2016 Asset Management Plan

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TOP ENERGY
Te Puna Hihiko

Introduction

It gives me great pleasure to present Top Energy's FYE2017-26 Network Asset Management Plan (AMP).

This 2016 AMP follows on from the 2014 AMP and 2015 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.

Our Network mission is 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 FYE2017-26 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 for the more than 10,000 consumers in the north of our supply area, who are dependent on a single 110kV transmission circuit that is in only average condition and that requires an annual maintenance outage that lasts for 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 high cost of the planned second circuit means that it is technically uneconomic under the most likely growth scenarios and only marginally economic if a low probability, high load growth outcome is assumed. Partly for this reason, in early 2015 we decided to defer completion until FYE2026. However, the alternative of installing diesel generation is unlikely to be an effective or sustainable long term solution and allowing the present situation to continue indefinitely is not considered an option.

- While there has been a significant improvement in our reliability of supply over the last five years, it remains the worst in the country. This is due to our fringe location on the transmission grid, the lack of a dominant urban centre, an inadequate subtransmission infrastructure 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 essential maintenance of these uneconomic lines. This has left a legacy of underinvestment, to the extent that our subtransmission network is only now becoming able to provide the level of supply reliability accepted as the norm in the rest of the country.

- Recent changes in the Health and Safety in Employment legislation could also adversely impact the rate at which we are able to improve our reliability of supply, as it is possible that they could result in Worksafe New Zealand restricting the use of live line maintenance for safety reasons. The Electricity Engineers' Association is working closely with Worksafe New Zealand on this issue and the outcome of these discussions is not clear at this stage. Restrictions on the use of live line maintenance would have an adverse impact on the reliability of supply to the Kaitaia region, as currently maintenance on the 110kV transmission line is undertaken live to the extent this is practical.

- Electricity volumes supplied to consumers peaked in 2012 following a period of relatively strong growth and have since declined from a peak of 333GWh to a current level of 321GWh in 2015. This decline is attributed to flat consumption by our large industrial consumers and energy efficiency initiatives implemented by other consumers. The flat industrial consumption is a function of the stagnant economic climate in our supply area, while energy efficiencies 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.

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.

The reliability forecasts presented in Schedule 12d, which is appended to this AMP, follow the Commission's requirement to forecast the raw reliability data prior to any normalisation. However, in assessing our compliance with the quality threshold under its default price quality regulatory regime, the Commission normalises this raw data. This involves limiting the impact of interruptions that occur on "major event days" to a predetermined boundary value and reducing the weighting of planned interruptions to 50% of their actual SAIDI or SAIFI impact. The purpose of this normalisation is to reduce the impact of events such as major storms on the measure, and so produce a measure of reliability that better reflects the impact of factors that an electricity distribution business is able to control

We use the Commission's normalised measures to assess and report on our supply reliability for internal management purposes. However, our internal targets are more challenging than the benchmarks used by the Commission for quality assessment purposes, in order to ensure that reliability improvements resulting from our investment programme are properly captured. These internal targets have also been reset for this AMP to better reflect the performance we expect from the network in a year of average weather conditions, to capture the impact of recent changes to the Commission's normalisation methodology and also to reflect changes on our approach to the management of planned interruptions. Our targets have been incrementally reduced over the planning period of this AMP to reflect the further reliability improvements that we expect from our continuing investment programme. This includes a slightly larger step improvement in FYE2019 to reflect the impact of the commissioning of the Kaeo substation the previous year.

In addition to the service level targets used by the Commerce Commission, we set our own targets for improvement in the performance of our five worst performing feeders and worst affected consumers. The expenditure forecasts in this AMP provide for specific performance improvement plans to FYE2019 for the Pukenui 33kV feeder and the 11kV South Road, Rangiahua, Totara North and Whangaroa feeders.

A more secure and reliable electricity supply has economic benefits for the region. It makes our supply area a more attractive place to do business. It will attract new investment, creating opportunities for employment and economic prosperity; we believe that's good for everyone.

Implementation of the plans described in this AMP will see us invest approximately $150 million on network capital expenditure and $50 million in network maintenance expenditure over the ten-year period of this AMP, based on current prices. The Board is 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, the Board recognises 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 the Electricity Engineers' Association Safety Climate Project. This is a project requiring staff engagement, at all levels, on safety and has 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.

In 2015 we achieved certification of our asset management and operational processes to the quality standard ISO 9001. This was a key milestone in steadily improving our processes toward alignment with the Asset Management Standard ISO 55001. In this AMP we have updated the Asset Management Maturity Assessment Tool (AMMAT) using the latest Electricity Engineers' Association AMMAT Guide, and through our continued improvement and quality systems put in place to achieve ISO 9001 certification it is pleasing to report an increased AMMAT score.

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

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1 Executive Summary

1.1 Overview

Top Energy Networks is the electricity lines business that distributes electricity to almost 32,000 electricity consumers in the Far North District Council's territorial area, covering 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 more than 200 people and is one of the biggest employers in our supply area, has four divisions:

- **Ngawha Generation**, which operates the 25MW Ngawha geothermal power plant;
- **Top Energy Networks**, which distributes electricity throughout the Far North District Council area;
- **Top Energy Contracting Services (TECS)**, which provides contracting services to the electric power industry; and
- **Phone Plus**, a contact centre business located in Kaikohe and Albany, Auckland.

As a large electricity lines business, we are 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 document for our Networks business. It describes how we plan to develop and manage our electricity network assets for the benefit of our consumers over the period 1 April 2017 to 31 March 2026. 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 FYE2017, 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.

1.2 Asset Management Policy

Our asset management policy has been developed in accordance with Top Energy's strategic objectives 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, the mission of our Networks business 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 at all times 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 due consideration to the impact of all that we do on our employees, contractors, consumer 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 in order 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, so that we are ready to modify our asset management strategies as necessary, in order to 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	31,901(1)
Grid Exit Point	Kaikohe
Embedded Generator Injection Point	Ngawha Geothermal
Network Peak Demand (FYE2016)	67.7MW[2]
Electricity Delivered to Consumers (FYE2015)	321GWh
Number of Distribution Feeders	56
Distribution Transformer Capacity	256MVA(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)	197km(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 2015.
Note 2: Estimated from SCADA data. May not correspond to FYE2016 information disclosure, which will be based on metered data.
Note 3: As at December 2015.
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 (FYE2015 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, which is sparsely populated and contains no dominant urban centre. Our network is 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 $216.7 million as at 31 March 2015; an increase of $17.4 million since 31 March 2014.

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 2013	**199,303**
Add:	
New assets commissioned	25,379
Indexed inflation adjustment	167
Less:	
Depreciation	8,072
Asset disposals	55
Asset value at 31 March 2015	**216,722**

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). This provided assistance with post-war farming productivity growth in remote areas and with supplying electricity to consumers located in sparsely populated rural areas, which would otherwise have been uneconomic to service.

Many of these lines now require extensive rebuilding and refurbishment, despite 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 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.

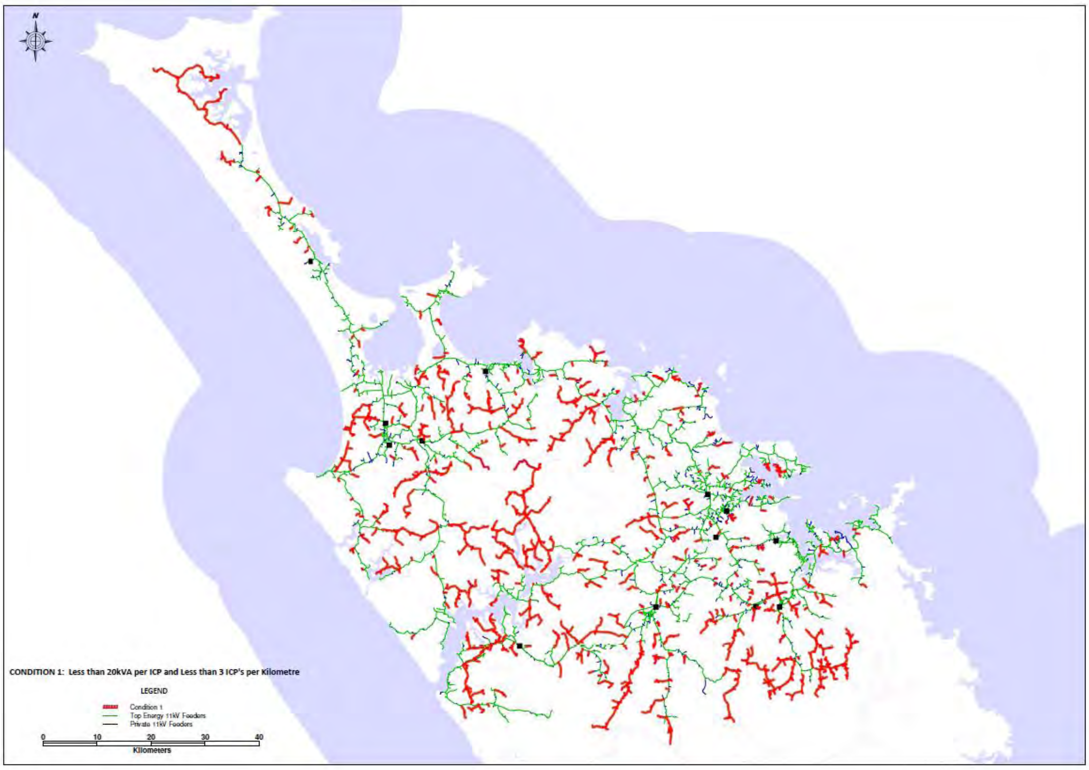


Figure 1.1: **Uneconomic Segments of the 11kV Distribution Network**

1.6 Asset Management Challenges

Supply Reliability

We remain the worst performing electricity distribution business in New Zealand for supply reliability.

This performance is a consequence of:

- the lack of supporting transmission infrastructure due to the 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 has limited the availability of funds to invest in the development of the network needed to keep abreast of changing consumer expectations.

With the support of our community, we have embarked on a carefully planned investment strategy to turn this situation around, in order to 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.

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.

1.7 Network Development

To address these issues and improve the reliability and security of supply, we will invest approximately $150 million over the planning period of this AMP as we undertake the largest single expansion in the history of our network. This is in addition to the development we have achieved to date.

Over the last five years 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 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 period of this AMP we plan to address the following network weaknesses.

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 annual planned maintenance interruptions that can last for nine hours or more.

We are planning to address this situation by constructing a second 110kV incoming circuit over an eastern coastal route that will 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 over half the landowners, there are some that are unwilling to negotiate, and we may need to apply to the Minister of Land Information for approval to compulsorily acquire an easement before construction of this line can commence. The legal processes involved are complex and time consuming, and we expect it to take until FYE2019 before the route is finally secured.

Assuming that we are successful in securing the route, construction of the new line will commence in FYE2020. However, the pace at which this project can proceed is limited by the anticipated availability of finance and the line is not expected to be fully commissioned until FYE2026, the final year of this AMP planning period.

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 significant number of consumers.

The construction of a new zone substation in Omanu Rd, Kaeo is now committed and commissioning of this project is planned for FYE2018. The new substation 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 is currently being utilised 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 currently expect this to be in FYE2025.

Supply to Russell peninsula

We have two submarine cables to 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. Over the last two years we have improved the supply to Russell, firstly by offloading the line between Kawakawa and the Waikare submarine cable to create a Russell express feeder, and more recently 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 increase the flexibility with which the two cables can be used. We are also planning to reinforce the network to relieve constraints on the Opua side of the Okiato point submarine cable. This work is planned for completion in FYE2020.

Omanaia substation transformer

The Omanaia substation transformer bank is now 62 years old and is reaching the end of its expected life. We are planning to replace this transformer in FYE2018. We are also intending to relocate the mobile substation to Omanaia after it is no longer required at Kawakawa.

Replacement of transmission assets

Some of the transmission assets acquired from Transpower are in poor condition, as evidenced by the two recent structure failures on the 110kV line. We have undertaken a formal condition assessment of all these transmission assets and have prioritised the asset 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.

Supply to Karikari peninsula

The Chinese owners of the Carrington Resort on the Karikari peninsula have applied for resource consent to develop and expand the resort with the addition of approximately 800 rooms. The scale of the proposed development is such that we are not able to supply the resort from the 11kV feeder currently serving the area and a new 33kV line and substation would be required. The resort expansion proposal has still to receive resource consent and many locals are apprehensive about its size and impact. We have a plan in place to supply the expanded resort should the development proceed, although this plan could impact the timing of some of the projects set out in this AMP. However, there remains a high level of uncertainty as to when the development could proceed, if it goes ahead, and we believe it would be premature to provide for it in this AMP.

1.8 Maintenance

Our vegetation management programme is undertaken in accordance with the Electricity (Hazards from Trees) Regulations 2003. Under these regulations, we are responsible for the “first cut” to ensure that a tree is clear of our line. After this first cut, a tree owner is required to meet the cost of ongoing trimming. Now that this first cut is complete across the majority of our network, we expect to recover more of our vegetation management costs from tree owners. Nevertheless, our opex forecast includes an annual provision of more than $1.8 million for tree clearance and vegetation management work. In FYE2017, a major focus of this programme will be the Rangiahua, Totara North and Whangaroa feeders, three of the least reliable feeders on the network.

The use of SAP as a maintenance management tool has increased the effectiveness of our maintenance effort and also allows us to record the condition of individual assets as they are inspected, for future reference. This should enable us to better assess the rate of deterioration, and hence the urgency of any required maintenance or replacement, during future inspection cycles.

We have also increased the use of planned outages for maintenance purposes and have reorganised our maintenance programme to ensure that all identified defects in a specific area are addressed at the one time. This allowed us to reduce our defect backlog from 2,750 to 1,400 over calendar year 2015. We were also able to fully complete all our planned inspections of line assets over this period.

1.9 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 benchmarks 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 of events that are outside our reasonable control in the measure of network reliability. 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 interruptions occurring on “major event days” to a boundary value in order to limit 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 normalised measure. This recognises 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 a large number of abnormally severe storms. In FYE2015, a year of abnormally bad weather, our actual SAIDI of 1837 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. It was also a year in which we aggressively used mobile generation to mitigate the impact of planned interruptions, a practice that we have now discontinued, after consultation with our consumers, because of the cost. 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, the average weather conditions experienced in our supply area and our current maintenance practices. The reset also captures the impact of the FYE2016 changes to the Commission’s normalisation methodology.

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

- there will be one planned transmission related interruption each year;
- the new 110 kV Wiroa-Kaitaia circuit will be not be commissioned before the end of the AMP planning period;
- that weather conditions will be average for the area;
- there are no unplanned outages of the 110kV Kaikohe-Kaitaia transmission lines; and
- 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.

• FYE	2017	2018	2019	2020	2021	2022	2022	2024	2025	2026
SAIDI										
Distribution Related	290	285	270	265	260	255	250	245	240	235
Transmission Related	60	60	60	60	60	60	60	60	60	60
Target	**350**	**345**	**330**	**325**	**320**	**315**	**310**	**305**	**300**	**295**
SAIFI										
Distribution Related	4.2	4.1	4.0	3.9	3.8	3.7	3.6	3.5	3.4	3.3
Transmission Related	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Target	**4.6**	**4.5**	**4.4**	**4.3**	**4.2**	**4.1**	**4.0**	**3.9**	**3.8**	**3.7**

Table 1.3: Reliability 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 of our network. 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 Commerce Commission's measurement methodology and finally the Commerce Commission's normalisation methodology changed from FYE2016 onwards, as discussed above.

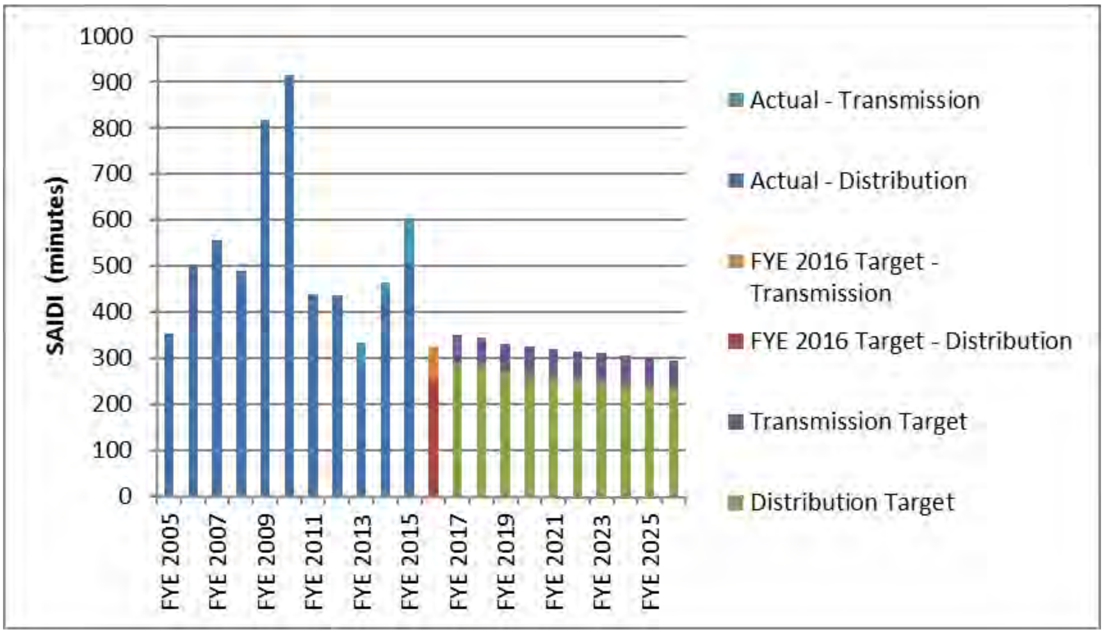


Figure 1.2: Historical and Target SAIDI

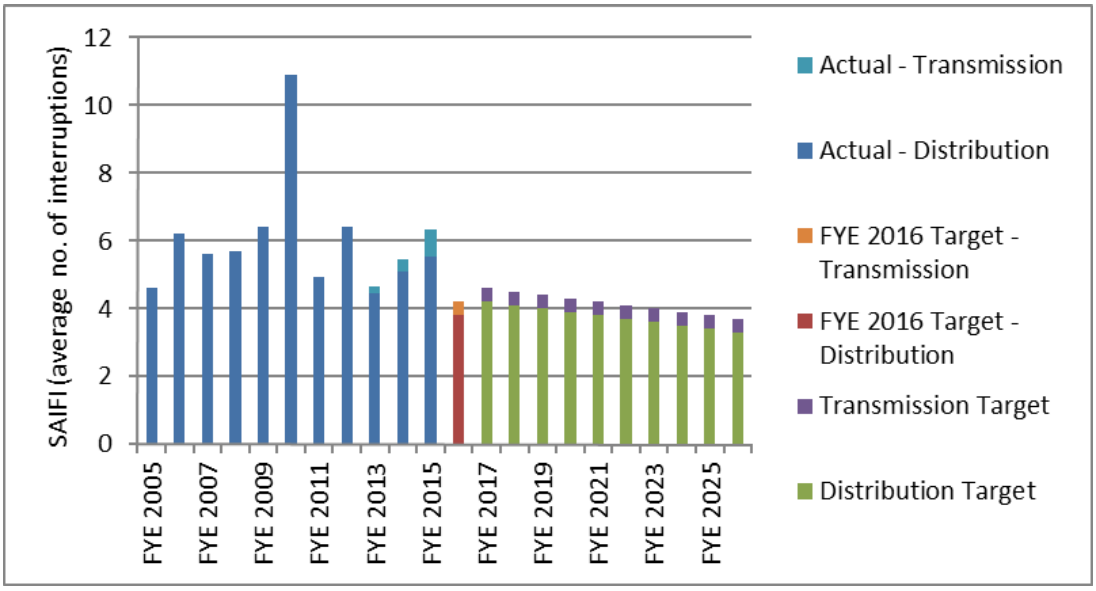


Figure 1.3: **Historical and Target SAIFI**

1.10 Capex Forecast

Table 1.4 shows the total network capital expenditure (capex) forecast for the period FYE2017-21, excluding an annual provision of $1.5 million for new consumer connections, highlighting in particular the major projects.

$ million (constant price)	FYE				
	2017	2018	2019	2020	2021
System Growth					
Acquisition of property rights for the 110kV line to supply the new Taipa substation and consenting for the use of the site	0.3	0.2	0.7		
Construction of the Kaeo and associated overhead lines	2.9	3.5			
Acquisition of property rights for the second incoming supply line to Kaeo			0.3		
Russell reinforcement			1.0		
11kV distribution network upgrades		1.1	0.5	0.6	1.0
Install new transformer T2 at Kaitaia to replace the existing unit			0.6	3.5	
Install second hand transformer at Omanaia			0.3		
SWER line upgrades			0.6		0.3
Other	0.4	0.2	1.1	0.6	
Total	**3.6**	**5.0**	**5.1**	**4.8**	**1.3**
Reliability, Safety and Environment					
110kV line property rights	2.1	4.4	1.6		
110kV line construction				1.9	4.6
Installation of 110kV bus zone protection at Kaikohe	0.6				
Installation of 110kV bus zone protection at Kaitaia			0.6		
11kV feeder interconnections				0.5	1.8
Replacement of control room SCADA software				0.8	
Other	1.4	0.7	1.1	0.6	0.4
	4.1	**5.1**	**3.3**	**3.8**	**6.8**
Asset Replacement and Renewal					
Pukenui 33kV line rebuild	0.6	0.4			
Kawakawa substation rebuild	1.0				
110kV line structure replacements and tower painting	0.5	0.6	0.5	0.6	0.6
Transmission substation replacements	0.2	0.3	0.6	0.3	0.2
Other planned network replacements	0.1	1.9	2.5	4.7	0.8
Provision for reactive defect remediation	2.0	2.0	2.4	2.1	2.4
	5.4	**5.2**	**6.0**	**7.7**	**4.0**
TOTAL	**13.1**	**15,3**	**14.4**	**16.3**	**12.1**

Table 1.4: Network Capex (excluding new connections) FYE2017-21.

1.11 Maintenance Expenditure

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	FYE				
	2017	2018	2019	2020	2021
Service interruptions and emergencies	1,200	1,200	1,200	1,200	1,200
Routine maintenance and inspection	1,765	1,765	1,774	1,783	1,792
Vegetation	1,833	1,833	1,835	1,837	1,839
Replacement and renewal	939	939	928	857	862
Total	**5,737**	**5,737**	**5,737**	**5,677**	**5,693**

Table 1.5: Forecast Maintenance Expenditure (FYE2017-21)

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 four divisions:

- **Ngawha Generation**, which operates the 25MW Ngawha geothermal power plant;
- **Top Energy Networks**, which distributes electricity throughout the Far North;
- **Top Energy Contracting Services (TECS)**, which provides contracting services to the electric power industry; and
- **Phone Plus**, a contact centre business located in Kaikohe and Albany, Auckland.

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 200 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.

Our electricity transmission and distribution network distributes electricity, sourced from the Transpower grid and the Ngawha power plant, to almost 32,000 electricity consumers. This Asset Management Plan (AMP) covers the management of our network and non-network assets, which had a regulatory asset value of almost $217 million as at 31 March 2015. This figure does not include assets owned by Top Energy's other operating divisions, which are not covered by this AMP.

The network is supplied with electricity from the termination points of Transpower's transmission grid at the incoming 110kV circuit breakers at the Kaikohe transmission substation and also from Ngawha Generation's geothermal power plant, which injects power directly into the 33kV subtransmission network. Table 2.1 below shows the key network parameters.

DESCRIPTION	QUANTITY
Area Covered	6,822km^2
Consumer Connection Points	31,901[(1)]
Grid Exit Point	Kaikohe
Embedded Generator Injection Point	Ngawha Geothermal
Network Peak Demand (FYE2016)	67.7MW[(2)]
Electricity Delivered to Consumers (FYE2015)	321GWh
Number of Distribution Feeders	56
Distribution Transformer Capacity	256MVA[(3,4)]
Transmission Lines (110 kV)	56km[(3)]
Subtransmission Cables (33kV)	20km[(3)]
Subtransmission Lines (33kV)	303km[(3)]
HV Distribution Cables (22, 11 and 6.35kV)	197km[(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 2015.
Note 2: Estimated from SCADA data. May not correspond to FYE2016 information disclosure, which will be based on metered data.
Note 3: As at December 2015.
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 (FYE2015 unless otherwise shown)

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

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.*

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.*

2.2.2.3 Strategic Challenges

In developing our asset management plan for the planning period FYE2017-26 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 for the approximately 10,000 consumers in the north of our supply area, who are dependent on a single 110kV transmission circuit that is in only average condition and that requires an annual maintenance outage that lasts for 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 high cost of the planned second circuit means that it is technically uneconomic under the most likely growth scenarios and only marginally economic if a low probability, high load growth outcome is assumed. Partly for this reason, in early 2015 we decided to defer completion until FYE2026. However, allowing the existing situation to continue indefinitely is not considered an option, and the alternative of installing diesel generation, which is discussed further in Section 5.11.3, is unlikely to be a sustainable long term solution.

- While there has been a significant improvement in our reliability of supply over the last five years, it remains the worst in the country. This is due to our fringe location on the transmission grid, the lack of a dominant urban centre, an inadequate subtransmission infrastructure 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, to the extent that our subtransmission network is unable to provide the level of supply reliability now accepted as the norm in the rest of the country.

- Recent changes in the Health and Safety in Employment legislation could also adversely impact the rate at which we are able to improve our reliability of supply, as they could result in Worksafe New Zealand limiting the use of live line maintenance for safety reasons. The Electricity Engineers Association is working closely with Worksafe New Zealand on this issue and the outcome of these discussions is not clear at this stage. Restrictions on the use of live line maintenance would have an adverse impact on the reliability of supply to the Kaitaia region, as currently maintenance on the 110kV transmission line is undertaken live to the extent this is practical.
- 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 321GWh in FYE2015. This decline is attributed to flat consumption by our large industrial consumers and energy efficiency initiatives implemented by other consumers. The flat industrial consumption is a function of the stagnant economic climate in our supply area, while energy efficiencies 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.

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 our network business that 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 transmission and distribution 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 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 the operation of our Network's division and the way we manage our physical network assets.

2.4.1 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 our annual consumer survey 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. The Group is currently developing formal corporate business processes to receive stakeholder feedback and deal with complaints and we will leverage off this; and
- enhancing stakeholder understanding by providing guidance and information. We have increased the amount and timeliness of information uploaded on to Top Energy's website to better communicate with our external stakeholders.

Sections 2.6.2 and 2.6.3 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.

2.4.2 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. Earlier this year we 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. We are planning to re-establish employee process improvement teams based on the Six Sigma model; and
- creating collaborative partnerships to achieve compliance and drive innovation. We will become more actively involved with industry groups such and the Electricity Networks Association (ENA), the Electricity Engineers Association (EEA) and the Business Health and Safety Forum to better understand our regulatory and legislative environment and to work collaborative towards the achievement of shared objectives.

2.4.3 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 manager 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.

2.4.4 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 new 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.

2.4.5 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.

2.5 Rationale for Asset Ownership

We use the assets covered by this AMP to deliver electricity to consumers located within the territorial area managed by the Far North District Council. The quality of this electricity supply is determined by the design of the network, the condition of the installed assets, as well as by environmental factors, such as the weather, over which we have no control.

The majority of our assets were originally installed as part of a distribution network designed to provide an electricity supply at minimum cost to consumers living in a large, sparsely populated, economically deprived area. At the time, supply availability was considered more important than reliability and cost was an overriding consideration. Hence, our network is characterised by a small number of long distribution feeders, supplied from a limited number of zone substations. Two wire and single wire earth return (SWER) lines are used extensively.

The network was never designed to supply the level of reliability required by a modern, developed economy and that our consumers now expect. We have therefore embarked on a major investment programme to relieve capacity constraints where these exist, but primarily to improve the reliability of the electricity supply that we provide our consumers. While there have already been some improvements in supply reliability as a result of the completion of a new transmission line between Kaikohe and Wiroa, the completion of new substations at Wiroa and Kerikeri, the installation of strategically targeted network automation and remote control devices, and the adoption of better maintenance practices, the reliability of our network is still the lowest in the country.

In order to significantly improve this reliability, the network architecture needs to be further upgraded by:

- upgrading the protection systems on our existing 33kV subtransmission systems so that the assets are capable of parallel operation. This initiative has been progressively implemented since 2012 and will be fully complete by the end of FYE016;
- providing a second high-capacity incoming transmission line to serve consumers in the north of the supply area; and
- providing additional points of injection into the medium voltage distribution system.

These improvements will have the following benefits:

- When subtransmission assets are operated in parallel, supply is automatically routed around a faulted asset without the need for manual switching. With the completion of this initiative most faults on the 33kV network will no longer cause a supply interruption.
- Consumers in the northern region will continue to receive an electricity supply when the one existing incoming transmission line is out of service, either for planned maintenance or as a result of an unplanned fault. Annual planned supply interruptions in the northern area, lasting up to nine hours, will no longer be needed.
- There will be the potential for increased utilisation of the existing high voltage distribution network assets through shorter feeders, which can carry higher currents on the existing wires without voltage drop becoming a significant issue.
- The shorter distribution feeders will also supply fewer consumers. This will reduce the average number of consumers affected by a single fault and often allow earlier restoration of supply to consumers not directly affected.
- Voltage will improve in many areas, increasing the quality of supply to consumers in remote locations.

2.6 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 particular 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.
- Project approval papers, 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 the 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 to be adopted 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 the Top Energy 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[I]. 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 FYE2017. 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.

[I] Commerce Commission Decision NZCC33, dated 28 November 2014. This decision was amended on 26 March 2015 by the *Electricity Distribution Services (Top Energy Limited) Default Price-Quality Path Amendment Determination 2015*, which corrected errors in the calculation of Top Energy's quality thresholds.

BACKGROUND AND OBJECTIVES

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 expected changes 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 into account 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 around 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.

2.6.1 Planning Periods Adopted

This AMP is dated 1 April 2016 and relates to the period from 1 April 2016 to 31 March 2026. It was approved by the Board on 29 March 2016 and replaces all previously published AMPs.

2.6.2 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 its asset management requirements and its 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 it believes is fair to all affected parties and is consistent with Top Energy's group values and objectives

2.6.3 Stakeholder Interests

Table 2.2 below identifies our key stakeholders, their individual interests and summarises the process that Top Energy has in place to accommodate their expectations.

STAKEHOLDER	EXPECTATIONS	CURRENT DATA SOURCE	MEASURES	ACTIONS
CONSUMERS	Fair Price	Commerce Commission, pricing spreadsheets/ budgets	Price-quality regulatory threshold	We control and manage expenditure against the current budget to ensure profitability and service levels are maintained with the prices allowed under the price-quality threshold.
		Billing System, DigSilent (network analysis software)	Loss factors	We measure network losses and our planning and design activities ensure they are maintained at an optimum level. We calculate loss factors for different parts of the network in accordance with the methodology approved by the Electricity Authority.
		SCADA, GIS, DigSilent	Asset utilisation	Our planning and design activities ensure optimum asset utilisation.
		Financial system, SCADA System, DigSilent	Transpower costs	We actively manage GXP demand using our water heater control system to ensure connection costs are minimised without adversely impacting the quality of supply as perceived by consumers.
		PriceWaterhouseCoopers and Commerce Commission performance analysis	Lines business rankings	We assess our network performance through comparison with peer group electricity distribution businesses (EDBs) with similar operating characteristics.
	Reliability	Reliability database, SCADA, GIS, Defects management system	SAIDI, SAIFI	We continually measure and review reliability against the targets detailed in the AMP. A portion of our capital and maintenance expenditure budgets are allocated to reliability improvement initiatives, which are targeted at known causes of poor reliability.
		GIS, DigSilent	Security standards	We have set security standards for the network. While these are currently aspirational in some areas, we have identified and are currently implementing projects to address non-compliances.
	Quality	Faults register	Voltage complaints	Modelling and actual consumer complaints identify problem areas within the network and we implement voltage improvement projects as a result.
	Communications	CMS (call management system)	Call centre statistics	Our Top Energy owned contact centre (Phone Plus) ensures consumers are directed to the appropriate point of contact for quick and efficient service.
RETAILERS	Communications	Fault records, SCADA and GIS	Outage data transfers	We share information with retailers in accordance with standard industry protocols.
		Use of Systems Agreement and industry regulations	Tariff changes	We coordinate the timing of any tariff changes with retailers.

STAKEHOLDER	EXPECTATIONS	CURRENT DATA SOURCE	MEASURES	ACTIONS
	Simple tariff	Regular face-to-face meetings or telephone conferences	Agreements from retailers	Our tariff structure is developed in conjunction with retailers and reflects the business needs of all parties.
	Open network access	Industry regulations and transparency	Published plans and price methodology	We have a transparent pricing structure that is explained clearly.
	Allocation of Losses	Monthly loss data and network analysis software	12 month rolling losses	We calculate loss factors for different parts of the network in accordance with the methodology approved by the Electricity Authority.
	Metering and Billing	ICP database, retailer records and systems	Random audits of retailers' systems and sites	We rely on retailers' systems to reconcile revenue.
BOARD	Safety	Industry regulations and standards	Accident report statistics and non-compliances	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 to meet the requirements of the Electricity Regulations 2010. We actively monitor safety outcomes and report these monthly to the Board.
	Profit	Financial system	Audited financial reports	We report financial outcomes monthly to the Board. This report includes a comparison against the budgets in this AMP.
	Reliability	Reliability database, SCADA, GIS	Fault statistics	Our reliability improvement expenditure is targeted at initiatives that are expected to improve reliability of supply.
	Accountability	Key performance indicators	Annual staff and plan performance reviews	Our employees' key performance indicators are linked to asset management service levels.
	Compliance	Correspondence and Board reports	Legal and statutory compliance	Our internal standards, policies and procedures ensure compliance with all legal and regulatory requirements.

STAKEHOLDER	EXPECTATIONS	CURRENT DATA SOURCE	MEASURES	ACTIONS
	Social responsibility	GIS and financial system	Capital contribution scheme	Our capital contribution scheme is designed to ensure equitable sharing of the costs of new construction that is installed for the benefit of individual consumers.
TOP ENERGY CONSUMER TRUST	Dividend	Financial system	Audited financial reporting	Our operating and capital expenditure is controlled and managed against our Annual Plans to ensure profitability and service levels are maintained.
	Grow asset value	Financial system, GIS asset database	Annually disclosed asset valuation	We endeavour to make timely investments to meet consumer needs using long-term value-adding assets.
	Retain ownership	Survey report	Ownership reviews as per Trust Deed requirement	We combine the Trust's desire for local ownership with a strong commitment for improving service levels and maintaining profitability.
REGULATOR	Compliance with regulations and determinations	Legislation and correspondence	Monthly reports against thresholds	A comparison of our reliability performance with both our internal targets and the thresholds set by the Commerce Commission forms and integral part of our monthly report to the Board.
STAFF	Health and safety	Safety database	Accident and non-compliance statistics	We have a safety management plan in place to ensure the safety of our staff in the work place. This complies with industry standards and is regularly reviewed.
	Job security and satisfaction	Administration spreadsheet	Staff survey results, staff turnover figures	We have training and development and recruitment plans in place so that relevant skill sets will be available when required.
	Training	Administration spreadsheet	Agreed professional development	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	Spreadsheet, GIS	Complaints	We implement our vegetation control programme in accordance with the Electricity (Hazards from Trees) Regulations 2003.

STAKEHOLDER	EXPECTATIONS	CURRENT DATA SOURCE	MEASURES	ACTIONS
		Reliability database, SCADA, GIS	Fault statistics	We target expenditure on vegetation control on the basis of the expected improvements in reliability of supply.
	Safety	Public safety management system	Non-conformance records	We have implemented a formal public safety management system to ensure that operation of our network assets does not pose risk or hazard to the general public. This is subject to regular audit.
	Land access rights upheld	CMS, GIS	Complaints	This AMP identifies future work that requires access to landowners' property. We comply with relevant regulations and consult with landowners and occupiers as appropriate.
COUNCIL	Resource management	Legislation, GIS	Consents for work	The timing of projects within the network development plan set out in this AMP provides sufficient time for obtaining required consents.
	Road management	Procedures, GIS	Consents for work	The timing of projects within the network development plan set out in this AMP provides sufficient time for obtaining required consents.
	Marine Crossings	Procedures, GIS	Consents for work	The timing of projects within the network development plan set out in this AMP provides sufficient time for obtaining required consents.

Table 2.2: Accommodation of Stakeholder Interests

2.6.4 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 approval papers, which must be prepared for projects with an estimated cost of $500,000 or more. It also actively monitors the ongoing operation of Networks 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.

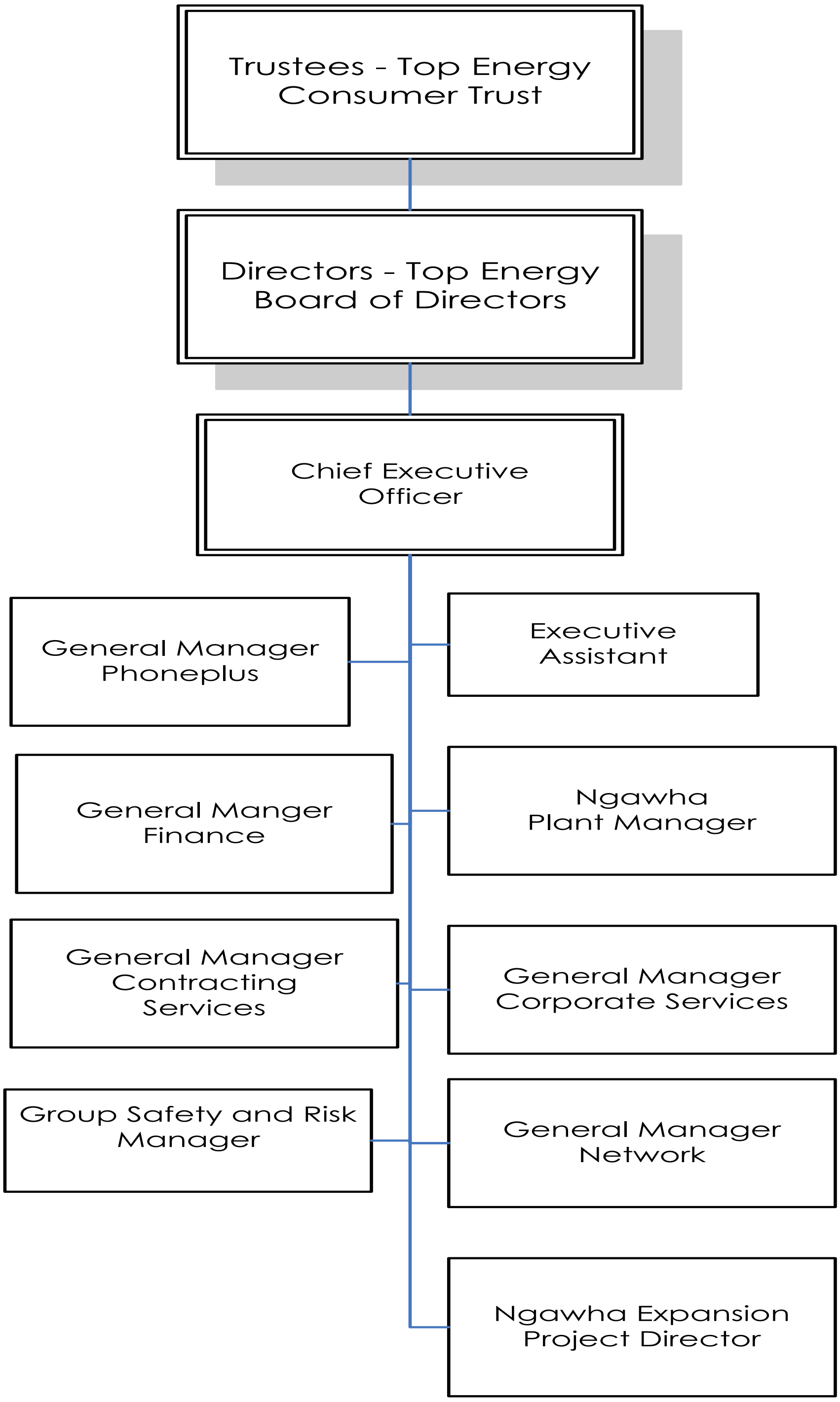


Figure 2.2: Top Energy Structure

BACKGROUND AND OBJECTIVES

At the executive level, the Chief Executive Officer (CEO) is appointed by the Board and has overall responsibility for the network asset management effort. Our Networks division is responsible for managing the network assets covered by this AMP. The Networks division 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 directly to the Board on our Networks operations.

