning Period	1 April 2014 – 31 March 2024
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	Our quality system was certified as ISO 9001 compliant in May 2015 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.		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	Our quality system was certified as ISO 9001 compliant in May 2015 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	Our quality system was certified as ISO 9001 compliant in May 2015 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. We are also 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.		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 7.2.3 and 7.2.4 of the AMP, we have a documented Emergency Preparedness Plan in place that defines roles, responsibilities and procedures to be followed when a situation arises that exceeds our capacity to manage in the normal course of business. This was activated for the July 2014 storm and the Plan has been reviewed and revised to incorporate the lessons learnt during that event. We are also 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 2014 – 31 March 2024
	Asset Management Standard Applied	PAS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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

Company Name	Top Energy Ltd
AMP Planning Period	1 April 2014 – 31 March 2024
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	Our quality system was certified as ISO 9001 compliant in May 2015 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.		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. The amount of work we have successfully completed over the last two years is documented in our AMP (see Section 5.12.2) and is testimony to our ability to deliver on a challenging work programme.		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 debriefs his direct reports, who in turn are required to formally debrief 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?	2	We have developed documented criteria and processes for the accreditation of external suppliers and contractors and implementation of these is well in hand. We also transferred responsibility for some asset management activities, in particular asset inspection and maintenance programming, from Top Energy Contracting Services (TECS) to Networks. The formal relationship between TECS and Networks is based on the asset manager - service provider model, but implementaton of this model has still to fully mature.		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 2014 – 31 March 2024**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2014 – 31 March 2024**
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	Documented work programmes, position descriptions and assessments of human resource requirements are in place. We do not have formal succession plans but our General Manager Networks provides the Board once a year a documented contingency plan describing the arrangements he would put in place to cover the availability of any of his direct reports.		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	A formal competency framework is in place for control room operators and is in development for the remainder of our business. Position descriptions are up to date for all positions and formal recruitment and selection processes, including psychometric testing, are in place. Staff training requirements are discussed agreed and signed off annually. Our training budget is up to 5% of salary costs is in place and training hours are routinely monitored.		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	We have a formal staff assessment system in place where a personal development plan (PDP) is prepared in consultation with each staff member in January. 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.		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 2014 – 31 March 2024
Asset Management Standard Applied	PAS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	Top Energy Ltd
AMP Planning Period	1 April 2014 – 31 March 2024
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	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.		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	This 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 except for some gaps on the LV network. 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?	3	Information is electronically entered into SAP from the field by asset inspectors using electronic PDIs. Currently GIS information is updated manually by a dedicated data management team but we are in the process of developing an electronic link between GIS and SAP. Getting "as built" information back from the field can be a problem. We have written an "as built" standard but compliance is still weak.		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 2014 – 31 March 2024**
Asset Management Standard Applied	**PAS 55**

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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