Networks 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, Networks 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 is now 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 exclusively by TECS which employs around 95 staff including supervisors, electricians and lines staff. TECS may in turn subcontract or outsource work that it is unable to resource.

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 2.13.4 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.

The degree of autonomy accorded to TECS depends upon the nature of the work. Large capital projects are managed directly by Networks staff. Networks also monitors the work undertaken by TECS through regular reports on work progress and financial performance against budget and this information is included in the General Manager Network's monthly Board report.

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

Networks has overall responsibility for the safety of all personnel working on the network and in 2011 we won the Electricity Engineers' Association (EEA) Workplace Safety Award. 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. 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.

The structure of our Networks division is outlined in Figure 2.3 below.

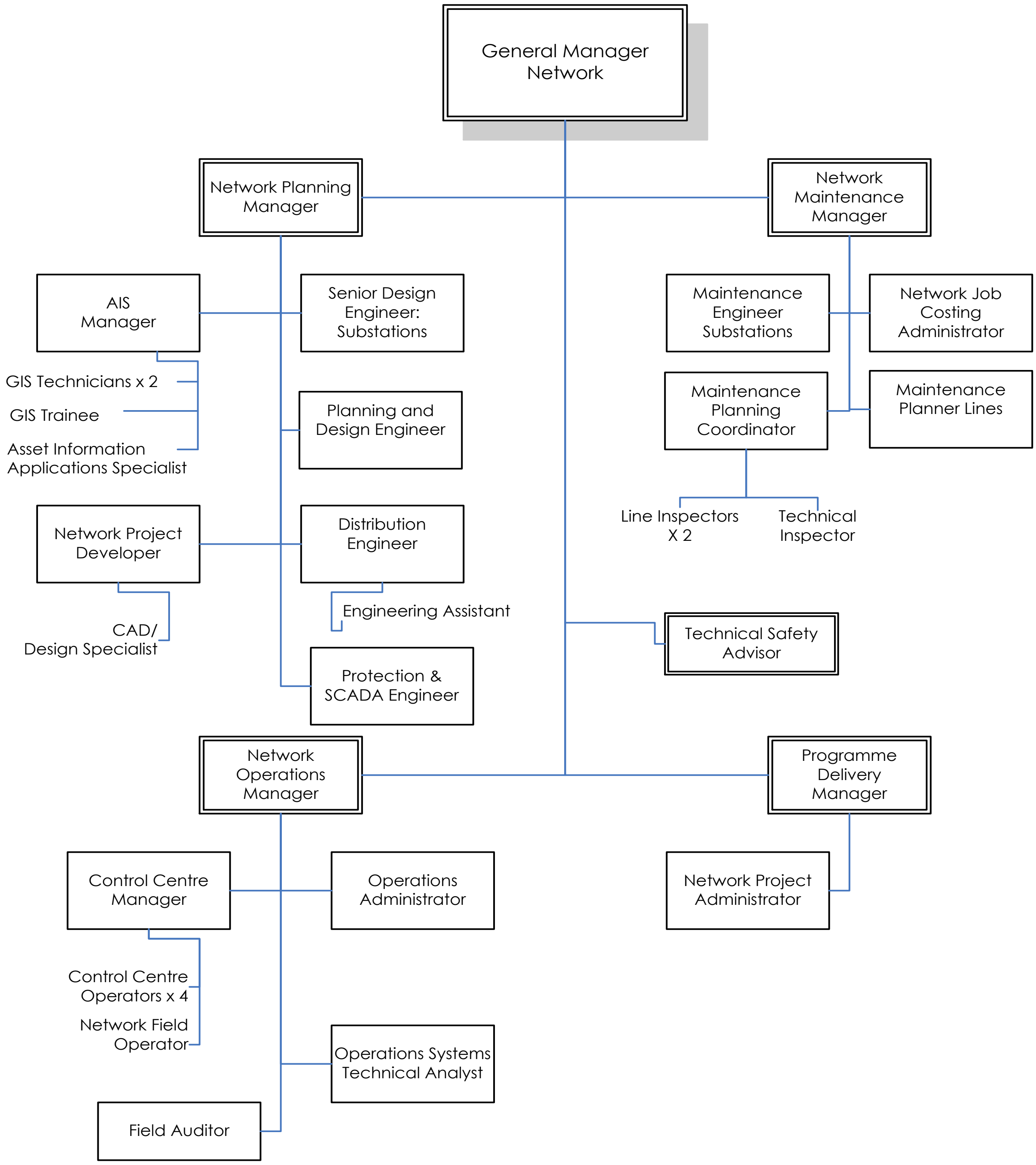


Figure 2.3: Top Energy Network Division - Structure

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 2.3: 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
Engineers	Nil present authority

Table 2.4: Top Energy order approval levels

2.7 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.

2.7.1 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.

2.7.2 Accounting/Financial Systems

The Group now 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 on a monthly basis 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.

2.7.3 GIS System

The Intergraph Geographic Information System (GIS) acts as an engineering asset register and provides a spatial representation of assets, their relationships 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 use this to manually generate our SAIDI and SAIFI reliability reports.

2.7.4 Network Analysis System

We use a 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 normal operations.

2.7.5 Consumer Management System

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

2.7.6 Drawing Management System

We use Bentley's MicroStation CAD software to generate construction drawings for subdivisions and new capital works.

In addition to the above, CAD drawings include:

- zone substation building and site plans;
- specialised equipment drawings;
- procedures manual diagrams; and
- control, circuit and wiring diagrams.

2.7.7 Maintenance Management System

We use the SAP asset management software modules as a repository for asset condition data and the basis for our maintenance planning and management. Each individual asset is assigned to a maintenance and inspection plan detailed within SAP, according to the type of asset, the required inspection frequency and the asset location. Asset inspection is undertaken internally by Networks and our asset inspectors work systematically through each maintenance 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.

2.8 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. 3 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 first full asset inspection cycle.

2.9 Asset Management Systems

2.9.1 Asset Inspections and Maintenance Management

As described in Section 2.7.7, we have developed a time-based asset inspection programme, which 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.

Defects identified during asset inspections and condition assessments are currently prioritised and actioned by TECS within approved budgets. Quality and efficiency is monitored through selective auditing and monthly reporting.

We have modified our approach to the planning and prioritisation of defect remediation so that all defects in a particular area are remedied at the same time through a planned area based defect remediation project. This has required a more proactive involvement by Networks staff in planning the maintenance programme.

We receive regular reports from TECS on maintenance work undertaken. These are used as the basis for Board reporting on maintenance work undertaken 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.

2.9.2 Network Development Planning and Implementation

Our network development plan, as described in Section 5, 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 it 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. To date these reviews have confirmed the general strategy developed in FYE2011 but have on occasions resulted in material changes to the timing of individual projects. The most significant change occurred in the FYE2015 AMP Update, when we deferred the planned completion of the second 110kV transmission to FYE2026 and accelerated the completion of the Kaeo zone substation and the reinforcement of the supply to the Russell peninsula. This change was driven by delays in securing the 110kV line route and the risks that we could incur had we commenced construction prematurely before the line route was confirmed over its full length. There was also an emerging realisation across the business that a compressed line construction schedule would absorb all available capital works funding over the construction period and that other work required to improve the reliability of the distribution network would need to be deferred as a result.

The network development plan is also reviewed at a more detailed level after the load forecast is updated, taking into account the actual peak demand on the network, which normally occurs in July or August each year. The actual network demand is checked against the previous forecast to ensure that network growth is being realistically and accurately determined. Where necessary, demand projections are modified

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. Load forecasting and the development of the network capital investment strategies are discussed in greater detail in Chapter 5 of this AMP.

2.9.3 Network Performance Measurement

We have developed an internal real time fault management system. 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.

We are currently reviewing options for upgrading our SCADA master station software with the intention of installing a replacement system in FYE2020. We would like this to incorporate an outage management system, which would automate the calculation of the SAIDI and SAIFI impact of interruptions to supply and replace our present manual, largely paper based system. It would also potentially make our response to network outages more efficient, particularly during severe weather conditions.

2.10 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 2.5 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 (now that supply into Kerikeri has been reinforced) 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 treaty of Waitangi claim and 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.	This assumption is based on the fact that power systems have to be designed to meet peak demand. Increased power system efficiency and minimisation of investment comes largely by minimising demand. Power factor is also directly related to power system efficiency and is part of demand side management. 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 focuses on the transmission and subtransmission network and, apart from increasing the points of injection, largely overlooks the distribution network. 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 intended to finance improvements to the transmission and subtransmission networks. This is a significant long term risk from the penetration of electric vehicles. There will need to be incentives in place

ISSUE	ASSUMPTION	BASIS FOR THE ASSUMPTION	POTENTIAL IMPACT OF UNCERTAINTY
			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 avoided.
RELIABILITY AND QUALITY	Consumers want an improvement in the reliability and quality of electricity supply.	Our current supply reliability is the worst in the country. 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. This risk could be exacerbated if the forecast increase in the demand for electricity does not materialise and future line charge increases are greater than currently anticipated. 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. Our 2015 price increase was below the price path set by the Commerce Commission as a result of the decision to defer the completion of the new transmission circuit to FYE2026.
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 will provide 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 25% 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. In the medium-term, the network development plan will also provide further SAIDI

ISSUE	ASSUMPTION	BASIS FOR THE ASSUMPTION	POTENTIAL IMPACT OF UNCERTAINTY
			improvements, because most transmission and subtransmission faults will no longer cause a supply interruption and also because increasing the number of zone substations will reduce the length of distribution feeders. 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. The poor reliability experienced in FYE2015 was due to abnormally severe weather conditions, that exceeded our fault response capacity by a significant margin.
INFLATION	Except where otherwise shown, cost estimates in the AMP are presented in real New Zealand dollars as at 31 March 2016. Where these cost estimates are expressed in nominal New Zealand dollars, an annual inflation rate of 2% is assumed for the whole of the planning period.	This is the mid-point of the Reserve Bank's long term target consumer price index (CPI) inflation rate of 1-3%. 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 in the latter part of the last decade cost increases were significantly higher. Nevertheless, prior to around 2004 cost increases were	

ISSUE	ASSUMPTION	BASIS FOR THE ASSUMPTION	POTENTIAL IMPACT OF UNCERTAINTY
		lower than CPI as equipment manufacturers reduced costs by relocating to developing countries. We see little point in attempting to develop a more accurate forecast, given the length of the planning period and the associated high levels of uncertainty in other elements of the plan.	

Table 2.5: AMP Assumptions and Uncertainties

2.11 Asset Management Strategy and Delivery

2.11.1 Asset Management Strategy

A gap analysis undertaken by Asset Management Consulting Proprietary Limited (AMCL) in April 2012 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:

- construction of a second 110kV transmission circuit between Kaikohe and Kaitaia to increase the security of supply to consumers in the Northern part of the supply area;
- construction of new substations in the high-growth areas of the eastern seaboard to address subtransmission capacity issues and reduce the number of long, heavily-loaded distribution feeders;
- installation of new protection systems on the subtransmission network to allow circuits to operate in parallel, so that the majority of subtransmission faults do not result in a loss of supply;
- replacement of assets that are in poor condition and nearing the end of their economic life;
- increasing the expenditure on vegetation management and targeting this programme at those parts of the network where supply reliability is poor.
- improving the efficiency of the maintenance effort through the introduction of a SAP maintenance management system.

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 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 2.7.7 and programmes the proactive replacement of assets at risk of premature failure due to accelerated deterioration or systemic design weaknesses are described in Section 6.

2.11.2 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 and the installation of diesel generators at Taipa.

2.11.3 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 for processes to identify and mange 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.

2.11.4 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 in regard to 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.

2.11.5 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.

2.12 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 does not record 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.

SAP was introduced in November 2012 to address this maintenance information management issue.

A mature process is in place for the management of GIS data, described in some detail in Section 2.8. Processes for the management of maintenance data in SAP are 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. While the quality of the data set will improve over time as assets are progressively inspected, a fully satisfactory data set will not be available until FYE2018.

2.13 Asset Management Documentation, Controls and Review

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

2.13.1 Asset Management Policy

At the time of the AMCL assessment, an asset management policy has been prepared in accordance with the requirements of PAS 55. This policy document was only a draft and had not been signed-off by the CEO and communicated to stakeholders. It also needed further review to confirm that it is fully aligned with the higher level corporate strategy set out in the SCI and meets the requirements of clause 4.2 of PAS 55.

Our asset management policy has now been updated and approved by both the CEO and the Board. It is presented in Section 1.2 of this AMP.

2.13.2 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 2011 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.*

The objectives set out in Chapter 4 of this AMP appear to meet this requirement. 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 the 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 its asset performance have still to be developed in some areas.

2.13.3 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.

2.13.4 Interface Agreement and Sourcing Strategy

These two documents define the formal relationship between Networks 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 Networks and TECS, which 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.

An internal reorganisation became effective on 1 April 2015 and functions such as asset inspection and maintenance planning are now undertaken directly by Networks staff rather than by TECS. While good progress in addressing the problems identified by AMCL has been made, some issues at the interface between Networks and TECS remain.

2.13.5 Documentation of the Asset Management System

We have implemented a public safety management system in accordance with the requirements of the Electricity Regulations 2010. AMCL noted that many of the public safety management system procedures and work instructions documented what was already occurring within Networks 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 of the implementation of this AMP.

Our long term goal of creating and implementing formalised, fully documented, PAS 55-certified asset management system remains. However, there is no time frame for this and no formal project to achieve this objective has been established.

2.13.6 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 has the ability to 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 the 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.

2.13.7 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 Networks lacked a clear "line of sight" into TECS; implying that Networks, as the asset owner, had limited meaningful involvement in the implementation of new project works once a decision is made to proceed to construction.

We believe that this issue was largely addressed in the company reorganisation discussed in Section 2.13.4, although we acknowledge that there are issues at the interface between Networks and TECS that still have to be satisfactorily resolved.

2.13.8 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 became effective at the beginning of FYE2016.

2.13.9 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 Networks' monthly Board report.

2.13.10 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.

2.13.11 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 yet 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 Networks. The preparation and ongoing improvement of this AMP is accorded a high priority to the extent that over the last few years we have engaged an external consultant with a good knowledge of our network to assist with the preparation of this document.

2.14 Communication and Participation Processes

2.14.1 Communication of the AMP to Stakeholders

Our SCI identifies this AMP as the defining document for our Networks business. All senior managers within Networks 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.

2.14.2 Top Management Communication and Support

Our executive management has undertaken a planned and highly visible 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 noted in Top Energy's 2012 Annual Report, one of the main drivers for the decision to introduce SAP was its proven functionality as a maintenance management tool.

2.14.3 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 Networks and TECS.

The restructure that was implemented at the beginning of FYE2015 was aimed at clarifying the lines of communication, accountability and responsibility for delivering the asset management plan.

2.15 Capability to Deliver

The investment programme described in this AMP is more ambitious than any previous investment in our network. We developed this programme in full consultation with its local community, as described in Section 4.4.2, 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 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, as described in Section 5.11.2.

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.

2.15.1 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 now the limiting constraint on the rate at which we can deliver our network development plan. In part 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.

In our 2015 AMP Update, we announced deferral of the completion of the 110kV Wiroa-Kaitaia line, which is now scheduled for commissioning in FYE2026. While availability of finance was a key reason for this decision, other factors included delays in securing the line route and a decision that a more balanced approach to network development, with capital expenditure spread more evenly across all parts of the network, was desirable. For example, deferral of the completion of this line has allowed us to bring forward the completion of the Kaeo substation, which should result in a significant improvement in the reliability of supply provided to consumers in Whangaroa and surrounding areas.

2.15.2 Line Routes

The ability to secure line routes, in particular the route for the new 110kV transmission line between Wiroa and Kaitaia, is also a risk to the timely delivery of the investment programme. We have identified a line route between Wiroa and Kaitaia and have a dedicated team negotiating with affected landowners. Of the 94 landowners along the route, 59 (63%) have either signed an agreement to grant an easement or agreed the amount of compensation and indicated a willingness to sign. Negotiations continue with the rest but a small number are strongly opposed to the line and unlikely to agree terms acceptable to us. We expect to have to apply to the Minister of Land Information in accordance with the provisions of s186 of the Resource Management Act to compulsorily acquire a small number of easements before the line route is secured, and now anticipate that it will be FYE2019 before the route is fully secured.

2.15.3 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 costs of the various projects.

2.15.4 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 is undertaken internally, while the construction of new substations is outsourced.

Section 3 Assets Covered

3 Asset Description

3.1 Overview

3.1.1 Distribution area

Top Energy manages the Northern-most network in New Zealand, covering an area of 6,822 square kilometres. 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

The majority of the district's land 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 31,901 consumer connection points on the network as at 31 March 2015 (including inactive connections).

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 FYE2015, 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 FYE2015, the maximum demand on our network was 68MW and the total energy delivered to consumers was 321 GWh. The majority 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 and 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 for 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 Far North 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 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 eight in the southern. The zone substations in turn supply 56 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 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, 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 FYE2020.

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 FYE2026.

3.1.6 Subtransmission system

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

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. This is currently installed at Kawakawa, where transformer T1 is out of service with a faulty on load tap changer.

SUBSTATION	UNIT	NOMINAL ONAN/ ONAF OR OFAF MVA RATINGS WITH EXISTING COOLING	PRESENT MAXIMUM MVA RATING
Southern GXP			
Kaikohe	T1	11.5/23MVA ONAN/OFAN (Has pumps but no fans)	17
	T2	11.5/23MVA ONAN/OFAN (Has pumps but no fans)	17
Kawakawa	T1	5MVA ONAN (Has no pumps or fans)	5
	T2	5MVA ONAN (Has no pumps or fans)	5
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	T1-1 R	0.917MVA ONAN (Has no pumps or fans)	2.75
	T1-2 Y	0.917 MVA ONAN (Has no pumps or fans)	
	T1-3 B	0.917MVA ONAN (Has no pumps or fans)	
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
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 no pumps, but fans are fitted)	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 is currently outside of the N-1 threshold. The Omanaia and Pukenui substations also do not meet the threshold, but due to their small size are not required to do so by our security standard.

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	>FYE2026
	T2	17			
Kawakawa	T1	5[1]	5	2.5	>FYE2020[2]
	T2	5			
Moerewa	T1	5	5	2.1	>FYE2026[3]
	T2	5			
Waipapa	T1	23	23	6	>FYE2026
	T2	23			
Omanaia	T1	2.75	-	0.3	Current
Haruru	T1	23	23	0.5	>FYE2026
	T2	23			
Mt Pokaka	T1	5	-	1.5	>FYE2026
Kerikeri	T1	23	23	6	>FYE2026
	T2	23			
Northern Area			Firm (N-1)	11kV feeder Switched Capacity	Year Substation N-1 Exceeded
Okahu	T1	11.50	11.50	3.70	>FYE2026
	T2	11.50			
Taipa	T1	6.25	-	4[3]	Current
Pukenui	T1	5.00	-	0.25	Current
NPL	T1	23.00	23	1	>FYE2026
	T2	23.00			

Table 3.2: Present Zone Substation Transfer/Switching Capabilities

Note 1: Currently out of service with a faulty on load tap changer and replaced by the mobile substation in the interim.

Note 2: It is planned to add fans to both transformers at Kawakawa in FYE2017. This will increase the capacity of each transformer to 6.25MVA, which will provide N-1 security to beyond FYE2026.

Note 3: Diesel generation

3.1.7 Distribution system

Our distribution system consists of 56 predominantly overhead rural feeders, which supply more than 5,930 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 95%, underground 5%
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 35 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 all but three 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 February 2016.

Transformer size kVA	Number Pole Mounts	Number of Pad Mounts
Distribution Transformers		
Under 10	170	-
10	174	1
15	2,766	16
20	2	-
25	47	-
30	1376	89
50	392	158
75	31	-
100	104	181
150	21	53
200	18	172
300	2	82
400	-	8
500	3	29
750	-	11
1000	-	6
Isolating Transformers		
50	4	
100	51	
200	13	
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.

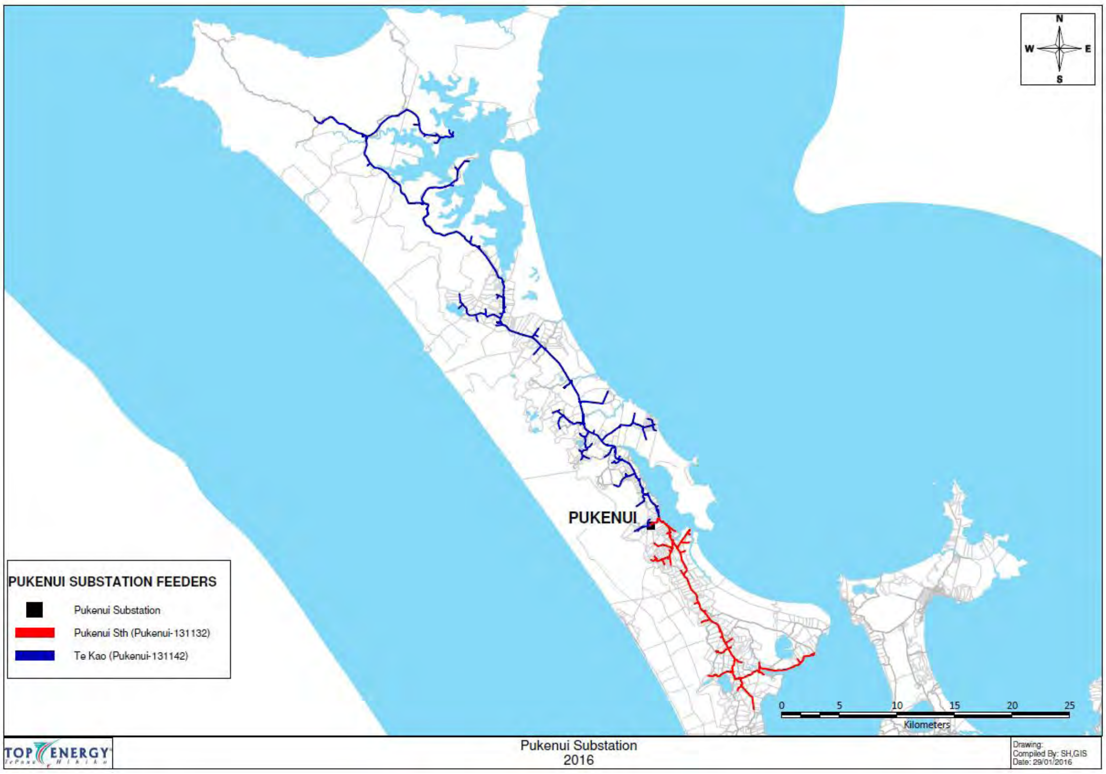


Figure 3.2: **Geographic diagram of the Pukenui zone substation**

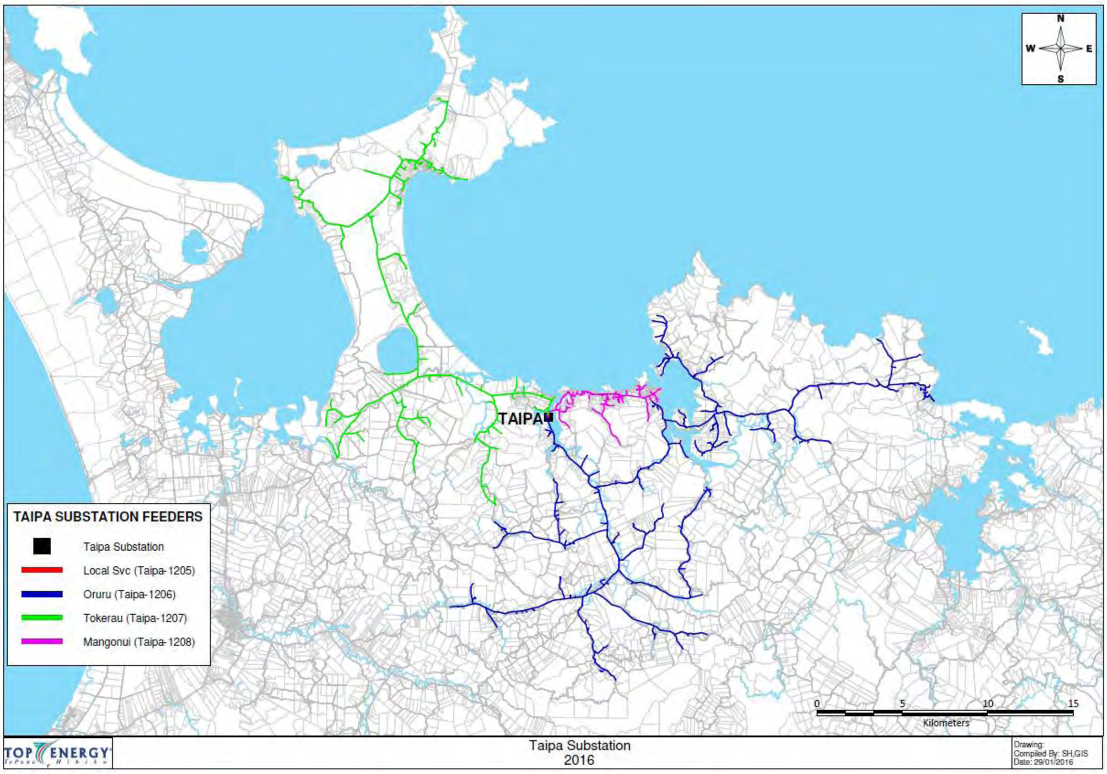


Figure 3.3: **Geographic diagram of the Taipa zone substation**

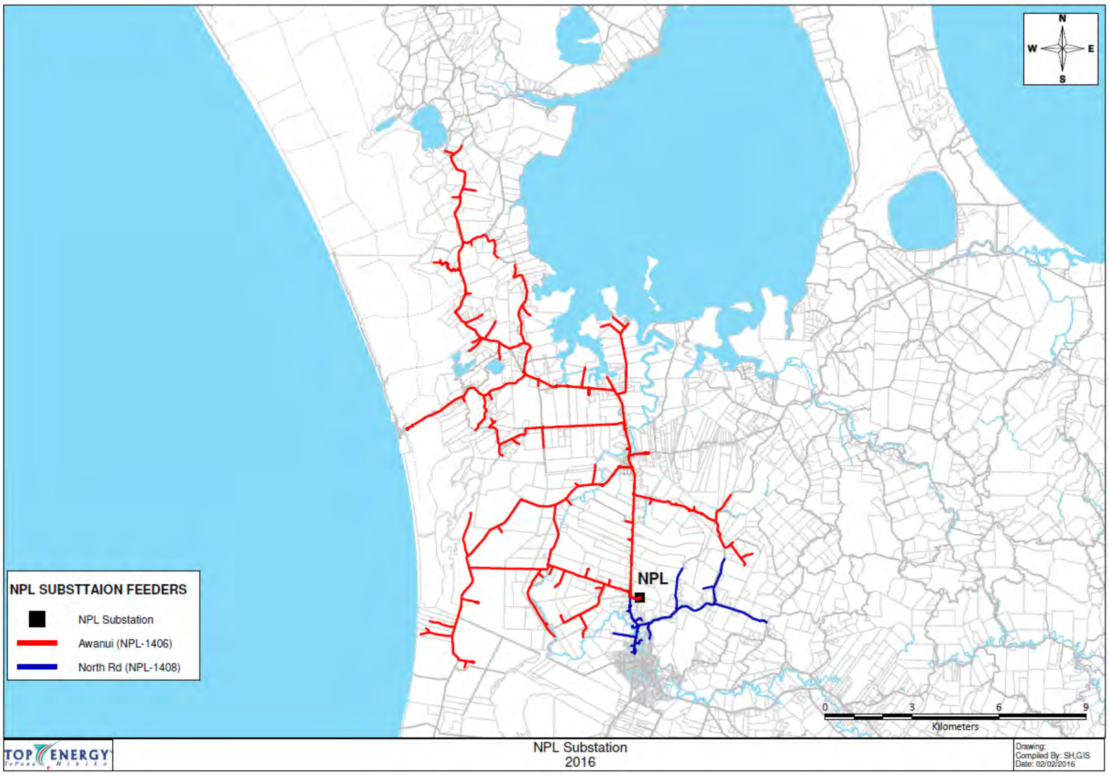


Figure 3.4: **Geographic diagram of the NPL zone substation**

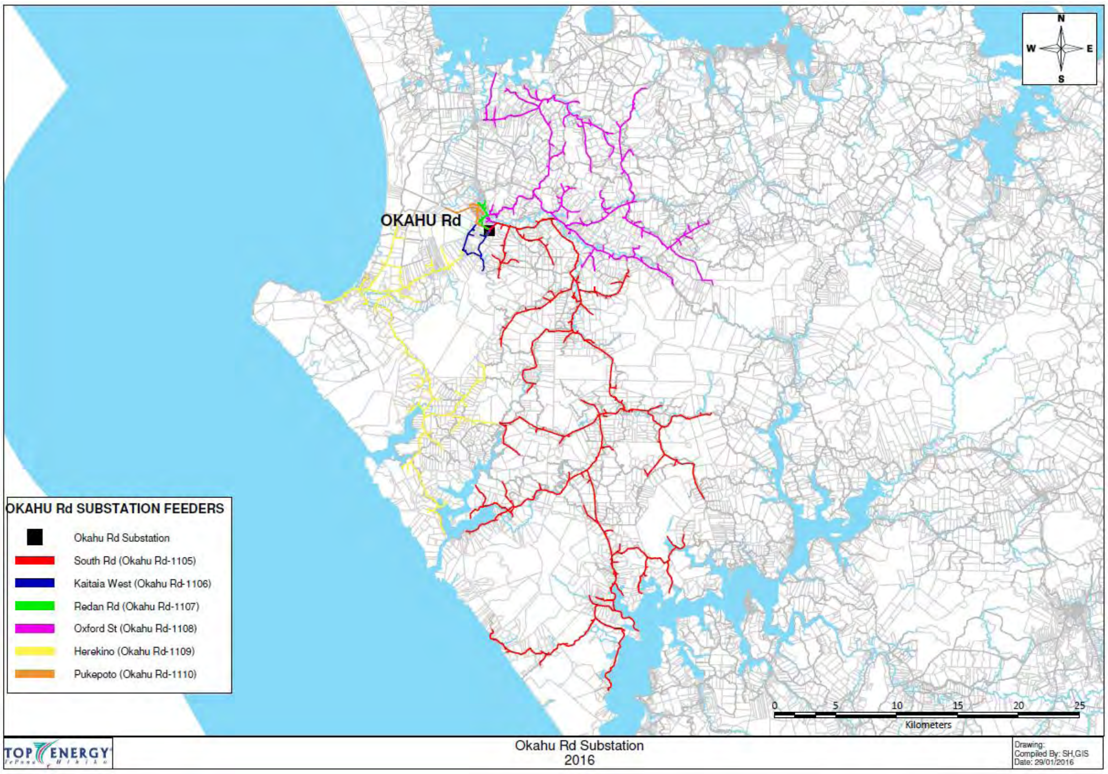


Figure 3.5: **Geographic diagram of the 33kV Okahu Road zone substation**

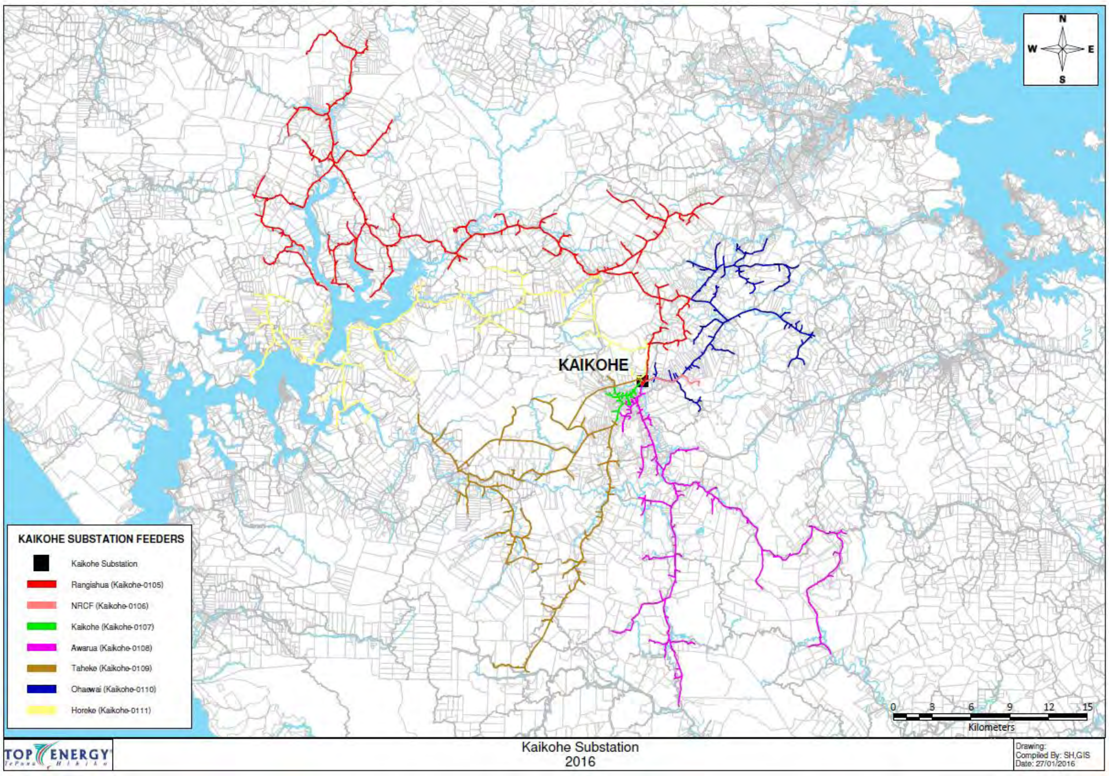


Figure 3.6: Geographic diagram of the Kaikohe zone substation

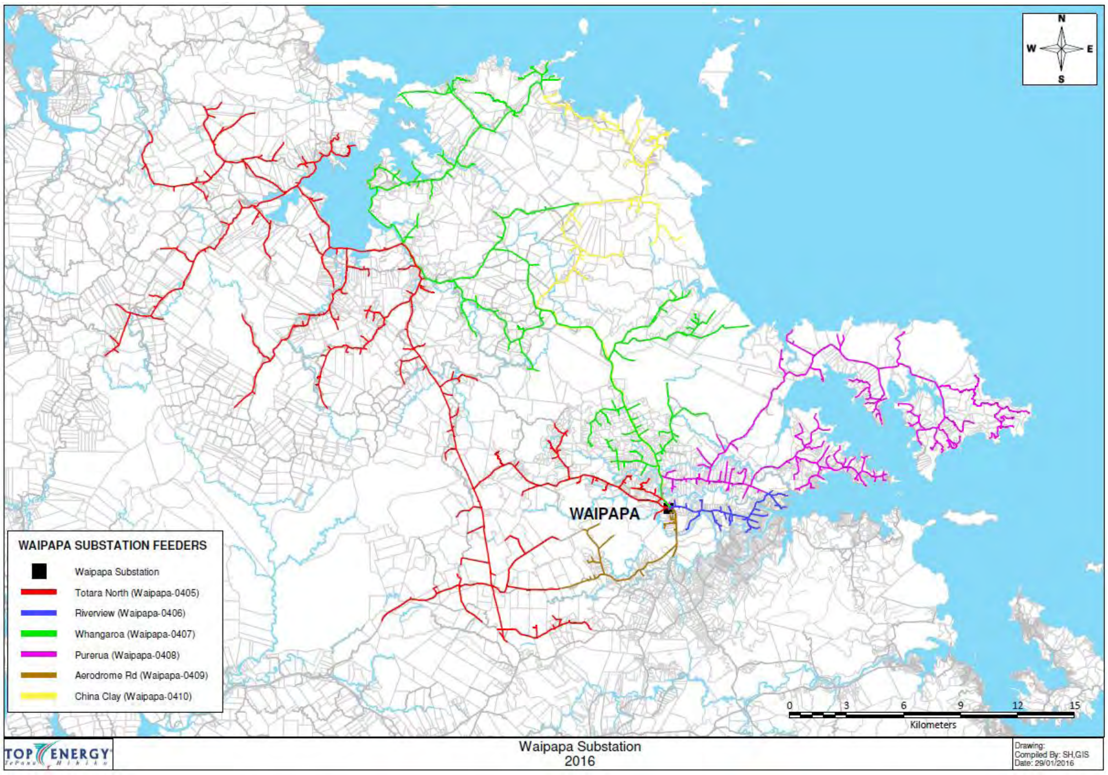


Figure 3.7: Geographic diagram of the Waipapa zone substation

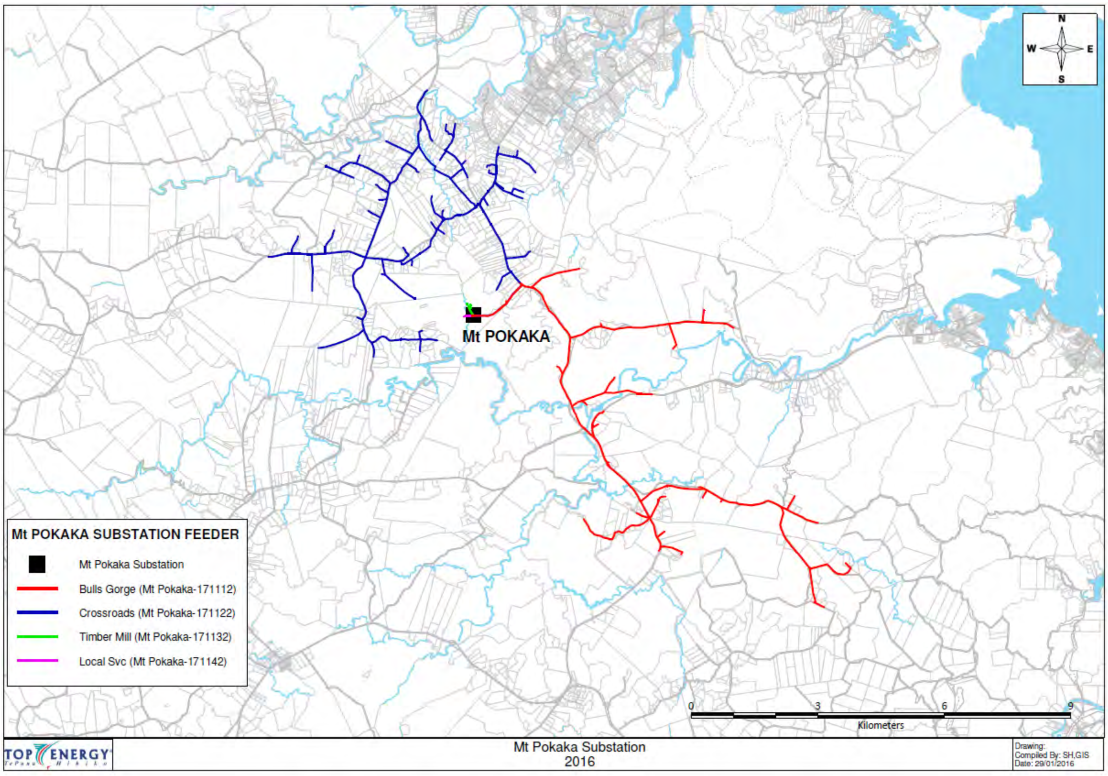


Figure 3.8: Geographic diagram of the Mt Pokaka zone substation

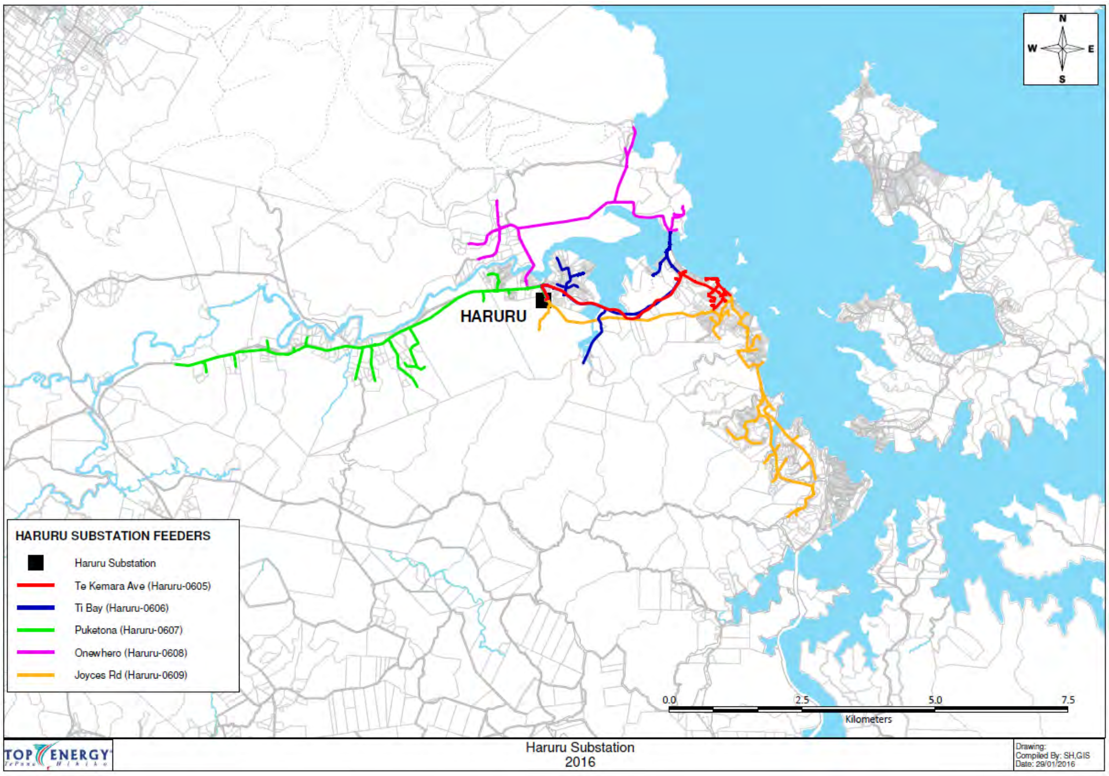


Figure 3.9: Geographic diagram of the Haruru zone substation

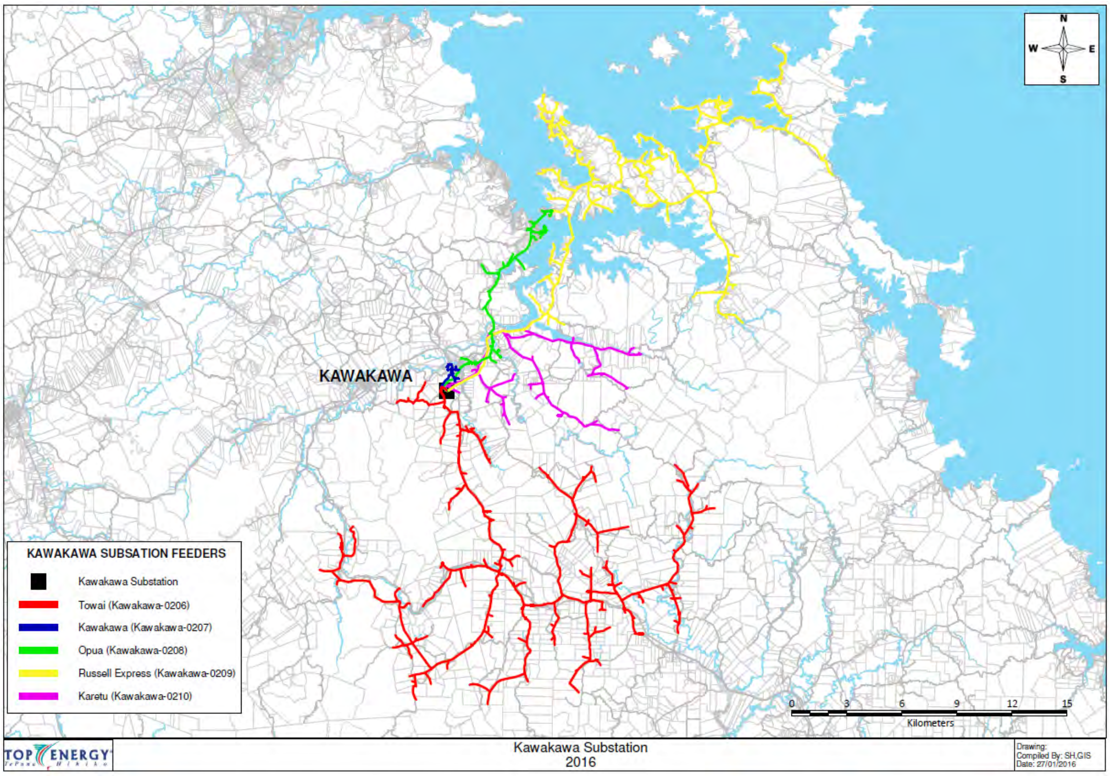


Figure 3.10: Geographic diagram of the Kawakawa zone substation

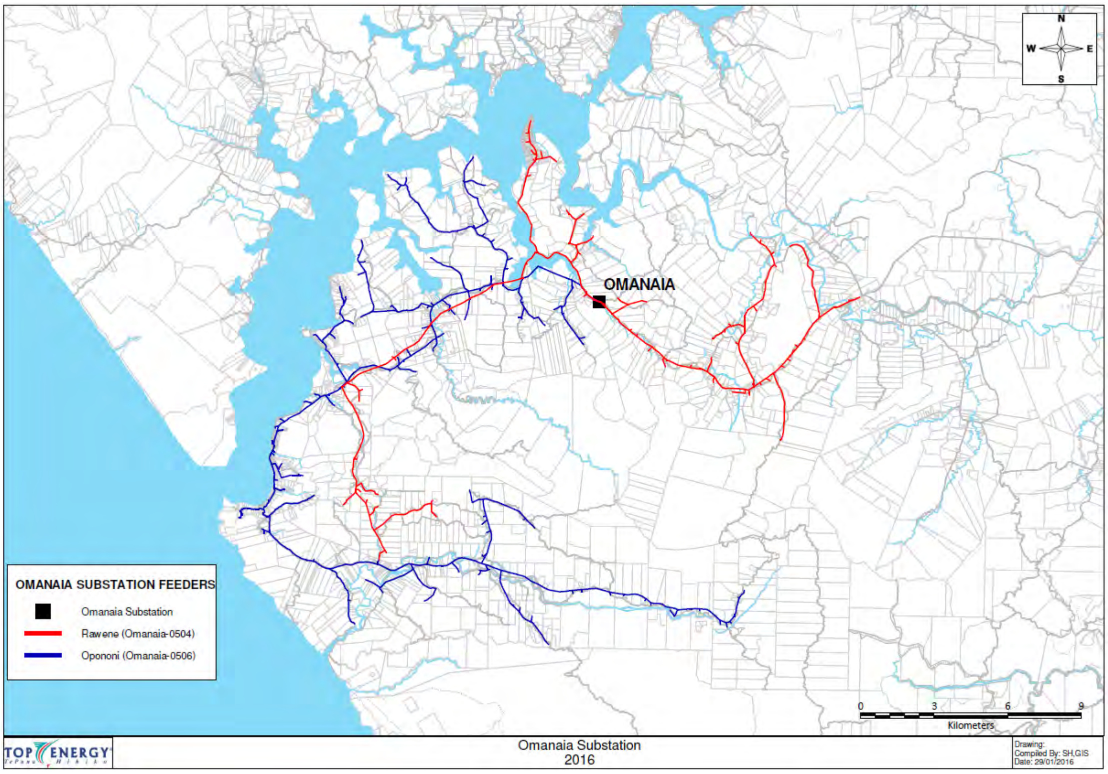


Figure 3.11: Geographic diagram of the Omanaia zone substation

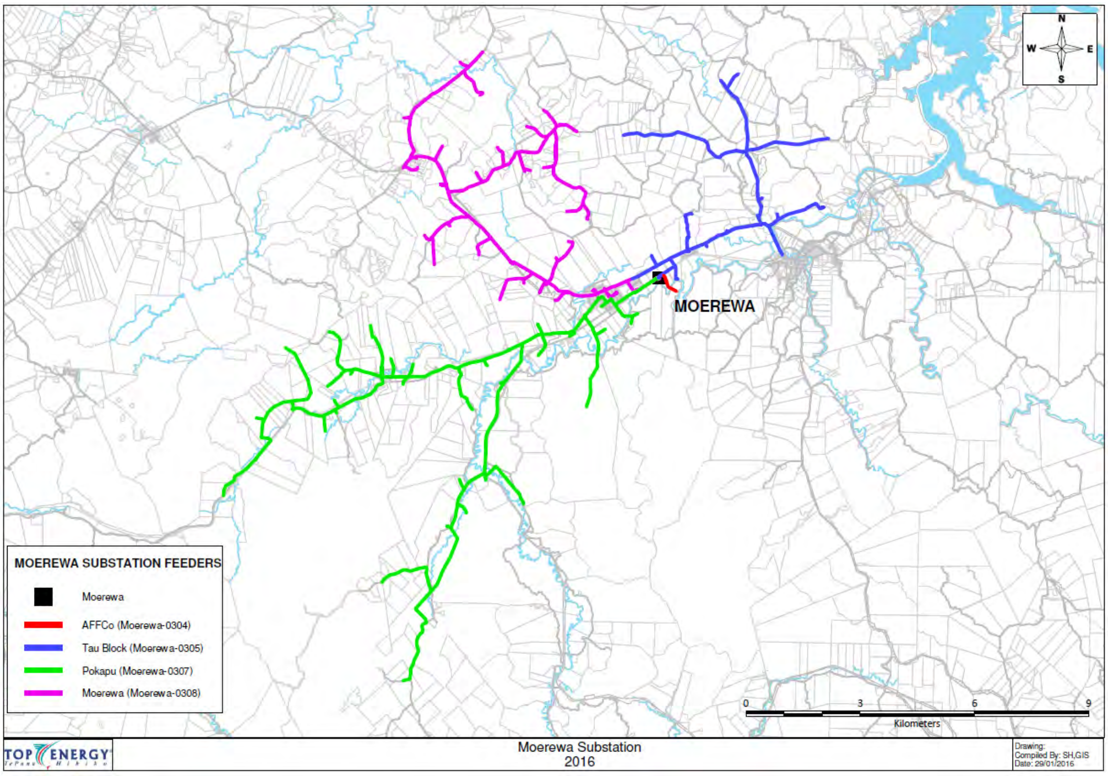


Figure 3.12: **Geographic diagram of the Moerewa zone substation**

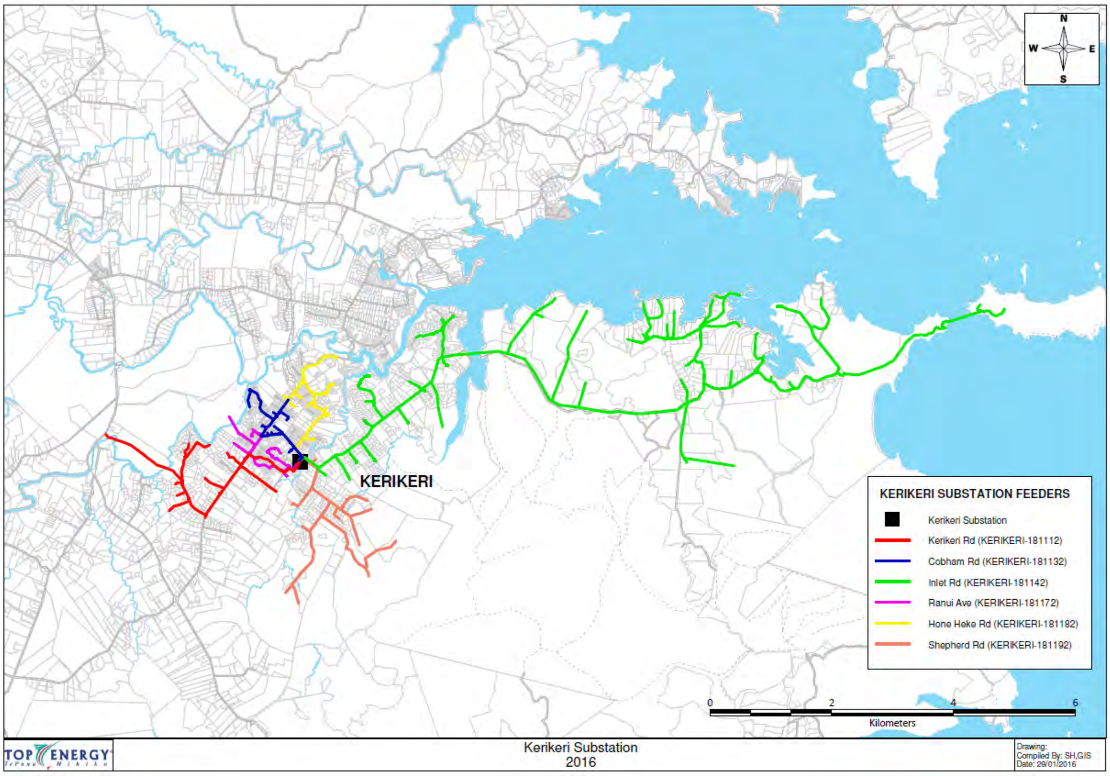


Figure 3.13: **Geographic Diagram of the Kerikeri Zone Substation**

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 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.

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.

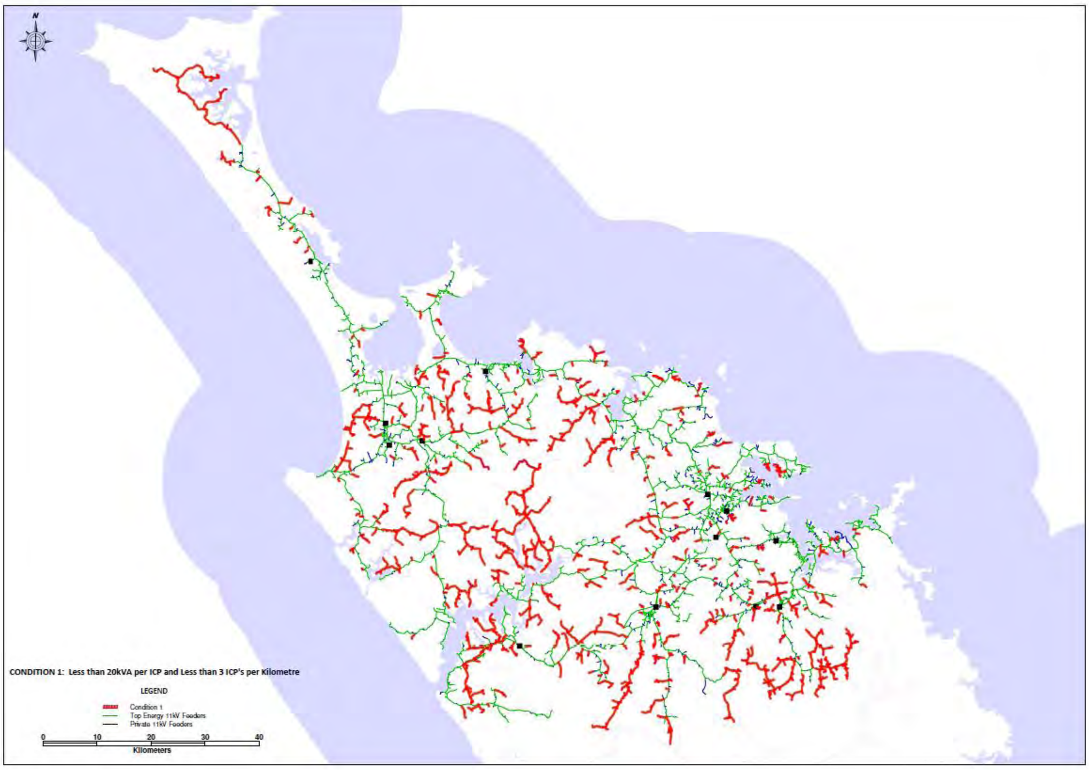


Figure 3.14: Uneconomic Segments of the 11kV Distribution Network

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 are treated 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. These protection limitations mean that the much of the subtransmission network has operated in a radial configuration, making uninterrupted N-1 security impossible.

We have progressively replaced the electromechanical protection relays in our zone substations. We have also installed fibre-optic cable on our 33kV subtransmission lines so that the existing overcurrent subtransmission line protection can be replaced with 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. This work is expected to be completed by the end of FYE2016, at which time all our two transformer substations (except Kawakawa, which is to be refurbished in FYE2017) should be capable of parallel operation.

3.1.8.2 SCADA and communications

Our system control and data acquisition (SCADA) 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 progressively 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 system 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 to actively manage our peak transmission charges and to 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 $216,722,000 as at 31 March 2015; an increase of $17,419,000 since 31 March 2014. This total was derived as shown in Table 3.4 below, and reflects the value of the assets commissioned in FYE2015 as part of our network development programme. These assets included the new double circuit 110 kV transmission line between Kaikohe and Wiroa (which was commissioned at 33kV as a temporary measure), new 33kV switchboards at Wiroa and Kaikohe, a new 11kV indoor switchboard at Moerewa and new supply lines to Opononi and Kaeo.

	\$000
Asset Value at 31 March 2014	**199,303**
Add:	
New assets commissioned	25,379
Indexed inflation adjustment	167
Less:	
Depreciation	8,072
Asset disposals	55
Asset value at 31 March 2015	**216,722**

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 slightly 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 $9.5 million as at 31 March 2015.

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[ii]. 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.

[ii] 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.

3.3.2 Poles and Structures

An age profile of the 110kV line structures, based on the information included in Top Energy's GIS database is shown in Figure 3.15. This does not include the poles on the new Kaikohe-Wiroa 110kV line, which is commissioned but operating at 33kV.

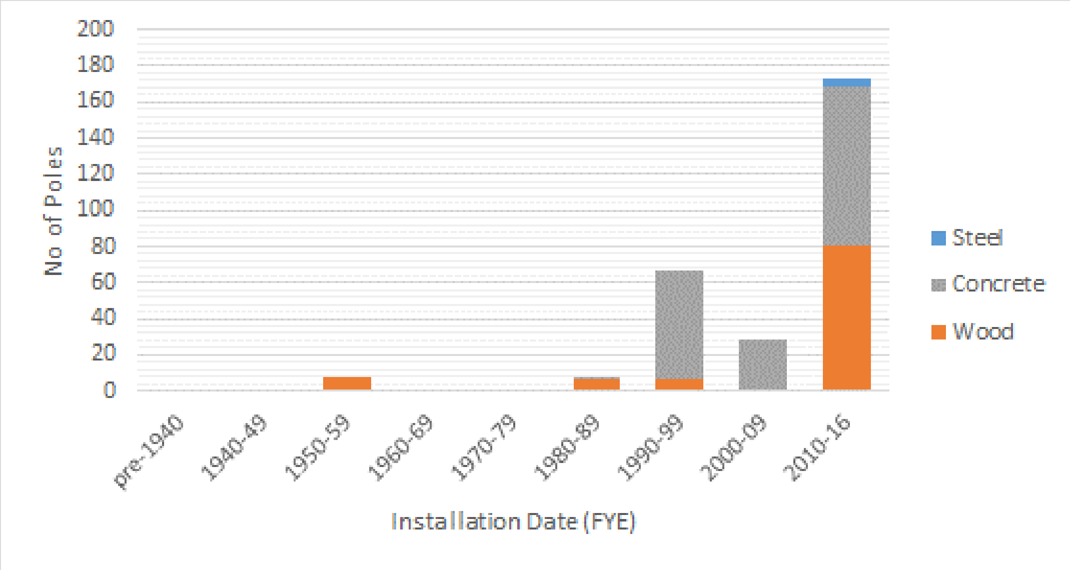


Figure 3.15: Age Profile of Transmission Line Structures

There are 178 concrete pole structures, 223 wood pole structures[III] and 13 steel towers on this line. As discussed in Section 6.3.1, 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.

3.4 Distribution Assets

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:

- Aluminium Conductor Steel Reinforced – ACSR;
- Hard Drawn All Aluminium Conductors – AAC;
- Bare Hard Drawn Copper;
- PVC Insulated Copper (LV); and
- Galvanised Steel Wire.

The network is in close proximity 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.

III Figure 3.14 shows structures, rather than poles. Each structure has two poles.

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.

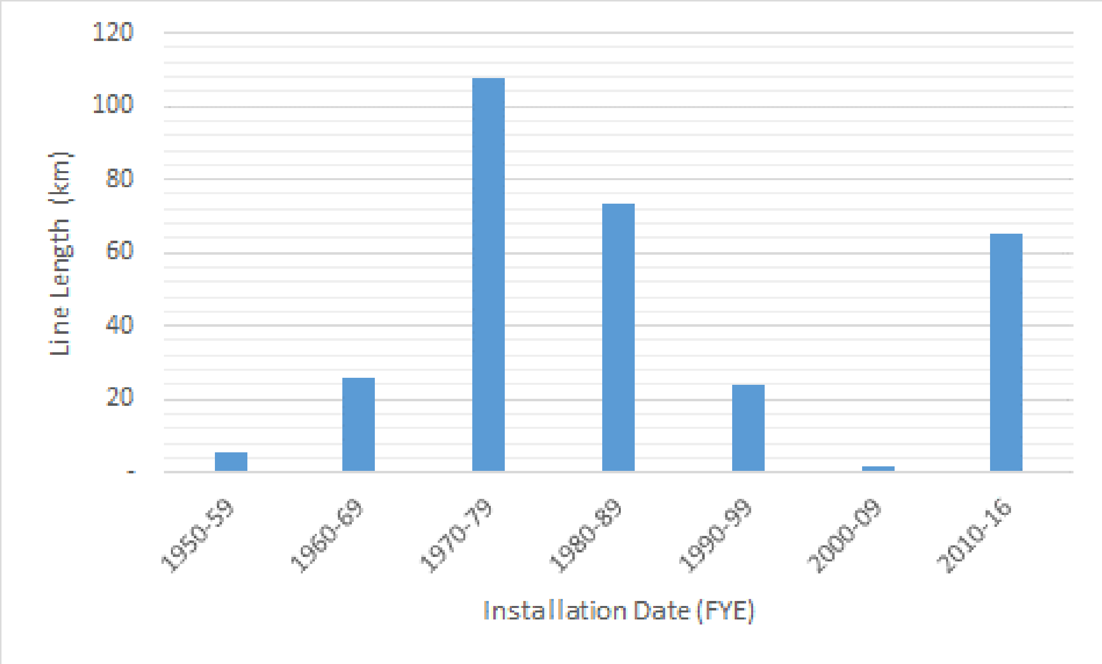


Figure 3.15: Age profile of subtransmission overhead conductors

There is a total of 303km circuit length of subtransmission overhead conductor, which is generally in an acceptable condition.

3.4.1.2 Distribution

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

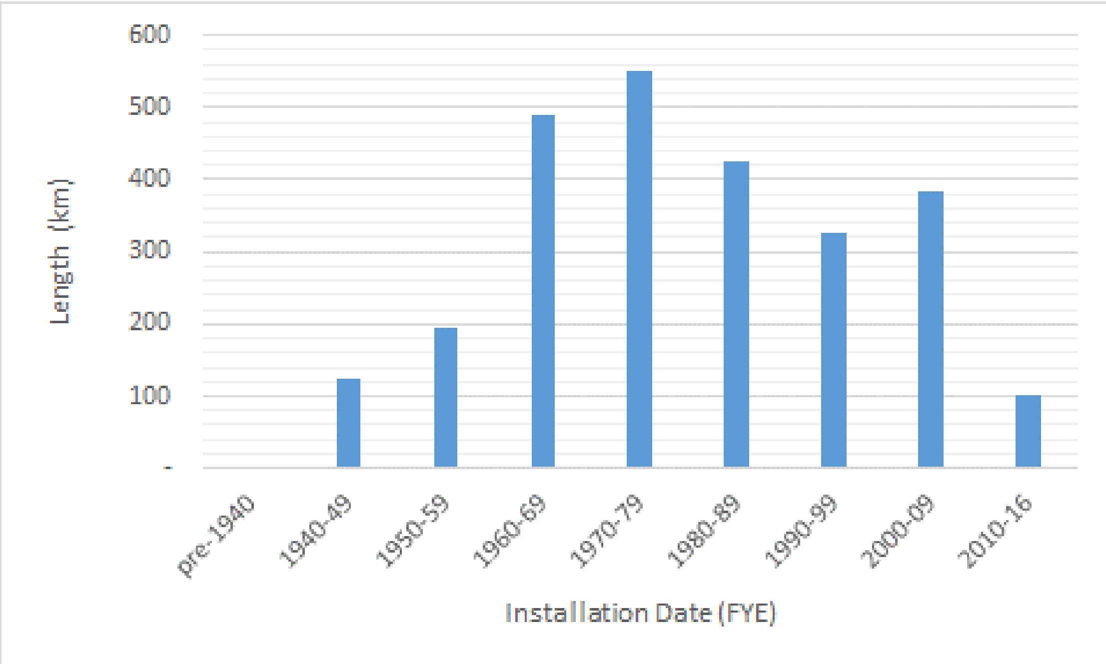


Figure 3.16: Age profile of distribution overhead conductors

There is a total of 2,597km circuit length of distribution overhead conductor. The condition of main feeder conductors is generally acceptable; however older conductor used on some SWER lines is reaching the end of its life and will require replacement during the planning period.

3.4.1.3 Low Voltage

Figure 3.17 below shows the age profile of low voltage overhead conductors.

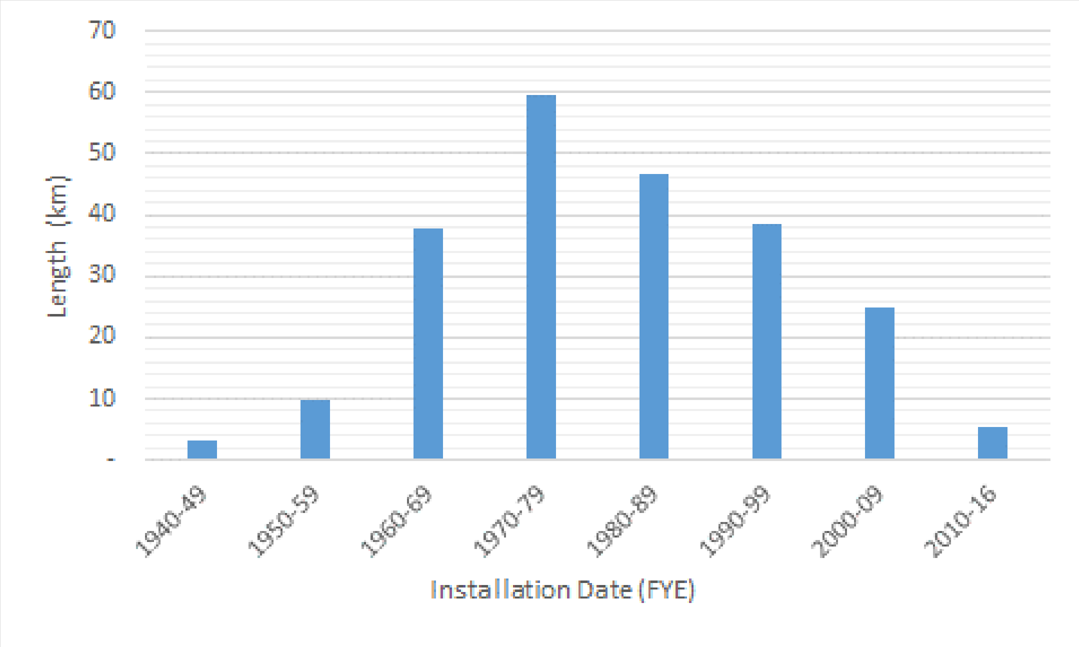


Figure 3.17: Age profile of low voltage overhead conductors

There is a total of 226km circuit length of low voltage overhead conductor, which is of 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 are now being phased out.

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. The age includes the 110kV poles at the Kaikohe end of the new Kaikohe-Wiroa 110kV line, which are currently in service at 33kV. Poles on the remainder of this line are steel.

Figure 3.18 shows the age profile of our subtransmission poles.

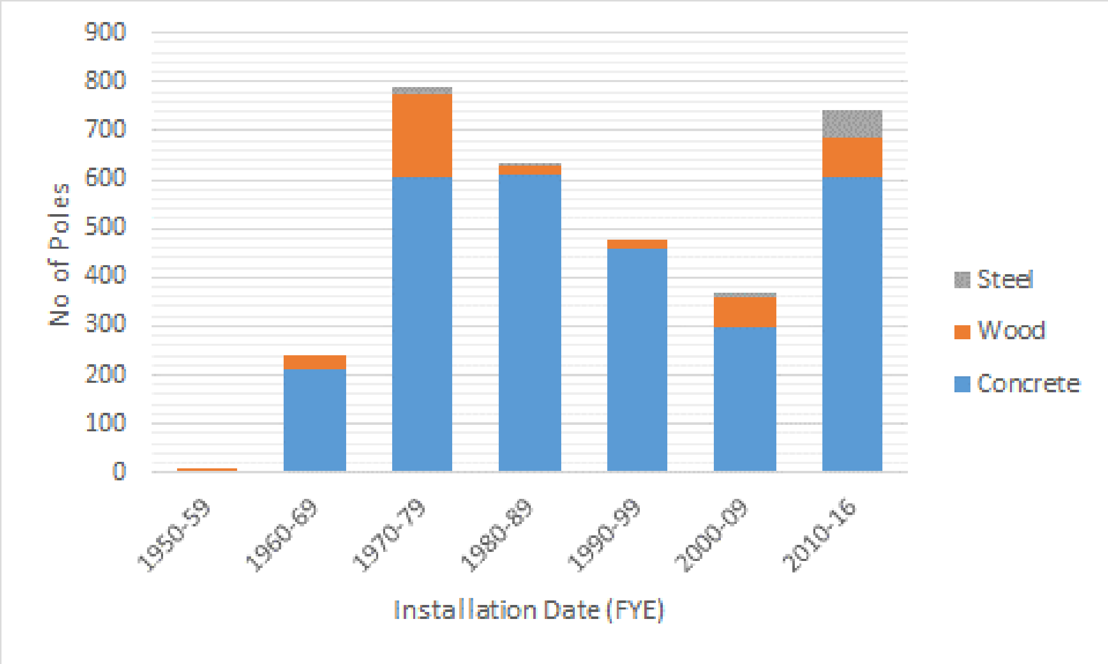


Figure 3.18: **Age profile of subtransmission poles**

There are 3,261 subtransmission poles on our network including the poles on the Kaikohe-Wiroa line, which is currently operating at 33kV, of which 86% are concrete 12% wood and 2% steel. These are inspected annually.

3.4.2.2 Distribution

Figure 3.19 shows the age profile of distribution poles.

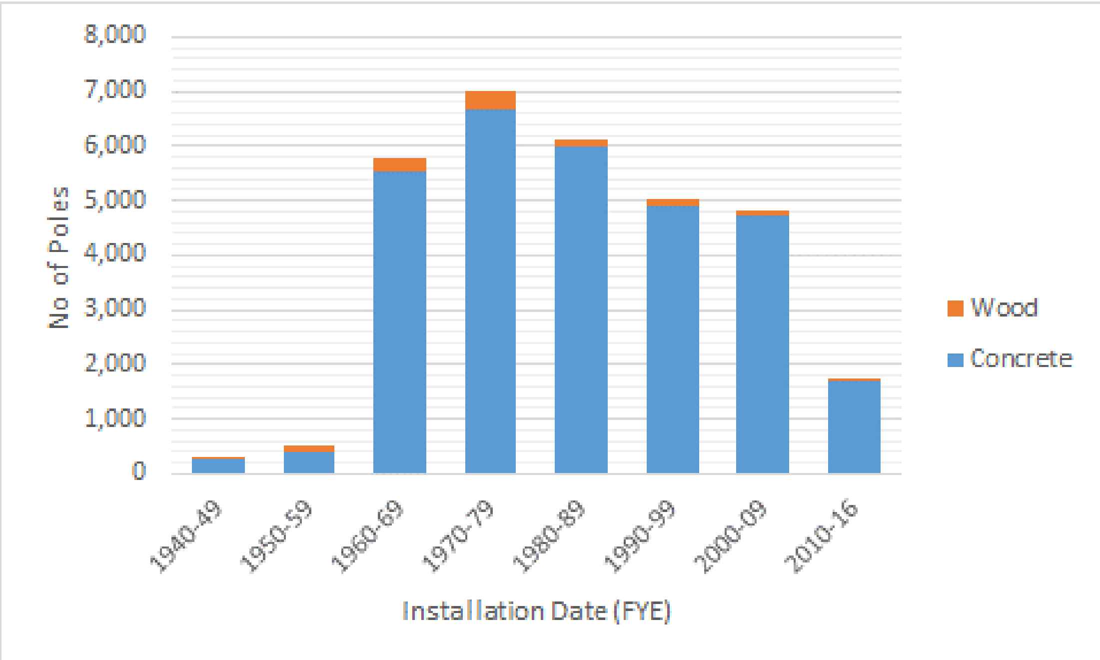


Figure 3.19 **Age profile of distribution poles**

There are over 31,300 distribution poles, of which more than 96% are concrete. Although our distribution poles are generally in good condition, some work is required on aging SWER lines. Most older wooden poles are on these lines and it is planned that they will be replaced by pre-stressed concrete poles over the next 15 years.

3.4.2.3 Low Voltage

Figure 3.20 below shows the age profile of low voltage poles.

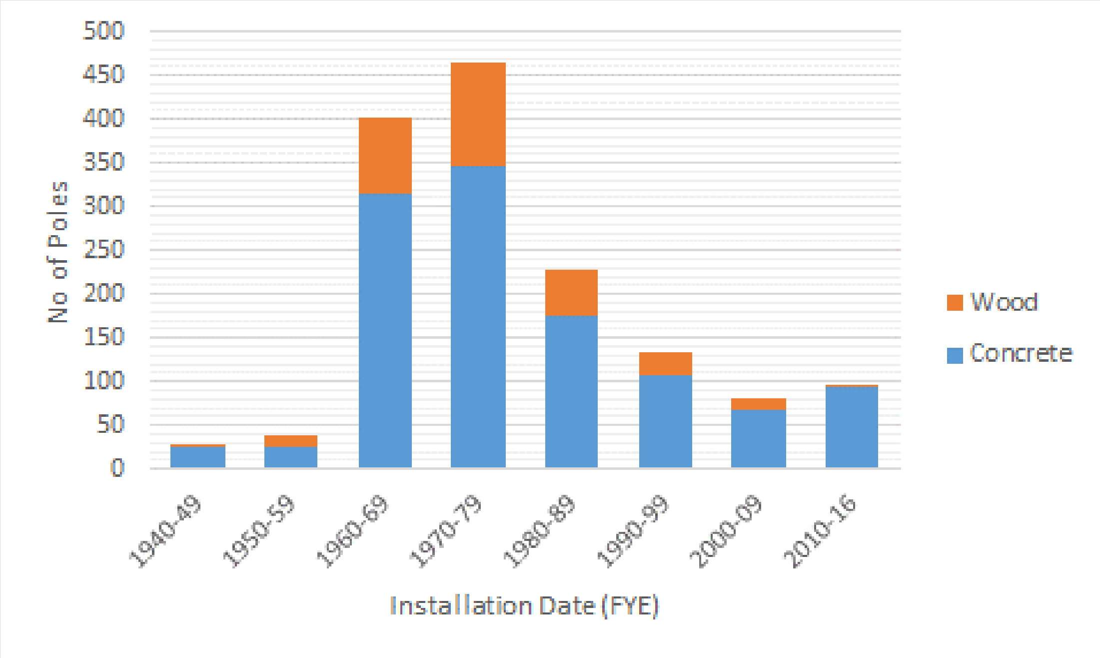


Figure 3.20 Age profile of low voltage poles

There are almost 1,500 low voltage poles, of which 79% are concrete. The condition of these assets will continue to be inspected on a regular basis and poles replaced as necessary. It is anticipated that all wooden poles on the low voltage network will be replaced over the next 15 years.

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 cables (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 will replace the existing 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. Underground cables are also used to supply the Kerikeri zone substation, which was commissioned in 2013. All cables are XLPE and in good condition.

There is currently a total of 20km of subtransmission cable in service.

3.4.3.2 Distribution

Figure 3.21 below shows the age profile of distribution underground cables.

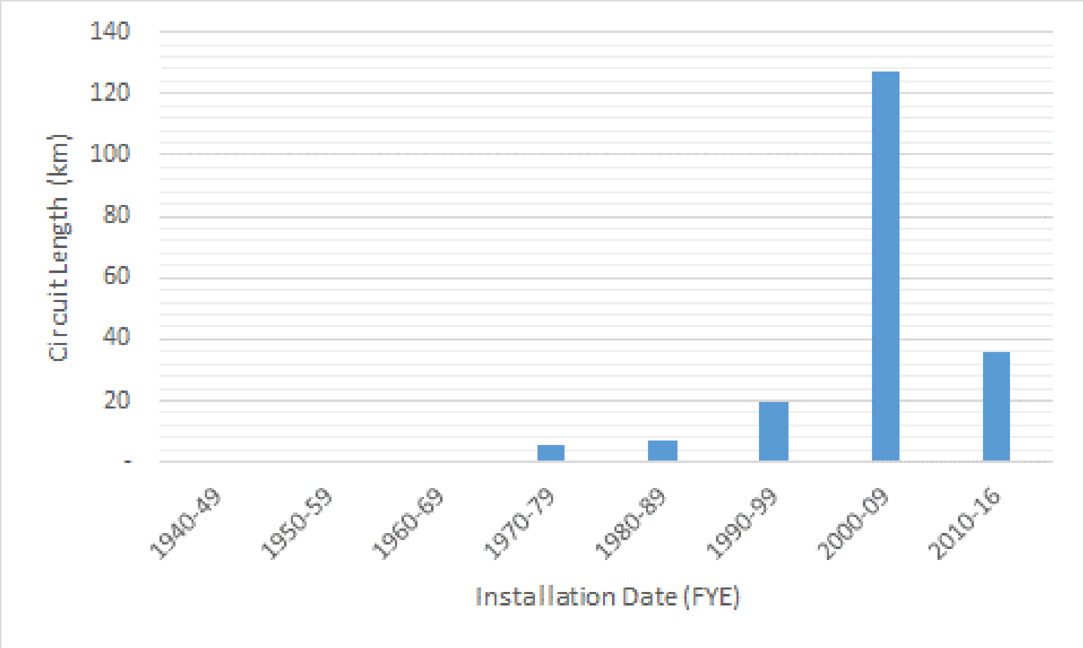


Figure 3.21: **Age profile of distribution underground cables**

There is a total of 197km of distribution underground cable, which is generally in good condition, with 63% 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

Figure 3.22 below shows the age profile of low voltage underground cables.