	Company Name	Top Energy Ltd
	AMP Planning Period	1 April 2014 – 31 March 2024
	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	As indicated in response to Q63 above systems for recording asset information are in place. While GIS has been used for some years, SAP is relatively new and its implementation is still being optimised to effectively meet our requirements.		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	We have a Public Safety Management system that is certified to NZS 7901 and externally audited. We also operate a risk register that is updated on an ad hoc basis. We are developing systems to identify and record design and operational risks. However these systems tend to be managed independently and we still have some way to go to develop a risk management system that is fully integrated with our asset management and corporate business 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	We have a Public Safety Management system that is certified to NZS 7901 and externally audited. We operate a risk register that is updated on an ad-hoc basis. We are also developing systems to identify and record design and operational risks. However these systems tend to be managed independently and we still have some way to go to develop a risk management system that is fully integrated with our asset management and corporate business		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 Corporate Services is responsible for identifying our legal obligations. However he is unlikely to capture all changes to our technical obligations. Our involvement with industry organisations such as the Electricity Networks Association and Electricity Engineers Association is increasing to the extent that it is unlikely changes in 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 2014 – 31 March 2024
Asset Management Standard Applied	PAS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2014 – 31 March 2024**
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	Artefacts relevant to the implementation of our asset management plans are all developed and in use. The use of these artefacts is documented in our ISO 9001 certified quality management system which is externally audited on a regular basis.		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	Processes that define how artefacts relevant to the implementation of our asset management plans are used and linked together are defined in our ISO 9001 certified quality management system, which is externally audited on a regular basis.		Having documented process(es) which ensure the asset management plan(s) are implemented in accordance with any specified conditions, in a manner consistent with the asset management policy, strategy and objectives and in such a way that cost, risk and asset system performance are appropriately controlled is critical. They are an essential part of turning intention into action (eg, as required by PAS 55 s 4.5.1).	Asset managers, operations managers, maintenance managers and project managers from other impacted areas of the business	Documented procedure for review. Documented procedure for audit of process delivery. Records of previous audits, improvement actions and documented confirmation that actions have been carried out.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	2	As previously described, we have a formal asset inspection programme in place and defined standards for recording and measuring asset condition. However these processes are reactive and we have not developed score cards or other leading indicators of the health of our asset base.		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. All SAIDI events over two SAIDI minutes are investigated. This is part of our ISO 9001 certified quality system, which is externally audited on a regular basis.		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	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 2014 – 31 March 2024
Asset Management Standard Applied	PAS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2014 – 31 March 2024**
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))?	2	Our ISO 9001 quality system and our NZS 7901 Public Safety Management System are audited in accordance with their certification requirements. Our measurement of supply reliability is also externally audited in accordance with the Commission's requirements. However we do not have a structured internal audit process that covers the whole of the asset management system.		This question seeks to explore what the organisation has done to comply with the standard practice AM audit requirements (eg, the associated requirements of PAS 55 s 4.6.4 and its linkages to s 4.7).	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit teams, together with key staff responsible for asset management. For example, Asset Management Director, Engineering Director. People with responsibility for carrying out risk assessments	The organisation's asset-related audit procedure(s). The organisation's methodology(s) by which it determined the scope and frequency of the audits and the criteria by which it identified the appropriate audit personnel. Audit schedules, reports etc. Evidence of the procedure(s) by which the audit results are presented, together with any subsequent communications. The risk assessment schedule or risk registers.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	2	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 Committee that prioritises business improvements including improvement suggestions made by staff. However, in the absence of a structured internal audit process that covers the whole of the asset management system, there is no formal process within TEN for instigating and monitoring the implementation of corrective actions that apply directly to the asset management system.		Having investigated asset related failures, incidents and non-conformances, and taken action to mitigate their consequences, an organisation is required to implement preventative and corrective actions to address root causes. Incident and failure investigations are only useful if appropriate actions are taken as a result to assess changes to a businesses risk profile and ensure that appropriate arrangements are in place should a recurrence of the incident happen. Widely used AM standards also require that necessary changes arising from preventive or corrective action are made to the asset management system.	The management team responsible for its asset management procedure(s). The team with overall responsibility for the management of the assets. Audit and incident investigation teams. Staff responsible for planning and managing corrective and preventive actions.	Analysis records, meeting notes and minutes, modification records. Asset management plan(s), investigation reports, audit reports, improvement programmes and projects. Recorded changes to asset management procedure(s) and process(es). Condition and performance reviews. Maintenance reviews
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	3	Our Board has a significant focus on business improvement and the Top Energy Group defines Executive level responsibility for identifying, prioritising and implementing business improvements. The successful certification of our NZS 7901 Public Safety Management System and our ISO 9001 Quality System are evidence of this. Within TEN, we are becoming increasingly engaged with the wider asset management community, particularly as it relates to the electricity distribution sector.		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 are increasing our engagement with the wider asset management community, particularly as it relates to electricity distribution, but our involvement with industry interest groups such as the EEA could still have more traction. Our staff have regular contact with vendors offering new and improved technologies and our staff training plans include, where appropriate, exposure to 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 Ltd
AMP Planning Period	1 April 2014 – 31 March 2024
Asset Management Standard Applied	PAS 55

SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

9.2 Appendix B – Nomenclature

GENERAL	
kV kilo-volt	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 kilo-Watt	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.
Buccholz 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 Occur less than once in 20 years	The event could occur at some time Occur once every 10 years	The event is not uncommon. Occur once every 5 years	Likely to occur despite best efforts. Occur once a year	Likely to occur several times. 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 Determination 2012 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, 2.5	
Purpose Statement			
3.3	The AMP must include a purpose statement that		
3.3.1	Makes the status of the AMP clear.	2.3	
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	2.8	
3.3.4	States how the different documented plans relate to one another with specific reference to any plans specifically dealing with asset management	2.8	
3.3.5	Includes a description of the interaction between the objectives of the AMP and other corporate goals, business planning processes and plans;	2.5	
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.	2.8.1	
3.5	The AMP must state the date on which the AMP was approved by the Board of Directors.	2.8.1	
Stakeholder Interests			
3.6	The AMP must identify the EDB's important stakeholders and indicate	2.8.3	
3.6.1	- how the interests of stakeholders are identified;	2.8.2	

Handbook Reference	Requirement	AMP Ref	Comment
Iii	- what these interests are;	2.8.3	
iv	- how these interests are accommodated in the EDB’s asset management practices: and	2.8.3	
v	- how conflicting interests are managed.	2.8.2	
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.	2.8.4	
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.	2.8.4	
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.	2.8.4	
Significant Assumptions and Uncertainties			
3.8	The AMP must identify significant assumptions, which must: :	2.12	
3.8.1	Be quantified where possible.	2.12	
3.8.2	Be clearly identified in a manner that makes their significance understandable to interested persons including:	2.12	
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.	2.12	
3.8.5	Include the price inflator assumptions used to prepare the information in Schedules 11a and 11b.	2.12 (final row)	
3.9	Include a description of the uncertainties that may lead to changes in future disclosures.	2.12	
Asset Management Strategy and Delivery			
3.10	To support the AMMAT disclosure, the AMP must include an overview of asset management strategy and delivery.	2.13 2.17	

Handbook Reference	Requirement	AMP Ref	Comment
Asset Management Data			
3.11	To supprt the AMMAT disclosure, the AMP must include an overview of the processes for managing asset management data; and	2.10, 2.14	
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.	2.10, 2.14	
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;	2.11.1	
3.13.2	- Planning and implementing network development projects; and	2.11.2	
3.13.3	- Measuring network performance.	2.11.3	
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.	2.15	
Communication and Participation Processes			
3.15	To support the AMMAT disclosure, the AMP must include an overview of communication and participation processes.	2.16	
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;	3.1.2	
4.1.3	- description of the load characteristics for different parts of the network; and	3.1.1 3.1.2	
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	

Handbook Reference	**Requirement**	**AMP Ref**	**Comment**
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;	3.1.3	
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;	3.1.5, 3.1.6 Table 3.1	
4.2.2	- the extent to which individual zone substations have N-x subtransmission security;	3.1.6 Table 3.2	
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	3.1.7	
4.2.6	- an overview of secondary assets such as ripple injection systems, SCADA and telecommunications systems.	3.1.8	
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	The condition of each asset category and relevant maintenance issues are discussed in Section 6.
4.5	The asset categories discussed must at least include:		
	[Transmission]	3.3	