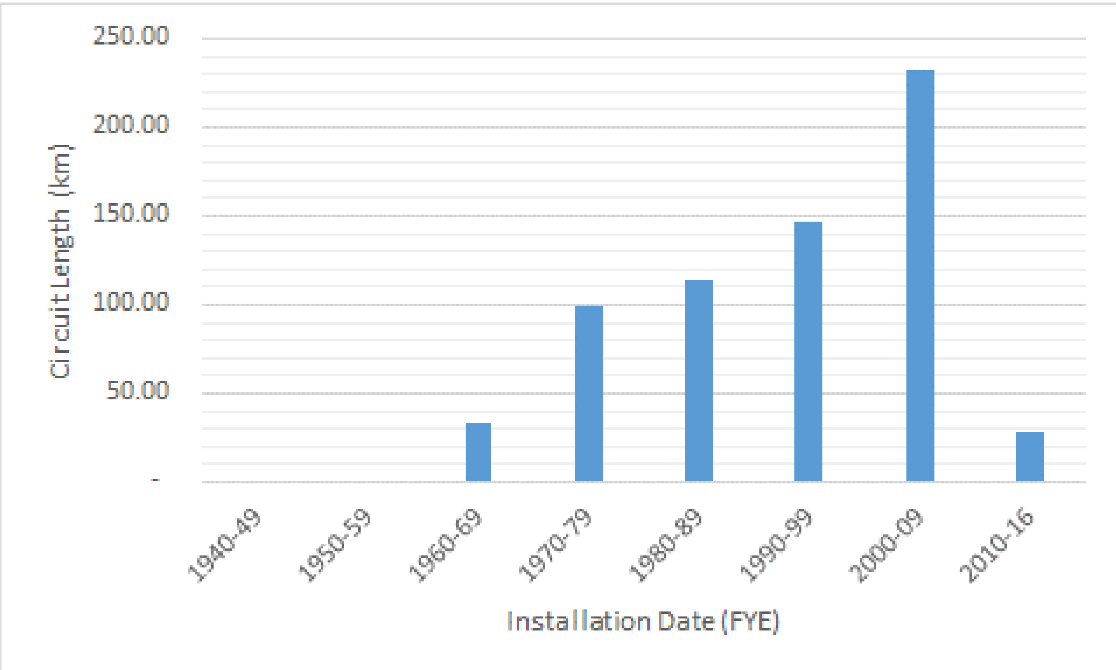


Figure 3.22: **Age profile of low voltage cables**

There is a total of 654km of low voltage underground cable, which is of average condition. 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 41 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 3.23 and Figure 3.24 below.

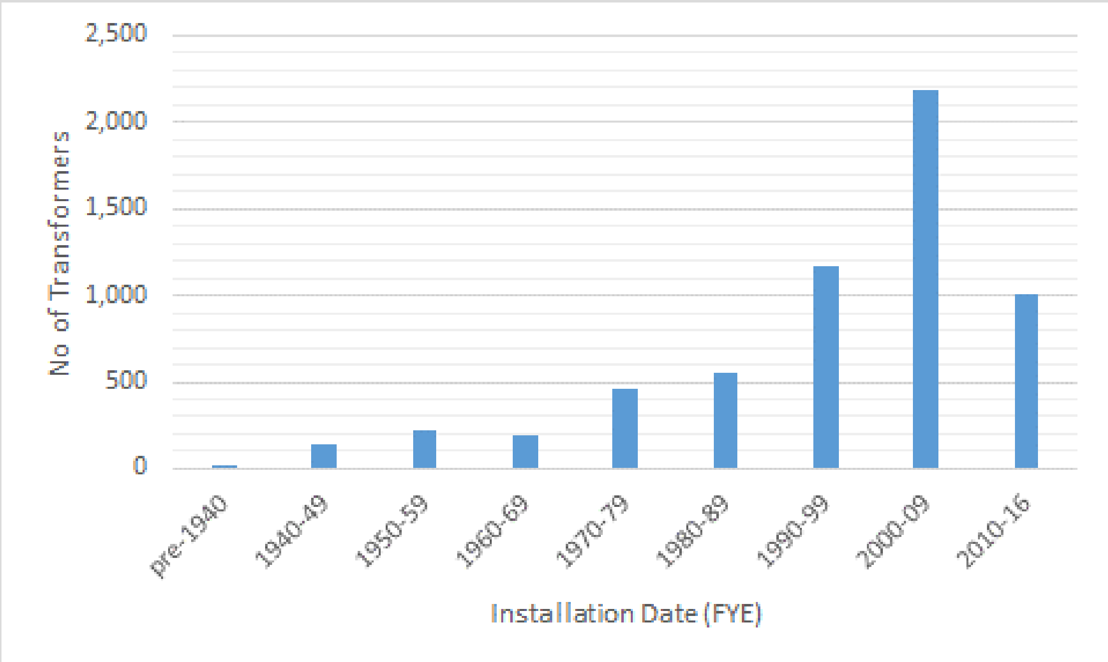


Figure 3.23: Age profile of distribution transformers (all capacities)

There are approximately 5,930 distribution transformers of various capacities on the network, with a total capacity of 256MVA. While a small number of transformers installed prior to 1940 are still in service, the fleet is relatively young with over 62% being less than 20 years old.

In general, our transformer population is of 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.

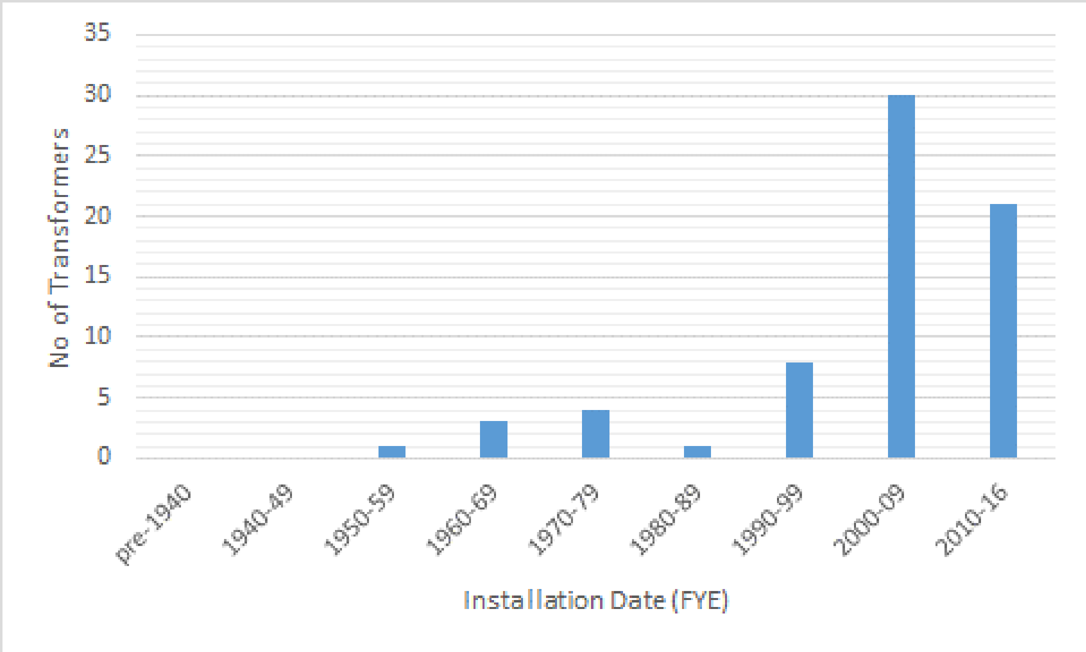


Figure3.24: Age profile of SWER isolating transformers

There are a total of 68 SWER isolating transformers, with the older units being of 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 more than 55% of the fleet is still 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.

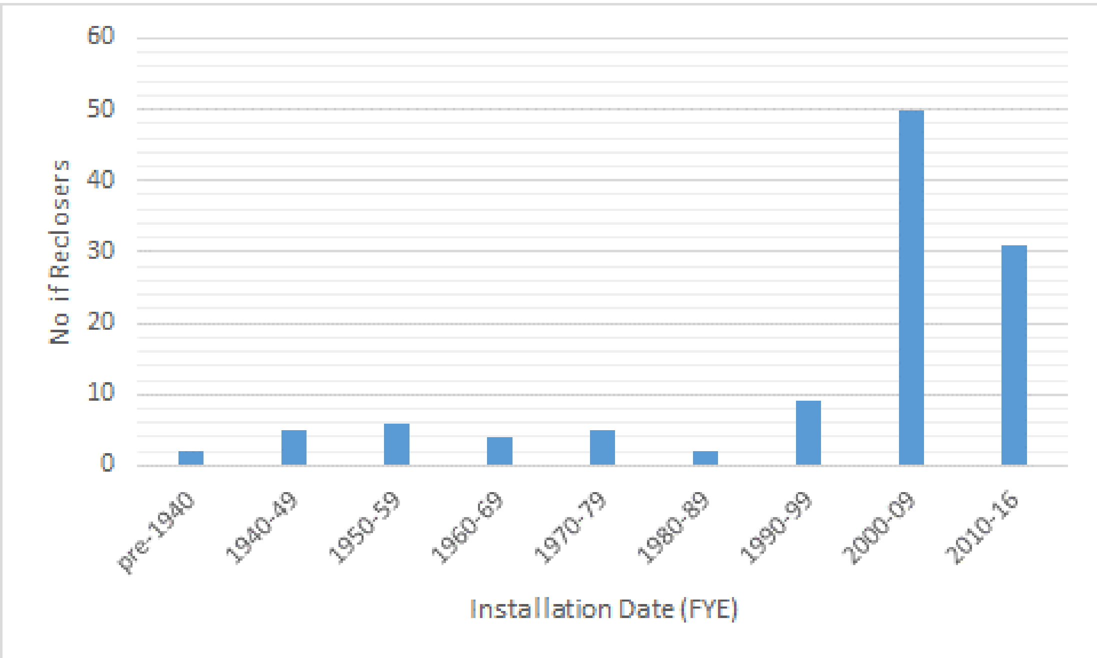


Figure 3.25: Age profile of reclosers

There are a total of 4 subtransmission and 110 distribution voltage reclosers on the network, about 55 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 23 single phase voltage regulators, arranged as seven two-phase and three three-phase banks. The oldest was installed in FYE2003 and all are in good condition. An annual condition inspection is carried out to identify maintenance requirements.

3.4.7 Ring Main Units (RMU)

Figure 3.26 below shows the age profile of RMUs on our network.

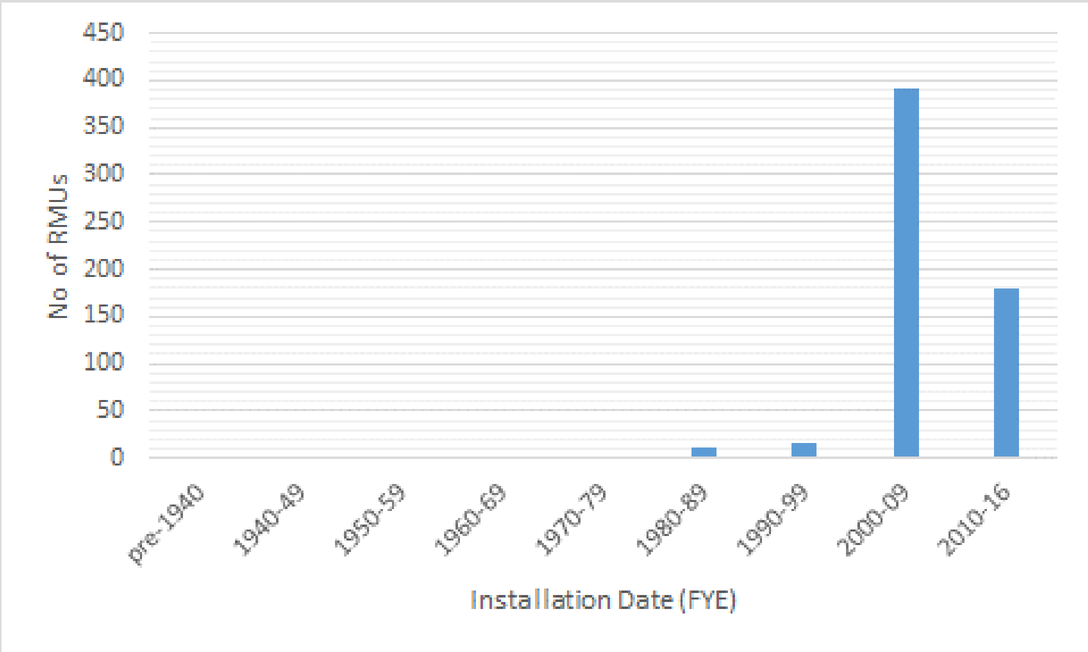


Figure 3.26: Age profile of ring main units

There are a total of 602 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

There are a total of 249 sectionalisers on our network, which are configured as remote controlled switches. The oldest of these units were installed in FYE2008. 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

Figure 3.27 below shows the age profile of air break switches on our network.

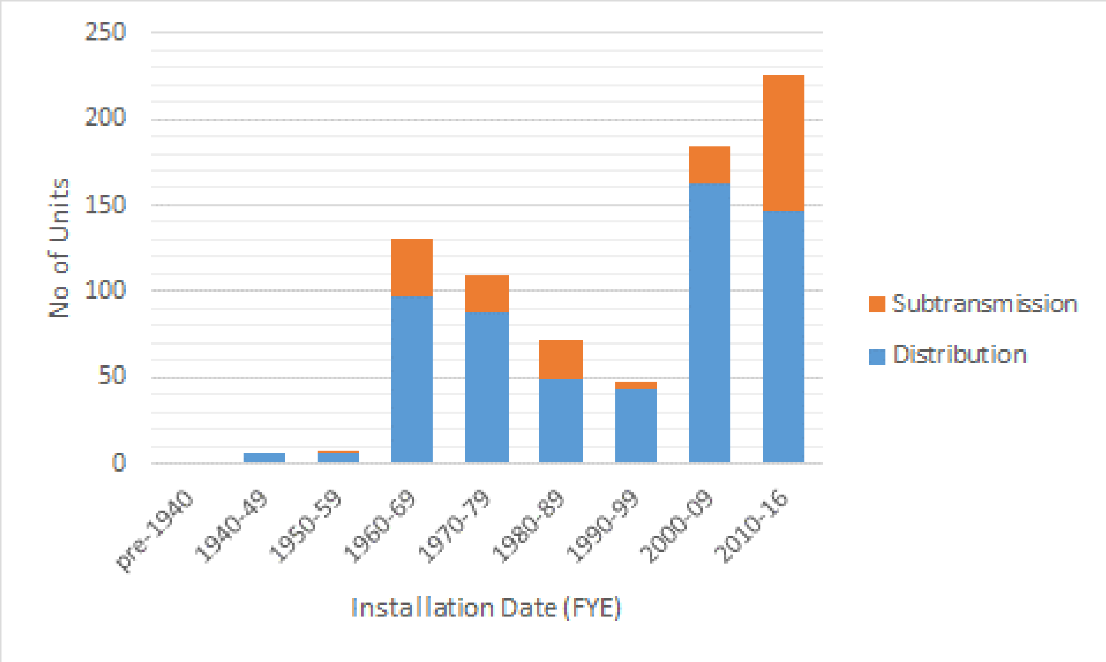


Figure 3.27: Age profile of air break switches

There are a total of 781 switches on our network, of which 183 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 3.28 below shows the age profile of capacitors on our network

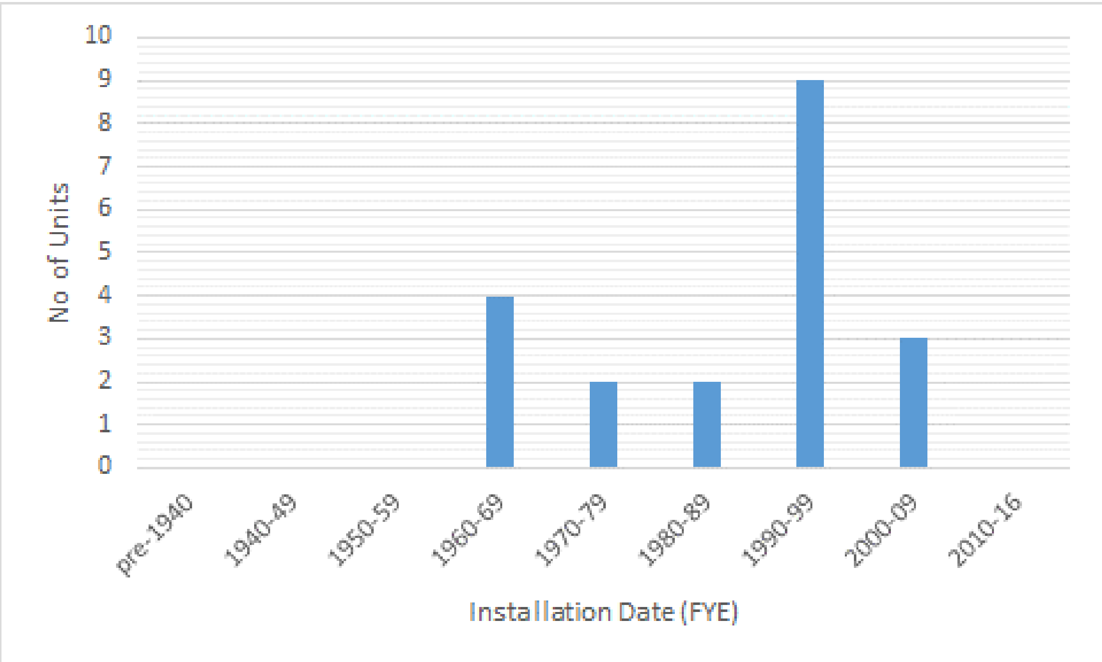


Figure 3.28 Age profile of capacitors

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

PRESENT SUBSTATION	UNIT	DESIGN RATING MVA	PRESENT RATING MVA	AGE[1]
Southern				
Kaikohe	T1	11.5/23	17	47
Kaikohe	T2	11.5/23	17	47
Kawakawa	T1	5	-[2]	55
Kawakawa	T2	5	5	55
Moerewa	T1	3/5	5	New
Moerewa	T2	3/5	5	New
Waipapa	T1	11.5/23	23	33
Waipapa	T2	11.5/23	23	33
Omanaia	T1-1 R	0.9	2.75.75	63
Omanaia	T1-2 Y	0.9		63
Omanaia	T1-3 B	0.9		63
Haruru	T1	11.5/23	23	29
Haruru	T2	11.5/23	23	9
Mt Pokaka	T1	3/5	5	7
Kerikeri	T1	11.5/23	23	3
Kerikeri	T2	11.5/23	23	3
Northern				
Okahu Rd	T1	11.5	11.5	38
Okahu Rd	T2	11.5	11.5	38
Taipa	T1	5/6.25	6.25	52
Pukenui	T1	5/6.25	5	52
NPL	T1	11.5/23.0	23	30
NPL	T2	11.5/23.0	23	30
Mobile Substation				
Mobile Substation	T1	5/7.5	7.5	14

Note 1: As at 31 March 2016
Note 2: Currently out of service with a faulty tap changer.

Table 3.5: 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 actual DP tests, which are undertaken if a major overhaul involving de-tanking at a transformer workshop is required. 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 ascertained during FYE2004, when paper samples of all power transformers were taken and analysed. The DPs were in two groups: most were between 695 and 1,300, indicating plenty of life left in the cellulose; whereas the three single phase Metropolitan Vickers units at Omanaia, which are now 63 years old, are closer to end of life at 274-465. These transformers will be replaced in FYE2019. In the meantime, the mobile transformer unit is available as a backup for the Omanaia bank, should this be required.

3.4.11.2 Circuit breakers

a) Subtransmission circuit breakers

Figure 3.29 below shows the quantities and age profile of the subtransmission circuit breakers installed within our zone substations.

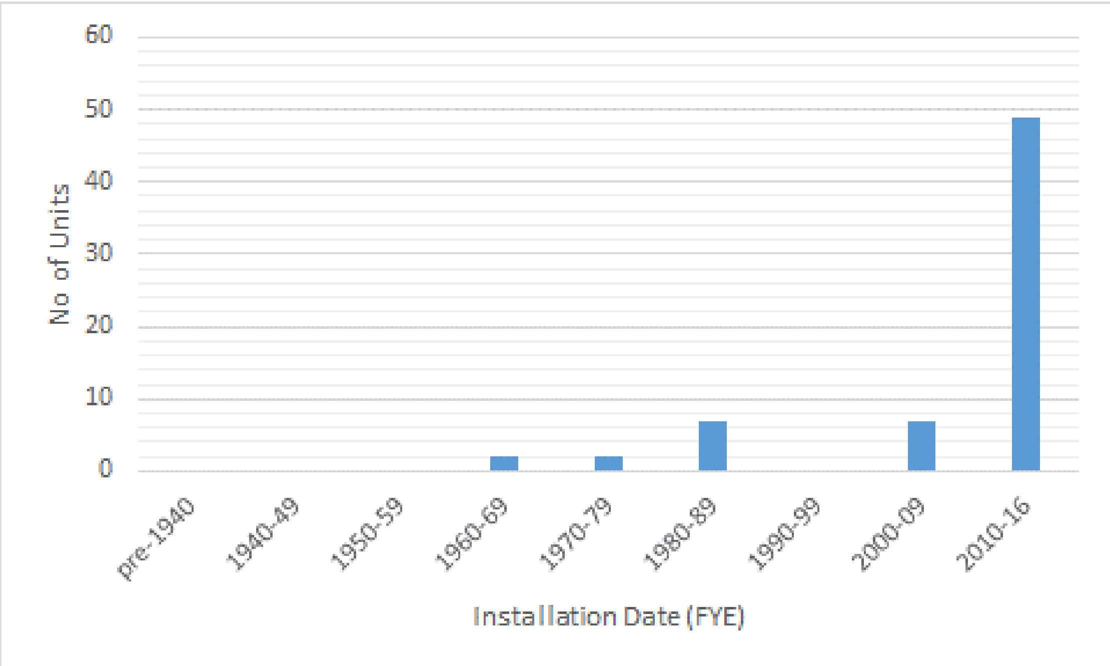


Figure 3.29: Age profile of subtransmission circuit breakers

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 this 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 3.30 below shows the age profile of 11kV distribution voltage circuit breakers presently in service on our network.

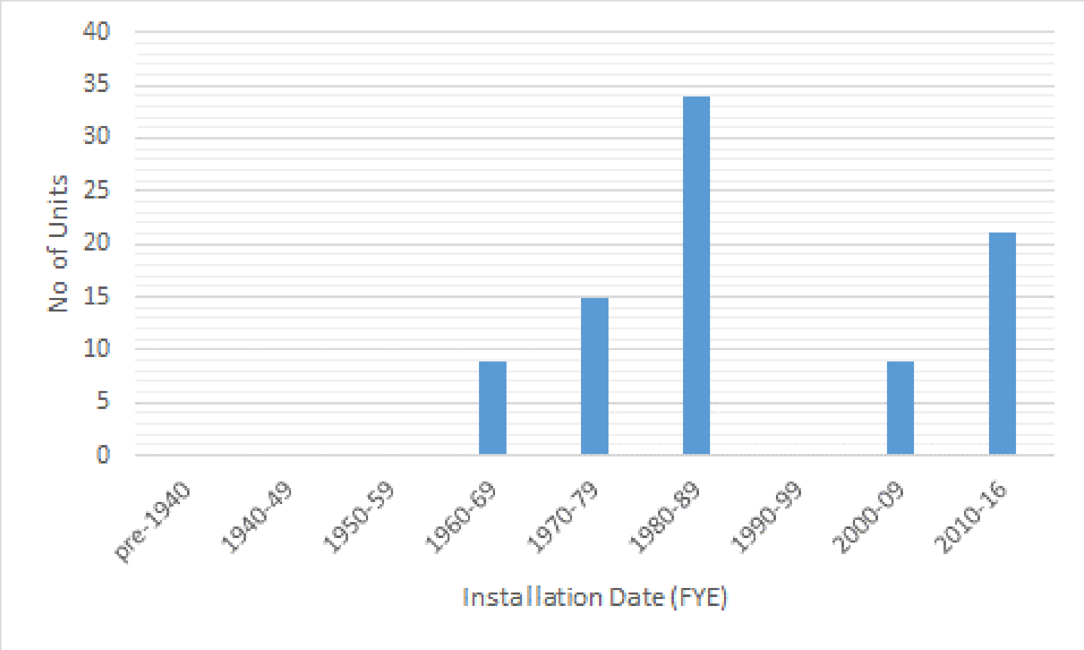


Figure 3.30: Age profile of distribution voltage circuit breakers

The condition of these 88 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 do have the advantage of extending the life of circuit breakers (and also reduce the risk of through-fault damage to power transformers).

The distribution voltage circuit breakers at Moerewa substation are currently being replaced with an indoor switchboard and this work should be complete by the end of FYE2016.

3.4.11.3 Zone Substation Structures

Our outdoor structures, like overhead lines, have a long life span. 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 switch items 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 have commenced an upgrade of all zone substation protection relays, moving to a numerical type with improved discrimination and capable of data logging. The low fault levels on our network complicate protection design and the new protection relays allow subtransmission lines and zone substation transformers to be operated in parallel, meaning that most faults on the subtransmission system should not result in a supply interruption.

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 substation buildings are listed in Table 3.6 below.

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

Table 3.6: 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 over 11,700 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.

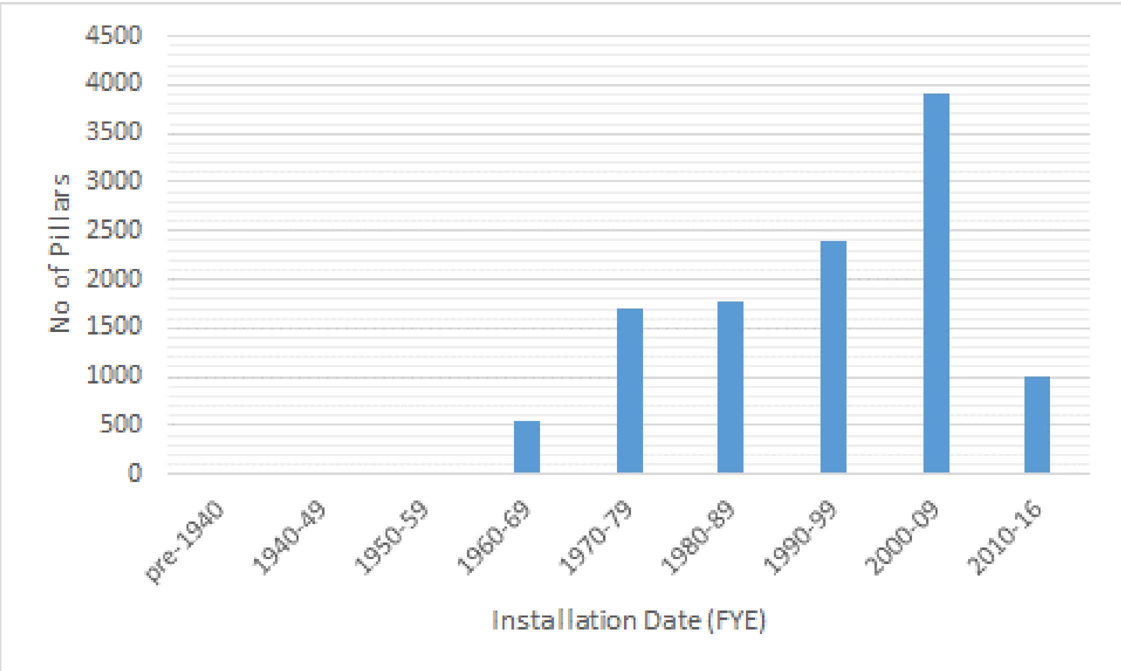


Figure 3.31: Age profile of consumer service pillars

3.4.13 SCADA and Communications

Our existing 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 3.32 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.

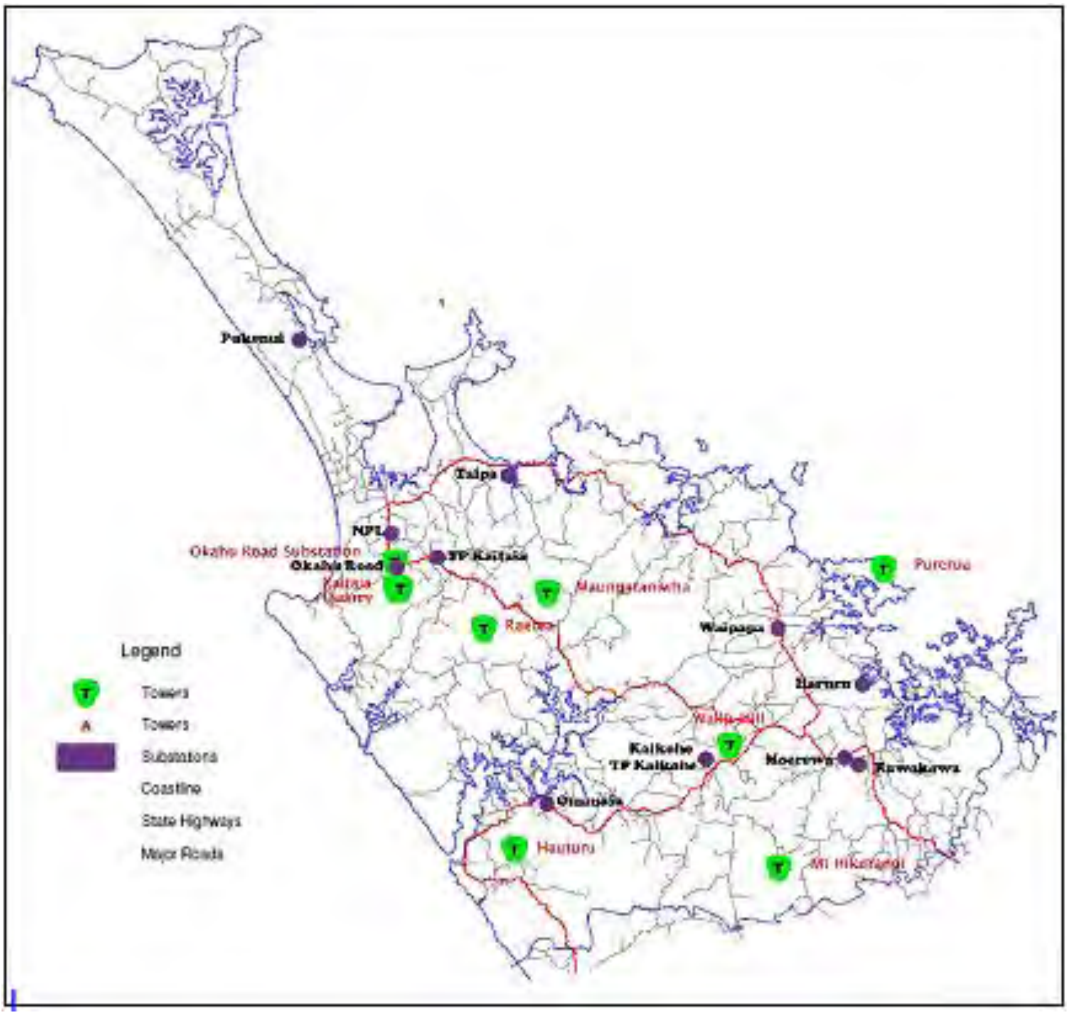


Figure 3.32: Repeater tower sites

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. It is currently located at the Kawakwa zone substation in place of T1 transformer, which is out of service with a faulty tap changer. 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 2.0MVA diesel generator sets at Taipa substation in FYE2012. 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 Networks staff, office equipment and miscellaneous equipment such as survey equipment. Our Networks staff, who recently relocated from Kaikohe to Kerikeri, operate out of a rented office building. Furthermore, 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 3.7 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 20-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	30	-
Distribution conductors	37	-
LV conductors	35	-
Subtransmission poles - concrete	25	60
Subtransmission poles - wood	28	45
Distribution poles – concrete	32	60
Distribution poles - wood	40	45

LV poles - concrete	38	60
LV poles - wood	41	45
Distribution cable - PILC	21	70
Distribution cable - XLPE	12	45-55[1]
LV cable	23	45-55[1]
Air break switches – subtransmission	21	35
Air break switches – distribution	24	35
Ring main units	9	40
SWER transformers	15	45
Distribution transformers	21	45
Consumer Service pillars	22	45

Note 1: 45 years for cables installed before 1985

Table 3.7: 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.

While the existing assets have historically met consumer requirements, the demand for electricity and consumers' expectations are now exceeding the capacity of the existing asset base. We are therefore implementing a network development plan (described in Section 5), which will put an augmented transmission and subtransmission infrastructure in place to meet the expectations of electricity users in the Far North for the next 20 years and beyond. The existing asset base forms the platform on which this higher capacity and more reliable network will be developed.

The current 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 high voltage distribution network comprises primarily three-wire and two-wire overhead and underground lines, but also includes many SWER lines of varying lengths to serve remote and sparsely populated rural areas. The low voltage network comprises two, three and four wire lines, which are largely underground.

The two transmission substations inject the electricity into our subtransmission network, which supplies the zone substations. The 33/11kV zone substations have one or two power transformers, depending upon the security and load requirements of the area, and inject the electricity into a network of 56 distribution feeders. These generally operate at 11kV and are long for this voltage.

Overall, this asset base is no longer adequate to provide acceptable supply reliability to consumers and comply with statutory requirements related to delivery voltages. Nevertheless, there are a few isolated areas where there is excess capacity. Identification of these individual surplus or over-capacity assets was considered in the initial optimisation process undertaken in 2004 for asset valuation purposes. This optimisation was updated in 2011.

Load growth between 2004 and 2011 resulted in some optimised asset capacity from the 2004 valuation being reabsorbed into the valuation following the 2011 review. Asset capacity that remains optimised out of the asset base is assigned zero value for regulatory purposes and is therefore not taken into account in regulatory financial and tariff analysis.

3.5.1 Transmission System

Our 110kV transmission substations at Kaikohe and Kaitaia are approximately 56km apart with a range of uninhabited hills in between. The southern and northern area distribution networks are interconnected at 11kV at only one remote location and our northern and southern area networks could not be practically interconnected using 33kV subtransmission lines.

Both 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 Maungatapere using a double circuit 110kV line to the Kaikohe substation; power is injected into our transmission system at the two incoming circuit breakers at Kaikohe. The Kaitaia transmission substation is, in turn, supplied using a single circuit 110kV line from the Kaikohe substation. As the Kaitaia substation is supplied with a single circuit, 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. The Ngawha power station is situated approximately 7km from the Kaikohe GXP and is connected to the network using two single-circuit 33kV lines.

No optimisation of the transmission system is possible.

3.5.2 Subtransmission Network

After considering the forecast load, N-1 security and voltage drop conditions under both normal and contingent operation, no optimisation is possible for the subtransmission network. As noted above, we believe the existing subtransmission network is only marginally adequate to supply current loads with an acceptable level of reliability.

3.5.2.1 Northern Network

Pukenui and Taipa substations are supplied using single circuit 33kV lines. The anticipated peak loads at the substations could not be supplied at 22/11kV voltage level due to the distances involved, the subsequent voltage drop and the projected load growth in the area. 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. Voltage drop under N-1 contingent operation and loss considerations under normal operation preclude a reduction in the conductor size of these lines.

3.5.2.2 Southern Network

At the time of the optimisation, Waipapa substation was supplied using two dedicated 33kV lines. The existing load in the Waipapa substation area would have resulted in excessive voltage drop under N-1 contingent operation precluding any reduction in the conductor size. The new Kerikeri zone substation and the Wiroa switching station were constructed to remedy this capacity shortfall.

Haruru, Kawakawa and Moerewa substations are all supplied using two shared 33kV circuits. Considering the present peak load and the voltage drop on both the lines under those conditions, a reduction of the conductor size on these lines is not viable.

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. This substation cannot be supplied at 22/11kV voltage level, due to the distance involved and subsequent voltage drop.

3.5.3 Zone Substations

Zone substations in the network are separated by significant distances and, in general, by low density rural land.

We also own a 7.5MVA 33/11kV mobile substation that was commissioned in FYE2003 and provides backup for single transformer substations. There is 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.

There are three areas of zone substation optimisation on our network. Firstly, due to the closure of the dairy factory at Moerewa and a reduction in load at the freezing works, the capacity of the 11.5/23MVA transformer at Moerewa zone substation was optimised to 5/10MVA. This transformer has now been replaced by two 3/5MVA units, which has freed up the mobile substation for use elsewhere. At Omanaia zone substation, there are three single phase transformer units with separate voltage regulators. This combination has been optimised to a single three phase unit with an internal on-load tap changer (OLTC).

All other zone substation transformers are of appropriate size to supply present load under normal operating condition and most, but not all, substations meet the N-1 security criteria as far as transformer size is concerned, given the forecast load increase for the planning period.

The second area of potential zone substation optimisation is where our standard design provided for extra switches at the time of construction. Where these switches are not required to provide N-1 contingent operation, they have been optimised out.

Finally, the zone substations' land and building have been adjusted to reflect an appropriate size. Single bank substation sites have been optimised to 2000m^2 and double bank substations to 3000m^2.

The possibility of optimising indoor 11kV zone substation switchgear to outdoor was reviewed and ruled out on the basis that the cost of an outdoor switch, its associated isolators and their mounting structures, exceed the value of its indoor equivalent. In any case, installation of outdoor distribution voltage switchgear at zone substations is no longer considered good industry practice, because of safety and reliability concerns, and this alone would now preclude such optimisation.

There is no double busbar arrangement, automatic fire fighting or fire detection systems installed in any of the zone substations.

Transformer oil bunding facilities are installed in all zone substations.

3.5.4 Distribution network

Factors such as current rating, losses and voltage drop were considered in determining whether distribution network conductors could be optimised to smaller size. Although we do not specify any N-1 security criterion for feeders due to the mainly rural nature of the network and therefore the impracticality of providing full back-up, we make use of feeder interconnections close to zone substations, and elsewhere where practical, to reduce the number of outages required for planned substation maintenance. This is standard industry practice. Where feeder interconnections are available, the conductor sizes on both feeders has to be adequate to carry their own load and that of any feeder they back up.

The next criterion for assessing whether a smaller conductor should be used is the relative cost of losses and capital. If the long term cost of losses exceeds the extra capital cost of the increased size of conductor, then a smaller conductor should not be used. The conductor comparisons we carried out suggest that, for any feeder with more than 1MW of peak load, the cost of losses exceeds the capital cost of the increased size conductor. That also precluded the optimisation of conductors.

The third criterion is the need to maintain voltage within acceptable levels. Figure 3.33 below shows the load capacity for Top Energy's medium conductor (Bee 130mm^2) and its light conductor (Ferret 40mm^2) based on a 4% volt drop.

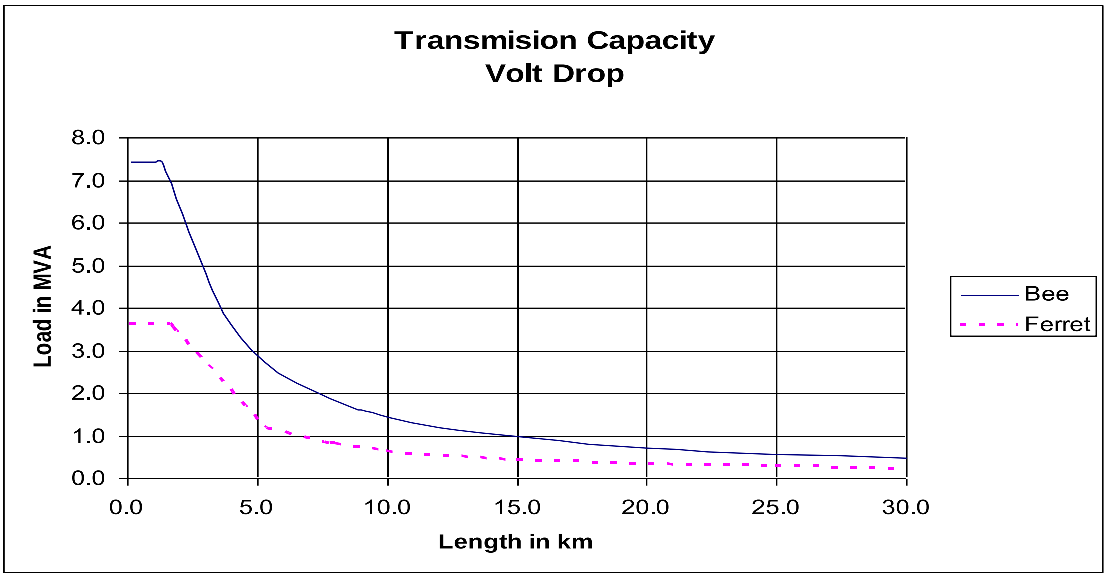


Figure 3.33: Conductor transmission capacity vs. distance

The figure above shows that any feeder longer than around 5km and with more than 1MW of load evenly spread along its length under normal or back up conditions, should use a medium conductor, at least.

The above criteria precluded optimisation of all feeders except Tau Block and Pokapu, supplied from Moerewa substation. Pokapu cannot sensibly be used to back up the AFFCo feeder, but has less than 1km of medium size conductor; therefore, optimisation is not considered material. Tau Block is used to back up the remaining two feeders out of Moerewa substation in order to meet the reliability requirements of the freezing works adjacent to the substation.

Therefore, no optimisation of the distribution network was possible. This lack of optimisation is indicative of the relatively high loading on parts of the distribution system and the very long feeder lengths. This is being alleviated by the network development plan, which is increasing the number of points at which electricity is injected into the distribution network in the Kerikeri and east coast peninsula areas.

3.5.5 Distribution transformers

The optimisation review undertaken in 2011 determined that the utilisation of distribution transformers was above 30%, so the distribution transformer capacity installed on the network was not excessive. In any case, the extent to which we are able reduce 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 and no optimisation is possible. 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; no optimisation is possible.

3.5.7 Voltage control devices

Voltage regulation is achieved at the zone substations using conventional on-load tap changers (OLTC), except at Omanaia. In addition, we have voltage regulator banks located within the distribution network. One three phase bank is situated at Omanaia zone substation and is subject to optimisation with the transformer. The others 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.

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.

No optimisation is possible; apart from the optimisation at Omanaia substation, which is based on the use of a modern equivalent asset rather than capacity.

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 any further aggregation. No optimisation is possible.

3.5.9 SCADA equipment

We use SCADA to monitor and control its zone substations, GXPs and strategic switches on the network.

We have installed remote control equipment such as motorised switches, reclosers and circuit breakers at both subtransmission and distribution voltage level, in order to improve reliability. With only 56 distribution feeders and almost 2,800km 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. No optimisation is possible.

3.5.10 Spares

The only critical spares held and included in the valuation 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. No optimisation is possible.

Section 4 Level of Service

4 Level of Service

4.1 Introduction

Historically, our consumers have experienced the worst supply reliability of any EDB in New Zealand. During FYE2015, on average, each consumer connected to our network experienced more than six supply interruptions and more than 30 hours without electricity as a result of faults and planned outages on our network. While this was an exceptionally bad year, as our supply area was hit by severe storms in April, July and December 2014 and two planned interruptions of the 110kV transmission line supplying Kaitaia were necessary following a structural failure on the line (which was due to land movement as a consequence of the storms), even in a normal year the reliability of supply we provide is poor when compared to the service levels provided by other rural EDBs with similar consumer densities. This is a result of a complex mix of historical design, investment, demographic, ecological and climatic factors. We now recognise that, with suitable development and maintenance strategies and adequate funding, the effects of these factors on supply reliability can largely be mitigated.

In part, the poor reliability of our network is a consequence of our fringe location and the resulting limitation of having only two transmission substations, when a more strategically located rural network of similar size would typically have many more. Further, the 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 the region 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 expansion in the history of the network. To facilitate this investment, in 2012 we acquired the region’s transmission assets from Transpower and we are already investing in improving and upgrading these assets. We have 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 so that supply to consumers in the northern area will no longer depend on a single transmission circuit. Furthermore, we are expanding and strengthening the 33kV subtransmission system in order to increase the number of bulk supply points at which power is injected into the distribution network. The result of this expansion will be a significantly more secure and reliable network to support future economic growth in our supply 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 present a number of 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 mostly complete[4]. We also installed equipment to reduce the number of faults caused by lightning 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. Overall, the result has been excellent. The average total minutes off supply per consumer, as measured by network SAIDI,

[4] 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.

reduced from 924 minutes in FYE2009 to 395 minutes in FYE2013 and just over 500 minutes in FYE2014[5]. This programme also reduced the average number of outages consumers experienced (as measured by network SAIFI) from more than ten in FYE2010 to less than five in FYE2013 and about six in FYE2014. This improvement is testimony to the success of our reliability improvement programme. In addition, the increased management focus on network reliability has undoubtedly improved the quality of our response to the faults that do occur.

We will continue to invest in technologies and strategies that offer the best performance gains when compared to the cost of implementation.

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, in order 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 and setting our targets, we use the normalising approach taken by the Commission in measuring the reliability of supply provided by all the EDBs that it regulates. Normalisation of the raw performance measure is designed to limit the impact of events that are outside our reasonable control on the measure of network reliability. 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

5 These figures have not been normalised to limit the impact of major event days. The FYE2014 reliability includes the impact of a maintenance shutdown of the Kaikohe-Kaitaia transmission line – there was no planned shutdown of this line in FYE2013. The corresponding figure in FYE2015 was 1,837 minutes, of which 1,143 minutes was attributed to a single storm in July 2014. However, our measured reliability in FYE2015 is not a fair reflection of the underlying performance of our network due to the severity of the storms that occurred and the need for two planned outages of the 110kV transmission line.

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 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 normalised 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 consumers, who receive advance notice of planned interruptions and are therefore able to minimise their inconvenience. In our October survey, consumers reiterated their earlier view that we should not use generators to mitigate the impact of planned outages given the significant cost impact.
- Major event days, where the actual SAIDI or SAIFI could be replaced by a boundary value for normalisation 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 any other EDB that is in a positon that 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, a practice that we have now discontinued because of its cost. 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, the weather conditions typically experienced in our supply area in an average year and our discontinued use of mobile generation.

We have therefore reset our reliability targets at what we consider to be more realistic levels. The SAIDI and SAIFI targets for FYE2017 are based on the collars set be the Commission for our reliability incentive scheme, and shown in Table 4.1. Going forward these targets have been incrementally reduced to reflect the improvements expected from our continuing investment programme, with a slightly larger step reduction in SAIDI in FYE2019 to reflect the impact of the commissioning of the Kaeo substation the previous year.

The new service level targets are based on the Commission's revised normalisation methodology and 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 most recent outage of 29 November 2015, when the normalised SAIDI impact was 58 minutes, we consider 60 minutes to be a prudent SAIDI target for each planned transmission interruption. This is well above the new SAIDI boundary value of 29.364 minutes.

Our reset targets assume that:

- there will be one planned transmission related interruption each year;

- the new 110 kV Wiroa-Kaitaia circuit will be not be commissioned before the end of the AMP planning period. Once this circuit has been commissioned, there will be no need for planned transmission interruptions as an alternative supply will be available;
- 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;
- 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 transmission outages and outages of the incoming 33kV circuit. While the use of mobile generation was our practice in FYE2013 and FYE2014, the costs were significant and the expenditure is better applied elsewhere. The responses to our last two consumer surveys indicate that our consumers agree with this.

The indicators measure only interruptions that originate within our network. Interruptions that originate outside the network, such as the automatic under-frequency load shedding event that occurred in November 2013, 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	2017	2018	2019	2020	2021	2022	2022	2024	2025	2026
SAIDI										
Distribution Related	290	285	270	265	260	255	250	245	240	235
Transmission Related	60	60	60	60	60	60	60	60	60	60
Target	**350**	**345**	**330**	**325**	**320**	**315**	**310**	**305**	**300**	**295**
SAIFI										
Distribution Related	4.2	4.1	4.0	3.9	3.8	3.7	3.6	3.5	3.4	3.3
Transmission Related	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Target	**4.6**	**4.5**	**4.4**	**4.3**	**4.2**	**4.1**	**4.0**	**3.9**	**3.8**	**3.7**

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.

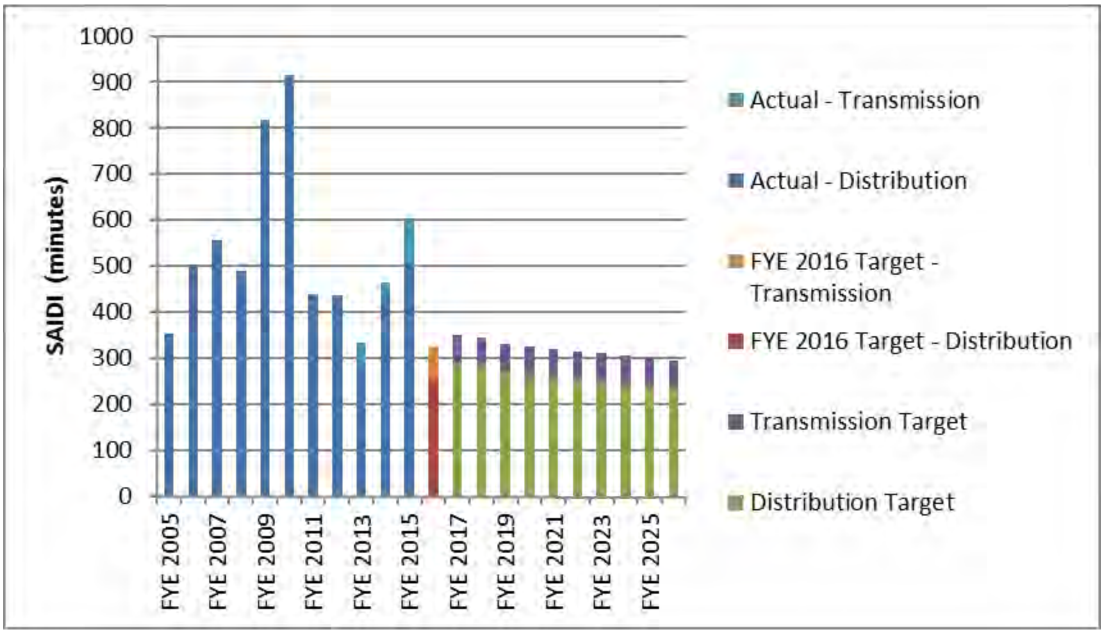


Figure 4.1: **Historical and Target SAIDI**

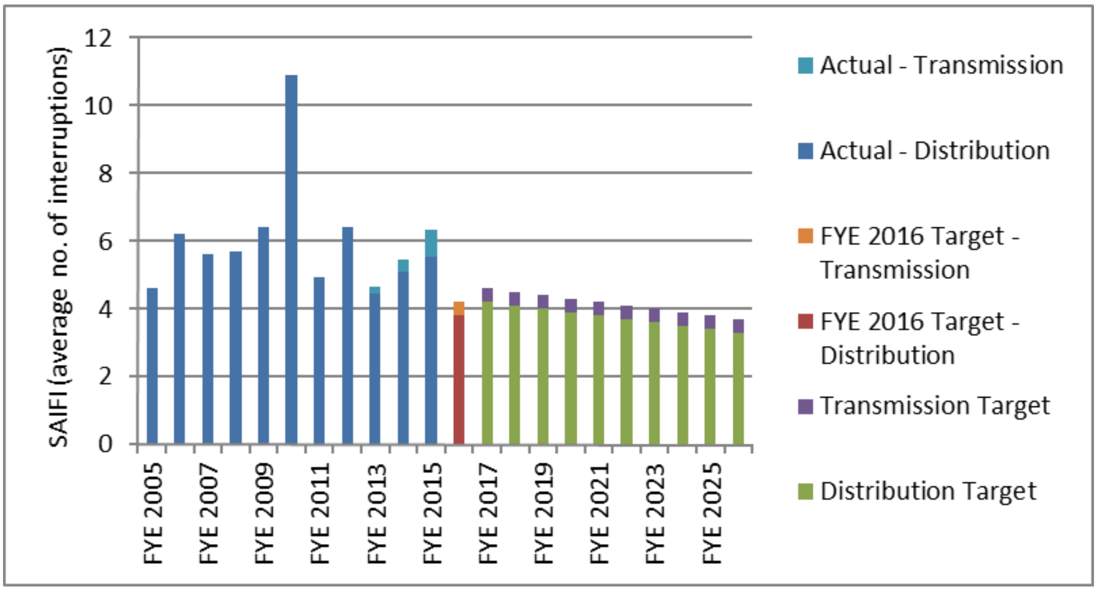


Figure 4.2: **Historical and Target SAIFI**

4.3 Asset Performance and Efficiency Targets

In order to ensure that its asset management strategies result in effective utilisation of its asset base, we have developed targets to reflect its 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. Energy losses 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 the lowest supply reliability and the highest loss ratio of any EDB in the country.

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. Losses should decrease once the second transmission circuit is commissioned but this is not now expected until FYE2026. Over time, distribution losses should also decrease incrementally as 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.

Our loss ratio targets have been revised from the 2013 AMP to reflect the deferral of the second 110kVline. We have maintained the FYE2016 target though to the end of the planning period, even though actual losses in FYE2015 were materially higher. The new targets for the planning period are shown in Table 4.4 and Figure 4.3 compares these targets with the recent historical performance.

FYE2017	FYE2018	FYE2019	FYE2020	FYE2021	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026
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

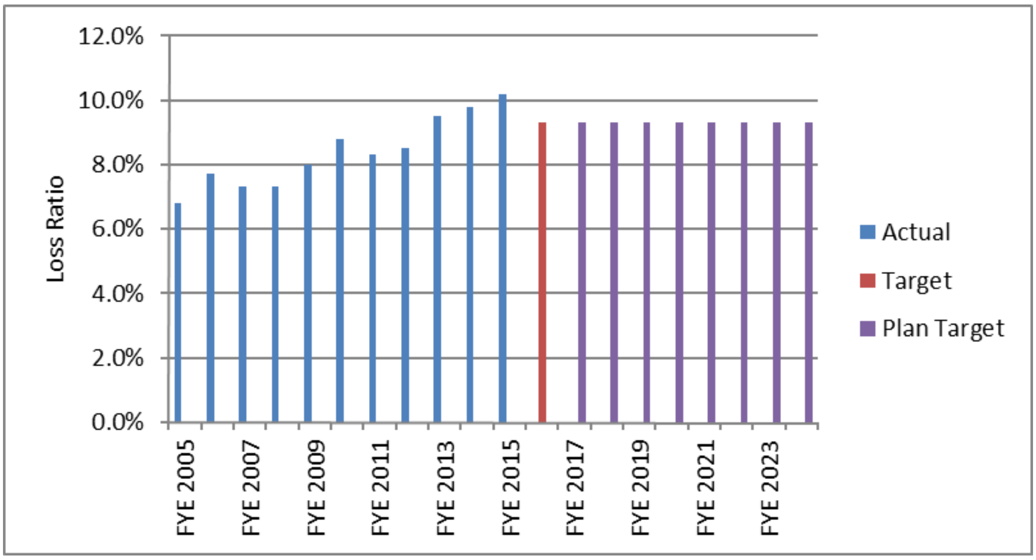


Figure 4.3: Loss Ratios of Top Energy since FYE2004

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 previously used our operational expenditure ratio as the indicator of the financial effectiveness of our asset management efforts. The operational expenditure ratio was defined as the ratio of our total operational expenditure during a measurement year to the replacement cost of our system fixed assets at the end of the measurement year. However, the Commission did not include this indicator in the revised templates for information disclosure relating to FYE2013 and subsequent years. Furthermore, the undepreciated replacement costs for the transmission assets acquired from Transpower are not known and can only be estimated. Therefore, we no longer use this indicator for performance measurement purposes.

In its place we use the ratio of total operational expenditure to total regulatory income. Like the operational expenditure ratio, 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 taken into account 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 does reflect the portion of the revenue from the provision of distribution line services that is allocated to operating expenditure, and is therefore directly relevant to consumers. All else being equal, a smaller ratio does reflect greater efficiency in the day to day management of assets.

We continue to 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 for year to year.

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

FYE2017	FYE2018	FYE2019	FYE2020	FYE2021	FYE2022	FYE2023	FYE2024	FYE2025	FYE2026
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 compared 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.

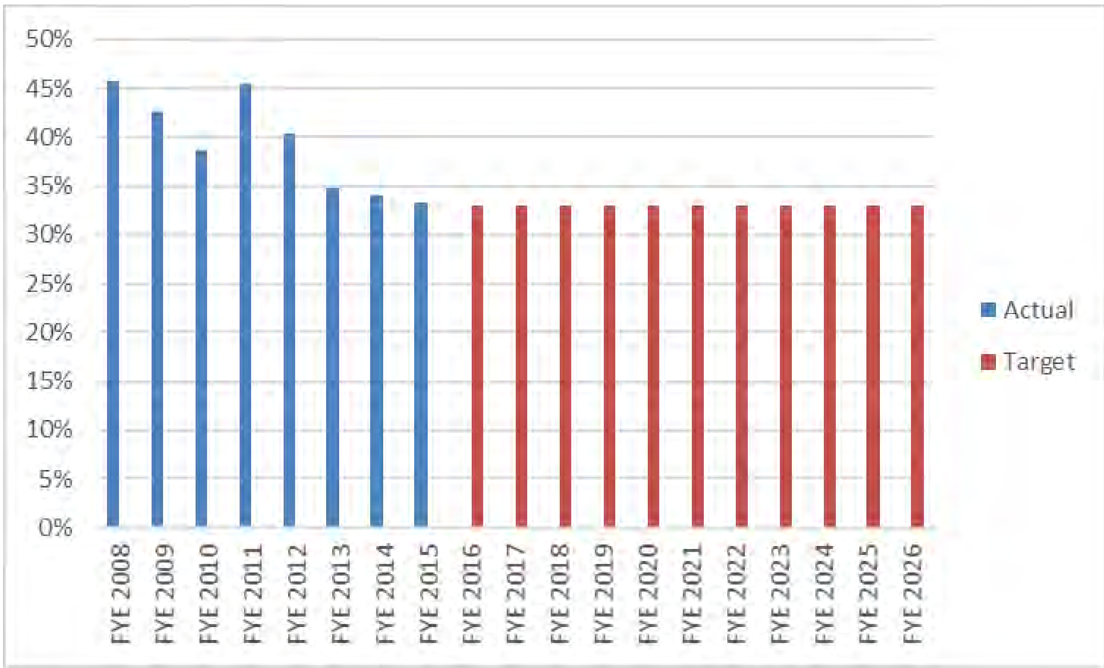


Figure 4.4: **Ratio of Total Operating Expenditure to Total Regulatory Income since FYE2008.**

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 3.1.4, 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 the consumer consultation process described in Section 4.4.1 below.

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 that are a 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 Formal Consumer Consultation

We have:

- advised our consumers about the price and quality trade-offs available to them in relation to the quality of supply provided;

- consulted with consumers about the quality of supply that they require, with reference to the price of its distribution service;
- properly considered the views expressed by consumers during and after that consultation; and
- adequately taken these views into account when making asset management decisions.

We have recommenced the use of formal telephone surveys to measure consumer satisfaction with the levels of service that we provide. Our most recent survey was in October 2015, which was undertaken independently by a specialist energy consultant. The findings of this survey, as summarised by the consultant were:

- A majority of consumers do not want any more price rises, with a possible exception being some consumers being willing to pay a few extra dollars per month storm hardening;
- While most consumers believe supply reliability is acceptable, the improvements in supply reliability made over previous years appear to be fading in consumers' minds;
- Willingness to have appliances and heat pumps controlled by us appears to be declining, suggesting that demand management might be harder to implement than previously thought; and
- A significantly increased number of consumers are considering solar panels.

One survey outcome that we found particularly pleasing, given that our previous annual survey was undertaken only three months after the extreme storm in July 2014, was that only 3% of respondents considered that reliability of the network had deteriorated over the last few years. 50% of respondents felt that network reliability had stayed the same while the remaining 47% said that it had improved a bit or improved a lot.

4.4.2 Other Community Engagement

Notwithstanding the results of the formal consumer consultation process, a number of factors led our Board to the conclusion that a substantial increase in the level of investment in the network was necessary to both support the economic development of our supply area and to meet longer term consumer aspirations. In particular:

- Demand in Kerikeri and surrounding area had increased to the extent that an increase in the subtransmission capacity bringing power into the area could no longer be deferred. This issue has now been addressed;
- There was ongoing community concern at the lack of security in the supply to the northern area and the fact that one third of consumers were denied an electricity supply for extended periods during annual maintenance shutdowns; and
- The low levels of supply reliability experienced in FYE2009 and FYE2010 were unsustainable in the regulatory environment within which we operate. In fact, the reliability experienced by consumers in the northern region was worse than indicated by these measures, since they did not include transmission driven interruptions.

We therefore embarked on a programme to raise community awareness of these issues and to seek the support of community leaders and decision makers. These stakeholders were consulted on a major investment initiative designed to raise the security and reliability of the network to levels comparable to the generally accepted norms for the New Zealand rural electricity supply sector. We engaged in an extensive community consultation process to determine the standard of electricity supply required to underpin the economic development of our supply area over the next two decades and, importantly, the amount our consumers are prepared to pay to secure an electricity supply of the quality that other rural New Zealanders have come to expect.

The earlier engagement established that 80% of consumers wish to see the reliability of supply to the northern area improve. In addition, there was also overwhelming support from community organisations for the construction of a second 110 kV circuit to secure the electricity supply to the Kaitaia region. This was evidenced by letters of support received from:

- The Far North District Council;
- The Northland Regional Council;
- The Top Energy Consumer Trust; and
- The Independent Farmers of New Zealand

As a result, we undertook to implement the extensive network development and maintenance improvement programmes described in Sections 5 and 6 of this AMP. With the support of the Commission, we also implemented significant price increases to fund the programmes with little overt community opposition. The plans described in this AMP are ambitious, but our Board and management strongly believe that they are consistent with the long-term interests of our local community. We look forward to continuing to work with its community to successfully implement these plans.

4.4.3 Justification for 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.

By the end of the current financial year we expect to have completed the upgrades to the protection on our duplicated 33kV subtransmission system that we have been progressively implementing. This will increase the resilience of the network to subtransmission faults, which should provide the short term improvement in reliability needed to meet the still ambitious targets. We estimate, based on a high level analysis of FYE2016 fault data through to the end of December 2015, that improvements to the 33kV protection systems could result in an improvement in measured system reliability of up to 20%.

4.4.4 Justification for Asset Performance and Efficiency Targets

4.4.4.1 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 line was expected to result in a material improvement to the measured loss ratio, but this has now been deferred until the end of the AMP planning period. The commissioning of the Kaeo substation will result in a reduction in line losses due to lower 33kV and 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.

4.4.4.2 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 FYE2015 throughout the planning period.

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 network security requirements are the main factors that drive these requirements, network development is also driven by a need to improve the reliability of supply to consumers.

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 feeders, low voltage is generally the first indicator of an emerging network capacity issue 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

In order to control the system voltage within the specified limit, 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

We use two different types of distribution voltage regulators on long rural distribution feeders:

- 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

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.

The installation of new zone substations at Kerikeri and Kaeo has avoided the need for overhead line upgrades on a number of long, highly loaded distribution feeders.

5.1.2 Security of Supply

Our security of supply criteria drives not only existing asset improvements, but also the design criteria for network extensions and improvements. The criteria require all zone substations with a load greater than 5MVA to have two supply transformers and two incoming 33kV circuits. In the event of the loss of any one transmission element, such as a transformer or incoming line, supply to consumers should not be interrupted. This requires that the contingent rating of each substation transformer should be sufficient to carry the peak load of the substation and that there be sufficient transfer capacity within the distribution system so that some load can be transferred to neighbouring substations to reduce the load of the transformer remaining in service to below its normal rating. In practice, there is limited transfer capacity within the distribution network, because of the sparsely populated rural nature of our supply area. This limits the level to which transformers can be loaded under normal operating conditions.

Where the load at a zone substation is less than 5MVA, a single transformer and single incoming line is permissible. In the event of a single element outage, consumers supplied from that substation could experience an interruption lasting up to 10 hours; depending on the cause of the fault and the location of the substation. In most situations, some limited power transfer capacity within the distribution network will be available, allowing power to be restored to some consumers well before this.

We own and operate a 7.5MVA mobile substation, which limits the maximum outage duration should a fault occur in a single transformer substation. The time required to relocate this unit from its present location to provide backup to other single transformer zone substations in the event of transformer failure is up to 10 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.

Until recently, our network has not conformed to the security of supply criteria, due mainly to protection constraints that limited the way the 33kV subtransmission network could be operated. The subtransmission system was operated in a radial, split bus arrangement with one line feeding each half of a substation. This meant that, in the event of a fault on the incoming line, supply to approximately half of the consumers supplied from the substation would be interrupted until the network could be reconfigured by switching.

Over the last five years we have been progressively addressing this issue by upgrading the protection on our 33kV network. Our solution has been to install unit protection on all parallel 33kV lines to overcome the low fault levels that we experience in our fringe network location and that compromised the effectiveness of our earlier protection systems. Unit protection detects a fault by continuously comparing the current entering and leaving a line. This requires a reliable and fast communication link between the two line ends, and to achieve this we have been progressively running pole mounted fibre-optic cables over our subtransmission line routes. This programme is expected to be complete by the end of FYE2016 and we are expecting material improvements in our measured reliability in coming years due to the more secure subtransmission network. The benefits of this have already been apparent, when recent bushing failures on new 33kV circuit breakers installed on new switchboards at Kaikohe, Wiroa and Kerikeri did not result in supply interruptions[6].

Consistent with standard industry practice, the network is not designed to cater for simultaneous outages of more than one transmission or subtransmission element. Should such a situation arise, emergency plans would be activated to restore supply to affected consumers as quickly as possible. In such an event, outages of more than 10 hours are possible.

Table 5.1 shows the level of security we expect to provide at all our zone substations by the end of FYE2016. Taipa is the only substation that will not meet our security criteria when the protection upgrade programme is complete. This is a single transformer substation with a load of just over 5MW, supplied by a single incoming 33kV circuit fed from our transmission substation at Pamapuria. We are planning to construct a new 110kV substation in Garton Rd, but this cannot be completed until the new 110kV line to Kaitaia is energised. In the meantime, we have installed two diesel generators at the substation with sufficient capacity to supply approximately 75% of peak demand. In the event of a fault on either the incoming line or the transformer there will be a relatively short interruption while the generators are started and put on load. At times of peak demand, when the generators are unable to supply the full requirement, we would need to ration load, with outages rotated amongst affected consumers until the fault was repaired or the mobile substation relocated.

The load on all of the other three single transformer substations is well below the 5MW threshold. Mt Pokaka has two incoming lines one supplied from Kaikohe and the second from Wiroa. The substation was built primarily to supply the mill and in the event of a transformer interruption there is sufficient transfer capacity in the 11kV network to supply all affected small use consumers.

Omanaia and Pukenui are remote substations with peak demands of approximately 2.5MW and 1.5MW respectively.

[6] We are in discussion with the manufacturer regarding the cause of these failures.

SUBSTATION	TRANSFORMER FAILURE	BACK UP TO AFFECTED TRANSFORMER	TIME REQUIRED TO RESTORE SUPPLY (HRS)
Southern Area			
Kaikohe	T1	T2	No interruption
	T2	T1	No interruption
Kawakawa	Mobile substation	T2	Switching time[1]
	T2	Mobile substation	Switching time
Moerewa	T1	T2	No interruption
	T2	T1	No interruption
Waipapa	T1	T2	No interruption
	T2	T1	No interruption
Omanaia	T1-1 R	Mobile Substation	9.5 hours
	T1-2 Y		
	T1-3 B		
Mt Pokaka	T1	Mobile Substation	9.0 hours[2]
Haruru	T1	T2	No interruption
	T2	T1	No interruption
Kerikeri	T1	T2	No interruption
	T2	T1	No interruption
Northern Area			
Okahu Rd	T1	T2	No interruption
	T2	T1	No interruption
Taipa	T1	Mobile Substation	9.5 hours[3]
Pukenui	T1	Mobile Substation	10.0 hours
NPL	T1	T2	No interruption
	T2	T1	No interruption

Note 1: Transformer T1 at Kawakawa is currently out of service due to an on load tap changer failure. When this is repaired and returned to service Kawakawa will fully meet our security requirements and a transformer failure should not result in a supply interruption.

Note 2: Switching time for small use consumers.

Note3: Generator start time for most consumers

Table 5.1: 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 5.2: 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 5/9MVA and 3/5MVA transformers are used. Transmission transformers rated at 110/33kV are standardised at 40/60MVA, although a smaller transformer size will likely be used at Taipa. 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 Distribution

Our network is predominantly rural and radial with many long feeders, often with a low number of consumers per kilometre. This means that the limiting factor determining the size of conductor is the voltage drop along the line, rather than the thermal current carrying capacity. We monitor the voltage level along our feeders by using sophisticated computer models and physically by installing data logging devices.

Investment made to meet the legally set voltage requirements for the forecast load can include converting parts of feeders from 11kV to 22kV (as we have done on the Rangiahua feeder), use of voltage regulators, and the use of both fixed and switched capacitors.

A problem with incremental augmentation of this nature is that it does little to improve the reliability of supply. Our network development plan addresses this issue in a number of ways, but in particular by increasing the number of points at which power is injected into the distribution network through the construction of new zone substations at Kerikeri and Kaeo. This allow the use of shorter feeders, which limit voltage drops, allows higher current loadings on existing conductors and reduces the number of consumers affected by an HV fault.

We are also planning to install more interconnections between distribution feeders to permit greater operating flexibility during faults. This improves reliability by allowing supply to be restored sooner to many consumers after a fault occurs.

5.3 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:

- Currently, our network losses are the highest in the country. While loss minimisation 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 measured network losses increased after the acquisition of the Transpower assets because these losses from these assets were material and had to be included in the measure. The commissioning of the second circuit should result in a significant reduction in our network losses.

- The Ngawha geothermal power station 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. Subtransmission losses incurred in transmitting the energy generated at Ngawha to the Kaikohe substation have been reduced now the second 33kV circuit between Ngawha and Kaikohe is finally commissioned.

- As discussed in Section 5.9, we actively control consumers' hot water heating and other load at times of peak demand in order to ensure more efficient use of the available network capacity. Load control is thought to reduce our network maximum demand by approximately 10MW.

- We are conducting a research project where energy generated by photovoltaic systems is stored in batteries and then released into the network at times of peak demand. While this research project is currently limited to a very small number injection points, there is potential for energy savings if this trial proves successful and the technology becomes more widely adopted. This project is discussed in Section 5.9.1.

- 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 taken into account during tender evaluation.

5.4 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.

5.5 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.

5.5.1 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 condition of the 33kV switchgear at Kaitaia transmission substations and the condition and capacity of the 110/33kV transformers at Kaitaia;
- the age and condition of the single phase supply transformers at Omanaia;
- a need to reinforce the existing distribution system in the Kaeo-Whangaroa-Matauri Bay and Russell areas. These areas, located on the rapidly developing eastern coastal strip, are experiencing relatively high load growth, but are not currently served by a local zone substation; and
- the need to improve reliability of supply. Despite improvements made to-date, reliability is still the lowest of any New Zealand EDB.

Our Board and Trust have determined that these issues cannot satisfactorily be addressed by means of incremental upgrades and that major investment is required to increase the supply security in the northern and eastern parts of the supply area. As discussed in Section 4.4.2, we have the support of our community for this investment. The major projects planned for the next 10 years and the basis for their prioritisation are discussed in Sections 5.11-5.13. The largest project in the programme, the second 110kV line to Kaitaia, is designed to address an existing security issue and is not demand-driven. Completion of this project is central to our network development strategy. The recently completed zone substation at Kerikeri, and also the Wiroa 33kV switching station leveraged off the southern section of this project and addressed a significant network limitation that was impacting the security of supply to one of the fastest growing provincial townships in the country.

Other large projects in the network development plan also leverage off the new 110kV line. They are designed either to address urgent security, capacity or reliability issues (Kaeo and Taipa) or replace existing assets that have reached the end of their economic life (Omanaia, the outdoor-indoor switchyard conversions and the replacements of the Kaitaia 110/33kV transformers). While there is always scope for timing or prioritisation adjustments, all major projects must proceed if the Board's overarching strategy of delivering a quantum improvement in the level of service to consumers is to be achieved. Hence, implementation of the programme is not dependent on demand growth, but is constrained by funding and deliverability limitations. Difficulty in securing new transmission line routes is a recurring problem for network service providers and securing a route for the new 110kV line between Wiroa and Kaitaia is no exception.

5.5.2 Incremental Capital Upgrades

Incremental capital upgrades generally have short lead-times and are managed within budget envelopes. They include asset replacements undertaken as a consequence of condition assessments and asset inspections. They also include refurbishment projects targeted at assets (including our transmission assets acquired from Transpower) that are insufficiently rated to meet continuing load growth or have deteriorated to the stage where asset reliability is a problem. 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 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. There has therefore been a high priority given to projects that will improve the reliability of the transmission and subtransmission networks, as outages of these networks affect a large number of consumers. Programmes involving the installation of remote controlled switches and interconnections between neighbouring feeders have also been prioritised for a similar reason.

5.6 Demand Forecasting Methodology

5.6.1 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.).

The financially restrained economy has resulted in subdued growth in demand since 2012 and while a scan of the external environment has identified some potential developments that could cause significant increases in demand in particular parts of the network, no development has matured to a stage where we considered it prudent to make provision in the forecast to alleviate a potential constraint. This is particularly the case now that the constrained incoming supply to Kerikeri and surrounding regions has been addressed with the completion of the 110kV circuit between Kaikohe and Wiroa (operating at 33kV), the Wiroa 33kV switching station and the Kerikeri zone substation, which are now all in service.

Hence our methodology focused on validating the forecast in our 2014 AMP against the actual peak demands experienced to date in FYE2016. While some might consider such an approach inadequate, we consider it fit for purpose in the current environment, where growth rates are subdued and the impact of new and emerging technologies on the future demand for electricity supplied through the grid is far from clear.

In our case demand increased quite rapidly up to FYE2012, but has since moderated significantly across the network. Hence a forecasting methodology that relied on medium term historic rates of demand growth could result in an excessively high forecast. Like much of the rest of the country, we noticed some firming in the demand for electricity over the 2015 winter, so we also do not believe our approach has produced a forecast that is unrealistically low.

Demand growth was forecast down to the zone substation level.

5.6.2 Forecast Methodology

We used our SCADA system data that provided the average current for each half hourly period from 1 March to 31 December 2015 as the base data for the forecast. From this we were able to determine the maximum half hourly demand at each zone substation. Peaks that appeared to be due to the network not being in its normal operating state were not considered. This observed peak was used as the base demand for the forecast demand at all substations, but at some substations the growth rates assumed in the 2014 AMP were modified as a result of the differences between the observed and forecast peaks. However, the observed demands were found to be remarkably consistent with the forecast so all adjustments were small. As the data we used were measurements of current, we assumed a power factor of 0.95.

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 FYE2016 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. We found that the growth rate in the southern area is significantly higher than in the north, mainly because the northern load is dominated by the demand of the Juken Nissho mill, which is not expected to increase over the planning period.

A significant change from the 2014 AMP forecast was the need to adjust for the Kaeo substation, which is now expected to be in service in time for the FYE2019 winter peak. We estimated the demand of the Kaeo substation on the basis of the actual loads on the Waipapa feeders that will be diverted into the new substation, as measured by the SCADA system.

5.7 Demand Forecasts

5.7.1 Forecast peak demand over planning period

Using the methodology described above, the load forecast for each zone substation is shown in Table 5.3 below. The peak demands shown in the tables are net of the peak demand reductions that we are able to achieve though the operation of its load control system. At present, apart from household PV 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.

	Actual FYE 2016	FYE 2017	FYE 2018	FYE 2019	FYE 2020	FYE 2021	FYE 2022	FYE 2023	FYE 2024	FYE 2025	FYE 2026
Southern Area											
Kaikohe	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Kawakawa	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.7
Moerewa	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Waipapa	10.1	10.3	10.5	5.7	5.8	5.9	6.1	6.2	6.3	6.4	6.6
Omanaia	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Haruru	5.5	5.6	5.7	5.8	6.0	6.1	6.2	6.3	6.4	6.6	6.7
Mt Pokaka	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5
Kerikeri	6.4	6.5	6.7	6.8	6.9	7.1	7.2	7.4	7.5	7.6	7.8
Kaeo				5.0	5.1	5.2	5.2	5.3	5.4	5.5	5.5
Northern Area											
Okahu Rd	8.1	8.2	8.3	8.3	8.4	8.5	8.6	8.7	8.8	8.9	8.9
Taipa	5.2	5.2	5.3	5.3	5.3	5.3	5.4	5.4	5.4	5.4	5.5
NPL	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7	11.7
Pukenui	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6

Table 5.3: Zone Substation Demand Forecast (MW)

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

	Actual FYE 2016	FYE 2017	FYE 2018	FYE 2019	FYE 2020	FYE 2021	FYE 2022	FYE 2023	FYE 2024	FYE 2025	FYE 2026
Kaikohe	43.8	44.4	44.9	45.5	46.0	46.6	47.2	47.8	48.4	49.0	49.6
Kaitaia	24.3	24.4	24.5	24.6	24.7	24.8	24.9	25.0	25.1	25.2	25.3
Network	67.7[1]	68.4	69.0	69.7	70.3	71.0	71.7	72.3	73.0	73.7	74.4

Estimated from SCADA data. May not correspond to disclosed demand in FYE2016 information disclosure.

Table 5.4: Transmission Substation and Network Demand Forecast (MW)

5.7.2 Uncertainties in the demand forecast

The Chinese owners of the Carrington Resort on the Karikari peninsula have applied for resource consent to develop and expand the resort with the addition of approximately 800 rooms. 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 and a new 33kV line and substation would be required. The proposal has still to receive resource consent and many locals are apprehensive about its size and impact. We have contingency plans in place to supply the expanded resort should it proceed and these plans could impact the timing of some of the projects set out in this AMP. However, there remains a high level of uncertainty as to when the development could proceed, if it goes ahead, and we believe it would be premature to provide for it in this AMP.

The Purerua area north of Kerikeri is also mooted for a potential large subdivision development equivalent to a small-to-medium size township. Should this proceed, a new zone substation will also be required. This development is on hold due to the current state of the property market in our supply area. There is still no sign of any significant upturn and we have assumed that any new substation will not be required until after the end or our planning period.

There are a number of subdivision developments already in progress or completed that have not yet resulted in connected load, but which could add to the present demand once the recession lifts in the region and building recommences. These developments may result in some increase in growth rates above the forecast levels, although some are in areas where there is a known potential for growth and this has been provided for in the forecast.