Handbook Reference	Requirement	AMP Ref	Comment
4.5.1	Subtransmission	3.4.1.1 3.4.2.1 3.4.3.1	
4.5.2	Zone substations	3.4.11	
4.5.3	Distribution and LV lines	3.4.1.2 3.4.1.3 3.4.2.2 3.4.2.3	
4.5.4	Distribution and LV cables	3.4.3.2 3.4.3.3	
4.5.5	Distribution substations and transformers	3.4.4 3.4.6	
4.5.6	Distribution switchgear	3.4.5 3.4.7 3.4.8 3.4.9	
4.5.7	Other system fixed assets	3.4.10 3.4.12 3.4.13 3.4.14	
4.5.8	Other assets	3.4.16	
4.5.9	Assets installed at bulk supply points owned by others	3.1.4	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	3.4.15	
4.5.11	Other generation plant.	N/A	While Top Energy owns the Ngawha geothermal power station, it is not considered a network asset and is not part of this AMP.
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 to reflect the duration of the network development plan.
7.	Performance indicators for which targets are defined should also include		

Handbook Reference	Requirement	AMP Ref	Comment
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 indiators by feeder to assist us mange network reliability. This is discussed in Section 8.2.1.1
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 5.3	
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	
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	

Handbook Reference	Requirement	AMP Ref	Comment
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	
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	5.12.1	
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 5.10	
	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:	5.12	
11.9.1	- the reasons for choosing a selected option for projects where decisions hae been made;	5.13 5.14 5.15 5.16	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-netowrk 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	-	These are short-term solutions that we have applied exptensively over the last decade. The shareholder and Board have determined that such strategies are no longer appropriate and that significant investment is required if consumer expectations are to be met in the longer term. This is noted throughout the AMP.
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;	5.13 5.14 5.15 5.16 5.17 5.18	

Handbook Reference	Requirement	AMP Ref	Comment
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.		
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.	5.9	
11.12	The AMP must include a description of the EDB's policies on non-network solutions including:	5.10	
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 maintianing each category of assets, including a description of the types of inspections, tests and condition monitoring and the intervals at which this is done;	6.1.2-6.1.4 6.2-6.22	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;		

Handbook Reference	Requirement	AMP Ref	Comment
12.2.3	- budgets for maintenance activities broken down be asset category for the AMP planning period	6.24	
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:	6.1.2 6.24 5.13-5.16	
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.	6.2-6.23	A discussion on the asset replacement and renewal requirements of each asset category is included in the relevant section.
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 5.17.1 6.27	The capex forecasts in section 5 include a provision for incremental maintenance CAPEX such as miscellaneous pole replacements. The maintenance CAPEX component of these forecasts is extracted and disaggregated in Table 6.6
12.3.4	- a summary of the projects planned for the next four years; and	5.10 6.24	
12.3.5	- an overview of the other work being considered for the remainder of the planning period.	5.12 6.24	
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;	3.14.6	
13.2	development, maintenance and renewal policies that cover them;	5.19 6.27	We do not consider our expenditure on non-network assets to be material, apart from expenditure on the new ADMS.
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:		
14.1	- methods, details and conclusions of risk analysis;	7.1	

Handbook Reference	Requirement	AMP Ref	Comment
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;	7.1.4 7.2	
14.3	- a description of the policies to mitigate or manage the risks of events identified in subclause 14.2 above; and	7.2	
14.4	- details of emergency response and contingency plans.	7.2.3 7.2.4	
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;	8.3	
15.2	- an evaluation and comparison of actual service level performance against targeted performance;	8.1 8.2	
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	8.4	Additional information is provided in the following sections: 2.11 2.12 2.13 2.14.
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.		
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;	2.17	
16.2	- the organisation structure and the processes for organisation and business capabilities will support the implementation of the AMP plans.	2.17	

9.5 Appendix E – Provisional Outage Reporting Standard

1. *Outages of equipment that does not form part of our **shared** 110kV, 33kV and 22/11kV network are excluded.*

   This includes:

   - outages of service lines and joint service lines that are beyond the point of connection to which we provide line function services.
   - Outages of distribution transformers and other equipment connected to service lines beyond the point of supply. While we might own this equipment, it does not form part of the shared network and should not be included.