We are also aware that the Northland tribes have yet to reach a treaty settlement with the Government and the Minister of Finance has noted that a settlement could inject $200 million into the Northland economy. The Prime Minister has also encouraged 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.

5.8 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. Our approach to DG is based on the following key principles:

- DG is able to 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.

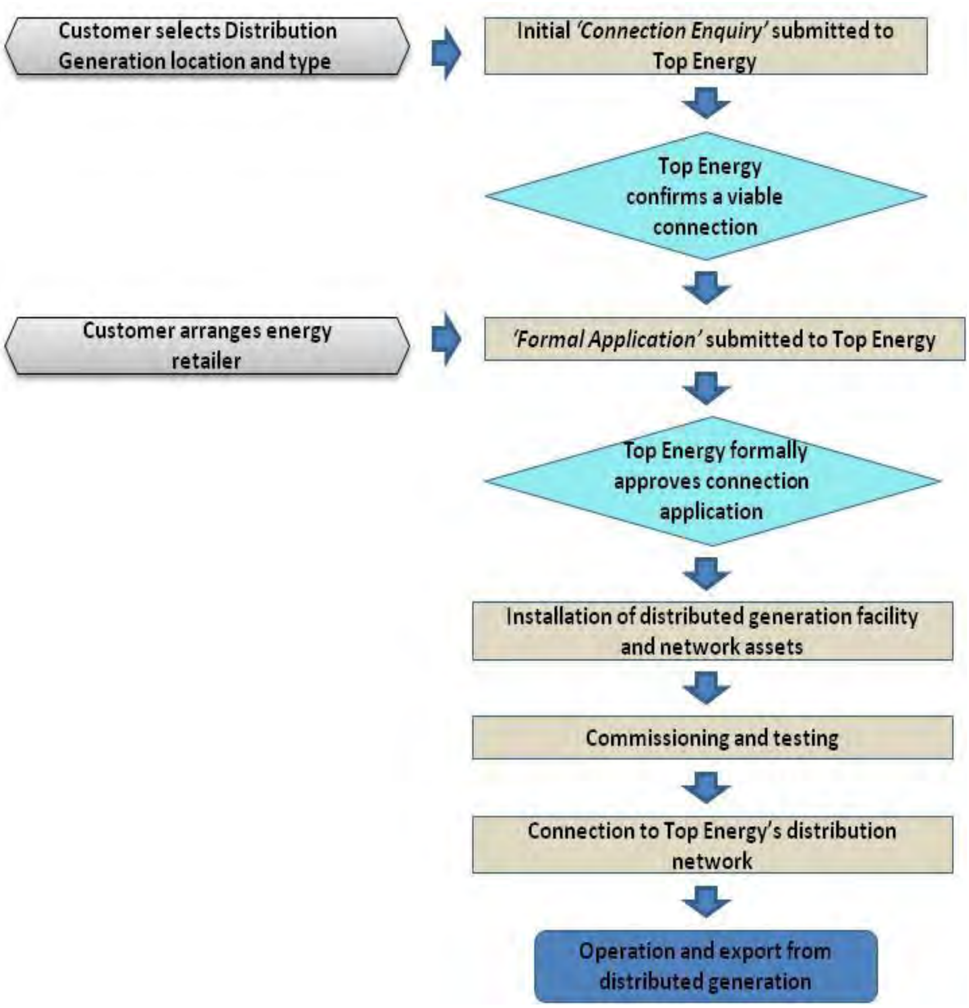


Figure 5.1: Distributed generation connection process

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 our own commitment to embedded generation by establishing the 25MW Ngawha Power Station and we now have the necessary resource consents (subject to appeal) 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. Our recent installation of 4MVA 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 synchronised 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 a number of our consumers have 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 so there is little incentive for them to cooperate with an EDB wanting to advance such a proposal.

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. Our network development programme is designed to address reliability rather than capacity issues and generation is generally not a solution to poor network reliability as the timing of network faults cannot be predicted. Given our current demand projections, the potential for us to come to a mutually beneficial commercial arrangement with an embedded generation proponent is therefore limited.

5.9 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. 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 5.5 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 5.5: 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.

5.9.1 Emerging Technologies

There is currently a high level of uncertainty within the industry regarding the impact of emerging technologies on the use of electricity and how the use by consumers of the services we provide as an electricity distributor might change. For example:

- Micro generation by small use consumers, using photovoltaics, small scale wind generation and, in the not too distant future, fuel cells is becoming increasingly economic and technically feasible. The ability of small use consumers to generate electricity in their own homes could potentially reduce the need to rely on shared grid connected generation.
- The emergence of new battery storage technologies and the reduction in the cost of this technology will make small scale photovoltaics and wind generation effectively dispatchable. Whereas excess electricity generated by these technologies currently has to be fed back into the network, with battery storage the generation can be stored locally for use at a later time when it is needed. It is possible that over time battery storage technology could develop to the point where is becomes economically feasible to disconnect completely from the grid.
- Technologies are emerging that allow consumers to use electricity more efficiently. Incandescent light bulbs are being increasingly replaced by LEDs that last substantially longer and provide a similar amount of light with less than 20% of the electricity consumption. Heat pumps are now being used not only for space heating, but also for heating water and drying clothes. While the impact of such energy efficient technology is difficult to quantify, most in the industry now believe that the use of such energy efficient lighting and appliances, as well as an increasing awareness by consumers of the environmental benefits of reducing energy consumption, are a significant driver of the moderation in the rate of growth in electricity consumption many EDB have experienced in recent years.

While these technologies all point to a reduction in the quantity of electricity delivered through our network other developments, such as an increased penetration of electric vehicles point to an increase in the consumption of electricity. Until recently, Australia experienced high rates of growth in electricity consumption in electricity demand driven by the increased use of air conditioning for domestic cooling and it is possible that we could see a similar trend emerge in our sub-tropical summer climate. The charging of electric vehicles, in particular, could lead to a significant increase in peak demand on our network if large numbers of vehicles are put on charge during peak load periods at the end of the working day. This will need to be managed either using load management technology or through the use of time of use tariffs that discourage the consumption of electricity during peak times. However, from another perspective, the batteries in electric vehicles are also a potential form of storage and the energy stored could be fed back into the network at peak times to reduce the peak demand.

The implication of these developments on the use of our network, and our future investment and asset management requirements is far from clear. In order to gain a better understanding as to what these developments might mean we have participated in a research program coordinated by the Electricity Networks Association where the Transform model, which was developed by EA technologies in the UK to help network operators understand the levels of investment required to meet the challenges of consumers adopting new technologies, has been applied to the New Zealand situation.

Key findings from this research exercise have been:

- The uptake of new technologies will not be uniform across of network and related network investment will need to be focused on those parts of the network where the uptake of new technologies is greatest. In our case we expect this to be in the Kerikeri and Bay of Islands areas.
- Most of our technology related investment will need to be on the 11kV distribution network. By the time the investment is required our subtransmission development will be complete. Investment thresholds on the low voltage network are expected to be higher and there is more headroom.
- While required investment levels are expected to ramp up over time, they are unlikely to become significant for another 10-15 years. There is little advantage to be gained by investing heavily in, for example, smart grid solutions in the short term.
- However, target trials in the application of these emerging technologies will help us prepare for the future.

We already have such a trial in place. We have 12 participants in the Kerikeri area, all of whom have photovoltaic cells operating in parallel with the grid. Two participants have battery storage, where photovoltaic generated electricity is stored and discharged into the grid over peak hours. Two participants have plug-in electric vehicles. The performance of these systems is monitored through a web based interface.

Key findings from this trial are:

- In our area 1kW of installed photovoltaic generation produces 1,350kWk per annum. This equates to a revenue reduction of $162 per kW installed per annum.
- A typical plug-in electric vehicle will consume approximately 500kWh of electricity per month or 6,000kWh per annum.

We have almost 200 photovoltaic generators connected to our networks. As the economics of such systems is currently marginal at best, these are likely to be early adaptors for whom economics is not a primary consideration. However, the economics of such systems is expected to improve over the next few years as battery technology improves and the cost of storage reduces. This could mean that the subdued rates of growth that we have experienced since 2012 may continue over the short to medium term as the penetration of photovoltaic systems increases.

The uptake of plug-in electric vehicles is expected to lag that of photovoltaic systems. However, these vehicles will create a significant new demand for electricity, which may not be fully offset by photovoltaics and energy efficient technologies. If this this is the case the current subdued electricity consumption growth rates may only be temporary and growth rate may well increase again in the medium to longer term.

5.10 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.

5.11 Network Development Plan

5.11.1 Introduction

Our integrated network development plan was announced in 2010 to address a number of significant network constraints and a reliability of supply that is still the lowest in the country.

- At times of peak demand, the subtransmission system serving consumers in the Kerikeri area was loaded in excess of its design level. As a result, much of the excess capacity built into the network to provide supply security in the event of a fault was being utilised to supply normal demand. The network was therefore operating at a reduced level of security and, in the event of an unplanned outage of a subtransmission element, the network voltage could drop to an unacceptable level.

- Approximately 10,000 consumers in our northern area are still reliant on a non-secure supply, due to the fact that 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.

- Many of the transmission assets, which were purchased from Transpower in 2012, are old and present safety and reliability risks. A particular problem was the capacity and condition of the existing transformers at Kaitaia. These were old, single phase units that testing indicated were in poor condition. They were also rated at 22MVA, which is less than the present load at the substation. The condition of the 33kV outdoor switchgear at both substations was also a concern.

  The condition of the 110kV line purchased from Transpower is also of concern, with two unexpected structure failures occurring in the last two years. Fortunately, neither failure resulted in an unplanned loss of supply, but in both cases planned shutdowns were needed to allow repairs to be undertaken in a timely manner.

- 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 of particular concern are Whangaroa-Kaeo-Matauri Bay area and the Russell peninsula.

- Many zone substations were being operated in a split bus, radial configuration in order to manage protection constraints. This meant that that supply interruptions were inevitable whenever a subtransmission fault occurred even within the core network. As 33kV subtransmission faults affect large numbers of consumers, this was a significant contributing factor to our poor network reliability.

- Outdoor switchgear at some substations, in particular Moerewa, Kawakawa and Waipapa was in poor condition and required replacement.

- The single phase transformer bank at Omanaia is now 63 years old and approaching the end of its economic life.

5.11.2 Work Completed or Underway

The following components of the network development plan have either been completed or, at the time of writing, were expected to be completed in FYE2016.

- A new 33kV zone substation was commissioned in May 2013 to supply Kerikeri town and surrounding areas. It is energised through two new incoming 33kV circuits; an underground circuit supplied from the Wiroa 33kV switching station and a combined overhead/underground circuit supplied from Waipapa.

- Construction of the Kaikohe-Wiroa 110kV circuit was completed in FYE2015 and is now operated at 33kV to supply the Wiroa switching station.

- Construction of the new 33kV switch room and switchboard at Wiroa has also been completed. It has two incoming 33kV circuits both supplied from Kaikohe. One circuit is new and uses the new 110kV line conductors and the second is the older circuit that also supplies Mt Pokaka.

Completion of the above projects has addressed the capacity constraint at Kerikeri. However, this is only a short term solution since at least one circuit of the transmission line from Kaikohe will need to operate at 110kV when the new line to Kaitaia is completed. We are therefore intending to install a new 110kV substation at Wiroa before the end of the planning period

- A new indoor 33kV switchboard has been constructed on land adjacent to the Kaikohe zone substation. This has replaced the existing outdoor 33kV switchyard at the Kaikohe transmission substation, which had reached the end of its economic life and was considered a maintenance safety hazard due to low electrical clearances.
- A new 40/60MVA, 110/33kV power transformer has been installed at the Kaitaia transmission substation to replace one of the two smaller three phase units that was showing signs of significant insulation deterioration.
- The No. 1 33kV line between Kaikohe and Kawakawa has been reconductored to secure the incoming supply to Kawakawa, Moerewa, Paihia and Russell.
- Upgrades to the protection systems on the core 33kV subtransmission network will be completed by the end of FYE2016. These upgrades 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. This should significantly reduce the number of supply interruptions resulting from 33kV network faults. Supplies to the smaller outlying zone substations at Pukenui and Omanaia are single radial circuits and will not be affected by this development.
- Diesel generation has been installed at Taipa to mitigate the reliability problem caused by 33kV subtransmission network faults. At Taipa this problem cannot be fully mitigated until the proposed new 110kV Garton Rd substation is completed, but this cannot be commissioned until after the Wiroa-Kaitaia 110kV line has been energised. The diesel generation, which has been installed as an interim solution will not eliminate the interruptions but will reduce their duration. It will also be operated during outages of the existing 110kV transmission line, reducing the impact of these outages on consumers supplied from Taipa.
- Work has been completed on the reconfiguration of the 11kV network north-east of Kawakawa to remove all load on the Russell feeder south of the Waikare inlet to create a Russell express feeder, which has increased the capacity and reliability of supply to the Russell peninsular. The removed load has been transferred to the new Karetu feeder.
- A new underground 11kV distribution feeder between the Haruru zone substation and Te Tii Bay has been commissioned to reinforce the supply to Paihia.
- A full rebuild of the Moerewa substation will be completed by the end of FYE2016. This has involved the installation of new 33kv and 11kV indoor switchboards to replace the old outdoor switchgear and the installation of two new 3/5MVA transformers.

5.11.3 Other Network Development Projects

5.11.3.1 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 generation in the area has always been an alternative which, on the surface, appears attractive, but which has proved elusive. A number of generation projects have been proposed in the past, but none have progressed past the feasibility stage. The most probable option is wind generation and we are aware of at least two proposals. However, wind generation is not dispatchable and therefore cannot provide the controllable output necessary for a credible alternative supply.

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 a number of 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.

We have looked closely at the installation of diesel generation, similar to that installed Taipa, at the other zone substations in the northern area. This would have a relatively low initial capital cost and could be completed sooner than a second line. While it would enable supply to be maintained to most consumers during planned transmission interruptions, it would have no impact on SAIFI as a short interruption would still be required when the generators were shut down to allow mains supply to be restored. Diesel generation would also not provide sufficient capacity to back up very large loads (our model did not include sufficient capacity to provide a backup supply for the Juken Nissho mill), high operating and maintenance costs, and there is a likelihood of significant increases in greenhouse gas emission costs over the longer term. We have concluded that diesel generation is a short sighted alternative that is likely to become increasingly less sustainable and that would not provide the level of supply reliability sought by job creating enterprises that could underpin the economic development of the Far North.

The need to reinforce the network to address the 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 has 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.

The second 110kV line between Kaikohe and Kaitaia will 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 continues. There are 94 affected properties and agreement in principle has been reached with 59 owners. One affected property is Maori land, but agreement has been reached with the beneficial owners and our application for an easement is working its way through the Maori Land Court. We anticipate that we will need to apply to the Minister of Land Information for compulsory acquisition of easements over a number of the remaining properties. These delays mean that it is likely to be FYE2019 before the full line route is secured. Line construction is planned to commence in FYE2020 and continue through to FYE2026, with constraints on the availability of funding preventing an earlier completion. When the new line is complete, it will be possible to take either 110kV circuit out of service without disrupting the supply to Kaitaia.

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

5.11.3.2 Wiroa 110kV Substation

Lower than expected demand growth has allowed energisation of the substation at 110kV to be deferred and the commissioning of the first transformer is now planned for FYE2023, with the second in FYE2025. The substation will have two 40/60MVA (110/33kV) transformers, which will provide sufficient capacity to supply Kerikeri, Waipapa and Kaeo for many years to come.

The Wiroa 110kV substation is required to be in service to maintain supply to the network when the first of the proposed two new 25MW geothermal units at Ngawha are connected to the network, as these units will be connected to the 110kV system at Kaikohe. While these units have now been consented, subject to any appeals, and timing of their construction will be determined by commercial factors. If it is decided to complete this substation prior to FYE2023 to enable connection of the first unit, the cost of bringing the project forward will be met from Top Energy's generation budget.

This project is categorised as network growth.

5.11.3.3 Kaeo Zone Substation

Supply to the coastal belt north of Waipapa, as well as the inland rural area to the north-west, is becoming increasingly constrained. The area served is large and development of the coastal strip between Matauri Bay and Whangaroa is becoming more intensive. Continuing to supply this area through long 11kV feeders is no longer tenable in terms of both supply capacity and reliability. Immery's Tableware, located near Matauri Bay, is in this region and is currently served from Waipapa using a long, heavily loaded rural feeder. A line between Waipapa and the Kaeo Gun Club on State Highway 10 is constructed at 33kV and currently operated at 11kV.

We had purchased land for a new 33kV zone substation on Martins Rd, south of Kaeo. However, this site proved unsuitable for geotechnical reasons and we recently purchased a new site in Omanu Rd, near the Kaeo township and close to the Kaeo hospital. The new substation will be supplied by two incoming 33kV circuits. One line will be supplied from Waipapa, and will be an extension of the existing 33kV line while the second circuit will be a new circuit from Wiroa, which will be included on the Wiroa-Kaitaia 110kV line for much of its route.

The substation will comprise two new transformers and five outgoing 11kV distribution feeders. Initially there will be only one incoming 33kV supply, as the second supply cannot be commissioned until construction of the second section of the Wiroa-Kaitaia 110kV line has been completed. Commissioning of this second incoming supply is currently scheduled for FYE2025.

The project will start in FYE2017 and is planned for completion by the end of FYE2018. Project works include the extension of the existing 33kV line to the new site, substation civil and electrical works and reconfiguration of the 11kV network to accommodate the five outgoing feeders.

Until the second circuit is complete, faults on the incoming 33kV circuit will still result in supply interruptions. Nevertheless, construction of the new substation will still result in an improvement in the quality of supply as it will resolve voltage drop issues resulting from the long 11kV feeders and will significantly reduce the number of consumers affected by each 11kV fault.

This project is categorised as system growth.

5.11.3.4 Kawakawa Substation Upgrade

A fault on the on load tap changer of one of the 5MVA transformers at Kawakawa substation, which supplies the Russell peninsula and Opua as well as Kawakawa and the surrounding rural area has highlighted the relatively poor condition of this substation. In FYE2017, we are planning to refurbish the faulted transformer, install fans on both transformers to increase their capacity to 6.5MVA, replace the oil filled circuit breaker trucks on the 11kV indoor switchboard with vacuum interrupters and replace the oil filled incoming transformer circuit breakers with vacuum reclosers.

5.11.3.5 Russell Reinforcement

There is an increasing level of consumer dissatisfaction over reliability of supply on the Russell peninsula, and in particular within the Russell township.

Under normal operating conditions almost all load on the Russell peninsula is supplied through the Russell express feeder and the submarine cable across the Waikare Inlet. There is a second submarine cable between Opua and Okiato Point but, as this is connected to the heavily loaded Opua feeder, the load that can be transferred through this feeder is limited and much lower than the rated capacity of the cable. Under normal operating conditions the load supplied through this second cable is limited to the area around Okiato Point. A further problem is that the termination point for both submarine cables is the Okiato Point 11kV spur line and there is no alternative point of injection into the remainder of the 11kV network. This means that, should a fault occur on the spur, the whole peninsula will lose supply until the fault is repaired, as there is no way to restore supply around the fault to consumers not directly affected.

During this current year, FYE2016, we completed the reconductoring of the 11kV network within Russell township. We are also planning to reconductor sections of the 11kV lines on the Joyces Rd and Opua feeders to relieve constraints on the supply side of the Opua submarine cable and to install a new 11kV underground cable between the termination of the Waikare Inlet submarine cable and the Russell-Whakapara Rd junction. This will provide a viable second supply into the peninsula and relieve the present situation where both submarine cables are terminated on the same spur line. Completion of this work is planned for FYE2019.

Expenditure on this project is categorised as network growth capex as it will increase the firm supply capacity into the peninsula.

5.11.3.6 Replacement of Major Transmission Substation Assets

Some of the transmission assets acquired from Transpower are in poor condition. A particular concern was the Kaitaia transformers, which were old single phase 22MVA banks with insufficient capacity to carry the full 25MW northern area demand under contingency conditions. Tests also showed the transformers were producing excessive amounts of gas, which is an indicator of insulation deterioration. The replacement of transformer T4 (which was in the worst condition) with a new 40/60MVA three phase unit (T1) is now complete and replacement of transformer T5 is expected in FYE2020.

A further concern is the condition of the 33kV outdoor switchyards at both sites. Outdoor switchyards at this voltage are now considered a safety hazard for maintenance workers, because of the low electrical clearances and the need for maintenance work to be undertaken in close proximity to live equipment. In the last 25 years, there have been four fatalities of workers undertaking maintenance work in Transpower's outdoor 33kV switchyards.

As construction of outdoor switchyards at this voltage is no longer considered good industry practice, Transpower has commenced a programme of replacing outdoor 33kV switchyards with indoor switchboards. Consistent with this, we have now replaced the outdoor switchyard at the Kaikohe transmission substation with an indoor switchboard and the replacement of the Kaitaia switchyard is programmed for FYE2026.

The replacement of the Kaitaia transformer is categorised as system growth, since the existing transformer does not have sufficient capacity to meet the peak substation demand under contingency operating conditions. Other replacements are driven primarily by asset condition and are categorised as asset replacement and renewal.

5.11.3.7 Replacement of Other Transmission Assets

Apart from the transformer and switchgear replacements discussed in Section 5.10.3.3, there is an ongoing need for asset replacements within the two transmission substations and on the existing 110kV Kaitaia-Kaikohe transmission line. Over the last two years there have been two structure failures on the 110kV line. Fortunately, these failures have not resulted in supply interruptions. However, in the first instance we were forced to initiate an unscheduled planned line outage and in the second case we had to being forward a scheduled outage in order to complete the repairs in a timely manner. As a result of the first failure, two planned shutdowns occurred within four months. Condition assessments have revealed that some older wooden poles have decayed to the extent that their strength has been significantly reduced and that there is advanced corrosion of steel tower foundations and some (non-critical) steel tower members.

Replacement of transmission assets in poor condition will occur throughout the planning period and is categorised as replacement and renewal.

5.11.3.8 Taipa Zone Substation

The existing zone substation at Taipa consists of a single 5/6.25 MVA transformer and is supplied by a single incoming 33kV circuit from the Kaitaia transmission substation. The peak demand has already exceeded the natural cooling capacity of the transformer and the level at which our security criteria require an N-1 supply to be available. The 11kV transfer capacity into the area is limited. As noted in Section 5.8, we have installed 4MVA of diesel generation at the site. This will provide some back-up in the event of a loss of supply, but is not a permanent solution.

Our original network development plan envisaged upgrading the substation to a dual 11/23MVA facility and construction of a new 33kV circuit between Kaeo (or Awanui) and Taipa to provide a back-up incoming supply. However, the construction of the new 110kV circuit between Wiroa and Kaitaia opened up new possibilities. One was to construct a second 33kV circuit from Kaitaia, with the circuit being incorporated into the new 110kV line over part of its route. However, the preferred option is to divert the 110kV circuit to a point closer to Taipa and to build a 110/11kV substation on a new site. Land for the new substation has been purchased at Garton Rd. The new substation will use zigzag transformers to ensure that the 11kV phasing is the same as the rest of the network.

While the new substation has now been deferred beyond the planning period until after construction of the new 110kV line has been fully completed, it remains an integral component of the network development plan. The existing generators will remain in place until after the new substation has been commissioned.

This project is categorised as system growth.

5.11.3.9 Omanaia Transformer Replacement

The deferral of the construction of the 110kV Taipa substation means that the existing Taipa transformer will not be available for relocation to Omanaia until FYE2024. We are still planning to replace the existing Omanaia transformers in FYE2019 and will purchase a transformer for this purpose. This may be a second hand unit.

This work is categorised as system growth since the peak demand at Omanaia is approaching the rated capacity of the Omanaia transformers.

5.11.3.10 Implementation Timeline and Costs FYE2017 – FYE2021

The implementation schedule for the network development plan over the first five years of the planning period is shown in Table 5.6 below.

$ million (real)	FYE				
	2017	2018	2019	2020	2021
System Growth					
Acquisition of property rights for the 110kV line to supply the new Taipa substation and consenting for the use of the site	0.3	0.2	0.7		
Construction of the Kaeo zone substation and associated overhead lines	2.9	3.5			
Acquisition of property rights for the second incoming supply line to Kaeo zone substation			0.3		
Russell reinforcement			1.0		
11kV distribution network upgrades		1.1	0.5	0.6	1.0
Install new transformer T2 at Kaitaia to replace the existing unit			0.6	3.5	
Install second hand transformer at Omanaia			0.3		
SWER line upgrades			0.6		0.3
Other	0.4	0.2	1.1	0.6	
Total	**3.6**	**5.0**	**5.1**	**4.8**	**1.3**
Reliability, Safety and Environment					
110kV line property rights	2.1	4.4	1.6		

110kV line construction				1.9	4.6
Installation of 110kV bus zone protection at Kaikohe	0.6				
Installation of 110kV bus zone protection at Kaitaia			0.6		
11kV feeder interconnections				0.5	1.8
Replacement of control room SCADA software				0.8	
Other	1.4	0.7	1.1	0.6	0.4
	4.1	**5.1**	**3.3**	**3.8**	**6.8**
Asset Replacement and Renewal					
Pukenui 33kV line rebuild	0.6	0.4			
Kawakawa substation rebuild	1.0				
110kV line structure replacements and tower painting	0.5	0.6	0.5	0.6	0.6
Transmission substation replacements	0.2	0.3	0.6	0.3	0.2
Other planned network replacements	0.1	1.9	2.5	4.7	0.8
Provision for reactive defect remediation	2.0	2.0	2.4	2.1	2.4
	5.4	**5.2**	**6.0**	**7.7**	**4.0**

Table5.6 CAPEX Forecast and Timeline FYE2017 to FYE2021

5.12 FYE2017 Capital Expenditure Work Plan

The tables in this section provide a more detailed breakdown of the FYE2017 CAPEX budget.

5.12.1 System Growth Expenditure

Project	Description	Budget ($000)
Garton Rd (Taipa) 110kV substation	Commence property acquisitions for 110kV incoming line deviation	110
Kaeo substation	Reconfigure 11kV network to be supplied from the new substation	940
Kaeo substation	Acquisition of property rights for the second incoming 33kV supply between the 110kV line and the substation site	160
Garton Rd 110kV substation	Preliminary design and consenting	215
Kaeo substation	Civil works and equipment purchase for the new substation	1,751
Kawakawa substation	Install fans on existing transformers	157
Miscellaneous	Other smaller system growth projects	241
TOTAL		**3,574**

Table 5.7: Breakdown of System Growth Capex Budget FYE2017

5.12.2 Reliability, Safety and Environment Expenditure

Project	Description	Budget ($000)
110kV Wiroa-Kaitaia line	Acquisition of property rights	2,067
11kV network	Miscellaneous power quality upgrades	290
Pad mounted distribution transformers	Retrofitting maximum demand indicators or data loggers on all transformers	129
Communications	Replace the existing Wallis Hill repeater station with a new installation on a site already owned by Top Energy	100
Load shedding	Upgrade the existing automatic under-frequency load shedding equipment to comply with Transpower standards	125
Kawakawa substation	Upgrade the feeder protection at Kawakawa substation to meet our current standards	105
Omanaia substation	Upgrade the transformer protection	170
Kawakawa substation	Upgrade the protection on transformer T1 at Kawakawa substation	115
SCADA	RTU upgrades	121
Kaikohe 110kV substation	Install bus zone protection on the 110kV bus	565
NPL substation	Rectify non-compliant switchyard clearances	170
Miscellaneous	Other smaller RSE projects	120
		4,077

Table 5.8: Breakdown of Reliability, Safety and Environment Capex Budget FYE2017

5.12.3 Asset Replacement and Renewal Expenditure

Project	Description	Budget ($000)
Pukenui 33kV line upgrade – Stage 4	Refurbishment of the Pukenui 33kV line - pole cross arm and insulator replacements as required - selected structures on a priority basis.	551
Taipa 33 kV line upgrade	Refurbishment of the Taipa 33kV line - replacement of wooden poles, cross arms, insulators and conductor as required.	285
Kawakawa/Waipapa double circuit line upgrade	Refurbishment of the double circuit line at the Kaikohe end of the Kawakawa 1 and Wiroa 2 circuits	97
Ring main units	Replacement or refurbishment of older units	264
Air break switches	Replacement or refurbishment of older units	258
Pole mounted transformer	Proactive replacement of larger pole mounted distribution transformers	258

Project	Description	Budget ($000)
Kawakawa substation	Replace circuit breaker trucks on the Kawakawa 11kV switchboard with vacuum interrupter units	640
Kawakawa substation	Replace 33kV transformer incoming circuit breakers	170
Kawakawa substation	Refurbish transformer T2	152
110kV transmission line	Structure replacements and tower repainting	470
110kV transmission substations	Replace protection relays with numerical units	160
General	Provision for reactive renewals and replacements after faults or to remedy defects identified during asset inspections	2,000
Other	Miscellaneous smaller projects	72
Total		**5,377**

Table 5.9: Breakdown of Asset Replacement and Renewal Capex Budget FYE2017

5.13 Capital Expenditure FYE2022 to FYE2026

We have prepared an indicative forecast of our capex requirements for the second half of the planning period. Some large projects are needed to complete the network development plan and require expenditure that has been deferred due to financial, scheduling or operational constraints

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 FYE2022-26 and may not represent the total cost of a particular project or programme.

5.13.1 System Growth Expenditure

Project	Budget ($M, real)	Indicative Timing (FYE)	Comment
Wiroa substation	8.6	2023-25	Construction of 110kV substation
Kaeo substation 33kV line	3.7	2024-25	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 $0.5 million per year is expected to be required for other work, in particular strategic load driven upgrades to the distribution network.
Total	**14.9**		

Table 5.10: Breakdown of System Growth Capex Forecast FYE2022-26

5.13.2 Reliability, Safety and Environment Expenditure

Project	Budget ($M, real)	Indicative Timing (FYE)	Comment
110kV Wiroa-Kaitaia line	21.5	2022-26	Construction works
11kV interconnections	2.8	2022-25	Construction of interconnections between adjacent 11kV feeders
Power quality upgrades	1.5	2022-26	Approximately $0.3 million per year has been allocated for the correction of power quality (mainly low voltage) issues on the network
Other	0.6	2022.26	
Total	**26.4**		

Table 5.11: Breakdown of System Reliability, Safety and Environment Capex Forecast FYE2022-26

5.13.3 Asset Replacement and Renewal Expenditure

Project	Budget ($M, real)	Indicative Timing (FYE)	Comment
Kaikohe zone substation	1.3	2022	Replace 11kV switchboard
Okahu Rd / Omanaia	0.6	2022	33kV line refurbishments
Kaikohe zone substation	1.0	2024	33/11kV transformer refurbishments
Miscellaneous	3.8	2022-26	11kV distribution network refurbishments
110kV transmission	3.2	2022-26	Refurbishments on existing 110kV transmission line
Kaitaia 110kV substation	2.6	2026	Replace outdoor 33kV switchyard with an indoor switchboard
Miscellaneous	1.3	2022-26	Service pillar replacements
Miscellaneous	1.0	2022-26	Transformer earth remediation
Miscellaneous	12.8	2022-26	Provision for reactive defect driven asset replacements
Total	**27.6**		

Table 5.12: Breakdown of System Replacement and Renewal Capex Forecast FYE2022-26

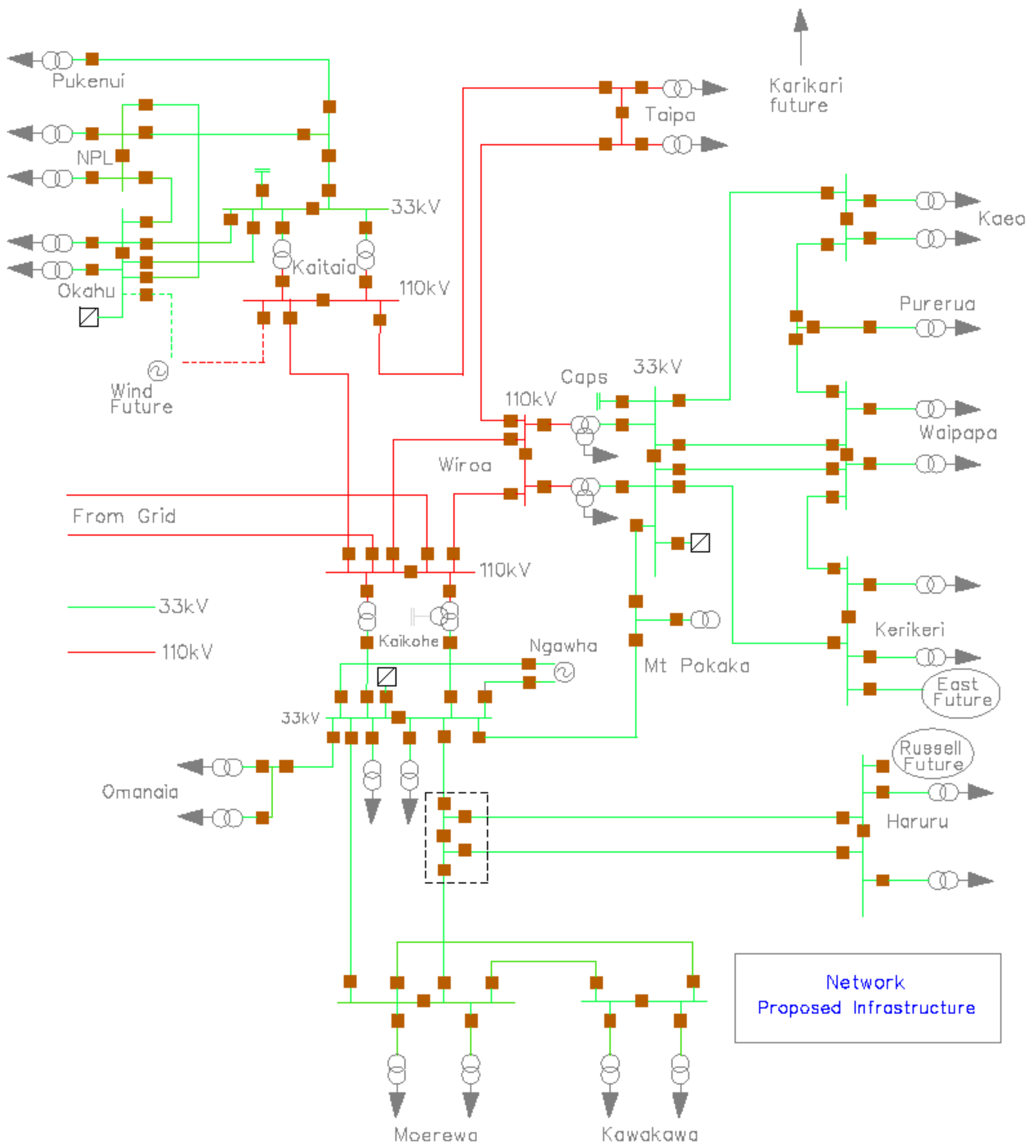
5.13.4 Consumer Connections

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.

5.14 Future Network

The Figure 5.3 below shows what the subtransmission network could look like at the end of the planning period.

Figure 5.3: Possible Infrastructure on Completion of Network Development Plan



5.15 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 5.13 below and shown graphically in Figure 5.4. 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.

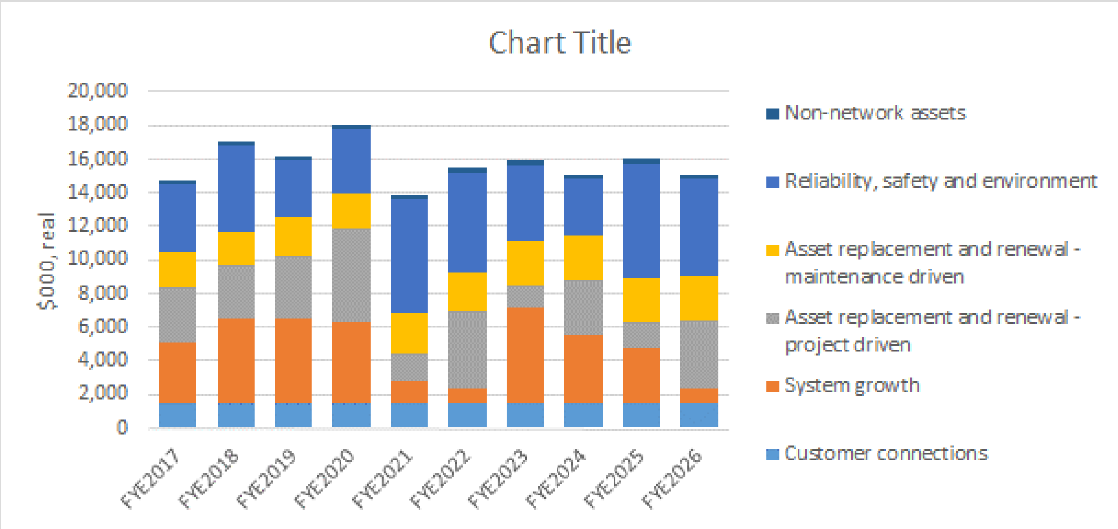


Figure 5.4 **Capital Expenditure Forecast Profile FYE2017 to FYE2026**

($000, real)										
FYE	2017	2018	2019	2020	20219	2022	2023	2024	2025	2026
Consumer connections	1,480	1,482	1,482	1,468	1,468	1,468	1,468	1,468	1,468	1,468
System growth	3,574	5,025	5,063	4,791	1,273	931	5,734	4,057	3,296	841
Asset replacement and renewal - project driven	3,376	3,206	3,657	5,646	1,678	4,608	1,263	3,299	1,537	4,069
Asset replacement and renewal - maintenance driven	2,000	2,000	2,392	2,115	2,405	2,272	2,641	2,641	2,641	2,641
Reliability, safety and environment	4,077	5,067	3,296	3,787	6,800	5,940	4,553	3,327	6,820	5,778
Asset relocations										
Non-network assets	255	255	255	255	255	255	255	255	255	255
Total	**14,762**	**17,036**	**16,145**	**18,062**	**13,880**	**15,475**	**15,915**	**15,048**	**16,017**	**15,053**

Table 5.13: Forecast Annual CAPEX FYE2017 to FYE2026

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 are utilised efficiently during their 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 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 manned 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 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.

Table 6.1 below illustrates this programme. The frequencies indicated represent the maximum time between inspection and it should be noted that some assets are subjected to multiple inspections at differing frequencies; and assets near schools or in high risk public areas may be inspected more frequently in accordance with our public safety management plan.

Our Networks section uses its own specialist field inspectors to undertake the inspection programme. Asset inspection schedules are resident in SAP and ensure that the programme proceeds in a systematic way consistent with the required inspection frequencies. These inspectors perform detailed inspections tailored to the maintenance strategies of the different asset groups and types. Asset condition reports and defects requiring remediation, as well as remediation urgency, are downloaded directly into SAP using hand held digital data input devices. Defects can include the existence of assets such as pencil connectors (see Section 6.4.1) that are known to be unreliable and likely to fail in service. The quality of the asset data reported from these field inspections is proving to be of a good standard and has improved over time with experience and continuous improvement to our inspection and reporting methodology. We how have standardised criteria specifying how asset condition is to be assessed and recorded in SAP for different asset types. Over time, SAP will be able to provide a historical record showing the rate of deterioration of each asset and we will be able to use this information to help us develop more effective and cost efficient maintenance strategies.

GROUP	ASSET	VOLTAGE	TYPE
Field Equipment	Poles/Conductors/Cables	33kV	Annual –ground based 6 year - aerial
		≤22kV	5 Year
	Pole Mounted Transformer	≤22kV	2 Year
	Ground Mounted Transformer	≤22kV	2 Year
	Switchgear – Pole Mounted	≤33kV	2 Year
	Switchgear – Ground Mounted	≤22kV	2 Year
	Regulator	≤22kV	Annual
	Capacitors	≤22kV	2 Year
	Service/Link Pillars	400V	3 Year
	Earths	≤33kV	2 Year
Substation Equipment	Buildings	Substation	Monthly
	Equipment (Generic)	Substation	Monthly
	No Break Power Systems	Substation	6 Monthly
	Transformer	33kV	Annual
	Switchgear/Bus (not oil filled)	<=33kV	4 Year
	Oil-filled switchgear	33kV	Annual
	Oil-filled switchgear	11kV	2 Year
	Earths	≤33kV	Annual
	Protection	≤33kV	4 Year
SCADA and Communications	Radio Repeater	Communications	Annual
	Substation Equipment	Communications	2 Year
	Field Equipment	Communications	3 Year
Vegetation Management	Pole Mounted Assets	33kV	Annual
		≤22kV	3 Year
	Ground Mounted Assets	≤33kV	Annual

Table 6.1: Asset Inspection Programme

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 the majority of our asset base and we are now moving into a phase where part of the cost of our vegetation management programme will be recovered from tree owners. While this is reflected in our forecasts of future vegetation management costs, we do not intend to reduce the intensity of our vegetation management programme below its current level.

6.1.4 Replacement and Renewal Maintenance

Replacement and renewal maintenance is condition-based maintenance that is usually triggered by the findings of the routine inspection and condition assessment programmes. Our renewal maintenance philosophy entails performing maintenance only when safety, reliability and performance are compromised. 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 assess and budget future renewal maintenance and asset replacement requirements.

We download schedules of defects identified during routine asset inspections as requiring remediation from SAP and use these to prepare our reactive maintenance works programmes. Once a defect is remedied, it is cleared in SAP so that up-to date records of current defects are always available. SAP is also now used to generate reports of defect backlogs.

Employees are expected to report asset defects identified as requiring attention and the public are encouraged to do the same. Asset defects are rated as summarised in Table 6.2 and the appropriate action is taken.

PRIORITY	ISSUE	RESPONSE TIME
X – Very High	Critical – Fault or near fault	Remediate within 48 hours.
A – High	Urgent – Unplanned, end of life	Remediate within 3 months.
B – Medium	Routine – Planned, end of life	Remediate within 12 months.
C – Low	Monitor – Approaching end of life	No remediation timeframe. Monitor condition.
D – Very Low	Passive – No operational impact	No remediation timeframe. No action required.

Table 6.2: Response Priority Definitions

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 this 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 reducing the level of maintenance, including letting assets run to failure where this is possible without compromising safety. For example, components subject to a replacement programme because they are known to be unreliable may be run to failure rather than proactively replaced. The result is likely to be higher rates of equipment failure and an increased number of outages on the uneconomic parts of our network. During storm conditions, supply restoration would be prioritised so that supply would first be restored to consumers connected to the economic parts of the distribution network.

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 and, as a result, the condition of the assets was generally good for their age. However, the assets are old and this is reflected in the acquisition price, which is well below their replacement cost, which we estimate to be approximately $35 million. 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

There are a total of 301 structures on the line comprising: 14 steel towers, 117 wood structures and 170 concrete structures. A full condition assessment of the lines 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 provides 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 were in need of 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 progressive replacement of the remaining wooden poles in poor condition with the octagonal steel poles being planned for the Wiroa-Kaitaia line. We also plan that, until the Wiroa-Kaitaia line is in service, these pole replacements will be undertaken using live line techniques.

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.

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 on the basis of 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;
- 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. No. 8 fencing wire has been used historically for emergency conductor repair. Although this practice has ceased, it is causing problems due to corrosion. Fencing wire is being replaced as it is found; however, there are no records of its use and it is difficult to locate and identify.

6.4.2 Planned Inspection & Maintenance Practices for Overhead Conductors

Ground-based visual inspection of subtransmission conductors is performed annually, and distribution and low voltage conductors are inspected on a five-year cycle. Thermal imaging of subtransmission lines is also conducted annually and six-yearly for distribution conductors. Helicopter-based inspection of subtransmission lines is conducted six-yearly, supplemented by the occasional inspection initiated for fault or operational reasons.

Identified problems are recorded and repairs are made in accordance with the processes identified in Section 6.1. The assessed condition of each asset is prioritised based upon condition criteria, which in turn is used to schedule maintenance and replacement.

6.4.3 Vegetation 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 in order to improve reliability by reducing the incidence of vegetation related faults and expenditure has now been reduced as we have transitioned to a more sustainable maintenance phase. Now that or first cut is complete, going forward we are looking to recover more of the cost of vegetation management from tree owners.

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 (FNDC) Relationship

The 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 are in discussion with the FNDC over this issue.

6.4.3.3 Targeted Cutting Strategy

Vegetation management in FYE2017 is budgeted at $1.83 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 on the basis of their contribution to network SAIDI. In FYE2017 the focus will be on the Rangiahua, Totara North and Whangaroa feeders.

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

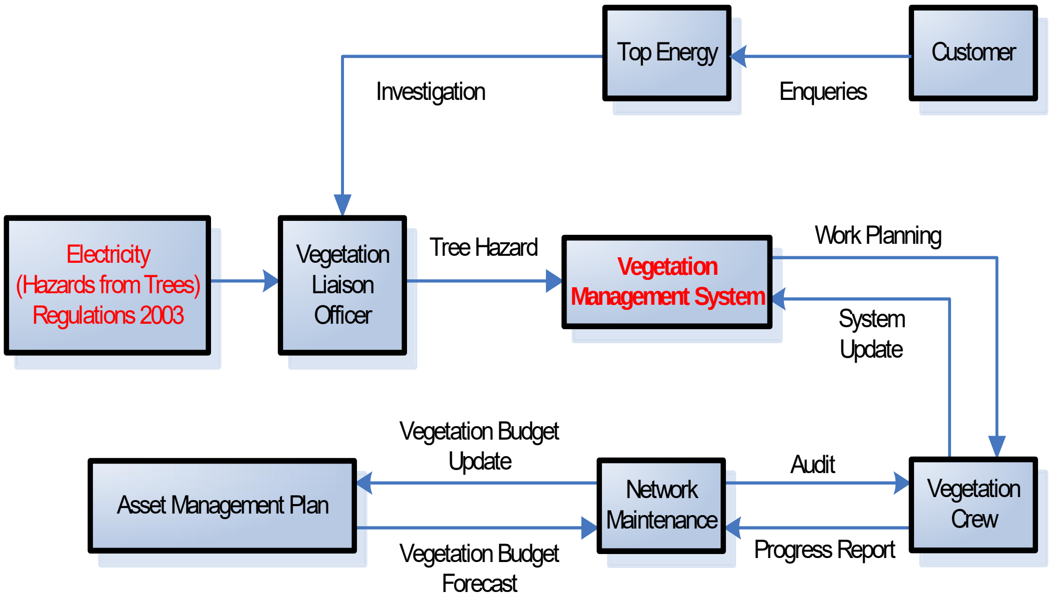


Figure 6.1: Information Flow – Vegetation Management

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. The majority 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. Older wooden poles are being phased out over a twenty-year period, starting with a proactive project to replace the wooden poles on the 33kV subtransmission line supplying the Pukenui zone substation.

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 now approximately 60 years old and 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 pole failure.

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 consequences of all of the above modes of failure are live conductors on the ground or low conductors, which pose a real safety risk.

6.5.2 Inspection & Maintenance Practices for Poles and Structures

The inspection schedule currently in place for poles and practices is as following:

Ground-Based Inspection: Ground-based inspection of transmission and subtransmission poles and structures is conducted annually and five-yearly for the distribution network. Thermal imaging and a radio frequency discharge detector are used on the subtransmission circuit to assess the condition of each insulator and connection. Hazardous poles are identified and tagged for priority attention and recorded in SAP. At present, we use traditional methods of condition assessment for wooden poles on the subtransmission and distribution network (i.e. a visual inspection together with a hit with a hammer/aural test for rot). This is performed in association with digging the ground out around the air/soil interface to allow a visual/probe inspection. Concrete poles are inspected visually for exposed reinforcing and possible degradation of the concrete.

Pole-Top Inspection: The periodic ground-based and inspection programme is considered sufficient at present and pole top inspections requiring poles to be climbed or using an elevated bucket are not normally carried out unless other work is being undertaken on the pole. The six yearly aerial helicopter-based inspections of subtransmission lines will also identify significant pole top issues.

Identified problems are recorded and repairs actioned in accordance with the processes identified in Section 6.1.2.

6.5.3 Asset Renewal Programme

We replace poles that are no longer considered fit for service well before unassisted pole failure is likely to occur.

Our strategy is to optimise the maintenance expenditure on cross-arm replacement. To this end, the complete pole is replaced whenever a wooden cross-arm requires replacement on an old pole that itself would be replaced in less than seven years. This is because it is not cost-effective to replace only the cross-arm where less than seven years of service is expected from the pole.

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 as a result of 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 it is 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 is monitored regularly 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 be retroactively fitting lighting arrestors on pole mounted transformers in lightning prone areas.

The majority of our consumers live either on farmland or in coastal locations. Farmland tends to have a low density population, whereas coastal areas tend to have a higher, and somewhat seasonal population. As a consequence, 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

Distribution transformers are inspected every two years. In addition to these condition monitoring inspections, all ground mounted transformers are inspected annually for safety. As part of this inspection process, minor maintenance work is undertaken, such as replacing any missing padlocks and clearing any vegetation from inside the cubicles. Asset condition such as corrosion, oil leakage, missing base plates are recorded in SAP in accordance with the processes described in Section 6.1.2.

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.

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, 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 cause of failure of RMUs within our geographical area is third-party vehicle accidents. Another problem is 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 21 years and 24 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 on a two yearly cycle 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 inspections 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. Provision is made in the in the capital expenditure forecast for the provision of bunding and oil interception facilities at Kawakawa and 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 taking 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, as required during the monthly station inspections. 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 it 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. It is proposed to lower and properly secure the transformers at the Kawakawa and Waipapa substations 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 scheduled for replacement in FYE2019. We are planning to buy a second hand unit as an interim replacement until the Taipa substation transformer becomes available after the end of the planning period. In the meantime, it is also planned to install the mobile substation at Omanaia, when it becomes available. We are also in the process of refurbishing both Kawakawa transformers.

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 > 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 Bushing Failures

In the past year we have experienced three failures of cable termination bushings on the 33kV switchboards recently installed at Kerikeri, Wiroa and Kaikohe. Both Vector and Transpower have experienced similar failures on switchgear of the same type. None of these failures has resulted in a supply interruption as these are critical assets and are designed with N-1 redundancy.

We believe that the bushings were faulty and are seeking to have the manufacturers replace these parts under warranty.

6.15.4 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. Refurbishment of the 11kV indoor switchboard and replacement of the 33kV transformer incoming minimum oil circuit breakers installed at Kawakawa are planned for FYE2017.

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 life span. 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 on a monthly basis.

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.

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. As long as the enclosure remains intact, components could be replaced indefinitely. 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 and 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 been therefore 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.

A total of almost $1.7 million (real) has been included in the asset replacement CAPEX forecast for the renewal of transformer earths.

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 on a monthly basis, 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.

Provision has also been made in the capex forecast for enhancements to the SCADA master station in FYE2020 to enable more information to be automatically passed between various systems in order to reduce the manual entry of data for both real-time operations and reporting purposes. This will include an outage management system that will increase the efficiency with which we manage supply interruptions and automatically calculate the SAIDI and SAIFI impact of each interruption and will replace the paper based system that we currently use.

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 on a monthly basis. 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. Table 6.3 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>Cost Code</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>
</table>

MR (all asset categories – distribution)	Replacement and renewal (distribution – broken down by asset category)	Replacement and renewal (distribution)	Asset replacement and renewal
MR (all asset categories – transmission)	Replacement and renewal (transmission – broken down by asset category)	Replacement and renewal (transmission)	

Table 6.3: Mapping of Top Energy's Asset Forecast

6.24.1 Service Interruptions and Emergencies

($000, real)	FYE									
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Lines and poles	450	450	450	450	450	450	450	450	450	450
Cables and pillars	150	150	150	150	150	150	150	150	150	150
Transformers	330	330	330	330	330	330	330	330	330	330
Buildings and grounds	-	-	-	-	-	-	-	-	-	-
Switchgear and protection	70	70	70	70	70	70	70	70	70	70
Secondary systems	200	200	200	200	200	200	200	200	200	200
	1,200	**1,200**	**1,200**	**1,200**	**1,200**	**1,200**	**1,200**	**1,200**	**1,200**	**1,200**

Table 6.4: Service Interruptions and Emergency Maintenance OPEX by Category

6.24.2 Routine and Corrective Maintenance

($000, real)	FYE									
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Routine maintenance & inspection	**1,675**	**1,675**	**1684**	**1,693**	**1,702**	**1,711**	**1,720**	**1,729**	**1,738**	**1,747**
Safety & Compliance	**90**	**90**	**90**	**90**	**90**	**90**	**90**	**90**	**90**	**90**
Vegetation	**1,833**	**1,833**	**1,835**	**1,837**	**1,839**	**1,841**	**1,843**	**1,845**	**1,847**	**1,849**
Asset replacement & renewal										
Lines and poles	639	639	628	557	562	567	572	577	582	587
Cables and pillars	25	25	25	25	25	25	25	25	25	25
Transformers	70	70	70	70	70	70	70	70	70	70
Buildings and grounds	20	20	20	20	20	20	20	20	20	20
Switchgear and protection	140	140	140	140	140	140	140	140	140	140
Secondary systems	45	45	45	45	45	45	45	45	45	45
Subtotal – replacement & renewal	**939**	**939**	**928**	**857**	**862**	**867**	**872**	**877**	**882**	**887**
TOTAL	**4,537**	**4,537**	**4,537**	**4,477**	**4,493**	**4,509**	**4,525**	**4,541**	**4,557**	**4,573**

Table 6.5: Breakdown of Routine and Corrective Maintenance

6.24.3 Summary of Maintenance Opex Forecast

($000, real)	FYE									
	2017	2018	2019	2020	2021	2022	2023	2024	202	2024
Service interruptions and emergencies	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Routine maintenance and inspection	1,765	1,765	1,774	1,783	1,792	1,801	1,810	1,819	1,828	1,837
Vegetation	1,833	1,833	1,835	1,837	1,839	1,841	1,843	1,845	1,847	1,849
Replacement and renewal	939	939	928	857	862	867	872	877	882	887
Total	**5,737**	**5,737**	**5,737**	**5,677**	**5,693**	**5,709**	**5,725**	**5,741**	**5,757**	**5,773**

Table 6.6: 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 general 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 5.10-5.12
- 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 5.13 includes a provision for this work, the cost of which is largely based on actual historic costs. Maintenance capex provisions are included in the capex forecasts in Sections 5.10 – 5.14. 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 6.7.

6.26 Non-network Capex

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 Networks staff, office equipment and miscellaneous equipment such as survey equipment. This situation is not expected to change over the planning period and expenditure is limited to the purchase of additional assets to accommodate increases in Networks staff levels and replacement of assets as required. The capex forecast in Appendix A, Schedule 11a, includes a provision of up to $255,000 per annum for non-network assets.

This forecast constitutes the non-network capex forecast in Schedule 11a on Appendix A.

6.27 Non-network OPEX

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 Networks asset management team, as shown in Figure 2.3; and

- the cost of the business support functions required for our Networks team to function effectively. These include governance, commercial, human resource, regulatory, finance and other support services, which are provided by Top Energy's corporate team and are shared with Top Energy's other operating divisions. The costs of providing these services are allocated to Networks 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									
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Transmission and subtransmission lines	140	140	167	148	168	159	185	185	185	185
Transmission and zone substations	140	140	167	148	168	159	185	185	185	185
Distribution lines	820	820	981	867	986	932	1083	1083	1083	1083
Distribution cables	140	140	167	148	168	159	185	185	185	185
Distribution substations and transformers	620	620	742	656	746	704	819	819	819	819
Distribution switchgear	140	140	167	148	168	159	185	185	185	185
Total	2,000	2,000	2,392	2,115	2,405	2,272	2,641	2,641	2,641	2,641

Table 6.7: Breakdown of Maintenance Capex Forecast

($000, real)	FYE									
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
System operations and network support	4,508	4,764	4,883	5,005	5,130	5,258	5,390	5,525	5,663	5,805
Business support	3,378	3,446	3,515	3,585	3,657	3,730	3,805	3,881	3,958	4,038
Total	**7,886**	**8,210**	**8,398**	**8,590**	**8,787**	**8,988**	**9,195**	**9,406**	**9,621**	**9,843**

Table 6.8: 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

Networks 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.

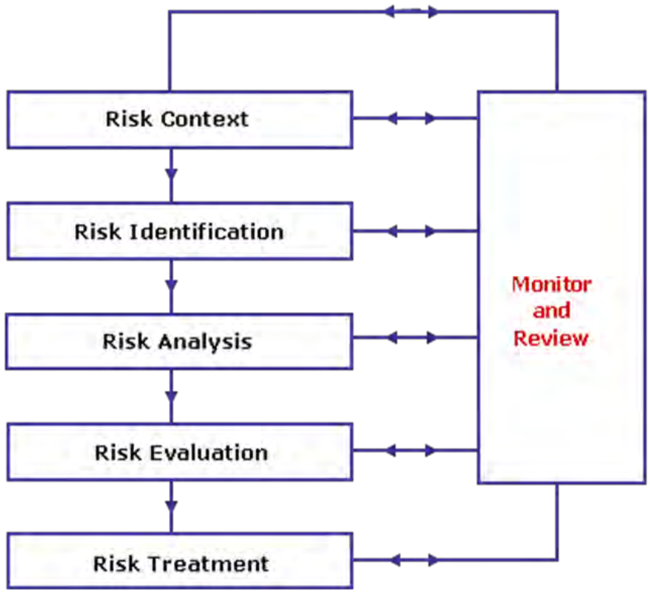


Figure 7.1 Network risk management process

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 Networks, 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 yr 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 assoc 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: hot stick live line; glove and barrier live line; 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.

In order 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.

Our health and safety system was recognised by the wider industry in 2010 when we obtained the Accident Compensation Corporation's (ACC's) tertiary level accreditation for workplace safety management practices at our first attempt. Further recognition was gained when we won the Electricity Engineers' Association's Public Safety Award in 2010 and its Workplace Safety Award in 2011. We have maintained our "tertiary" level accreditation for ACC workplace safety management practices.

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 construct a second 110kV circuit. When this is commissioned there will be no need for planned transmission system interruptions and little risk of unplanned interruptions. There should also be no need for live line maintenance on the transmission system.

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 Networks 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.

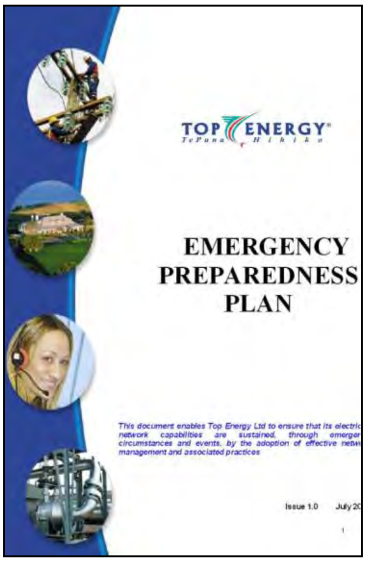
7.2.2.3 Network Critical Spares

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 situation, irrespective of whether or not 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 in order to stabilise the situation from further danger, damage and unnecessary outages.
- **Recovery** following Response, in order 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, in order 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 has voluntarily committed to work with the Northland Civil Defence Emergency Management Group to provide use of the ripple control network for the activation of audible alarm sirens or tones. A procedure has been adopted to ensure that we meet its 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 5.9.

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.

7.2.8 Public Safety Management System

We have in place a formalised public safety management system designed to minimise the risk of our network assets causing harm to the general public. This system is independently audited on a regular basis.

Section 8 Evaluation of Performance

8 Evaluation of Performance

This section presents a review of our financial and service level performance for FYE2015, 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 a comparison is made against internal and external 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 against Targets

Consistent with the requirements of the default price path and information disclosure regimes, network reliability is measured by SAIDI and SAIFI. These measures are also used for internal monitoring purposes and target service levels are included in Section 4. In FYE2015, as a result of faults originating within our network, there were a total of:

- 401 unplanned 11kV and 33kV supply interruptions; and
- 171 planned 11kV, 33kV and 110kV outages.

FYE	2011	2012	2013	2014	2015		2016	
RELIABILITY MEASURE[1]	Actual				Target	Actual	Target	Actual (to 31 Dec)
SAIDI (distribution network)	440	435	277	435	284	487	254	333
SAIDI (transmission network but excluding Transpower)	-	-	56	30	56	112	70	58
SAIDI (including transmission, but excluding Transpower)	**-**	**-**	**333**	**465**	**324**	**600**	**324**	**391**
SAIFI (distribution network)	4.9	6.4	4.4	5.2	3.7	5.6	3.8	3.9
SAIFI (transmission network but excluding Transpower)	-	-	0.2	0.3	0.4	0.7	0.4	0.3
SAIFI (including transmission, but excluding Transpower)	**-**	**-**	**4.7**	**5.8**	**4.1**	**6.4**	**4.1**	**4.2**
Number of consumers without power for 24 hours	226	56	18		<25	8,993	<25	98
Number of consumers without power for more than 3hrs	19,789	15,629	20,208		<7,000	63,491	<7,000	23,345

Note 1: Prior to FYE2013, any faults on the 110kV transmission system acquired from Transpower are not included in the above table.

Table 8.1: Normalised network reliability performance

Table 8.1 compares the actual reliability of the network during FYE2015 with the targets set out in the 2014 AMP and FYE2015 Statement of Corporate Intent. Normalised reliability measures are shown separately for the transmission and distribution networks to enable the distribution network performance to be compared directly with prior years. It can be seen that the reliability of supply in FYE2015 was lower than any of the earlier four years. While this is disappointing it is a primarily result of the extreme weather we experienced during the year.

On 17 April 2014 our network was hit by the remnants of Tropical Cyclone Ita, which on a single day resulted in a total of 32 high voltage supply interruptions with a total SAIDI[7] impact of 82.9 minutes. Then, on 8 July 2014, we were hit by a second severe weather event that caused winds well in excess of gale force and extensive flooding, which intensively damaged not only our network but also roads and other public infrastructure. While this storm was not categorised as a cyclone, a blocking high pressure area to the south east of New Zealand caused it to remain stationary over our supply area and persist for several days. State Highway 1 was closed for a number of days by a slip south of Kawakawa, which has only recently been permanently repaired. Over the month of July, we experienced a total of 87 unplanned high voltage interruptions with a total SAIDI impact of 1,362 minutes or almost 23 hours. Then, just prior to Christmas 2014 we discovered a land slip on the top of the Maungataniwha Ranges, which caused a tower on the 110kV Kaikohe-Kaitaia transmission line to move almost 10 metres and some of the tower members to break. An unanticipated planned outage of this line to replace the damaged structure, with a SAIDI impact of about 120 minutes, was necessary in March 2015. The damaged tower supported long spans and was located in isolated and difficult terrain. It was not possible to engineer and fabricate a replacement in time for the planned outage that occurred on 1 February 2015. Hence we were forced to have two planned day long outages, each impacting one third of our consumers, within the space of two months.

The impact of the weather on the performance of our network is shown in Table 8.2, which shows the number of unplanned consumer interruptions on our distribution network and the consequent SAIDI impact for each month of FYE2015. The data in this table has not been normalised.

Month	No of Interruptions	SAIDI	SAIDI per Interruption
April	52	87.7	1.7
May	21	6.7	0.3
June	28	30.2	1.1
July	89	1250.8	14.1
August	30	32.0	1.1
Sept	32	34.5	1.1
Oct	27	27.8	1.0
Nov	26	13.2	0.5
Dec	35	59.5	1.7
Jan	15	7.3	0.5
Feb	14	12.0	0.9
March	31	29.6	1.0
Totals	**400[1]**	**1591.2**	

Note 1: There was also one unplanned transmission network interruption with a SAIDI impact of 0.5 minutes which is not shown in this table. This occurred in May and the cause of the interruption is not known. It was the first unplanned interruption of this circuit for several years.

Table 8.2: Unplanned Distribution Network Interruption FYE2015

It can be seen from Table 8.2 that 44% of the unplanned interruptions and 88% of the resulting SAIDI impact occurred during the months of April, July and December. December was a particularly wet month, resulting in the ground conditions that caused the transmission tower foundation failure. The table also shows that it takes

[7] SAIDI in an acronym for System Average Interruption Duration Index and measures the cumulative time that the average consumer is without an electricity over a measurement period (which for regulatory purposes extends from 1 April until 31 March the following year).

longer to repair a fault during storm conditions and this exacerbates the SAIDI impact. It is clear from the table that the damage caused to our network during the July storm exceeded our response capacity and we are grateful for the support of Northpower and WEL, who both provided line crews to assist.

Other factors that adversely impacted our measured reliability during FYE2015 were the need for two planned transmission outages and our decision in during FYE2014 to stop using portable diesel generators to mitigate the SAIDI impact of planned interruptions, after our consumers told us in our 2014 consumer survey that they would prefer that the money was spent on improving the network. The SAIDI impact of planned distribution network interruptions in FYE2015 was 45 minutes from 169 interruptions, compared to only 25 minutes from 253 interruptions in FYE013.

Our measured reliability to date in FYE2016 is already lower than the normalised targets for the full year, as is apparent from Table 8.1. In part this is due to two major event days that, in both cases, were an indirect consequence of the implementation of our network development programme.

- On Friday 18 April 2015 an insulator failed on our Kaikohe - Wiroa No 2 line, which is the older circuit that also supplies Mt Pokaka. This event should not have caused an interruption as the load on this line should have been transferred to the new 110kV circuit and Mt Pokaka back fed from Wiroa. Unfortunately, at the time of the fault, the new line was on a planned outage for the installation of a fibre-optic ground wire. Supply could not be restored until the new line had been made safe and all men and earths were clear.

  This event interrupted supply to almost 10,000 consumers in the Mt Pokaka, Kerikeri, Waipapa and Kaeo areas for over three hours and has a SAIDI impact of 35.3 minutes. For measurement purposes, this is normalised to 29.4 minutes using the methodology described in Section 4.

- On Sunday 22 November 2015, more than 20,000 consumers in our southern area lost supply for almost two hours when the bus zone protection on the recently commissioned 33kV switchboard tripped. We think that the tripping was caused by a transient earth fault on one of the 33kV outgoing circuits that was not seen by the primary protection, and never physically located[8].

  Setting automatic protection systems is a specialist task and it can be difficult to develop settings that operate as intended in all fault situations. The Kaikohe bus zone protection settings were prepared for us by an external consultant and have now been adjusted to prevent a reoccurrence.

There have been two other events so far this year that have impacted the reliability of supply as seen by our consumers.

- On Friday 9 October 2015 Transpower's two 110kV circuits at Maungatapere both tripped, causing a complete loss of supply for all our consumers of up to four hours in some cases. Protection constraints prevent operation the Ngawha power station when our network is isolated from the grid. The fact that two independent systems detected an event at the same time suggests that the cause was not a random failure of the protection electronics. The most likely cause of such an event would be a fault either within the Kaikohe substation switchyard or on the Kaitaia 110kV line close in to the substation. However, helicopter patrols by Transpower and a close inspection of our relevant assets failed to find a cause and there has been no repeat of the event. The SAIDI impact of the event was 156 minutes but we are not counting it as an interruption caused by our assets. This is because it was the operation of Transpower's protection that caused the interruption and neither ourselves nor Transpower have been able to conclusively establish that our network assets were at fault. As a result of this incident, we are now planning to install bus zone protection on the Kaikohe 110kV bus to minimise the probability of a similar event causing both incoming circuits to trip simultaneously.

- On Sunday 29 November 2015, we had our annual planned maintenance shutdown of the 110kV Kaitaia line. This lasted over nine hours and affecting almost 10,800 consumers. It had a SAIDI impact of 116 minutes, which was normalised to 58 minutes using the Commission's new normalisation methodology, which reduces the SAIDI and SAIFI impact of planned interruptions by 50%. Major event days cannot arise from planned interruptions under the Commission's new normalisation approach.

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8 This is not unusual. An example of a transient fault is a branch being blown onto a line and then falling away.

Our normalised reliability since FYE2012 shown in Table 8.1 indicates that, given the present state of our network, our current reliability targets are only achievable in benign weather conditions, such as we experienced in FYE2013, and are unachievable in a normal year. We have therefore reset our reliability targets to be more realistic and the revised targets are presented in Chapter 4. We are confident that, in the absence of extreme weather conditions in the last quarter, our normalised reliability in FYE2016 will not exceed the Commission's reliability limits shown in Table 4.2. We are also very confident that our network development plan is soundly based, given its objective of improving the reliability of supply that our network is able to provide, and that our consumers will see the benefits of this investment over coming years.

8.1.2 Strategies to Improve Reliability

Analysis of our interruption statics shows that it has taken on average 89 minutes over the first three quarters of FYE2016 to restore supply following an interruption caused by an unplanned fault on of distribution network. During FYE2015 the corresponding average was 94 minutes if our performance during the July storm is treated as an outlier and not considered. This is not out of line with international norms for a sparsely populated rural network like ours and suggests that reliability improvement strategies should be targeted at improving SAIFI by reducing the incidence of faults on the network and the impact of these faults on consumers. This is being achieved in a number of ways:

- The completion of the second 110kV line to Kaitaia will improve reliability both by avoiding the need for an annual transmission outage and also by ensuring that any unplanned transmission fault should not result in a supply interruption.
- By FYE2016, we will have completed protection upgrades to our 33kV subtransmission system. This will enable the duplicated lines supplying our larger zone substations to be run in parallel so that faults on this part of the transmission system should no longer cause a supply interruption.
- Increasing the number of 11kV feeders on the system will reduce the average number of consumers connected to each feeder, which should reduce the average number of consumers affected by a fault on the distribution network. Eight new feeders were added in FYE2014, six from the new Kerikeri zone substation, and one each from the Haruru and Kawakawa zone substations. Completion of the Kaeo substation in FYE2018 will introduce five new feeders and should improve the reliability of supply experienced by consumers north of Waipapa.
- We have already shown that vegetation control is an effective way of managing reliability since those areas most susceptible to tree contact faults can be readily identified and targeted. We will continue our vegetation management efforts and targeting the subtransmission network and the most vulnerable sections of the core 11kV distribution network. Our "first cut" under the Electricity (Hazards from Trees) Regulations 2003 has now been mostly completed and, in accordance with the provisions of these Regulations, we will now be looking to tree owners to partly fund our vegetation management efforts.
- We are focusing our short-term network renewal and replacement expenditure on three of our five worst performing feeders, Pukenui, South Road, and Rangiahua. We have also accelerated the completion of the Kaeo substation, largely because this will split the other two worst performing feeders, Totara North and Whangaroa, into three sections, which should significantly improve their reliability.
- We have upgraded our overhead line design standard to comply with AS/NZS 7000: 2010, the Australian and New Zealand Standard for Overhead Line Design – Detailed Procedures. All our new and upgraded overhead lines are now being designed and constructed to this standard. In addition, we are investigating the use of overhead covered conductor designs in some difficult locations.

8.2 Asset Performance and Efficiency

Table 8.4 compares our achieved asset performance and efficiency measures in FYE2015 with the target levels set out in the 2014 AMP.

PERFORMANCE MEASURE	FYE2015 TARGET	ACTUAL PERFORMANCE	VARIANCE
Loss Ratio	9.5%	10.2%	+0.7%
Operational Expenditure to Total Regulatory Income	34.5%	33.3%	(1.2%)

Table 8.3: Comparison of actual asset performance and efficiency with target levels for FYE2013

As indicated by the table, the loss ratio target was not met during FYE2015 but the operational expenditure measure was bettered. Our assessed performance against both measures is taken from our audited FYE2015 information disclosures.

The high loss ratio is a reflection of the current state of the network. As noted in Section 4.3.1, it is no coincidence that our network has both the lowest reliability and the highest loss ratio of any EDB in the country. That said, our loss ratio now also includes transmission losses so is not directly comparable with many other EDBs. Implementation of the network development plan described in Section 5 of this AMP should bring about an improvement in the loss ratio. In the short term it may be that the reduction in line losses is offset by an increase in transformer losses as more power transformer capacity is added to the network, although we have not analysed the relative impacts. We expect the commissioning of the second 110kV line in FYE2026 to result in a material improvement to our measured loss ratio.

8.3 Financial and Physical Performance

A comparison of our actual expenditure in FYE2015 for both network capital expenditures and network maintenance with the budgeted expenditures, as presented in the 2014 AMP is provided in Table 8.4. It can be seen that while there are variances between the different 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 FYE2015	ACTUAL SPEND FYE2015	VARIANCE	
Network capital expenditure ($000)				
Consumer connection	1,000	1,471	471	47%
System growth	2,830	2,876	46	2%
Asset replacement and renewal	9,039	9,369	330	4%
Reliability, safety and environment	11,910	10,274	(1,636)	(14%)
Asset relocations	-	-	-	-
Subtotal – network capital expenditure	**25,054**	**24,638**	**(416)**	**(2%)**
Maintenance expenditure ($000)				
Service Interruptions and emergencies	1,500	1,721	271	15%
Vegetation management	2,145	2,078	57	(3%)
Routine and corrective maintenance and inspection	2,036	1,058	1,078	(48%)
Asset replacement and renewal	616	937	321	52%
Subtotal – maintenance expenditure	**6,297**	**5,794**	**503**	**(8%)**
TOTAL DIRECT NETWORK EXPENDITURE	**31,351**	**30,432**	**(919)**	**(3%)**

Table 8.4: Comparison of actual and budget network Capex and network maintenance Opex for FYE2015

8.3.1.1 Network Capital Expenditure

The actual FYE2015 capex shown in Table 8.4 is taken from our 2015 information disclosure, which indicates that 98% budgeted capex for FYE2015 was utilised. Consumer connection capex was significantly higher than budgeted (off a low base) due to higher than expected demand for now connections. We have little control over this. There was also some reallocation of expenditure across the other capex categories. During the year we made significant progress on our network development programme as shown in Table 8.5 below.

Project	Comment
System Growth	
110kV Kaikohe Wiroa line	Stringing of the northern section of this line was completed and it is now in service at 33kV.
Kerikeri substation 33kV incoming cable	Installation of both incoming cables supplying Kerikeri substation was completed and both are now in service.
Asset Replacement and Renewal	
Kaitaia transformer replacement	The replacement 110/33kV transformer at Kaitaia transmission substation was installed and commissioned.
Moerewa outdoor-indoor switchgear replacement	A new switchgear building was constructed and the new indoor 11kV switchboard was installed and commissioned
Reliability Safety and Environment	
110kV Wiroa-Kaitaia line	It was decided not to commence construction of this line until the route had been secured. Negotiations with affected property owners continued.
Kaikohe outdoor-indoor 33kV switchgear replacement	This project was completed and the switchboard commissioned and put into service.

Table 8.5: Significant Network Development Project Achievements in FYE2015.

8.3.1.2 Network Maintenance Expenditure

As shown in Table 8.4 network maintenance expenditure in FYE2015 was 8% less than budgeted. This was primarily due to significant under-expenditure by TECS on routine maintenance, after it became resource constrained and prioritised other work. Responsibility for planning and managing the asset inspection and routine maintenance programme was transferred from TECS to Networks in the reorganisation that became effective on 1 April 2014. Our asset inspectors are now attached to Networks and no longer available to TECS in an initiative intended to ensure that the asset inspection programme remains on track.

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 has been running for a number of years and that has 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 goal of also achieving ISO 55000 certification remains aspirational at this stage and no formal project has been established to achieve this. Instead we are focusing on improving those areas that we know to be weak and to be impeding the efficient implementation of our asset management system. Much of these weaknesses are still at the interface between Networks and TECS and efforts to improve the communication links between these two business units will continue.

Our asset management goals for FYE2017 include:

- Further development of our asset inspection standards to provide more consistency in the classification of defects and to increase the usefulness of the asset condition information recorded into SAP;
- Improvements in the planning and implementation of our maintenance effort to improve the efficiency with which it is delivered. This will include the preparation of maintenance work packages for TECS, with the expectation that all work in a maintenance work package, which could include all known defects within a specific geographic area, would be undertaken at the same time as a single project. This approach should capture potential efficiencies in maintenance delivery;

- Increasing the extent to which the more complex substation maintenance work is made contestable and open to contractors other than TECS, with the objective of ensuring that shortages of key skills within TECS does not impede maintenance delivery.
- Updating design and procurement standards and general arrangement drawings to ensure that not only are new designs fit for purpose, but also repetition in the design and planning of both capital and maintenance projects is avoided and that services and materials are procured only from prequalified suppliers in a consistent manner. A project was initiated in late FYE2016 to create automated links between the CAD general arrangement drawings, their associated Bills of Materials and the relevant SAP procurement stock numbers.