   However, if the outage interrupts other consumers connected to the network upstream of the point of supply, it should be included. The rationale for this is that that there should be drop-out fuses at the point of connection and locating these at the transformer is a network design issue.

   Justification:

   Our performance should not be measured for assets that we do not own or operate, since management decisions relating to these assets are made by the consumer. Furthermore, service line repairs are often chargeable, and this can create consumer driven delays that we cannot control.

2. *Outages of our low voltage reticulation are excluded.*

   These outages are not currently included in the Commission's information disclosure requirements or in the measurement of SAIDI and SAIFI for assessing compliance with its regulatory price-quality path. Where low voltage interconnection and excess capacity exists to allow supply to be maintained via the low voltage network, an outage on the high voltage system does not have a material impact on consumer supply. High voltage outages will therefore not be included in performance measures where an alternative supply via the low voltage system is possible.

   Justification:

   This policy encourages delivery of security at the low voltage level, which has the greatest impact on robustness of supply for urban consumers. However, we have a low level of investment in low voltage interconnection.

3. *Planned distribution transformer outages are excluded.*

   This approach, which is common in the industry, reflects that fact that these outages do not need to be included in regulatory disclosures if the low voltage feeders are disconnected before the transformer is taken out of service. This is often possible and the alternative approach of interrupting supply to consumers by interrupting the high voltage incoming supply to a distribution transformer has no impact on the service level provided.

   This exclusion applies only to planned outages. Unplanned distribution transformer outages should be included in the unplanned interruption statistics.

   Justification:

   This policy focuses reliability statistics on lines rather than transformers. Disclosures report comparators between networks on a "per km" basis so there is an argument for specific measures for transformers. It follows that a high number of transformer faults would give a false indication of the performance of a lines network.

4. *Single phase interruptions, such as those caused by the operation of a single drop-out fuse, are excluded where supply is maintained on other phases*

   Justification:

   This is established industry practice justified on the basis that total supply has not been lost.

5. *Unplanned outages that are not a consequence of a fault on our network and extended outage durations due to factors outside of our control are excluded*

   These are normally an emergency or safety response issue such as:

- a fire resulting in the Fire Service requesting supply to be de-energised. There may be an inspection required before assets can be re-livened or the Fire Service need to complete an investigation before repair work commences;
- a car vs pole scenario there the primary emergency response service has taken responsibility for control of the site and we are required to comply with their instructions regarding repair and relivening. For example, the police may prevent repairs being made until they have completed their accident investigation. Where repairs are necessary to restore supply, the clock will start from the time we are given clear access to the site to undertake repairs and restore supply;
- emergency tree clearing, where engagement of specialist contractors is the responsibility of the tree owner. Our crews may need to stand clear while trees are felled or dragged clear. Access may be blocked by debris. Where repairs are necessary to restore supply, the clock will start from the time we are given clear access to the site to undertake repairs and restore supply; or
- road access blockages caused by tress, slips, bridge washouts etc. where the road authority may prevent access while attending to other priorities. Again, where repairs are necessary to restore supply, the clock will start from the time we are given clear access to the site to undertake repairs and restore supply;

Justification:

In these scenarios we are not the primary manager of the overall response and the primary issue is not the restoration of supply. We are required to coordinate our response with other emergency services and act in accordance with their instructions.

6. *For reliability measurement, a fault will commence at the time a consumer advises us of a supply interruption or, where we are advised a response can be delayed, the agreed time at which we will start to respond, or when a fault person is dispatched.*

- Where we are aware of an interruption before any consumer reports it (for example, from a SCADA alarm) we can undertake a restoration action without this counting as restoration time;
- Where a consumer does not require an immediate response, such as where supply is only required in the morning or some other convenient time, then the response may be delayed without a time penalty.

Justification:

It is inefficient to deliver a service not requested or not required by a consumer, since an unrequired service is a low value service. It is equally in the consumer's interest to consider the trade-off between the service delivered and the cost of that service.

Not all EDBs have the same level of automation or visibility over their networks and not all consumers within a network enjoy the same benefit from automation. Consequently, the only normalized response start point is when a consumer reports that an interruption is affecting them and requests the fault service. Automation is applied where the most benefit can be delivered to the most number of consumers – it would be perverse if interruption statistics penalized investment that allows a faster response.

It is only reasonable to measure the performance of our fault service from the time we are aware of a fault and sufficiently resourced to deal with it. It is a fact of life in rural networks that communications coverage is limited.

A large low voltage reticulation fault may have a higher restoration priority than a high voltage distribution fault. Likewise, a single connection like a hospital might have a higher priority than another fault that affects as larger number of connections. It would be a perverse outcome to attend to the lower priority issue because it has a greater impact on measured reliability.

7. *When a fault response is deliberately delayed or suspended, either as a result of an agreement with the affected consumer or a management decision, the clock determining consumer minutes lost will also be suspended.*

Scenarios where this might occur include:

- after hours site access is not available;
- situations where a consumer would prefer to deal with the fault during working hours. For example, the consumer may not wish to shift stock, prime pumps, or deal with trees in darkness;

- where there is a safety issue associated with patrolling in the dark, bad weather etc., or where a site has safety management requirements that cannot be met during certain hours – for example, where a forest owner's clearance is required that trees are stable and cleared and the forest is safe to enter; or
- Where specialist equipment, such as a digger or bucket truck, or access to safety information, such as cable locations or pole condition records, is required.

Justification:

Performance time pressures will not be permitted to compromise safety or drive impractical and unreasonable response decisions. These issues will be specified in our revised service standards.

The Health and Safety at Work Act 2015 requires us to coordinate our response with other businesses and we need to adhere to the codes of practices of these businesses, which may not be organised for emergency response or out of hours operation.

8. *The response phase of the fault service is deemed completed when supply has been restored to 90% of consumers affected by an interruption. The clock stops at this point.*

Justification:

This is a common industry practice and is consistent with international practice. It is related to the level of service provided for by security standards that typically do not target 100% restoration of supply but adopt a "stepped" approach that requires the ability to restore blocks of load within prescribed times. At the distribution level, these standards do not put a time limit on restoration of the final load block. It creates an efficient investment signal in that it provides a balance in the fault response decision as to whether to restore supply to the final block of load with a permanent repair or more quickly with a temporary repair. Temporary repairs can be expedient in terms of response times but not in the longer-term interest of consumers – for example there may be poorer voltage conditions while the temporary repair is in place and the total interruption time as a result of the fault could be longer as a subsequent interruption may be required to make the temporary repairs permanent.

9. *The normalization methodology approved by the Commerce Commission for reporting reliability to assess compliance with price-quality path regulatory framework will be applied when measuring SAIDI and SAIFI for internal management purposes and when reporting network reliability to consumers (for example, in our Annual Report).*

The Commission's normalisation methodology permits the actual unplanned SAIDI and SAIFI experienced by consumers on a Major Event Day (as defined by the Commission) to be replaced by a boundary value (also determined by the Commission) and permits the impact of planned interruptions to be included in the measure at 50% of their actual impact. This approach acknowledges that consumers are given advance notice of planned interruptions and therefore have time to mitigate their impact. Major event days usually experience multiple interruptions spread across the network and are normally a result of storms and high winds.

Justification:

Interruptions that occur on major event days overwhelm our fault response capacity and generally have a common cause that we cannot control. Performance indicators that are dominated by the impact of interruptions on such days are therefore not a meaningful indicator of management performance. The de-weighting of planned interruptions recognizes the advance notice and provides an incentive to invest in initiatives that prevent future unplanned interruptions, particularly now we are now that our revised risk management processes significantly limit live line work practices.