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
Schedule 14	Schedule 14a

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SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

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sch ref

			Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
7			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8		for year ended	**31 Mar 16**	**31 Mar 17**	**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**
9		**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10		Consumer connection	1,570	1,480	1,512	1,542	1,558	1,589	1,621	1,654	1,687	1,721	1,755
11		System growth	3,040	3,574	5,126	5,267	5,084	1,378	1,027	6,457	4,660	3,862	1,005
12		Asset replacement and renewal	7,090	5,376	5,310	6,294	8,236	4,420	7,596	4,397	6,823	4,895	8,019
13		Asset relocations											
14		Reliability, safety and environment:											
15		Quality of supply	3,750	4,077	5,168	3,429	4,019	7,361	6,559	5,128	3,822	7,990	6,906
16		Legislative and regulatory											
17		Other reliability, safety and environment											
18		**Total reliability, safety and environment**	3,750	4,077	5,168	3,429	4,019	7,361	6,559	5,128	3,822	7,990	6,906
19		**Expenditure on network assets**	15,450	14,507	17,117	16,532	18,897	14,748	16,804	17,635	16,993	18,468	17,685
20		Expenditure on non-network assets	95	255	260	265	271	276	282	287	293	299	305
21		**Expenditure on assets**	15,545	14,762	17,377	16,798	19,168	15,024	17,085	17,922	17,286	18,767	17,989
22													
23	*plus*	Cost of financing	83	331	935	840	305	206	719	1,215	1,433	1,861	2,384
24	*less*	Value of capital contributions	1,468	1,052	1,073	1,095	1,102	1,124	1,038	1,038	1,038	1,038	1,038
25	*plus*	Value of vested assets	10	26	27	55	56	56	86	87	89	120	120
26													
27		**Capital expenditure forecast**	14,170	14,067	17,265	16,598	18,427	14,163	16,852	18,186	17,769	19,709	19,456
28													
29		Assets commissioned	13,750	8,031	14,220	30,085	18,199	11,360	11,152	14,584	12,769	10,993	10,310
30			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
31		for year ended	**31 Mar 16**	**31 Mar 17**	**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**
32			**$000 (in constant prices)**										
33		Consumer connection	1,570	1,480	1,482	1,482	1,468	1,468	1,468	1,468	1,468	1,468	1,468
34		System growth	3,040	3,574	5,025	5,063	4,791	1,273	931	5,734	4,057	3,296	841
35		Asset replacement and renewal	7,090	5,376	5,206	6,049	7,761	4,083	6,880	3,904	5,940	4,178	6,710
36		Asset relocations	-	-	-	-	-	-					
37		Reliability, safety and environment:											
38		Quality of supply	3,750	4,077	5,067	3,296	3,787	6,800	5,940	4,553	3,327	6,820	5,778
39		Legislative and regulatory	-	-	-	-	-	-					
40		Other reliability, safety and environment	-	-	-	-	-	-					
41		**Total reliability, safety and environment**	3,750	4,077	5,067	3,296	3,787	6,800	5,940	4,553	3,327	6,820	5,778
42		**Expenditure on network assets**	15,450	14,507	16,781	15,890	17,807	13,625	15,220	15,660	14,793	15,762	14,798
43		Expenditure on non-network assets	95	255	255	255	255	255	255	255	255	255	255
44		**Expenditure on assets**	15,545	14,762	17,036	16,145	18,062	13,880	15,475	15,915	15,048	16,017	15,053
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											

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sch ref												
50												
51		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
52	for year ended	**31 Mar 16**	**31 Mar 17**	**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**
53	**Difference between nominal and constant price forecasts**	**$000**										
54	Consumer connection	-	-	30	60	90	121	153	185	218	252	286
55	System growth	-	-	101	205	293	105	97	723	603	566	164
56	Asset replacement and renewal	-	-	104	244	475	337	716	493	883	717	1,309
57	Asset relocations	-	-	-	-	-	-	-	-	-	-	-
58	Reliability, safety and environment:											
59	Quality of supply	-	-	101	133	232	561	618	574	495	1,171	1,127
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	-	-	-	-	-	-	-	-	-	-
62	**Total reliability, safety and environment**	-	-	101	133	232	561	618	574	495	1,171	1,127
63	**Expenditure on network assets**	-	-	336	642	1,090	1,123	1,584	1,976	2,200	2,706	2,887
64	Expenditure on non-network assets	-	-	5	10	16	21	27	32	38	44	50
65	**Expenditure on assets**	-	-	341	652	1,106	1,144	1,611	2,008	2,237	2,750	2,937
66												

67		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
68	**11a(ii): Consumer Connection**						
69	*Consumer types defined by EDB**	**$000 (in constant prices)**					
70	All types	1,570	1,480	1,482	1,482	1,468	1,468
71							
72							
73							
74							
75	**include additional rows if needed*						
76	**Consumer connection expenditure**	1,570	1,480	1,482	1,482	1,468	1,468
77	*less* Capital contributions funding consumer connection	1,468	1,052	1,052	1,052	1,038	1,038
78	**Consumer connection less capital contributions**	102	427	430	430	430	430
79	**11a(iii): System Growth**						
80	Subtransmission	520	320	507	1,031	300	-
81	Zone substations	438	2,227	3,228	882	3,905	-
82	Distribution and LV lines	1,159	1,012	1,161	2,187	586	1,273
83	Distribution and LV cables	923	15	129	964	-	-
84	Distribution substations and transformers						
85	Distribution switchgear						
86	Other network assets						
87	**System growth expenditure**	3,040	3,574	5,025	5,063	4,791	1,273
88	*less* Capital contributions funding system growth						
89	**System growth less capital contributions**	3,040	3,574	5,025	5,063	4,791	1,273
90							

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sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
92		for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
93	**11a(iv): Asset Replacement and Renewal**		**$000 (in constant prices)**					
94	Subtransmission		1,730	1,557	1,715	1,180	1,120	812
95	Zone substations		2,981	1,304	502	1,919	3,464	190
96	Distribution and LV lines		1,297	836	1,262	1,422	1,491	986
97	Distribution and LV cables		168	140	140	167	409	451
98	Distribution substations and transformers		745	878	957	929	843	1,191
99	Distribution switchgear		169	661	632	431	433	453
100	Other network assets							
101	**Asset replacement and renewal expenditure**		7,090	5,376	5,206	6,049	7,761	4,083
102	*less* Capital contributions funding asset replacement and renewal							
103	**Asset replacement and renewal less capital contributions**		7,090	5,376	5,206	6,049	7,761	4,083
104								

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
106		for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
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
121		for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
122	**11a(vi):Quality of Supply**							
123	*Project or programme**		**$000 (in constant prices)**					
124	Wiroa-Kaitaia 110kV line - property rights		2,018	2,067	4,372	1,644		
125	Wiroa-Kaitaia 110kV Line - construction						1,936	4,578
	Zone substations		157	1,402	403	928	230	114
126	Distribution lines		326	290	292	382	794	2,109
127	Distribution cables			129	-	129	-	-
128	Distribution switchgear		326	90	-	213	-	-
129	**include additional rows if needed*							
130	All other projects or programmes - quality of supply		923	99		-	827	-
131	**Quality of supply expenditure**		3,750	4,077	5,067	3,296	3,787	6,800
132	*less* Capital contributions funding quality of supply							
133	**Quality of supply less capital contributions**		3,750	4,077	5,067	3,296	3,787	6,800
134								

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sch ref

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
136	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
137	**11a(vii): Legislative and Regulatory**						
138	*Project or programme**	**$000 (in constant prices)**					
139							
140							
141							
142							
143							
144	**include additional rows if needed*						
145	All other projects or programmes - legislative and regulatory						
146	**Legislative and regulatory expenditure**	-	-	-	-	-	-
147	*less* Capital contributions funding legislative and regulatory						
148	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
149							
150		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
151	**11a(viii): Other Reliability, Safety and Environment**						
152	*Project or programme**	**$000 (in constant prices)**					
153							
154							
155							
156							
157							
158	**include additional rows if needed*						
159	All other projects or programmes - other reliability, safety and environment						
160	**Other reliability, safety and environment expenditure**	-	-	-	-	-	-
161	*less* Capital contributions funding other reliability, safety and environment						
162	**Other reliability, safety and environment less capital contributions**	-	-	-	-	-	-
163							
164		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
165	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme**	**$000 (in constant prices)**					
169							
170							
171							
172							
173							
174	**include additional rows if needed*						
175	All other projects or programmes - routine expenditure	95	255	255	255	255	255
176	**Routine expenditure**	95	255	255	255	255	255
177	**Atypical expenditure**						
178	*Project or programme**						
179							
180							
181							
182							
183							
184	**include additional rows if needed*						
185	All other projects or programmes - atypical expenditure						
186	**Atypical expenditure**	-	-	-	-	-	-
187							
188	**Expenditure on non-network assets**	95	255	255	255	255	255

Company Name	**Top Energy**
AMP Planning Period	**1 April 2016 – 31 March 2026**

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 16**	**31 Mar 17**	**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**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,370	1,200	1,224	1,248	1,273	1,299	1,325	1,351	1,378	1,406	1,434
11	Vegetation management	2,110	1,833	1,870	1,907	1,945	1,984	2,024	2,064	2,106	2,148	2,191
12	Routine and corrective maintenance and inspection	1,750	1,765	1,800	1,836	1,873	1,910	1,949	1,988	2,027	2,068	2,109
13	Asset replacement and renewal	730	939	958	977	996	1,016	1,037	1,057	1,079	1,100	1,122
14	**Network Opex**	5,960	5,737	5,852	5,969	6,088	6,210	6,334	6,461	6,590	6,722	6,856
15	System operations and network support	4,094	4,508	4,859	5,080	5,311	5,553	5,805	6,070	6,346	6,635	6,938
16	Business support	3,216	3,378	3,515	3,657	3,804	3,958	4,118	4,285	4,458	4,637	4,826
17	**Non-network opex**	7,310	7,886	8,374	8,737	9,116	9,511	9,923	10,355	10,805	11,273	11,763
18	**Operational expenditure**	13,270	13,623	14,226	14,706	15,204	15,721	16,258	16,816	17,395	17,994	18,620

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 16**	**31 Mar 17**	**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**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,370	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
23	Vegetation management	2,110	1,833	1,833	1,835	1,837	1,839	1,841	1,843	1,845	1,847	1,849
24	Routine and corrective maintenance and inspection	1,750	1,765	1,765	1,774	1,783	1,792	1,801	1,810	1,819	1,828	1,837
25	Asset replacement and renewal	730	939	939	928	857	862	867	872	877	882	887
26	**Network Opex**	5,960	5,737	5,737	5,737	5,677	5,693	5,709	5,725	5,741	5,757	5,773
27	System operations and network support	4,094	4,508	4,764	4,883	5,005	5,130	5,258	5,390	5,525	5,663	5,805
28	Business support	3,216	3,378	3,446	3,515	3,585	3,657	3,730	3,805	3,881	3,958	4,038
29	**Non-network opex**	7,310	7,886	8,210	8,398	8,590	8,787	8,988	9,195	9,406	9,621	9,843
30	**Operational expenditure**	13,270	13,623	13,947	14,135	14,267	14,480	14,697	14,920	15,147	15,378	15,616
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	169	202	250	255	260	265	270	276	281	287	292

37 ** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 16**	**31 Mar 17**	**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**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	24	48	73	99	125	151	178	206	234
43	Vegetation management	-	-	37	72	108	145	183	221	261	301	342
44	Routine and corrective maintenance and inspection	-	-	35	62	90	118	148	178	208	240	272
45	Asset replacement and renewal	-	-	19	49	139	154	170	185	202	218	235
46	**Network Opex**	-	-	115	232	411	517	625	736	849	965	1,083
47	System operations and network support	-	-	95	197	306	423	547	680	821	972	1,133
48	Business support	-	-	69	142	219	301	388	480	577	679	788
49	**Non-network opex**	-	-	164	339	526	724	935	1,160	1,399	1,652	1,920
50	**Operational expenditure**	-	-	279	571	937	1,241	1,561	1,896	2,248	2,616	3,004

Company Name	**Top Energy**
AMP Planning Period	**1 April 2016 – 31 March 2026**

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref					Asset condition at start of planning period (percentage of units by grade)						
7											
8											
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
10	All	Overhead Line	Concrete poles / steel structure	No.	0.35%	0.97%	91.24%	7.44%	-	3	1.00%
11	All	Overhead Line	Wood poles	No.	0.51%	20.15%	73.91%	5.42%	-	3	4.00%
12	All	Overhead Line	Other pole types	No.	-	-	-	100.00%	-	4	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	89.04%	10.96%	-	2	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	100.00%	-	-	2	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	2.74%	97.27%	-	3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	NA	NA	NA	NA	NA	N/A	NA
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	NA	NA	NA	NA	NA	N/A	NA
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	NA	NA	NA	NA	NA	N/A	NA
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	NA	NA	NA	NA	NA	N/A	NA
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	NA	NA	NA	NA	NA	N/A	NA
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	NA	NA	NA	NA	NA	N/A	NA
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	NA	NA	NA	NA	NA	N/A	NA
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	NA	NA	NA	NA	NA	N/A	NA
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	80.00%	20.00%	-	4	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	100.00%	-	-	4	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	5.56%	94.44%	-	4	5.56%
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	8.16%	28.57%	63.27%	-	3	8.16%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	NA	NA	NA	NA	NA	N/A	NA
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	4.62%	21.54%	39.23%	34.62%	-	3	5.00%
30	HV	Zone substation switchgear	33kV RMU	No.	NA	NA	NA	NA	NA	N/A	NA
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	NA	NA	NA	NA	NA	N/A	NA
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	10.00%	60.00%	30.00%	-	4	10.00%
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	13.33%	-	68.34%	18.33%	-	3	13.33%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	3.70%	70.37%	25.93%	-	3	45.00%
35											

Company Name	**Top Energy**
AMP Planning Period	**1 April 2016 – 31 March 2026**

SCHEDULE 12a: REPORT ON ASSET CONDITION

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

sch ref											
36					**Asset condition at start of planning period (percentage of units by grade)**						
37											
38	**Voltage**	**Asset category**	**Asset class**	**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	10.53%	5.26%	57.89%	26.32%	-	4	15.79%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2.24%	1.97%	91.58%	4.21%	-	2	1.00%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	NA	NA	NA	NA	NA	N/A	NA
42	HV	Distribution Line	SWER conductor	km	17.23%	7.51%	71.45%	3.81%	-	2	2.00%
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	77.81%	22.19%	-	2	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	99.22%	0.78%	-	2	-
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	83.33%	16.67%	-	2	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	4.44%	0.28%	67.50%	27.78%	-	3	5.00%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	NA	NA	NA	NA	NA	N/A	NA
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	9.81%	6.17%	65.26%	18.76%	-	3	15.00%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	NA	NA	NA	NA	-	N/A	NA
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	0.33%	71.10%	28.57%	-	3	5.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	8.32%	2.68%	73.99%	15.01%	-	3	10.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.37%	0.49%	85.21%	13.94%	-	3	10.00%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	58.33%	41.67%	-	3	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	100.00%	-	-	3	-
55	LV	LV Line	LV OH Conductor	km	1.42%	2.60%	93.79%	2.20%	-	2	-
56	LV	LV Cable	LV UG Cable	km	0.78%	4.79%	90.85%	3.58%	-	2	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	0.21%	97.70%	2.09%	-	2	-
58	LV	Connections	OH/UG consumer service connections	No.	-	-	-	-	-	2	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	-	-	-	-	3	-
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	100.00%	-	-	3	-
61	All	Capacitor Banks	Capacitors including controls	No.	-	20.00%	80.00%	-	-	3	-
62	All	Load Control	Centralised plant	Lot	-	-	100.00%	-	-	4	-
63	All	Load Control	Relays	No.	-	-	100.00%	-	-	4	-
64	All	Civils	Cable Tunnels	km	NA	NA	NA	NA	NA	N/A	NA

Company Name	**Top Energy**
AMP Planning Period	**1 April 2016 – 31 March 2026**

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	5	5	N-1	3	99%	7	84%	No constraint within +5 years	
11	Moerewa	4	5	N-1	2	82%	5	200%	No constraint within +5 years	
12	Waipapa	11	23	N-1	6	46%	23	27%	No constraint within +5 years	
13	Omanaia	2	-	N-0	-	-	-	-	Transformer	Mobile transformer available. There is also a single incoming subtransmission circuit
14	Haruru	6	23	N-1	1	25%	23	27%	No constraint within +5 years	
15	Mt Pokaka	2	-	N-0	1	-	-	-	Transformer	Mobile transformer available.
16	Kerikeri	7	23	N-1	6	29%	23	32%	No constraint within +5 years	
17	Kaeo	-	-	N-1		-	9	61%	Subtransmission circuit	There will be only one incoming subtransmission circuit until the souther section of the 110kV line is completed, expected to be in FYE2022.
18	Okahu Rd	9	12	N-1	4	74%	12	78%	No constraint within +5 years	
19	Taipa	5		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	54%	23	54%	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	46	30	N-1	25	154%	30	164%	Transformer	Transfer capacity is Ngawha generation, which is connected to the 33kV subtransmission network and which is normally in operation.
23	Kaitaia 110kV	26	25	N-1	4	102%	40	65%	Subtransmission circuit	Transfer capacity is Taipa generation. Firm capacity limited by single incoming 110kV circuit.
24						-			[Select one]	
25						-			[Select one]	
26						-			[Select one]	
27						-			[Select one]	
28						-			[Select one]	

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 2016 – 31 March 2026**

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 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
11	*Consumer types defined by EDB**							
12	[EDB consumer type]		255	255	255	255	255	255
13	[EDB consumer type]		5	5	5	5	5	5
14	[EDB consumer type]							
15	[EDB consumer type]							
16	[EDB consumer type]							
17	**Connections total**		260	260	260	260	260	260
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 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
25	GXP demand		43	43	44	45	45	46
26	*plus* Distributed generation output at HV and above		25	25	25	25	25	25
27	**Maximum coincident system demand**		68	68	69	70	70	71
28	*less* Net transfers to (from) other EDBs at HV and above							
29	**Demand on system for supply to consumers' connection points**		68	68	69	70	70	71
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		175	179	183	186	190	194
32	*less* Electricity exports to GXPs		15	15	15	15	15	15
33	*plus* Electricity supplied from distributed generation		200	200	200	200	200	200
34	*less* Net electricity supplied to (from) other EDBs							
35	**Electricity entering system for supply to ICPs**		360	364	368	371	375	379
36	*less* Total energy delivered to ICPs		325	330	333	337	340	343
37	**Losses**		35	34	34	34	35	35
38								
39	**Load factor**		61%	61%	61%	61%	61%	61%
40	**Loss ratio**		9.7%	9.3%	9.3%	9.3%	9.3%	9.3%

Company Name	**Top Energy**
AMP Planning Period	**1 April 2016 – 31 March 2026**
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							
8		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	190.0	200.0	200.0	200.0	200.0	200.0
12	Class C (unplanned interruptions on the network)	360.0	250.0	245.0	230.0	225.0	220.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	1.33	1.50	1.50	1.50	1.50	1.50
15	Class C (unplanned interruptions on the network)	4.95	3.85	3.75	3.65	3.55	3.45

Company Name	**Top Energy**
AMP Planning Period	**1 April 2016 – 31 March 2026**
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 in the process of implementing a network development programme that is focused on improvement in reliability over time. This is guiding our investment in the creation of new assets. We also have a formal 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 still need 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).

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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

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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.

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

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	3	Our 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 five years is documented in our AMP (see Section 5.11.2) 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 completed an internal reorganisation at the beginning of FYE2015, which 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.

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Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
37	Structure, authority and responsibilities	What has the organisation done to appoint member(s) of its management team to be responsible for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s)?	Top management has not considered the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management understands the need to appoint a person or persons to ensure that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s).	Top management has appointed an appropriate people to ensure the assets deliver the requirements of the asset management strategy, objectives and plan(s) but their areas of responsibility are not fully defined and/or they have insufficient delegated authority to fully execute their responsibilities.	The appointed person or persons have full responsibility for ensuring that the organisation's assets deliver the requirements of the asset management strategy, objectives and plan(s). They have been given the necessary authority to achieve this.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
40	Structure, authority and responsibilities	What evidence can the organisation's top management provide to demonstrate that sufficient resources are available for asset management?	The organisation's top management has not considered the resources required to deliver asset management.	The organisations top management understands the need for sufficient resources but there are no effective mechanisms in place to ensure this is the case.	A process exists for determining what resources are required for its asset management activities and in most cases these are available but in some instances resources remain insufficient.	An effective process exists for determining the resources needed for asset management and sufficient resources are available. It can be demonstrated that resources are matched to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
42	Structure, authority and responsibilities	To what degree does the organisation's top management communicate the importance of meeting its asset management requirements?	The organisation's top management has not considered the need to communicate the importance of meeting asset management requirements.	The organisations top management understands the need to communicate the importance of meeting its asset management requirements but does not do so.	Top management communicates the importance of meeting its asset management requirements but only to parts of the organisation.	Top management communicates the importance of meeting its asset management requirements to all relevant parts of the organisation.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
45	Outsourcing of asset management activities	Where the organisation has outsourced some of its asset management activities, how has it ensured that appropriate controls are in place to ensure the compliant delivery of its organisational strategic plan, and its asset management policy and strategy?	The organisation has not considered the need to put controls in place.	The organisation controls its outsourced activities on an ad-hoc basis, with little regard for ensuring for the compliant delivery of the organisational strategic plan and/or its asset management policy and strategy.	Controls systematically considered but currently only provide for the compliant delivery of some, but not all, aspects of the organisational strategic plan and/or its asset management policy and strategy. Gaps exist.	Evidence exists to demonstrate that outsourced activities are appropriately controlled to provide for the compliant delivery of the organisational strategic plan, asset management policy and strategy, and that these controls are integrated into the asset management system	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	3	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.

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Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
48	Training, awareness and competence	How does the organisation develop plan(s) for the human resources required to undertake asset management activities - including the development and delivery of asset management strategy, process(es), objectives and plan(s)?	The organisation has not recognised the need for assessing human resources requirements to develop and implement its asset management system.	The organisation has recognised the need to assess its human resources requirements and to develop a plan(s). There is limited recognition of the need to align these with the development and implementation of its asset management system.	The organisation has developed a strategic approach to aligning competencies and human resources to the asset management system including the asset management plan but the work is incomplete or has not been consistently implemented.	The organisation can demonstrate that plan(s) are in place and effective in matching competencies and capabilities to the asset management system including the plan for both internal and contracted activities. Plans are reviewed integral to asset management system process(es).	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
49	Training, awareness and competence	How does the organisation identify competency requirements and then plan, provide and record the training necessary to achieve the competencies?	The organisation does not have any means in place to identify competency requirements.	The organisation has recognised the need to identify competency requirements and then plan, provide and record the training necessary to achieve the competencies.	The organisation is the process of identifying competency requirements aligned to the asset management plan(s) and then plan, provide and record appropriate training. It is incomplete or inconsistently applied.	Competency requirements are in place and aligned with asset management plan(s). Plans are in place and effective in providing the training necessary to achieve the competencies. A structured means of recording the competencies achieved is in place.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
50	Training, awareness and competence	How does the organization ensure that persons under its direct control undertaking asset management related activities have an appropriate level of competence in terms of education, training or experience?	The organization has not recognised the need to assess the competence of person(s) undertaking asset management related activities.	Competency of staff undertaking asset management related activities is not managed or assessed in a structured way, other than formal requirements for legal compliance and safety management.	The organization is in the process of putting in place a means for assessing the competence of person(s) involved in asset management activities including contractors. There are gaps and inconsistencies.	Competency requirements are identified and assessed for all persons carrying out asset management related activities - internal and contracted. Requirements are reviewed and staff reassessed at appropriate intervals aligned to asset management requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
53	Communication, participation and consultation	How does the organisation ensure that pertinent asset management information is effectively communicated to and from employees and other stakeholders, including contracted service providers?	3	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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

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

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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 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 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 processes.		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

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
64	Information management	How has the organisation's ensured its asset management information system is relevant to its needs?	The organisation has not considered the need to determine the relevance of its management information system. At present there are major gaps between what the information system provides and the organisations needs.	The organisation understands the need to ensure its asset management information system is relevant to its needs and is determining an appropriate means by which it will achieve this. At present there are significant gaps between what the information system provides and the organisations needs.	The organisation has developed and is implementing a process to ensure its asset management information system is relevant to its needs. Gaps between what the information system provides and the organisations needs have been identified and action is being taken to close them.	The organisation's asset management information system aligns with its asset management requirements. Users can confirm that it is relevant to their needs.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
69	Risk management process(es)	How has the organisation documented process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle?	The organisation has not considered the need to document process(es) and/or procedure(s) for the identification and assessment of asset and asset management related risks throughout the asset life cycle.	The organisation is aware of the need to document the management of asset related risk across the asset lifecycle. The organisation has plan(s) to formally document all relevant process(es) and procedure(s) or has already commenced this activity.	The organisation is in the process of documenting the identification and assessment of asset related risk across the asset lifecycle but it is incomplete or there are inconsistencies between approaches and a lack of integration.	Identification and assessment of asset related risk across the asset lifecycle is fully documented. The organisation can demonstrate that appropriate documented mechanisms are integrated across life cycle phases and are being consistently applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
79	Use and maintenance of asset risk information	How does the organisation ensure that the results of risk assessments provide input into the identification of adequate resources and training and competency needs?	The organisation has not considered the need to conduct risk assessments.	The organisation is aware of the need to consider the results of risk assessments and effects of risk control measures to provide input into reviews of resources, training and competency needs. Current input is typically ad-hoc and reactive.	The organisation is in the process ensuring that outputs of risk assessment are included in developing requirements for resources and training. The implementation is incomplete and there are gaps and inconsistencies.	Outputs from risk assessments are consistently and systematically used as inputs to develop resources, training and competency requirements. Examples and evidence is available.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
82	Legal and other requirements	What procedure does the organisation have to identify and provide access to its legal, regulatory, statutory and other asset management requirements, and how is requirements incorporated into the asset management system?	The organisation has not considered the need to identify its legal, regulatory, statutory and other asset management requirements.	The organisation identifies some its legal, regulatory, statutory and other asset management requirements, but this is done in an ad-hoc manner in the absence of a procedure.	The organisation has procedure(s) to identify its legal, regulatory, statutory and other asset management requirements, but the information is not kept up to date, inadequate or inconsistently managed.	Evidence exists to demonstrate that the organisation's legal, regulatory, statutory and other asset management requirements are identified and kept up to date. Systematic mechanisms for identifying relevant legal and statutory requirements.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	3	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 appropriate.	Process(es) and procedure(s) for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances. Documentation of assigned responsibilities and authority to employees. Job Descriptions, Audit reports. Common communication systems i.e. all Job Descriptions on Internet etc.

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Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
88	Life Cycle Activities	How does the organisation establish implement and maintain process(es) for the implementation of its asset management plan(s) and control of activities across the creation, acquisition or enhancement of assets. This includes design, modification, procurement, construction and commissioning activities?	The organisation does not have process(es) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning but currently do not have these in place (note: procedure(s) may exist but they are inconsistent/incomplete).	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning. Gaps and inconsistencies are being addressed.	Effective process(es) and procedure(s) are in place to manage and control the implementation of asset management plan(s) during activities related to asset creation including design, modification, procurement, construction and commissioning.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
91	Life Cycle Activities	How does the organisation ensure that process(es) and/or procedure(s) for the implementation of asset management plan(s) and control of activities during maintenance (and inspection) of assets are sufficient to ensure activities are carried out under specified conditions, are consistent with asset management strategy and control cost, risk and performance?	The organisation does not have process(es)/procedure(s) in place to control or manage the implementation of asset management plan(s) during this life cycle phase.	The organisation is aware of the need to have process(es) and procedure(s) in place to manage and control the implementation of asset management plan(s) during this life cycle phase but currently do not have these in place and/or there is no mechanism for confirming they are effective and where needed modifying them.	The organisation is in the process of putting in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process for confirming the process(es)/procedure(s) are effective and if necessary carrying out modifications.	The organisation has in place process(es) and procedure(s) to manage and control the implementation of asset management plan(s) during this life cycle phase. They include a process, which is itself regularly reviewed to ensure it is effective, for confirming the process(es)/ procedure(s) are effective and if necessary carrying out modifications.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
95	Performance and condition monitoring	How does the organisation measure the performance and condition of its assets?	The organisation has not considered how to monitor the performance and condition of its assets.	The organisation recognises the need for monitoring asset performance but has not developed a coherent approach. Measures are incomplete, predominantly reactive and lagging. There is no linkage to asset management objectives.	The organisation is developing coherent asset performance monitoring linked to asset management objectives. Reactive and proactive measures are in place. Use is being made of leading indicators and analysis. Gaps and inconsistencies remain.	Consistent asset performance monitoring linked to asset management objectives is in place and universally used including reactive and proactive measures. Data quality management and review process are appropriate. Evidence of leading indicators and analysis.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
99	Investigation of asset-related failures, incidents and nonconformities	How does the organisation ensure responsibility and the authority for the handling, investigation and mitigation of asset-related failures, incidents and emergency situations and non conformances is clear, unambiguous, understood and communicated?	The organisation has not considered the need to define the appropriate responsibilities and the authorities.	The organisation understands the requirements and is in the process of determining how to define them.	The organisation are in the process of defining the responsibilities and authorities with evidence. Alternatively there are some gaps or inconsistencies in the identified responsibilities/authorities.	The organisation have defined the appropriate responsibilities and authorities and evidence is available to show that these are applied across the business and kept up to date.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Score	Evidence—Summary	User Guidance	Why	Who	Record/documented Information
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	2	Our ISO 9001 quality system and our 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 Networks 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 Public Safety Management System and or ISO 9001 Quality System are evidence of this. Within networks we are becoming increasingly engaged with the wider asset management community, particularly as it relates to the electricity distribution sector. While we still have some way to go in the implementation of an asset management system that fully meets PAS 55 requirements, the progress we have made since our last AMMAT assessment has been significant.		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.

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SCHEDULE 13: REPORT ON ASSET MANAGEMENT MATURITY (cont)

Question No.	Function	Question	Maturity Level 0	Maturity Level 1	Maturity Level 2	Maturity Level 3	Maturity Level 4
105	Audit	What has the organisation done to establish procedure(s) for the audit of its asset management system (process(es))?	The organisation has not recognised the need to establish procedure(s) for the audit of its asset management system.	The organisation understands the need for audit procedure(s) and is determining the appropriate scope, frequency and methodology(s).	The organisation is establishing its audit procedure(s) but they do not yet cover all the appropriate asset-related activities.	The organisation can demonstrate that its audit procedure(s) cover all the appropriate asset-related activities and the associated reporting of audit results. Audits are to an appropriate level of detail and consistently managed.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
109	Corrective & Preventative action	How does the organisation instigate appropriate corrective and/or preventive actions to eliminate or prevent the causes of identified poor performance and non conformance?	The organisation does not recognise the need to have systematic approaches to instigating corrective or preventive actions.	The organisation recognises the need to have systematic approaches to instigating corrective or preventive actions. There is ad-hoc implementation for corrective actions to address failures of assets but not the asset management system.	The need is recognized for systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit. It is only partially or inconsistently in place.	Mechanisms are consistently in place and effective for the systematic instigation of preventive and corrective actions to address root causes of non compliance or incidents identified by investigations, compliance evaluation or audit.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.
113	Continual Improvement	How does the organisation achieve continual improvement in the optimal combination of costs, asset related risks and the performance and condition of assets and asset systems across the whole life cycle?	The organisation does not consider continual improvement of these factors to be a requirement, or has not considered the issue.	A Continual Improvement ethos is recognised as beneficial, however it has just been started, and or covers partially the asset drivers.	Continuous improvement process(es) are set out and include consideration of cost risk, performance and condition for assets managed across the whole life cycle but it is not yet being systematically applied.	There is evidence to show that continuous improvement process(es) which include consideration of cost risk, performance and condition for assets managed across the whole life cycle are being systematically applied.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

115	Continual Improvement	How does the organisation seek and acquire knowledge about new asset management related technology and practices, and evaluate their potential benefit to the organisation?	The organisation makes no attempt to seek knowledge about new asset management related technology or practices.	The organisation is inward looking, however it recognises that asset management is not sector specific and other sectors have developed good practice and new ideas that could apply. Ad-hoc approach.	The organisation has initiated asset management communication within sector to share and, or identify 'new' to sector asset management practices and seeks to evaluate them.	The organisation actively engages internally and externally with other asset management practitioners, professional bodies and relevant conferences. Actively investigates and evaluates new practices and evolves its asset management activities using appropriate developments.	The organisation's process(es) surpass the standard required to comply with requirements set out in a recognised standard. The assessor is advised to note in the Evidence section why this is the case and the evidence seen.

Company Name	Top Energy Ltd
For Year Ended	31 March 2017

Schedule 14a Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012)

1. This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.5.

2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

3. In the box below, comment on the difference between nominal and constant price capital expenditure for the disclosure year, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

We have derived the nominal capital expenditure forecast by escalating the constant price forecast by 2% per annum after FYE2017. While this is higher than the current inflation rate, it is appropriate for a long term forecast as it is the mid-point of the Reserve Bank's 1-3% inflation target. In our view, there is little point in deriving a more accurate estimate of inflationary cost increases, given the high level of uncertainty in the other paramaters and assumptions on which our forecast is based.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the disclosure year, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

We have derived the nominal operational expenditure forecast by escalating the constant price forecast by 2% per annum after FYE2017. While this is higher than the current inflation rate, it is appropriate for a long term forecast as it is the mid-point of the Reserve Bank's 1-3% inflation target. In our view, there is little point in deriving a more accurate estimate of inflationary cost increases, given the high level of uncertainty in the other paramaters and assumptions on which our forecast is based.

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	The event could occur at some time	The event is not uncommon.	Likely to occur despite best efforts.	Likely to occur several times.
Occur less than once in 20 years	Occur once every 10 years	Occur once every 5 years	Occur once a year	Occur more than once per year

Table C.1: Assessment of risk probability

CONSEQUENCE	HEALTH & SAFETY	FINANCIAL IMPACT	ENVIRONMENTAL IMPACT	PUBLIC IMAGE REPUTATION	BUSINESS INTERRUPTION	REGULATORY
Catastrophic	Multiple fatalities Serious long-term health impact on public	Financial costs or exposure exceeds $75M (DCF basis) Shareholder flight	An incident that causes significant, extensive or long-term (5 years or more) ecological harm .	Continuing long-term damage to company reputation. International or government Investigation. Long-term impact on public memory.	Total service cessation for a week or more	Jail term of any length or fine exceeding $100,000.
Major	Single fatality and or multiple serious injuries	Financial cost or exposure exceeds $10M (DCF basis). Share value stagnation, shareholder dissatisfaction.	An incident which causes significant, but confined, ecological harm over 1-5 years.	Local TV news headlines and/or regulator investigation. Medium-term impact on public memory.	Cessation of service to Northern or Southern areas for a number of days	Prosecution of Director or employee
Moderate	Individual serious injury or multiple/recurring minor injuries	Loss or increased costs from $1M to $10M (DCF basis).	Significant release of pollutants with mid-term recovery	Local press attention and or low profile regulator investigation	Cessation of service for over 10% of consumer base for more than a week	Prosecution of business or prohibition notice.
Minor	First aid injuries only	Loss or increased costs from $50k to $1M (DCF basis)	Transient environmental harm	Limited local press attention	Cessation of service for more than a week	Improvement notice.
Insignificant	No requirement for treatment	Loss or increased costs less than $50,000 (DCF basis).	An incident which causes minor ecological impacts that can be repaired quickly through natural processes.	No impact on public memory	Cessation of service for more than a 24hrs	Regulator expresses verbal or written concern.

Table C2: Assessment of risk consequence

	INSIGNIFICANT 1	MINOR 2	MODERATE 3	MAJOR 4	CATASTROPHIC 5
Almost certain 1	High	High	Extreme	Extreme	Extreme
Likely 2	Moderate	High	High	Extreme	Extreme
Possible 3	Low	Moderate	High	Extreme	Extreme
Unlikely 4	Low	Low	Moderate	High	Extreme
Rare 5	Low	Low	Moderate	High	High

Table C.3: Assessment of risk severity

Extreme	Extreme Risk - Should be brought to the attention of Directors and continuously monitored
High	High Risk – Requires the attention of the CEO and General Managers
Moderate	Moderate Risk – appropriately monitored by middle management
Low	Low Risk – Monitored at a supervisory level

Table C.4: Risk management accountability

9.4 Appendix D – Cross References to Information Disclosure Requirements

The table below cross references the requirements of Attachment A of the Commerce Commission's Electricity Distribution Information Disclosure 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, 2.3	
Purpose Statement			
3.3	The AMP must include a purpose statement that		
3.3.1	Makes the status of the AMP clear.	2.2	
3.3.2	States the corporate mission or vision as it relates to asset management	2.3, 2.5	
3.3.3	Identifies the documented plans produced as outputs of the annual business planning process	2.6	
3.3.4	States how the different documented plans relate to one another with specific reference to any plans specifically dealing with asset management	2.6	
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 2.6	
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.	2.6.1	
3.5	The AMP must state the date on which the AMP was approved by the Board of Directors.	2.6.1	
Stakeholder Interests			
3.6	The AMP must identify the EDB's important stakeholders and indicate	2.6.3	
3.6.1	- how the interests of stakeholders are identified;	2.6.2	

Handbook Reference	Requirement	AMP Ref	Comment
Iii	- what these interests are;	2.6.3	
iv	- how these interests are accommodated in the EDB's asset management practices: and	2.6.3	
v	- how conflicting interests are managed.	2.6.2	
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.	2.6.4	
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.	2.6.4	
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.	2.6.4	
Significant Assumptions and Uncertainties			
3.8	The AMP must identify significant assumptions, which must: :	2.10	
3.8.1	Be quantified where possible.	2.10	
3.8.2	Be clearly identified in a manner that makes their significance understandable to interested persons including:	2.10	
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.	2.10	
3.8.5	Include the price inflator assumptions used to prepare the information in Schedules 11a and 11b.	2.10 (final row)	
3.9	Include a description of the uncertainties that may lead to changes in future disclosures.	2.10	
Asset Management Strategy and Delivery			

Handbook Reference	Requirement	AMP Ref	Comment
3.10	To support the AMMAT disclosure, the AMP must include an overview of asset management strategy and delivery.	2.11	
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	2.8, 2.12	
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.	2.8, 2.12	
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;	2.9.1	
3.13.2	- Planning and implementing network development projects; and	2.9.2	
3.13.3	- Measuring network performance.	2.9.3	
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.	2.13	
Communication and Participation Processes			
3.15	To support the AMMAT disclosure, the AMP must include an overview of communication and participation processes.	2.14	
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	

Handbook Reference	Requirement	AMP Ref	Comment
4.1.4	- the peak demand and total electricity delivered in the previous year, broken down by geographically non-contiguous network, if any.	2.1 Table 2.1	
4.2	Description of the Network Configuration		
4.2.1	The AMP must include a description of the network configuration which includes: - identification of the bulk electricity supply points and any embedded generation with a capacity greater than 1 MW;	3.1.3	
4.2.1	- the existing firm supply capacity and current peak load at each bulk supply point;	3.1.4	
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		

Handbook Reference	Requirement	AMP Ref	Comment
	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	
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			

Handbook Reference	Requirement	AMP Ref	Comment
6.	Performance indicators for which targets are defined must include SAIDI and SAIFI values for the next 5 disclosure years.	4.2.1	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		
7.1	- Consumer orientated service targets that preferably differentiate between different consumer types	4.2.1	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 5.2	
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.	5.1.5	
11.5	The AMP must include a description of the strategies or processes (if any) that promote the energy efficient operation of the network.	5.3	
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.	5.1.5	

Handbook Reference	Requirement	AMP Ref	Comment
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.	5.5	
11.8	Demand Forecasts		
11.8.1	The AMP must describe the demand forecasting methodology, including all the factors used in preparing the estimates.	5.6	
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.	5.7.1	
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.	5.7.2	
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	5.10.1	
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.	5.8 5.9	
	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:	5.10	
11.9.1	- the reasons for choosing a selected option for projects where decisions hae been made;	5.10.3	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;		

Handbook Reference	Requirement	AMP Ref	Comment
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;	5.10.2 5.11	
11.10.2	- a summary description of the programmes and projects planned for the next four years (where known); and	5.10.3	
11.10.3	- an overview of the material projects being considered for the remainder of the AMP planning period.	5.12	
11.11	The AMP must include a description of the EDB's policies on distributed generation, including the policies for connecting distributed generation. The impact of such generation on network development plans must also be stated.	5.8	
11.12	The AMP must include a description of the EDB's policies on non-network solutions including:	5.9	
11.12.1	- economically feasible and practical alternatives to conventional network augmentation. These are typically approaches that would reduce network demand and/or improve asset utilisation;		
11.12.2	- the potential for non-network solutions to address network problems or constraints.		
Lifecycle Asset Management Planning (Maintenance and Renewal)			
12	The AMP must provide a detailed description of the lifecycle asset management processes, including:		
12.1	The key drivers for maintenance planning and assumptions.	6.1	

Handbook Reference	Requirement	AMP Ref	Comment
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;		
12.2.3	- budgets for maintenance activities broken down be asset category for the AMP planning period	6.23	
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:	6.1.1 6.1.3 6.24 5.10-5.12	
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.	6.2-6.22	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;	5.11 6.24	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	

Handbook Reference	Requirement	AMP Ref	Comment
13.2	development, maintenance and renewal policies that cover them;	6.25	We do not consider our expenditure on non-network assets to be material.
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	
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;	8.2.3	
15.2	- an evaluation and comparison of actual service level performance against targeted performance;	8.2.2	
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	8.3	Additional information is provided in the following sections: 2.11 2.12 2.13 2.14.

Handbook Reference	Requirement	AMP Ref	Comment
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;	2.15	
16.2	- the organisation structure and the processes for organisation and business capabilities will support the implementation of the AMP plans.	2.15	

9.5 Appendix E – Certification for Year Beginning Disclosures

TOP ENERGY®
TePuna Hihiko

Certification for Year-beginning Disclosures

Pursuant to Schedule 17

Clause 2.9.1 of section 2.9

Electricity Distribution Information Disclosure Determination 2012

We, Paul Anthony Byrnes 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.

P A Byrnes

G M Steed

29 March 2016

Top Energy Limited
Level 2, John Butler Centre
60 Kerikeri Road
Kerikeri
PO Box 43 Kerikeri 0245
New Zealand