10. *Planned interruptions intended to reduce the total interruption duration due to a single job will be counted as a single event.*

For example, a situation where two planned interruptions were used to cut and then subsequently reconnect jumpers will be counted as a single event.

Justification:

This is a deliberate management strategy intended to reduce outage that would otherwise distort the disclosure statistics on the number of outages occurring on the network.

11. *A consumer is defined as the person holding the contract for supply. A consumer's property or installation may include a number of ICPs that are connected to our network at a single point. The consumer count will*

therefore need to be consistent with the number of connections to our shared network and the demarcation between our network and consumer service lines.

Justification:

It is the consumer we are servicing. It is a perverse outcome if we favour low priority multiple supplies over high priority single supplies.

9.6 Appendix F – Benchmarking

9.6.1 FYE2017 Operations and Maintenance Expenditure

$000 (real 2017)/km	Top Energy	Peer Group Performance									Top Energy Target	
		EDB A	EDB B	EDB C	EDB D	EDB E	EDB F	EDB G	EDB H	Average	FYE 2023	FYE 2028
Service Interruptions	406	389	201	280	370	261	418	344	352	335	335	314
Vegetation Management	437	173	180	177	227	206	174	336	151	202	202	186
Routine Maintenance and Inspection	483	994	269	230	350	270	430	444	415	433	433	327
Asset Replacement and Renewals	136	43	256	470	348	42	0	400	179	207	207	216
Total	**1,462**	**1,599**	**906**	**1,157**	**1,295**	**779**	**1,022**	**1,524**	**1,097**	**1,178**	**1,178**	**1,043**

Table F.1: Benchmarking of Network Operations and Maintenance Expenditure

9.6.2 FYE2017 SAIDI

SAIDI (by cause)	Top Energy	Peer Group Performance								
		EDB A	EDB B	EDB C	EDB D	EDB E	EDB F	EDB G	EDB H	Average
Lightning	7.7	0.1	0.3	1.3	2.6	17.1	0.1	1.0	0.7	2.9
Vegetation	94.6	11.2	4.1	36.8	9.7	26.7	7.3	17.7	10.0	15.4
Adverse Weather	110.0	6.2	9.4	78.6	31.7	42.5	5.2	18.8	2.3	24.3
Adverse Environment	1.6	0.0	0.0	1.2	1.8	1.4	1.6	0.9	0.0	0.9
3rd Party Interference	50.4	22.2	29.3	16.0	12.8	31.3	12.3	15.7	21.0	20.1
Wildlife	143.9	17.0	0.0	9.0	11.8	2.1	9.9	8.2	0.0	7.3
Human Error	6.7	3.8	1.1	0.0	2.0	0.2	0.0	1.7	1.2	1.3
Defective Equipment	121.0	34.0	27.5	59.6	78.5	60.8	50.2	18.0	46.2	46.9
Unknown	24.5	5.4	5.1	18.2	27.2	16.9	9.8	12.3	10.1	13.1
Planned	42.9	69.6	110.6	195.7	101.2	130.2	121.7	60.0	95.5	110.6
Total	**603.3**	**169.5**	**187.4**	**416.4**	**279.3**	**329.2**	**218.1**	**154.3**	**187.0**	**242.7**

Table F.2: Benchmarking of Network SAIDI (prior to normalisation)

Certification for Year-beginning Disclosures

Pursuant to Schedule 17

Clause 2.9.1 of section 2.9

Electricity Distribution Information Disclosure Determination 2012

We, Euan Richard Krogh and Gregory Mark Steed, 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 clause 2.6.1 and subclauses 2.6.3(4) and 2.6.5(3) 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.

E R Krogh

G M Steed

25 September 2018

Top Energy Limited
Level 2, John Butler Centre
60 Kerikeri Road
Kerikeri
PO Box 43 Kerikeri 0245
New Zealand

www.topenergy.co.nz

TOP ENERGY®
Te Puna Hihiko